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Project Title:	Alamitos Energy Center - Compliance
TN #:	232866
Document Title:	Title V Permit Engineering Evaluation
Description:	Engineering Evaluation in Support of Revised Title V Permit
Filer:	Jeff Miller
Organization:	AES
Submitter Role:	Applicant
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AES Alamitos Energy Center
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April 29, 2020

Mr. Joseph Douglas
Compliance Project Manager
California Energy Commission
1516 9th Street
Sacramento, CA 95814

Subject: Alamitos Energy Center (13-AFC-01C)
Condition of Certification AQ-SC6 SCAQMD Engineering Evaluation in Support of Title V Permit Revision

Dear Mr. Douglas,

Attached is the Engineering Evaluation conducted by the SCAQMD in support of the recent Title V Permit Revision.

Please let me know if you have any questions.

Sincerely,

Jeff Miller
Compliance Manager
AES Alamitos Energy Center

CC: Stephen O'Kane/AES
Ron Rodrique/AES

AES ALAMITOS, LLC
690 N. STUDEBAKER RD
LONG BEACH, CA 90803-2221

FACILITY ID: 115394

EQUIPMENT LOCATION: 690 N. Studebaker Rd
Long Beach, CA 90803-2221

Contact: Stephen O'Kane, Manager, Sustainability and Regulatory Compliance

COMBINED- AND SIMPLE-CYCLE TURBINE OPERATING SCHEDULES CHANGES & MISCELLANEOUS UPDATES TO PERMITS TO CONSTRUCT

EQUIPMENT DESCRIPTION
SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

Note: *The applications submitted for the Auxiliary Boiler, Auxiliary Boiler SCR, and Title V/RECLAIM Revision (A/N 604014, 613323, and 604013) were evaluated in a separate evaluation because the auxiliary boiler will be started up prior to the turbines. After expedited EPA review, the permits were issued on 7/10/19.*

*The applications submitted for the two Combined-Cycle Turbines, four Simple-Cycle Turbines, two SCR/CO Catalysts for the Combined-Cycle Turbines, and Storage Tank-1 (aqueous ammonia for combined-cycle turbines) (A/N 604015, 604018, 604020, 608431-608433, 610354-610360) (**"Application"**) will be evaluated in this evaluation.* Although the condition changes for the Auxiliary Boiler and SCR were evaluated in a separate evaluation, the boiler will be included in this evaluation for the facility-wide modeling and health risk assessment in support of the CEC's analysis of the *Petition for Post-Certification Amendment*.

*Applications were **not** submitted for the four SCR/CO Catalysts for the Simple-Cycle Turbines, Storage Tank-2 (aqueous ammonia for simple-cycle turbines), and two Oil/Water separators.* However, this equipment is included in the equipment descriptions below (smaller font) and in this evaluation as applicable to provide context.

The changes to the facility permit shown below are to the facility permit that was issued for the Permits to Construct on 4/18/17.

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
PROCESS 4: INORGANIC CHEMICAL STORAGE					
STORAGE TANK, TANK-1 (COMBINED-CYCLE TURBINES), AQUEOUS AMMONIA 19 PERCENT, ~~40,000~~ **22,290** GALS; DIAMETER: ~~13~~ **10** FT; LENGTH: ~~45~~ **36** FT A/N: ~~579167~~ **604020**	D163			***Note*: *E74.1 will be removed from all Phase I equipment.***	C157.1, ~~E74.1~~, E144.1, E193.4, E193.5
STORAGE TANK, TANK-2 (SIMPLE-CYCLE TURBINES), AQUEOUS AMMONIA 19 PERCENT, 40,000 GALS; DIAMETER: 13 FT; LENGTH: 45 FT A/N: 579168 – **No Change**	D164			***Note*: *E74.2 will be added for all Phase II equipment.***	C157.1, E74.1, **E74.2,** E144.1, E193.4, E193.5
PROCESS 12: INTERNAL COMBUSTION – POWER GENERATION					
SYSTEM 1: COMBINED-CYCLE TURBINES (AEC CCGT POWER BLOCK)					
GAS TURBINE, NO. CCGT-1, COMBINED-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL 7FA.05, 2275 MMBTU/HR HHV AT 28 F, WITH DRY LOW-NOX COMBUSTOR, GE DLN 2.6, WITH A/N: ~~579142~~ ~~**604015**~~ **610354** GENERATOR, NO. CCGT-1 , 236.645 MW GROSS AT 28 F HEAT EXCHANGER, HEAT RECOVERY STEAM GENERATOR (HRSG), NO. CCGT-1 GENERATOR, STEAM TURBINE GENERATOR **(**STG**)**, 219.615 MW GROSS AT 28 F, COMMON WITH HRSG NO. CCGT-2	D165 [B166] [B167] [B168]	C169	NOX: MAJOR SOURCE**	**CO**: 1.5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2**: 120 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 Subpart TTTT, 10-23-2015]; **CO2**: 1000 LBS/GROSS MWH NATURAL GAS (8A) [40 CFR 60 Subpart TTTT, 10-23-2015] **NOx**: 2 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]; NOx: 8.35	A63.2, A99.1, A99.2, A195.8, A195.9, A195.10, A327.1, B61.1, C1.3, C1.4, D29.2, D29.3, D82.1, D82.2, ~~E74.1~~, E193.4, E193.5, E193.8, E193.11, E193.12, E193.14, E448.1, I297.1, K40.4

				LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, ~~7-6-2006~~ **3-20-2009**]; NOx: 16.66 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **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: 8.5 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) [40 CFR 60 SUBPART KKKK, ~~7-6-2006~~ **3-20-2009**] **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
CO OXIDATION CATALYST, NO. CCGT-1, SYNERGY CATALYST, 342.5	C169	D165, C170			~~E74.1~~, E193.5

CU. FT.; WIDTH: 25 FT 9 IN; HEIGHT: 76 FT; LENGTH: 2.1 IN A/N: ~~579160~~ **608431**					
SELECTIVE CATALYTIC REDUCTION, NO. CCGT-1, CORMETECH, TITANIUM/ VANADIUM/TUNGSTEN, 1289 CU. FT.; WIDTH: 25 FT 8.5 IN; HEIGHT: 71 FT 7.2 IN; LENGTH: 1 FT 6 IN WITH A/N: ~~579160~~ **608431** AMMONIA INJECTION, AQUEOUS AMMONIA	C170 [B171]	C169, S172		**NH3**: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.15, D12.9, D12.10, D12.11, D29.4, ~~E74.1~~, E193.4, E193.5
STACK, TURBINE NO. CCGT-1, HEIGHT: ~~140~~ **150** FT; DIAMETER: 20 FT A/N: ~~579142~~ ~~**604015**~~ **610354**	S172	C170			
GAS TURBINE, NO. CCGT-2, COMBINED-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL 7FA.05, 2275 MMBTU/HR HHV AT 28 F, WITH DRY LOW-NOX COMBUSTOR, GE DLN 2.6, WITH A/N: ~~579143~~ ~~**604018**~~ **610355** GENERATOR, NO. CCGT-2 , 236.645 MW GROSS AT 28 F HEAT EXCHANGER, HEAT RECOVERY STEAM GENERATOR (HRSG), NO. CCGT-2 GENERATOR, STEAM TURBINE GENERATOR (STG), 219.615 MW GROSS AT 28 F, COMMON WITH HRSG NO. CCGT-1	D173 [B174] [B175] [B176]	C177	NOX: MAJOR SOURCE**	**CO**: 1.5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2**: 120 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 Subpart TTTT, 10-23-2015]; **CO2**: 1000 LBS/GROSS MWH NATURAL GAS (8A) [40 CFR 60 Subpart TTTT, 10-23-2015] **NOx**: 2 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005,	A63.2, A99.1, A99.2, A195.8, A195.9, A195.10, A327.1, B61.1, C1.3, C1.4, D29.2, D29.3, D82.1, D82.2, ~~E74.1~~, E193.4, E193.5, E193.8, E193.11, E193.12, E193.14, E448.1, I297.2, K40.4

				12-4-2015]; NOx: 8.35 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, ~~7-6-2006~~ **3-20-2009**]; NOx: 16.66 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **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: 8.5 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) [40 CFR 60 SUBPART KKKK, ~~7-6-2006~~ **3-20-2009**]; **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
CO OXIDATION CATALYST, NO. CCGT-2, SYNERGY CATALYST, 342.5	C177	D173, C178			~~E74.1~~, E193.5

CU. FT.; WIDTH: 25 FT 9 IN; HEIGHT: 76 FT; LENGTH: 2.1 IN A/N: ~~579161~~ **608432**					
SELECTIVE CATALYTIC REDUCTION, NO. CCGT-2, CORMETECH, TITANIUM/ VANADIUM/TUNGSTEN, 1289 CU. FT.; WIDTH: 25 FT 8.5 IN; HEIGHT: 71 FT 7.2 IN; LENGTH: 1 FT 6 IN WITH A/N: ~~579161~~ **608432** AMMONIA INJECTION, AQUEOUS AMMONIA	C178 [B179]	C177, S180		**NH3:** 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.15, D12.9, D12.10, D12.11, D29.4, ~~E74.1~~, E193.4
STACK, TURBINE NO. CCGT-2, HEIGHT: ~~140~~ **150** FT; DIAMETER: 20 FT A/N: ~~579143~~ ~~**604018**~~ **610355**	S180	C178			
BOILER, AUXILIARY, WATER-TUBE, NATURAL GAS, BABCOCK & WILCOX, MODEL FM 103-88, WITH LOW NOX BURNER, FLUE GAS RECIRCULATION, 70.8 MMBTU/HR WITH A/N: ~~579158~~ **604014** BURNER, NATURAL GAS, JZHC/COEN, MODEL RMB, WITH LOW NOX BURNER, 70.8 MMBTU/HR	D181 [B182]	C183		**SEE SEPARATE ENGINEERING EVALUATION FOR AUXILIARY BOILER (A/N 604014), AUXILIARY BOILER SCR (A/N 613323 & RECLAIM/TITLE V REVISION (A/N 604013). P/Cs ISSUED ON 7/10/19.**	
SELECTIVE CATALYTIC REDUCTION, AUXILIARY BOILER, BABCOCK & WILCOX, VANADIUM, 46 CU. FT.; WIDTH: 5 FT 5 IN; HEIGHT: 3 FT 8 IN; LENGTH: 7 FT 3 IN WITH A/N: ~~579166~~ **613323** AMMONIA INJECTION, AQUEOUS AMMONIA	C183 [B184]	D181 S211			
STACK, AUXILIARY BOILER, HEIGHT: 80 FT; DIAMETER: 3 FT A/N: ~~579158~~ **604014**	S211	C183			
PROCESS 12: INTERNAL COMBUSTION – POWER GENERATION					
SYSTEM 2: SIMPLE-CYCLE TURBINES (AEC SCGT POWER BLOCK)					

GAS TURBINE, NO. SCGT-1, SIMPLE-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS-100 PB, 882 MMBTU/HR AT 59 DEG F, WITH INTERCOOLER AND DRY LOW-NOX COMBUSTOR WITH A/N: ~~579145~~ **610356** GENERATOR, 100.438 MW GROSS AT 59 F	D185 [B186]	C187	NOX: MAJOR SOURCE**	**CO**: 2.0 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2**: 120 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 Subpart TTTT, 10-23-2015]; **NOx**: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]; NOx: 11.21 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, ~~7-6-2006~~ **3-20-2009**]; NOx: 25.24 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **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: 6.23 LB/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-	A63.3, A99.3, A99.4, A195.10, A195.11, A195.17, A327.1, B61.1, C1.5, C1.6, D29.2, D29.3, D82.1, D82.2, E74.1, **E74.2,** E193.4, E193.5, E193.9, E193.13, E193.15, E448.1, I297.3, K40.4

				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) [40 CFR 60 SUBPART KKKK, ~~7-6-2006~~ **3-20-2009**]; **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
CO OXIDATION CATALYST, NO. SCGT-1, BASF, MODEL CAMET, 165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 22 FT; LENGTH: 36 FT 1.5 IN A/N: 579162 - **No Change**	C187	D185 C188			
SELECTIVE CATALYTIC REDUCTION, NO. SCGT-1, CORMETECH, MODEL CMHT, TITANIUM/VANADIUM/ TUNGSTEN, 621.96 CU. FT.; WIDTH: 4 FT 11 IN; HEIGHT: 11 FT; LENGTH: 11 FT 6 IN WITH A/N: 579162 - **No Change** AMMONIA INJECTION, AQUEOUS AMMONIA	C188 [B189]	C187 S190		**NH3**: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
STACK, TURBINE NO. SCGT-1, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN A/N: ~~579145~~ **610356**	S190	C188			
GAS TURBINE, NO. SCGT-2, SIMPLE-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS-100 PB, 882 MMBTU/HR AT 59 DEG F, WITH INTERCOOLER AND DRY LOW-NOX COMBUSTOR WITH A/N: ~~579147~~ **610357** GENERATOR, 100.438 MW GROSS AT 59 F	D191 [B192]	C193	NOX: MAJOR SOURCE**	**CO**: 2.0 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2**: 120 LBS/MMBTU	A63.3, A99.3, A99.4, A195.10, A195.11, A195.17, A327.1, B61.1, C1.5, C1.6, D29.2, D29.3, D82.1, D82.2, E74.1, **E74.2,** E193.4, E193.5,

				NATURAL GAS (8) [40 CFR 60 Subpart TTTT, 10-23-2015]; **NOx**: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]; NOx: 11.21 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, ~~7-6-2006~~ **3-20-2009**]; NOx: 25.24 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **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: 6.23 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) [40 CFR 60	E193.9, E193.13, E193.15, E448.1, I297.4, K40.4

				SUBPART KKKK, ~~7-6-2006~~ **<u>3-20-2009</u>**]; **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
CO OXIDATION CATALYST, NO. SCGT-2, BASF, MODEL CAMET, 165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 22 FT; LENGTH: 36 FT 1.5 IN A/N: 579163 - **No Change**	C193	D191 C194			
SELECTIVE CATALYTIC REDUCTION, NO. SCGT-2, CORMETECH, MODEL CMHT, TITANIUM/VANADIUM/ TUNGSTEN, 621.96 CU. FT.; WIDTH: 4 FT 11 IN; HEIGHT: 11 FT; LENGTH: 11 FT 6 IN WITH A/N: 579163 - **No Change** AMMONIA INJECTION, AQUEOUS AMMONIA	C194 [B195]	C193, S196		**NH3**: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
STACK, TURBINE NO. SCGT-2, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN A/N: ~~579147~~ **<u>610357</u>**	S196	C194			
GAS TURBINE, NO. SCGT-3, SIMPLE-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS-100 PB, 882 MMBTU/HR AT 59 DEG F, WITH INTERCOOLER AND DRY LOW-NOX COMBUSTOR WITH A/N: ~~579150~~ **<u>610358</u>** GENERATOR, 100.438 MW GROSS AT 59 F	D197 [B198]	C199	NOX: MAJOR SOURCE**	**CO**: 2.0 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2**: 120 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 Subpart TTTT, 10-23-2015]; **NOx**: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]; NOx: 11.21 LBS/MMSCF	A63.3, A99.3, A99.4, A195.10, A195.11, A195.17, A327.1, B61.1, C1.5, C1.6, D29.2, D29.3, D82.1, D82.2, E74.1, **<u>E74.2,</u>** E193.4, E193.5, E193.9, E193.13, E193.15, E448.1, I297.5, K40.4

				NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, ~~7-6-2006~~ **3-20-2009**]; NOx: 25.24 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **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: 6.23 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) [40 CFR 60 SUBPART KKKK, ~~7-6-2006~~ **3-20-2009**]; **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
CO OXIDATION CATALYST, NO. SCGT-3, BASF, MODEL CAMET, 165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 22 FT; LENGTH: 36 FT 1.5 IN A/N: 579164 - **No Change**	C199	D197 C200			

SELECTIVE CATALYTIC REDUCTION, NO. SCGT-3, CORMETECH, MODEL CMHT, TITANIUM/VANADIUM/ TUNGSTEN, 621.96 CU. FT.; WIDTH: 4 FT 11 IN; HEIGHT: 11 FT; LENGTH: 11 FT 6 IN WITH A/N: 579164 - **No Change** AMMONIA INJECTION, AQUEOUS AMMONIA	C200 [B201]	C199, S202		**NH3**: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
STACK, TURBINE NO. SCGT-3, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN A/N: ~~579150~~ **610358**	S202	C200			
GAS TURBINE, NO. SCGT-4, SIMPLE-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS-100 PB, 882 MMBTU/HR AT 59 DEG F, WITH INTERCOOLER AND DRY LOW-NOX COMBUSTOR WITH A/N: ~~579152~~ **610359** GENERATOR, 100.438 MW GROSS AT 59 F	D203 [B204]	C205	NOX: MAJOR SOURCE**	**CO**: 2.0 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD- BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; **CO2**: 120 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 Subpart TTTT, 10-23-2015]; **NOx**: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]; NOx: 11.21 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, ~~7-6-2006~~ **3-20-2009**]; NOx: 25.24 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005];	A63.3, A99.3, A99.4, A195.10, A195.11, A195.17, A327.1, B61.1, C1.5, C1.6, D29.2, D29.3, D82.1, D82.2, E74.1, **E74.2,** E193.4, E193.5, E193.9, E193.13, E193.15, E448.1, I297.6, K40.4

				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: 6.23 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) [40 CFR 60 SUBPART KKKK, 7-~~6-2006~~ **3-20-2009**]; **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
CO OXIDATION CATALYST, NO. SCGT-4, BASF, MODEL CAMET, 165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 22 FT; LENGTH: 36 FT 1.5 IN A/N: 579165 - **No Change**	C205	D203 C206			
SELECTIVE CATALYTIC REDUCTION, NO. SCGT-4, CORMETECH, MODEL CMHT, TITANIUM/VANADIUM/ TUNGSTEN, 621.96 CU. FT.; WIDTH: 4 FT 11 IN; HEIGHT: 11 FT; LENGTH: 11 FT 6 IN WITH A/N: 579165 - **No Change** AMMONIA INJECTION, AQUEOUS AMMONIA	C206 [B207]	C205, S208		NH3: 5 PPMV (4) RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
STACK, TURBINE NO. SCGT-4, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN A/N: ~~579152~~ **610359**	S208	C206			
PROCESS 13: OIL/WATER SEPARATION					
OIL WATER SEPARATOR, NO. OWS-1 (COMBINED-CYCLE TURBINES), WASTE	D209				

WATER, ABOVE GROUND, 5000 GALS; DIAMETER: 5 FT 6 IN; LENGTH: 30 FT A/N: 579169 - **No Change**					
OIL WATER SEPARATOR, NO. OWS-2 (SIMPLE-CYCLE TURBINES), WASTE WATER, ABOVE GROUND, 5000 GALS; DIAMETER: 5 FT 6 IN; LENGTH: 30 FT A/N: 579170 - **No Change**	D210				

(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.

FACILITY CONDITIONS

Note: All facility conditions appear in both Section D (Permits to Operate) and Section H (Permits to Construct). Conditions F9.1, F18.1, and F24.1 are existing facility conditions from Section D. The other conditions are conditions for the AEC.

F2.1 The operator shall limit emissions from this facility as follows:

Contaminant	Emissions Limit
PM2.5	Less than 100 tons in any one year

The operator shall not operate any of the Boilers Nos. 1, 2, 3, 4, 5, 6 (Devices D39, D42, D45, D48, D51, D3, respectively), Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 (Devices D165 and D173, respectively), Auxiliary Boiler (Device D181), or Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Devices D185, D191, D197, and D203 respectively) unless compliance with the annual emission limit for PM2.5 is demonstrated.

Compliance with the annual emission limit shall be based on a 12-month rolling average basis. The operator shall calculate the PM2.5 emissions for the facility by summing the PM2.5 emissions for each of the sources by using the equation below.

Facility PM2.5, tons/year = (FF1*EF1 + FF2*EF2 + FF3*EF3 + FF4*EF4 + FF5*EF5 + FF6*EF6 + FF7*EF7 + FF8*EF8 + FF9*EF9 + FF10*EF10 + FF11*EF11+ FF12*EF12 + FF13*EF13)/2000

FF1 = Boiler No. 1 monthly fuel usage in mmscf; EF1 = 1.19 lb/mmscf
FF2 = Boiler No. 2 monthly fuel usage in mmscf; EF2 = 1.19 lb/mmscf
FF3 = Boiler No. 3 monthly fuel usage in mmscf; EF3 = 1.19 lb/mmscf
FF4 = Boiler No. 4 monthly fuel usage in mmscf; EF4 = 1.19 lb/mmscf

FF5 = Boiler No. 5 monthly fuel usage in mmscf; EF5 = 1.19 lb/mmscf
FF6 = Boiler No. 6 monthly fuel usage in mmscf; EF6 = 1.19 lb/mmscf

FF7 = Combined-Cycle Turbine No. CCGT-1 monthly fuel usage in mmscf; EF7 = 3.92 lb/mmscf
FF8 = Combined-Cycle Turbine No. CCGT-2 monthly fuel usage in mmscf; EF8 = 3.92 lb/mmscf

FF9 = Auxiliary Boiler monthly fuel usage in mmscf; EF9 = 7.42 lb/mmscf

FF10 = Simple-Cycle Turbine No. SCGT-1 monthly fuel usage in mmscf; EF10 = 7.44 lb/mmscf
FF11 = Simple-Cycle Turbine No. SCGT-2 monthly fuel usage in mmscf; EF11 = 7.44 lb/mmscf
FF12 = Simple-Cycle Turbine No. SCGT-3 monthly fuel usage in mmscf; EF12 = 7.44 lb/mmscf
FF13 = Simple-Cycle Turbine No. SCGT-4 monthly fuel usage in mmscf; EF13 = 7.44 lb/mmscf

Any changes to these emission factors must be approved in advance by the South Coast AQMD in writing and be based on unit specific source tests performed using South Coast AQMD-approved testing protocol.

AES Alamitos, LLC shall submit written reports of the monthly PM2.5 compliance demonstration required by this condition. The report submittal shall be included with the semi-annual Title V report as required under Rule 3004(a)(4)(f). Records of the monthly PM2.5 compliance demonstration shall be maintained on site for at least five years and made available upon South Coast AQMD request.

For the purpose of this condition, any one year shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new 12-month period beginning on the first day of each calendar month.

[Rule 1325, 11-4-16]

Note: The PM2.5 emission limit was updated from 100 tpy (FDOC) to 70 tpy pursuant to the evaluation for Auxiliary Boiler (A/N 604014) and Auxiliary Boiler SCR (A/N 613323). See P/Cs issued on 7/10/19.

Update: Pursuant to the Rule 1325 analysis in this evaluation, the PM2.5 emission limit in condition F2.1 will be corrected to 100 tpy. The reason is that the actual construction of Phase I (combined-cycle turbines and associated equipment) was commenced on or prior to 8/14/17 (earliest date that the 70 tpy threshold would become applicable). As analyzed below, Rule 1325, amended 1/4/19, is not applicable until a "major modification" occurs.

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]

F18.1 *This condition sets forth the Acid Rain SO_2 Allowance Allocation for affected units, Boilers No. 1 - 6, applicable to calendar years 2010 and beyond.*

[40 CFR 73 Subpart B, 1-11-1993]

F24.1 Accidental release prevention requirements of Section 112(r)(7):

a). The operator shall comply with the accidental release prevention requirements pursuant to 40 CFR Part 68 and shall submit to the Executive Officer, as a part of an annual compliance certification, a statement that certifies compliance with all of the requirements of 40 CFR Part 68, including the registration and submission of a risk management plan (RMP).

b). The operator shall submit any additional relevant information requested by the Executive Officer or designated agency.

[RULE 40 CFR 68 – Accidental Release Prevention, 5-24-1996]

Note: Facility condition F24.1 is applicable to the four existing ammonia tanks (Devices D19, D151, D152, and D153) in Section D (Permits to Operate), because they are permitted to contain 29% aqueous ammonia. This condition is not applicable to the two new ammonia tanks (Devices D163, D164) installed for the AEC project because they are permitted to contain 19% ammonia. Condition F24.1 will be removed from the facility permit after the four existing tanks are removed from the facility.

F52.1 The facility is subject to the applicable requirements of the following rules or regulations(s):

The facility shall submit a detailed retirement plan for the permanent shutdown of Boilers Nos. 1, 2, 6 and 3 (Devices D39, D42, D3, and D45, respectively), describing in detail the steps and schedule that will be taken to render Boilers Nos. 1, 2, 6, and 3 permanently inoperable.

The retirement plan shall be submitted to ~~SCAQMD~~ **South Coast AQMD** within 60 days after Permits to Construct for Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 (Devices D165 and D173, respectively), common Steam Turbine Generator, and Simple-

Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Devices D185, D191, D197, and D203 respectively) are issued.

AES shall not commence any construction of the Alamitos Energy **Center** Project including Gas Turbines Nos. CCGT-1, CCGT-2, SCGT-1, SCGT-2, SCGT-3, and SCGT-4, unless the retirement plan is approved in writing by ~~SCAQMD~~ **South Coast AQMD**. If ~~SCAQMD~~ **South Coast AQMD** notifies AES that the plan is not approvable, AES shall submit a revised plan addressing ~~SCAQMD~~ **South Coast AQMD's** concerns within 30 days.

Within 30 calendar days of actual shutdown but no later than ~~December 29, 2019~~ **January 10, 2020**, AES shall provide ~~SCAQMD~~ **South Coast AQMD** with a notarized statement that Boilers Nos. 1, 2, and 6 are permanently shut down and that any re-start or operation of the boilers shall require new Permits to Construct and be subject to all requirements of Nonattainment New Source Review and the Prevention Of Significant Deterioration Program.

AES shall notify ~~SCAQMD~~ **South Coast AQMD** 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boilers Nos. 1, 2, and 6, or advise ~~SCAQMD~~ **South Coast AQMD** as soon as practicable should AES undertake permanent shutdown prior to ~~December 29, 2019~~ **December 31, 2019**.

AES shall cease operation of Boilers Nos. 1, 2, and 6 within 90 calendar days of the first fire of Gas Turbines No. CCGT-1 or CCGT-2, whichever is earlier.

Within 30 calendar days of actual shutdown but no later than ~~December 31, 2020~~ **January 10, 2021 (unless the December 31, 2020 OTC compliance date is extended by SWRCB)**, AES shall provide ~~SCAQMD~~ **South Coast AQMD** with a notarized statement that Boiler No. 3 is permanently shut down and that any re-start or operation of the boiler shall require a new Permit to Construct and be subject to all requirements of Nonattainment New Source Review and the Prevention Of Significant Deterioration Program.

In the event that the State Water Resources Control Board (SWRCB) extends the December 30, 2020 Once Through Cooling Policy compliance date for Boiler No. 3, AES shall: (1) Notify South Coast AQMD within 3 months of the approval of an extension, and (2) Within 30 calendar days of actual shutdown of Boiler No. 3, provide South Coast AQMD with a notarized statement that Boiler No. 3 is permanently shut down and that any re-start or operation of the boiler shall require a new Permit to Construct and be subject to all requirements of Nonattainment New Source Review and the Prevention of Significant Deterioration Program.

AES shall notify ~~SCAQMD~~ **South Coast AQMD** 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boiler No. 3, or advise ~~SCAQMD~~

South Coast AQMD as soon as practicable should AES undertake permanent shutdown prior to December 31, 2020.

AES shall cease operation of Boiler No. 3 within 90 calendar days of the first fire of Gas Turbines No. SCGT-1, SCGT-2, SCGT-3, or SCGT-4, whichever is earliest.

[RULE 1304(a)—Modeling and Offset Exemption, 6-14-1996; RULE 1313(d), 12-7-1995]

F52.2 The facility is subject to the applicable requirements of the following rules or regulations(s):

The "facility" is defined as the Alamitos Energy Center. The equipment includes Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2, common Steam Turbine Generator, and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4.

For all circuit breakers at the facility utilizing SF6, including the circuit breakers serving Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2; common Steam Turbine Generator; and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4, the operator shall install, operate, and maintain enclosed-pressure SF6 circuit breakers with a maximum annual leakage rate of 0.5 percent by weight. The circuit breakers shall be equipped with a 10 percent by weight leak detection system.

The leak detection system shall be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and records of all calibrations shall be maintained on site.

The total CO2e emissions from all circuit breakers shall not exceed 74.55 tons per calendar year.

The operator shall calculate the SF6 emissions due to leakage from the circuit breakers by using the mass balance in equation DD-1 at 40 CFR Part 98, Subpart DD, on an annual basis.

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~~ **South Coast AQMD**.

[RULE 1714, 12-10-2012**, RULE 1714, 3-1-2019**]

DEVICE CONDITIONS

COMBINED-CYCLE TURBINES

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

CONTAMINANT	EMISSIONS LIMIT
CO	Less than or equal to 95,023 LBS IN ANY CALENDAR MONTH
VOC	Less than or equal to 13,314 LBS IN ANY CALENDAR MONTH
PM10	Less than or equal to 6324 LBS IN ANY CALENDAR MONTH
PM2.5	**Less than or equal to 6324 LBS IN ANY CALENDAR MONTH**
SOx	Less than or equal to 3616 LBS IN ANY CALENDAR MONTH
CO	Less than or equal to ~~180,544~~ **194717** LBS IN ANY ONE YEAR
VOC	Less than or equal to ~~52,668~~ **63488** LBS IN ANY ONE YEAR
PM10	Less than or equal to ~~39,440~~ **55633** LBS IN ANY ONE YEAR
PM2.5	**Less than or equal to 55633 LBS IN ANY ONE YEAR**
SOx	Less than or equal to ~~7435~~ **10483** LBS IN ANY ONE YEAR

For the purposes of this condition, the above 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~~ **South Coast AQMD** shall be notified in writing once the commissioning process for each turbine is completed.

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.

The operator shall calculate the monthly emissions for CO, VOC, PM10, **PM2.5**, and SOx using the equation below.

Monthly Emissions, lb/month = (Monthly fuel usage in mmscf/month) * (Emission factors indicated below)

The following emission factors shall be used to demonstrate compliance with the monthly emission limits.

For commissioning, the emission factors shall be as follows: CO, 61.18 lb/mmcf; VOC, 8.86 lb/mmcf; PM10**/PM2.5**, 5.11 lb/mmcf; and SOx, 2.92 lb/mmcf.

For normal operation, the emission factors shall be as follows: ~~CO, 15.28 lb/mmcf;~~ VOC, 4.70 lb/mmcf; PM10**/PM2.5**, 3.92 lb/mmcf; and SOx, 2.24 lb/mmcf.

For normal operation, the CO emissions shall be measured with the certified CO CEMS. For the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the emission factor shall be CO, 15.28 lb/mmcf.

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.

Compliance with the annual emission limits shall be based on a 12-operating month-rolling-average basis, following completion of the commissioning period.

The emission factors for the monthly emission limits shall be the same as the emission factors used to demonstrate compliance with the annual emission limits, except the annual emission factor for SOx is 0.75 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~~ **South Coast AQMD**. 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 1304.1, 9-6-2013; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition: D165, D173]

A99.1 The 16.66 lbs/mmscf NOx emission limit(s) shall only apply during the turbine commissioning period to report RECLAIM emissions, not to exceed one year after start of unit operations.

The operator shall maintain records of natural gas usage for this period.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D165, D173]

A99.2 The 8.35 lbs/mmscf NOx emission limit(s) shall only apply during the interim period after commissioning but prior to CEMS certification to report RECLAIM emissions, not to exceed one year after start of unit operations.

The operator shall maintain records of natural gas usage for this period.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D165, D173]

A195.8 The 2.0 PPMV NOx 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 1703(a)(2) - PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]

[Devices subject to this condition: D165, D173]

A195.9 The 1.5 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; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition: D165, D173]

A195.10 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: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

A327.1 For the purpose of determining compliance with ~~District~~ **South Coast AQMD** 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: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

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

Compound	Range	Grain per 100 scf
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~~ **South Coast AQMD** 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: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

C1.3 The operator shall limit the number of start-ups to no more than 62 in any one calendar month.

The number of cold startups shall not exceed 15 in any calendar month, with no more than 2 startups in any one day.

The number of cold startups shall not exceed 80 in any calendar year, and the number of startups shall not exceed 500 in any calendar year.

For the purposes of this condition, a cold startup is defined as a startup which occurs after the combustion turbine has been shut down for 48 hours or more. A cold startup shall not exceed 60 minutes. The NOx emissions from a cold startup shall not exceed 61 lbs. The CO emissions from a cold startup shall not exceed 325 lbs. The VOC emissions from a cold startup shall not exceed 36 lbs.

For the purposes of this condition, a non-cold startup is defined as a startup which occurs after the combustion turbine has been shut down less than 48 hours. A non-cold startup shall not exceed 30 minutes. The NOx emissions from a non-cold startup shall not exceed 17 lbs. The CO emissions from a non-cold startup shall not exceed 137 lbs. The VOC emissions from a non-cold startup shall not exceed 25 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~~ **South Coast AQMD**.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]

[Devices subject to this condition: D165, D173]

C1.4 The operator shall limit the number of shutdowns to no more than 62 in any one calendar month.

The number of shutdowns shall not exceed 500 in any calendar year.

Each shutdown shall not exceed 30 minutes. The NOx emissions from a shutdown event shall not exceed 10 lbs. The CO emissions from a shutdown event shall not exceed 133 lbs. The VOC emissions from a shutdown event shall not exceed 32 lbs.

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~~ **South Coast AQMD**.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]

[Devices subject to this condition: D165, D173]

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
NOx emissions	~~District~~ **South Coast AQMD** Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	~~District~~ **South Coast AQMD** Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOx emissions	**South Coast** AQMD Laboratory Method 307-91	~~District~~ **South Coast AQMD** Approved Averaging Time	Fuel Sample
VOC emissions	~~District~~ **South Coast AQMD** method 25.3 Modified	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A/ ~~District~~ **South Coast AQMD** Method 5.1	~~District~~ **South Coast AQMD** Approved Averaging Time	Outlet of the SCR serving this equipment
PM 2.5	EPA Method 201A and 202	~~District~~ **South Coast AQMD** Approved Averaging Time	Outlet of the SCR serving this equipment
NH3 emissions	~~District~~ **South Coast AQMD** Method 207.1 ~~and 5.3 or EPA method 17~~	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted after ~~District~~ **South Coast AQMD** approval of the source test protocol, but no later than 180 days after initial start-up. The ~~District~~ **South Coast AQMD** shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, the combined-cycle turbine and steam turbine generating output in MW-gross and MW-net, and the simple-cycle turbine generating output in MW-gross and MW-net.

The test shall be conducted in accordance with a ~~District~~ **South Coast AQMD** approved source test protocol. The protocol shall be submitted to the ~~SCAQMD~~ **South Coast AQMD** engineer no later than 90 days before the proposed test date and shall be approved by the ~~District~~ **South Coast AQMD** 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 PM 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 combined-cycle turbine is operating at loads of 45, 75, and 100 percent of maximum load, and the simple-cycle 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~~ **South Coast AQMD**, the operator shall use ~~SCAQMD~~ **South Coast AQMD** 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 **South Coast** 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 **South Coast** AQMD Method 25.3, nor does it mean that it may be used in lieu of **South Coast** 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~~ **South Coast AQMD**.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

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
SOx emissions	**South Coast** AQMD Laboratory Method 307-91	~~District~~ **South Coast AQMD** Approved Averaging Time	Fuel Sample
VOC emissions	~~District~~ **South Coast AQMD** method 25.3 Modified	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A/ ~~District~~ **South Coast AQMD** Method 5.1	~~District~~ **South Coast AQMD** 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 and the results submitted to the ~~District~~ **South Coast AQMD** within 60 days after the test date. The ~~SCAQMD~~ **South Coast AQMD** shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted when this equipment 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~~ **South Coast AQMD**, 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,

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 **South Coast** 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 **South Coast** AQMD Method 25.3, nor does it mean that it may be used in lieu of **South Coast** 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~~ **South Coast AQMD**.

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 1703(a)(2)-PSD-BACT, 10-7-1988]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

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

CO concentration in ppmv.

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

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

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

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*Cco*Fd[20.9/(20.9% - %O_2 d)][(Qg * HHV)/10E+06], where:

1. K = 7.267 *10E-08 (lb/scf)/ppm
2. Cco = Average of four consecutive 15 min. average CO concentrations, ppm
3. Fd = 8710 dscf/MMBTU natural gas
4. %O_2 d = Hourly average % by volume O_2 dry, corresponding to Cco

5. Qg = Fuel gas usage during the hour, scf/hr

6. HHV = Gross high heating value of fuel gas, BTU/scf

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

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

Background: Although the facility has a certified flow meter under RECLAIM, the F factor is still needed in the equation to calculate the CO mass emissions. F factors are used to calculate exhaust flow rates in the stack. The only time an F factor would not be used is when then there is a meter in the exhaust stack which measures ACFM. A certified fuel flow meter only provides part of the equation for stack flow. The mass is determined as the product of concentration and stack flow. Stack flow comes from either the product of fuel flow and F factor or a certified stack flow monitor. Also, when the NOx CEMS is not operational, missing data procedures are applicable. Since there are no missing data procedures for CO calculations, the condition requires the use of the last four 15-minute average CO concentrations.

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

NOx concentration in ppmv.

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

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~~ **South Coast AQMD** REG XX CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from ~~SCAQMD~~ **South Coast AQMD**.

Rule 2012 provisional RATA testing shall be completed and submitted to the ~~SCAQMD~~ **South Coast AQMD** within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3).

[RULE 1703(a)(2) - PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015; RULE 2012, 5-6-2005]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

E74.1 Notwithstanding the requirements of Section E conditions, the Operator may commence the construction of Phase II of this project if all the following condition(s) are met:

The BACT/LAER determination for the Phase II of this project shall be reviewed and modified (by South Coast AQMD) as appropriate at the latest reasonable time which occurs no later than 18 months prior to the commencement of construction of Phase II of the project.

[40 CFR 52.21 – PSD, 6-19-1978]

[Devices subject to this condition: ~~D165, D173 (combined-cycle)~~, D185, D191, D197, D203 (simple-cycle), ~~D181 (auxiliary boiler), C169, C170, C177, C178 (combined-cycle control),~~ C187, C188, C193, C194, C199, C200, C205, C206 (simple-cycle control), ~~C183 (auxiliary boiler control),~~ ~~D163~~, D164 (ammonia tank), ~~D209~~, D210 (oil-water separator)]

<u>E74.2 Notwithstanding the requirements of Section E conditions, the Operator may commence the construction of Phase II of this project if all the following condition(s) are met:</u>

<u>Rule 1325 compliance for the Phase II of this project shall be reviewed and required by South Coast AQMD as appropriate prior to the commencement of construction of Phase II of the project.</u>

<u>[Rule 1325, 11-4-16; RULE 1325, 1-4-19</u>]

<u>[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle), C187, C188, C193, C194, C199, C200, C205, C206 (simple-cycle control), D164 (ammonia tank), D210 (oil-water separators)]</u>

E193.4 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 13-AFC-01 project.

[~~CA PRC CEQA, 11-23-1970~~ **<u>CA PRC CEQA, 5-12-2017</u>**]

[Devices subject to this condition: D163, D164, D165, C170, D173, C178, D181, C183, D185, C188, D191, C194, D197, C200, D203, C206, D209, D210]

E193.5 The operator shall install this equipment according to the following requirements:

The Permit to Construct shall expire one year from the issuance date, unless an 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.

Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D163, and oil water separator D209) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the Permitting Authority.

Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D164, and oil water separator D210) shall commence within 18 months of ~~May 31, 2020~~ **June 30, 2022** unless an extension is granted by the Permitting Authority.

Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.

[RULE 205, 1-5-1990, 40 CFR 52.21 – PSD, 6-19-1978]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle), D181 (auxiliary boiler), C169, C170, C177, C178 (combined-cycle control), C187, C188, C193, C194, C199, C200, C205, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

E193.8 The operator shall operate and maintain this equipment according to the following requirements:

Total commissioning hours shall not exceed 996 hours of fired operation for each turbine from the date of initial turbine start-up. Of the 996 hours, commissioning hours without control shall not exceed 216 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 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~~ **South Coast AQMD**. The records shall include, but not be limited to, the total number of commissioning hours, number of commissioning hours without control, and natural gas fuel usage.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: D165, D173]

E193.11 The operator shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

The 1000 lbs per gross megawatt-hours CO2 emission limit (inclusive of degradation) shall only apply if this turbine supplies greater than 1,481,141 MWh-net electrical output to a utility power distribution system on both a 12-operating-month and a 3-year rolling average basis.

Compliance with the 1000 lbs per gross megawatt-hours CO2 emission limit (inclusive of degradation) 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.

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

[Devices subject to this condition: D165, D173]

E193.12 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 shall only apply if this turbine supplies no more than 1,481,141 MWh-net electrical output to a utility power distribution system on either a 12-operating-month or a 3-year rolling average basis.

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.

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

[Devices subject to this condition: D165, D173]

E193.14 The operator shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

The operator shall record the total net power generated in a calendar month in megawatt-hours.

The operator shall calculate and record greenhouse gas emissions for each calendar month using the following formula:

GHG = 61.41 * FF

Where GHG is the greenhouse gas emissions in tons of CO2 and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the CO2 emissions in pounds per net megawatt-hour based on a 12-month rolling average. The CO2 emissions from this equipment shall not exceed ~~610,480~~ **861,119** tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO2 emissions shall not exceed ~~937.88~~ **916.01** lbs per gross megawatt-hours (inclusive of equipment degradation).

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~~ **South Coast AQMD**.

[RULE 1714, 12-10-2012, **RULE 1714, 3-1-2019**]

[Devices subject to this condition: D165, D173]

E448.1 The operator shall comply with the following requirements:

The total electrical output on a gross basis from Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 (Devices D165 and D173, respectively), common Steam Turbine Generator, and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Device D185, D191, D197, and D203, respectively) shall not exceed 1094.7 MW-gross at 59 deg F.

The gross electrical output shall be measured at the single generator serving each of the combined-cycle turbines, the single generator serving the common steam turbine, and the single generator servicing each of the simple-cycle turbines. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/- 0.2 percent. The gross electrical output from the generators shall be recorded at the CEMS DAS over a 15-minute averaging time period.

The operator shall record and maintain written records of the maximum amount of electricity produced from this equipment 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~~ **South Coast AQMD**.

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

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

I297.1 This equipment shall not be operated unless the facility holds 108377 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

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

[Devices subject to this condition: D165]

I297.2 This equipment shall not be operated unless the facility holds 108377 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

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

[Devices subject to this condition: D173]

K40.4 The operator shall provide to the ~~District~~ **South Coast AQMD** a source test report in accordance with the following specifications:

Source test results shall be submitted to the ~~District~~ **South Coast AQMD** no later than 90 days after the source tests required by conditions D29.2, D29.3, and D29.4 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; RULE 1703(a)(2) - PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

SIMPLE-CYCLE TURBINES

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

CONTAMINANT	EMISSIONS LIMIT
CO	Less than or equal to 8594 LBS IN ANY CALENDAR MONTH
VOC	Less than or equal to 1973 LBS IN ANY CALENDAR MONTH
PM10	Less than or equal to 4638 LBS IN ANY CALENDAR MONTH
<u>**PM2.5**</u>	<u>**Less than or equal to 4638 LBS IN ANY CALENDAR MONTH**</u>
SOx	Less than or equal to 1207 LBS IN ANY CALENDAR MONTH
CO	Less than or equal to ~~29,730~~ <u>**24543**</u> LBS IN ANY ONE YEAR
VOC	Less than or equal to ~~7510~~ <u>**4533**</u> LBS IN ANY ONE YEAR

PM10	Less than or equal to ~~14,695~~ **6596** LBS IN ANY ONE YEAR
PM2.5	**Less than or equal to 6596 LBS IN ANY ONE YEAR**
SOx	Less than or equal to ~~1275~~ **573** LBS IN ANY ONE YEAR

For the purposes of this condition, the above 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~~ **South Coast AQMD** shall be notified in writing once the commissioning process for each turbine is completed.

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.

The operator shall calculate the monthly emissions for CO, VOC, PM10, **PM2.5**, and SOx using the equation below.

Monthly Emissions, lb/month = (Monthly fuel usage in mmscf/month) * (Emission factors indicated below)

The following emission factors shall be used to demonstrate compliance with the monthly emission limits.

For commissioning, the emission factors shall be as follows: CO, 112.03 lb/mmcf; VOC, 3.69 lb/mmcf; PM10**/PM2.5**, 2.00 lb/mmcf; and SOx, 7.69 lb/mmcf.

For normal operation, the emission factors shall be as follows: ~~CO, 8.84 lb/mmcf~~; VOC, 3.17 lb/mmcf; PM10**/PM2.5**, 7.44 lb/mmcf; and SOx, 1.94 lb/mmcf.

For normal operation, the CO emissions shall be measured with the certified CO CEMS. For the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the emission factor shall be CO, 8.84 lb/mmcf.

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.

Compliance with the annual emission limits shall be based on a 12-operating month-rolling-average basis, following completion of the commissioning period.

The emission factors for the monthly emission limits shall be the same as the emission factors used to demonstrate compliance with the annual emission limits, except the annual emission factor for SOx is 0.65 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~~ **South Coast AQMD**. 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 1304.1, 9-6-2013; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition: D185, D191, D197, D203]

A99.3 The 25.24 lbs/mmscf NOx emission limit(s) shall only apply during the turbine commissioning period to report RECLAIM emissions, not to exceed one year after start of unit operations.

The operator shall maintain records of natural gas usage for this period.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D185, D191, D197, D203]

A99.4 The 11.21 lbs/mmscf NOx emission limit(s) shall only apply during the interim period after commissioning but prior to CEMS certification to report RECLAIM emissions, not to exceed one year after start of unit operations.

The operator shall maintain records of natural gas usage for this period.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D185, D191, D197, D203]

A195.11 The 2.5 PPMV NOx 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 1703(a)(2) - PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]

[Devices subject to this condition: D185, D191, D197, D203]

A195.17 The 2.0 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; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition: D185, D191, D197, D203]

A195.10 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: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

A327.1 For the purpose of determining compliance with ~~District~~ **South Coast AQMD** 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: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

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

Compound	Range	Grain per 100 scf
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~~ **South Coast AQMD** 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: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

C1.5 The operator shall limit the number of start-ups to no more than 62 in any one calendar month.

The number of startups shall not exceed 2 startups in any one day. The number of startups shall not exceed 500 in any calendar year.

A startup shall not exceed 30 minutes. The NOx emissions from a startup shall not exceed 16.6 lbs. The CO emissions from a startup shall not exceed 15.4 lbs. The VOC emissions from a startup shall not exceed 2.80 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~~ **South Coast AQMD**.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: D185, D191, D197, D203]

C1.6 The operator shall limit the number of shutdowns to no more than 62 in any one calendar month.

The number of shutdowns shall not exceed 500 in any calendar year.

Each shutdown shall not exceed 13 minutes. The NOx emissions from a shutdown event shall not exceed 3.12 lbs. The CO emissions from a shutdown event shall not exceed 28.1 lbs. The VOC emissions from a shutdown event shall not exceed 3.06 lbs.

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~~ **South Coast AQMD**.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: D185, D191, D197, D203]

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
NOx emissions	~~District~~ **South Coast AQMD** Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	~~District~~ **South Coast AQMD** Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOx emissions	**South Coast** AQMD Laboratory Method 307-91	~~District~~ **South Coast AQMD** Approved Averaging Time	Fuel Sample
VOC emissions	~~District~~ **South Coast AQMD** method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A/ ~~District~~ **South Coast AQMD** Method 5.1	~~District~~ **South Coast AQMD** Approved Averaging Time	Outlet of the SCR serving this equipment
PM 2.5	EPA Method 201A and 202	~~District~~ **South Coast AQMD** Approved Averaging Time	Outlet of the SCR serving this equipment
NH3 emissions	~~District~~ **South Coast AQMD** Method 207.1 ~~and 5.3 or EPA method 17~~	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted after ~~District~~ **South Coast AQMD** approval of the source test protocol, but no later than 180 days after initial start-up. The ~~District~~ **South Coast AQMD** shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, the combined-cycle turbine and steam turbine generating output in MW-gross and MW-net, and the simple-cycle turbine generating output in MW-gross and MW-net.

The test shall be conducted in accordance with a ~~District~~ **South Coast AQMD** approved source test protocol. The protocol shall be submitted to the ~~SCAQMD~~ **South Coast AQMD** engineer no later than 90 days before the proposed test date and shall be approved by the ~~District~~ **South Coast AQMD** 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 PM 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 combined-cycle turbine is operating at loads of 45, 75, and 100 percent of maximum load, and the simple-cycle 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~~ **South Coast AQMD**, the operator shall use ~~SCAQMD~~ **South Coast AQMD** 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 **South Coast** 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 **South Coast** AQMD Method 25.3, nor does it mean that it may be used in lieu of **South Coast** 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~~ **South Coast AQMD**.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

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
SOx emissions	**South Coast** AQMD Laboratory Method 307-91	~~District~~ **South Coast AQMD** Approved Averaging Time	Fuel Sample
VOC emissions	~~District~~ **South Coast AQMD** method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A/ ~~District~~ **South Coast AQMD** Method 5.1	~~District~~ **South Coast AQMD** 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 and the results submitted to the ~~District~~ **South Coast AQMD** within 60 days after the test date. The ~~SCAQMD~~ **South Coast AQMD** shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted when this equipment 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~~ **South Coast AQMD**, 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,

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 **South Coast** 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 **South Coast** AQMD Method 25.3, nor does it mean that it may be used in lieu of **South Coast** 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~~ **South Coast AQMD**.

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 1703(a)(2)-PSD-BACT, 10-7-1988]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

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

CO concentration in ppmv

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

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

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

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*Cco*Fd[20.9/(20.9% - %O_2 d)][(Qg * HHV)/10E+06], where:

1. K = 7.267 *10E-08 (lb/scf)/ppm
2. Cco = Average of four consecutive 15 min. average CO concentrations, ppm
3. Fd = 8710 dscf/MMBTU natural gas
4. %O_2 d = Hourly average % by volume O_2 dry, corresponding to Cco
5. Qg = Fuel gas usage during the hour, scf/hr
6. HHV = Gross high heating value of fuel gas, BTU/scf

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

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

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

NOx concentration in ppmv

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

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~~ **South Coast AQMD** REG XX CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from ~~SCAQMD~~ **South Coast AQMD**.

Rule 2012 provisional RATA testing shall be completed and submitted to the ~~SCAQMD~~ **South Coast AQMD** within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3).

[RULE 1703(a)(2) - PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015; RULE 2012, 5-6-2005]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

E74.1, E193.4, E193.5 -- See conditions E74.1, E193.4, and E193.5 under *Combined-Cycle Turbines* above.

E193.9 The operator shall operate and maintain this equipment according to the following requirements:

Total commissioning hours shall not exceed 280 hours of fired operation for each turbine from the date of initial turbine start-up. Of the 280 hours, commissioning hours without control shall not exceed 4 hours.

Four 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~~ **South Coast AQMD** with written notification of the initial startup date. The operator shall maintain records in a manner approved by the ~~District~~ **South Coast AQMD** to demonstrate compliance with this condition and the records shall be made available to ~~District~~ **South Coast AQMD** personnel upon request. The records shall include, but not be limited to, the total number of commissioning hours, number of commissioning hours without control, and natural gas fuel usage.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]

[Devices subject to this condition: D185, D191, D197, D203]

E193.13 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: D185, D191, D197, D203]

E193.15 The operator shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

The operator shall record the total net power generated in a calendar month in megawatt-hours.

The operator shall calculate and record greenhouse gas emissions for each calendar month using the following formula:

GHG = 61.41 * FF

Where GHG is the greenhouse gas emissions in tons of CO_2 and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the CO_2 emissions in pounds per net megawatt-hour based on a 12-month rolling average. The CO_2 emissions from this equipment shall not exceed ~~120,765~~ **54,185** tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO_2 emissions shall not exceed ~~1356.03~~ **1506.98** lbs per gross megawatt-hours (inclusive of equipment degradation).

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~~ **South Coast AQMD**.

[RULE 1714, 12-10-2012**, RULE 1714, 3-1-2019**]

[Devices subject to this condition: D185, D191, D197, D203]

E448.1 The operator shall comply with the following requirements:

The total electrical output on a gross basis from Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 (Devices D165 and D173, respectively), common Steam Turbine Generator, and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Device D185, D191, D197, and D203, respectively) shall not exceed 1094.7 MW-gross at 59 deg F.

The gross electrical output shall be measured at the single generator serving each of the combined-cycle turbines, the single generator serving the common steam turbine, and the single generator servicing each of the simple-cycle turbines. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/- 0.2 percent. The gross electrical output from the generators shall be recorded at the CEMS DAS over a 15-minute averaging time period.

The operator shall record and maintain written records of the maximum amount of electricity produced from this equipment 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~~ **South Coast AQMD**.

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

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

I297.3 This equipment shall not be operated unless the facility holds ~~68575~~ **21322** pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

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

[Devices subject to this condition: 185]

I297.4 This equipment shall not be operated unless the facility holds ~~68575~~ **21322** pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

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

[Devices subject to this condition: 191]

I297.5 This equipment shall not be operated unless the facility holds ~~68575~~ **21322** pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

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

[Devices subject to this condition: 197]

I297.6 This equipment shall not be operated unless the facility holds ~~68575~~ **21322** pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

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

[Devices subject to this condition: 203]

K40.4 The operator shall provide to the ~~District~~ **South Coast AQMD** a source test report in accordance with the following requirements:

Source test results shall be submitted to the ~~District~~ **South Coast AQMD** no later than 90 days after the source tests required by conditions D29.2, D29.3, and D29.4 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; RULE 1703(a)(2) - PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

SCR/CO CATALYSTS FOR COMBINED-CYCLE TURBINES

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

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

NH_3 (ppmvd) = [a-b*(c*1.2)/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 NOx across the SCR (ppmvd at 15% O2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx 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.

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

[Devices subject to this condition: C170, C178 (combined-cycle), C188, C194, C200, C206 (simple-cycle)]

D12.9 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 ~~44~~ **20** and 242 pounds per hour, except during startups and shutdowns.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011;~~ RULE 2005, 12-4-2015]

[Devices subject to this condition: C170, C178]

D12.10 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 ~~570~~ **450** degrees F and ~~692~~ **800** degrees F, except during startups and shutdowns.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: C170, C178]

D12.11 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 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 1.6 inches water column.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: C170, C178]

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

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

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

The test(s) shall be conducted quarterly during the first twelve months of operation of the catalytic control device and annually thereafter when four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit. If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the ammonia emissions limits prior to resuming annual source tests.

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~~ **South Coast AQMD** 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 1135, 11-2-2018; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: C170, C178 (combined-cycle), C188, C194, C200, C206 (simple-cycle)]

Note: For P/Cs issued on 7/10/19 for the Auxiliary Boiler, Auxiliary Boiler SCR, and Title V/RECLAIM Revision (A/N 604014, 613323, and 604013), the auxiliary boiler was removed from condition D29.4 applicability. A new condition D29.7 was added for the auxiliary boiler SCR that incorporated the new requirements of *Rule 1146--Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, amended 12/7/18*.

E74.1, E193.4, E193.5 -- See conditions E74.1, E193.4, and E193.5 under *Combined-Cycle Turbines* above.

AMMONIA TANKS

C157.1 The operator shall install and maintain a pressure relief valve set at 50 psig.

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

[Devices subject to this condition: D163, D164]

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: D163, D164]

E74.1, E193.4, E193.5 -- See conditions E74.1, E193.4, and E193.5 under *Combined-Cycle Turbines* above.

BACKGROUND AND FACILITY DESCRIPTION

NOTE: This evaluation will follow the organization of the Final Determination Of Compliance (FDOC), issued on 11/18/16. The tables in this evaluation that were in the FDOC will have the same numbering as in the FDOC.

Existing Facility—Alamitos Generating Station (AGS)

Southern California Edison (SCE) installed Utility Boiler No. 1 in 1956, No. 2 in 1957, No. 3 in 1961, No. 4 in 1962, No. 5 in 1969, and No. 6 in 1966. AB 1890 was adopted in 1996 and was the start of a process to deregulate electricity generation in California. As part of the deregulation process, the investor owned utilities, including SCE, were required to divest much of their conventional generation. Consequently, SCE sold the power plant to the AES Corporation in 1998.

AES Alamitos, LLC (AES) (ID 115394), a wholly owned subsidiary of The AES Corporation (AES), operates the existing Alamitos Generating Station (AGS), which consists of the six utility boilers (Units 1 - 6), six Selective Reduction Systems (SCRs), four aqueous ammonia tanks (29 wt. %), and Rule 219 exempt equipment.

The electric utility boiler generators are permitted as summarized in the table below.

Table 1 – Existing Utility Boilers

Application No. (Permit No.)	Equipment Description (Device No.)	Rating
A/N 408704 (F97795)	Boiler No. 1, Babcock and Wilcox, Natural Gas (D39)	1785 MMBtu/hr, 175 MW
A/N 408705 (F97796)	Boiler No. 2, Babcock and Wilcox, Natural Gas (D42)	1785 MMBtu/hr, 175 MW
A/N 408706 (F97797)	Boiler No. 3, Babcock and Wilcox, Natural Gas (D45)	3350 MMBtu/hr, 320 MW
A/N 408707 (F97798)	Boiler No. 4, Babcock and Wilcox, Natural Gas (D48)	3350 MMBtu/hr, 320 MW
A/N 408728 (F97901)	Boiler No. 5, Babcock and Wilcox, Natural Gas (D51)	4750 MMBtu/hr, 480 MW
A/N 408708 (F57292)	Boiler No. 6, Babcock and Wilcox, Natural Gas (D3)	4752.2 MMBtu/hr, 480 MW
Total Generating Capacity		**19,772.2 MMBtu/hr, 1950 MW**

The AGS facility is subject to Title V, Acid Rain, and RECLAIM (Cycle 1). The facility is in compliance with all federal, state, and local rules and regulations.

Alamitos Energy Center - Under Construction

- ***Permitting History of Alamitos Energy Center (AEC)***
  On 12/20/13, AES Southland, LLC (AES), a wholly owned subsidiary of The AES Corporation, submitted applications for Permits to Construct a combined-cycle gas turbine project, the Alamitos Energy Center (original AEC). On 12/27/13, AES submitted an Application for Certification (AFC) for the original AEC to the California Energy Commission (CEC). This repowering project was proposed to replace the six utility boilers (Units 1 - 6) at the AGS. The original AEC project was to consist of four 3-on-1 combined-cycle gas turbine power blocks, with twelve natural-gas-fired combustion turbine generators, twelve heat recovery steam generators, twelve SCR and CO oxidation catalyst systems, and four steam turbine generators; two aqueous ammonia tanks; and three oil/water separators. The AEC was to have a net generating capacity of 1936 MW and a gross generating capacity of 1995 MW. In November 2014, AES received notice from Southern California Edison (SCE) that it was shortlisted for a power purchase agreement (PPA). The power plant configuration selected by SCE for a PPA was different from the project configuration

proposed for the original AEC. Consequently, on December 17, 2014, AES requested the South Coast AQMD to cancel the permit applications.

On 10/23/15, AES Southland Energy, LLC (AES), a different wholly-owned subsidiary of The AES Corporation, submitted new applications for Permits to Construct an amended AEC in the configuration selected by SCE. On 10/26/15, AES submitted a Supplemental Application for Certification (SAFC) (13-AFC-01) for the amended AEC to the CEC. AES will construct, own, and operate the AEC, a natural-gas-fired, air-cooled, combined- and simple-cycle electrical generating facility with a gross generating capacity of 1094.702 megawatts (MW) and net generating capacity of 1072.67 MW. The proposed AEC will replace four existing electric utility boiler generator Units 1, 2, 3 and 6 with a new gas turbine generating system. The new generating system will consist of two natural gas-fired GE 7FA.05 combined-cycle gas turbine generators configured with a shared steam turbine generator, and four natural gas-fired GE LMS100PB simple-cycle turbine generators. The combined generating capacity of the AEC will be 1094.7 megawatts (MW) (nominal) which replaces most of the generating capacity of the existing Unit 1 (175 MW), Unit 2 (175 MW), Unit 3 (320 MW), and Unit 6 (480 MW), except for 55.3 MW. The new AEC will be equipped with air pollution control equipment, which consists of catalysts (selective catalytic reduction and oxidation catalysts). Additional new proposed equipment will include an auxiliary boiler equipped with selective catalytic reduction, two aqueous ammonia storage tanks, and two oil/water separators.

In February 2016, AES was informed that permit conditions will be included to limit annual emissions and cold start-ups on an annual and monthly basis. On 3/30/16, AES submitted revisions to the applications submitted on 10/23/15, primarily to increase the number of cold startups for the combined-cycle turbines on a monthly and annual basis. The revisions included revised emissions calculations and modeling, and incorporated revisions resulting from previous discussions with the South Coast AQMD over the course of permitting for the Huntington Beach Energy Project (HBEP) and AEC. The South Coast AQMD did not require new applications to be submitted to replace the applications submitted on 10/23/15. On 4/12/16, AES submitted revised sections for Air Quality, Biological Resources, and Public Health Assessment to the CEC to update the SAFC submitted on 10/26/15.

The South Coast AQMD issued the Preliminary Determination of Compliance (PDOC) and proposed revised Title V permit for the AEC project on 6/30/16. The original public notice was published on 7/8/16. The CEC made the Preliminary Staff Assessment (PSA) available on July 13, 2016. The South Coast AQMD reissued the PDOC and proposed Title V permit for renotice on 11/10/16. The renotice was to provide interested parties the opportunity to review the PDOC concurrently with the PSA. The second public notice was published on 11/17/16. The South Coast AQMD issued the Final Determination of Compliance (FDOC) package, including the Draft Facility Permit for FDOC, on 11/18/16, based on the original notice published on 7/8/16. The FDOC included an "Addendum—Responses To Comments Received" which set forth the written comments submitted by (1) AES Alamitos on July 19, 2016 and (2) Helping Hand Tools (Rob Simpson) on August 9, 2016, and the South Coast AQMD responses to these comments.

CEC released the Final Staff Assessment (FSA) Part 2 (Air Quality/Greenhouse Gas Emissions and Public Health) on 12/8/16. On 12/2/16, a Title V hearing request was submitted by Harvey Eder. On 12/20/16, the PDOC re-noticing public comment period ended. On 12/20/16, Bob Sarvey from Helping Hand Tools submitted a comment letter. On 1/13/17, South Coast AQMD sent a letter denying the Title V hearing to Harvey Eder. On 2/8/17, South Coast AQMD sent a response letter to Bob Sarvey. On 2/9/17, South Coast AQMD forwarded its response letter to Bob Sarvey's comment letter to the EPA for a 45-day review. (The South Coast AQMD response letter to Bob Sarvey's comment letter is not included in the "Addendum—Responses To Comments Received" in the FDOC, which was issued on 11/18/16. The FDOC was not revised as a result of Mr. Sarvey's comments.)

On 3/1/17, EPA provided early termination of review. On 3/27/17, the EPA 45-day review period would have ended absent the early termination. On 3/28/17, the public period (60 days) to petition EPA to object to the permit started, with an end date of 5/27/17.

The CEC issued the Presiding Member's Proposed Decision (PMPD) on 2/13/17. The CEC approved the SAFC for the amended AEC on 4/12/17 by adopting the Energy Commission Order, which in turn adopted the PMPD, Errata, and the Committee recommendations set forth therein for the SAFC. These adopted documents and recommendations comprise the Commission's Decision and were incorporated by reference into the Order. The Order was adopted, issued, effective, and final on 4/12/17.

- ***Permits to Construct Issued***

  On 4/18/17, the South Coast AQMD issued the Permits to Construct for the following equipment for the Alamitos Energy Center. The cover letter explained that the permit would become effective May 22, 2017, unless a petition is filed with the EPA's EAB, by that date pursuant to 40 CFR §124.19. In the event that a petition is filed with the EAB, construction of the facility is not authorized under this permit until resolution of the EAB petition(s). No EAB petition was filed.

  Note: On 11/18/16, the South Coast AQMD issued the Final Determination of Compliance (FDOC) and the Draft Facility Permit for FDOC. Comments were received on the FDOC and draft facility permit. The *FDOC Addendum--Permits To Construct Issuance*, dated 4/18/17, lists and describes the minor equipment description and permit condition changes made to the Draft Facility Permit for FDOC that were incorporated into the Permits to Construct.

Table 1A – Permits to Construct Issued

Application No.	Equipment Description
579140	RECLAIM/Title V Significant Revision
579142	GE 7FA.05 Combined-Cycle Gas Turbine Generator, Unit CCGT-1
579143	GE 7FA.05 Combined-Cycle Gas Turbine Generator, Unit CCGT-2
579145	GE LMS-100PB Simple-Cycle Gas Turbine Generator, Unit SCGT-1
579147	GE LMS-100PB Simple-Cycle Gas Turbine Generator, Unit SCGT-2
579150	GE LMS-100PB Simple-Cycle Gas Turbine Generator, Unit SCGT-3
579152	GE LMS-100PB Simple-Cycle Gas Turbine Generator, Unit SCGT-4
579158	Auxiliary Boiler
579160	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit CCGT-1
579161	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit CCGT-2
579162	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit SCGT-1
579163	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit SCGT-2
579164	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit SCGT-3
579165	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit SCGT-4
579166	Air Pollution Control Equipment, SCR for Auxiliary Boiler
579167	Aqueous Ammonia Storage Tank for Combined-Cycle Turbines
579168	Aqueous Ammonia Storage Tank for Simple-Cycle Turbines
579169	Oil/Water Separator for Combined-Cycle Turbines
579170	Oil/Water Separator for Simple-Cycle Turbines

- ***Permits to Construct Extension***
  Because the AEC project is a multi-year, multi-phase project, condition E193.5 sets forth requirements for the extension of the expiration date for the Permits to Construct. As discussed below, AES is currently in compliance with the condition E193.5 requirements.

  Condition E193.5 states in part: "The Permit to Construct shall expire one year from the issuance date, unless an 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." On 4/17/18, the South Coast AQMD extended the expiration date of the Permits to Construct from 4/17/18 to 4/17/19. The South Coast AQMD's policy regarding multi-year projects is to grant a one-year permit to construct extension as long as the project proponent is meeting the increments of progress towards completing construction. AES had provided a permit extension request letter, dated 3/2/18, that indicated construction of the combined cycle units (Power Block 1) was initiated on August 7, 2017 and was currently on-going. Construction on Power Block 1 was expected to continue through to the 4th quarter of 2019. Construction of the simple cycle units (Power Block 2) was expected to begin in the third quarter of 2020. In addition, AES provided a major project milestones table. Based on the information provided, the South Coast AQMD extended the expiration date an additional year.

  On 4/12/19, the South Coast AQMD extended the expiration date of the Permits to Construct to 4/17/20. AES had provided a permit extension request letter, dated 3/15/19, that reiterated construction of the combined cycle gas turbine generators (Power Block 1) was initiated on August 7, 2017 and was currently on-going. As of March 15, 2019, all above ground structures and equipment have been erected and placed on foundations. Construction of Power Block 1 is approximately 70 percent completed and is expected to continue through to the 4th quarter of 2019 followed by commissioning of the combined-cycle gas turbine generators. First fire of the first combined-cycle turbine is scheduled for October 3, 2019. **Update**: The construction of Power Block 1 continued into the 4^{th} quarter of 2019. The first fire for Combined-Cycle Turbine No. 1 occurred on 10/3/19 and for Combined-Cycle Turbine No. 2 on 10/11/19.

Construction of the simple cycle gas turbine generators (Power Block 2) was expected to begin in the third quarter of 2020 (a delay from May 2020 in the FDOC) after the combined cycle gas turbine generators have reached commercial operation. Construction of Power Block 2 cannot commence until construction and commissioning of Power Block 1 is complete and existing AES Alamitos generating station units 1, 2 and 6 have been permanently retired from service. The start of construction of Power Block 2 is constrained by the space on the site dedicated to Power Block 1 construction activity and interconnection capacity in the switchyard serving the site. Based on the information provided, the South Coast AQMD extended the expiration date an additional year. **Update**: As discussed and shown below in *Table 3 - AEC Schedule Major Milestones*, the start of construction of Power Block 2 has been postponed to third quarter 2022.

- ***Project Description***
  The Alamitos Energy Center (AEC), as permitted, will consist of two gas turbine power blocks.

  - **Power Block 1** will consist of one 2-on-1 combined-cycle gas turbine (CCGT) power block with two natural-gas-fired combustion turbine generators (CTGs), two unfired heat recovery steam generators (HRSGs), an steam turbine generator (STG), and an air-cooled condenser. The CTGs are shown on the facility permit as No. CCGT-1 (D165) and No. CCGT-2 (D173). An auxiliary boiler (D181) equipped with an SCR (C183) provides enhanced startup times for the CTGs.

    For the purpose of the equipment description on the facility permit, the applicable operating scenario is the scenario that yields the highest Btu/hr consumption for the turbine. From *Table 15 - Combined-Cycle Turbine Operating Scenarios*, below, the applicable operating scenario is Case 1, based on 100% load, 28 ºF ambient temperature, and without inlet cooling. At those conditions, each combustion turbine generator is rated 236.645 MW-gross and 235.907 MW-net, at 28 ºF. The steam generator is rated 219.615 MW-gross and 208.965 MW-net, at 28 ºF.

    For the purposes of Rule 1304(a)(2) compliance demonstration and Rule 1304.1 fee calculation, the applicable operating scenario is the scenario that yields the maximum gross output for the equipment (two combined-cycle turbines and the steam generator). The applicable operating scenario is Case 12, based on 100% load, 59 ºF. At those conditions, each combustion turbine generator is rated 231.197 MW-gross and 230.459 MW-net, at 59 ºF. The steam generator is rated 230.557 MW-gross and 215.402 MW-net, at 59 ºF.

Two selective catalytic reduction (SCR) systems (C170, C178) and CO oxidation catalysts (C169, C177) will be utilized for control of NOx and CO/VOC emissions, respectively. One 40,000-gallon ammonia (NH_3) storage tank (D163) will store 19% aqueous ammonia which is the reducing agent in the SCRs. An oil/water separator (D209) will be used to collect equipment wash water and rainfall. This power block is collectively the AEC CCGT and will be located on the southern-most portion of the AEC site.

- **Power Block 2** will consist of four simple-cycle gas turbines (SCGTs) with intercoolers. The CTGs are shown on the facility permit as No. SCGT-1 (D185), No. SCGT-2 (D191), No. SCGT-3 (D197), and No. SCGT-4 (D203). For the purposes of the equipment description, Rule 1304(a)(2) compliance demonstration, and Rule 1304.1 fee calculation, the applicable scenario from *Table 31 - Simple-Cycle Turbine Operating Scenarios* is Case 12, based on 100% load, 59 ºF. At those conditions, each combustion turbine generator is rated 100.438 MW-gross and 99.087 MW-net, at 59 ºF. Four SCR/CO oxidation catalysts systems (C188/C187, C194/C193, C200/C199, C206/C205), a second 40,000-gallon aqueous ammonia tank (D164), and a second oil/water separator (D210) are included. This power block is collectively the AEC SCGT and will be located on the northern portion of the AEC site.

The AEC will meet the demand for new generation in the Los Angeles basin local electrical reliability area caused in large part by the closure of the San Onofre Nuclear Generating Station and anticipated retirement of older, natural-gas-fired generation currently using once-through ocean water cooling.

The California State Water Resources Control Board's *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (OTC Policy) was adopted on 5/4/2010 and became effective on 10/1/2010. The Policy applies to existing power plants that currently have the ability to withdraw cooling water from the State's coastal and estuarine waters using a single-pass system, also known as once-through cooling (OTC). The existing Utility Boilers at AGS use once-through ocean water cooling. The repowering will bring the AGS into compliance by the current facility compliance date of December 31, 2020 by eliminating the use of ocean water for once-through cooling at the site. The proposed combined-cycle combustion turbine generators will employ an air-cooled condenser for the steam turbine cycle heat rejection system, which receives exhaust water from the low-pressure section of the steam turbine and condense it to water for reuse. The proposed simple-cycle turbines will employ one air-cooled closed loop fluid cooler per two CTGs to reject waste heat from the intercooler and other gas turbine auxiliaries.

The technology for AEC will be configured and deployed as a multi-stage generating (MSG) asset designed to generate power across a wide range of capacity with relatively constant thermal efficiency and maximum operating flexibility. The project includes include multiple generators, often termed "embedded generating units," whereby combinations of embedded generating units comprise the full operational capability for each power block, from minimum to maximum generating capacity. AEC will have the ability to generate power across a wide range of output from minimum turndown of a single AEC SCGT to maximum output of the entire project. The AEC CCGT, including the steam turbine generator, is designed to function in a 1-on-1 configuration at minimum load up to the maximum heat input of two combustion turbines and two HRSGs operating at 100 percent load.

AEC is being constructed on the brownfield site of the existing AGS, and located on an approximately 21-acre site within the larger 71.3-acre AGS parcel. The AGS parcel is bounded to the north by the SCE switchyard and State Route 22 (East 7th Street); to the east by the San Gabriel River and, beyond that, the Los Angeles Department of Water and Power Haynes Generating Station; to the south by the former Plains West Coast Terminals petroleum storage facility and undeveloped property; and to the west by the Los Cerritos channel, AGS cooling-water canals, and the residences west of the channel.

The demolition of the existing and operating Utility Boilers 1 – 6 is not necessary for the construction of AEC. These units will continue to provide essential electrical service concurrent with the construction of the AEC CCGT power block. Units 1, 2, and 6 will be retired once the AEC CCGT reaches the commissioning stage and become operational. **Update:** As discussed above, the facility requested that condition F52.1 be revised to set the permanent shutdown date for Boilers 1, 2, and 6 as December 31, 2019. AES has shut down these boilers as of December 31, 2019, and has submitted all necessary documentation (including a notarized statement) required under Condition F52.1. The South Coast AQMD has verified that the subject boilers were shut down according to the approved boiler retirement plan.

Units 3, 4 and 5 may operate through December 31, 2020, the current facility compliance date imposed by the OTC Policy. **Update**: The State Water Board is planning to extend the OTC compliance date for Units 3, 4, and 5 to December 31, 2023. Any extension of the OTC compliance date for Unit 3, however, cannot go beyond 90-days of the start of operation of the simple-cycle gas turbines, which is currently identified as 4rd quarter 2023 (see *Table 2* below). Condition F52.1 has been updated to reflect this possible extension of the OTC deadline.

The AEC facility will be federal Title V, Acid Rain, and RECLAIM facility (Cycle 1).

- ***Modeling and Offset Exemption***
  South Coast AQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler repower projects. The exemption applies to: "The source is replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The new equipment must have a maximum electrical power rating (in megawatts) that does not allow basinwide

electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset." Offsets are provided from the South Coast AQMD internal offset accounts.

The initial purpose of this exemption was to facilitate the replacement of older, less efficient utility boilers and steam turbines with newer lower NOx-emitting gas turbines for electric power generating systems to comply with Rule 1135—Emissions of Oxides of Nitrogen from Electric Power Generating Systems. As the RECLAIM program subsequently superseded Rule 1135, the exemption was expanded to include modifications to comply with RECLAIM requirements.

Rule 1304(a)(2) provides an exemption for new qualifying equipment, such as combined-cycle turbines and simple-cycle turbines with intercoolers, that have a maximum electrical rating (in megawatts) that is less than or equal to the maximum electrical rating (in megawatts) of the electric utility steam boiler(s) that the new equipment will replace. Both the new equipment and the existing electric utility boiler(s) must have the same owner and be located in the basin. This exemption is discussed in more detail under the rule analysis for *Rule 1303(b)(1)—Modeling*, below.

- **<u>Condition F52.1—Retirement Plan</u>**
  Condition F52.1 sets forth requirements for the utility boilers retirement plan, permanent shutdown of the utility boilers, and first fire of the turbines to ensure compliance with Rule 1304(a)(2).

  - **<u>FDOC Summary</u>**
    On 6/16/17, South Coast AQMD approved AES's Revised Permanent Unit Retirement Plan dated 6/15/17. AES will replace existing Utility Boilers No. 1 (175 MW-gross), No. 2 (175 MW-gross), No. 6 (480 MW-gross), and No. 3 (320 MW-gross) with the two combined-cycle turbines (692.951 MW-gross total) and four simple-cycle turbines (401.751 MW-gross total), as shown in the table below. For the Preliminary Determination of Compliance (PDOC), AES had proposed the retirement of Units 1, 2, 5, and 3. On 10/26/16, AES proposed the retirement of Unit 6 instead of Unit 5. Since both units are identical, South Coast AQMD accepted this change for the FDOC. At this time, AES has not identified plans for the surplus 55 MWs from the retirements of these four utility boilers. In addition, AES has not identified plans for the MWs from the retirement of Utility Boiler No. 4 (320 MW) and Utility Boiler No. 5 (480 MW).

  - **<u>Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)</u>**
    The Title V/RECLAIM Revision, A/N 604013, proposes to revise facility condition F52.1 to update the permanent shutdown date for Boilers No. 1, 2, and 6 from December 29, 2019 (FDOC) to January 2, 2020. As discussed below, all proposed facility condition changes, including to condition F52.1, will be consolidated in this engineering evaluation, with A/N 610360 acting as the RECLAIM/Title V revision application.

As requested by the South Coast AQMD, in a letter dated 5/10/19, Stephen O'Kane submitted a revised "Boiler Retirement Plan for the Alamitos Energy Center (Facility ID 115394)," and a revised "Boiler Retirement Schedule for the Huntington Beach Energy Project (Facility ID 115389.)" The revised retirement plan for the AEC changed the permanent shutdown date for Boilers No. 1, 2, and 6 from the January 2, 2020 (proposed by A/N 604013) to December 31, 2019. The December 31, 2019 date is correct because the first fire of CCGT-1 on 10/3/19 plus 90 days will be January 1, 2020. (*Rule 1313(d*) states: "For a new source or modification which will be a replacement, in whole or part, for an existing source on the same or contiguous property, a maximum of 90 days may be allowed as a start-up period for simultaneous operation of the subject sources.") Further, the revised retirement plan changed the date that AES will provide a notarized statement that Boilers Nos. 1, 2, and 6 are permanently shut down from December 29, 2019 (FDOC) to January 10, 2020. Still further, the date that AES will provide a notarized statement that Boiler No. 3 is permanently shut down was changed from December 31, 2020 (FDOC) to January 10, 2021.

Condition F52.1 will be revised as follows:

> Within 30 calendar days of actual shutdown but no later than ~~December 29, 2019~~ **January 10, 2020**, AES shall provide ~~SCAQMD~~ **South Coast AQMD** with a notarized statement that Boilers Nos. 1, 2, and 6 are permanently shut down….
>
> AES shall notify ~~SCAQMD~~ **South Coast AQMD** 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boilers Nos. 1, 2, and 6, or advise ~~SCAQMD~~ **South Coast AQMD** as soon as practicable should AES undertake permanent shutdown prior to ~~December 29, 2019~~ **December 31, 2019**….
>
> Within 30 calendar days of actual shutdown but no later than ~~December 31, 2020~~ **January 10, 2021 (unless the December 31, 2020 OTC compliance date is extended by SWRCB)**, AES shall provide ~~SCAQMD~~ **South Coast AQMD** with a notarized statement that Boiler No. 3 is permanently shut down and that any re-start or operation of the boiler shall require a new Permit to Construct and be subject to all requirements of Nonattainment New Source Review and the Prevention Of Significant Deterioration Program.
>
> **In the event that the State Water Resources Control Board (SWRCB) extends the December 30, 2020 Once Through Cooling Policy compliance date for Boiler No. 3, AES shall: (1) Notify South Coast AQMD within 3 months of the approval of an extension, and (2) Within 30 calendar days of actual shutdown of Boiler No. 3, provide South Coast AQMD with a notarized statement that Boiler No. 3 is permanently shut down and that any re-start or operation of the boiler shall require a new Permit to Construct and be subject to all requirements of**

Nonattainment New Source Review and the Prevention of Significant Deterioration Program.

- **Table 2 – AES Rule 1304(a)(2) Offset Plan**
  - **FDOC Summary**

    The Rule 1304(a)(2) offset plan proposed by AES for the three repowering projects with offsets coming from the shutdown of utility boilers (retirement of units) at the three existing AES power plants is summarized in *Table 2* below. At AES Huntington Beach, the existing plant is the Huntington Beach Generating Station (HBGS) and the repowering project is the Huntington Beach Energy Project (HBEP). At AES Redondo Beach, the existing plant is the Redondo Beach Generating Station (RBGS) and the repowering project is the Redondo Beach Energy Project (RBEP). All of these AES entities are wholly owned subsidiaries of the AES Corporation.

    The combined generating capacity of the AEC will be 1094.7 megawatts (MW) (nominal) which replaces most of the generating capacity of the existing Unit 1 (175 MW), Unit 2 (175 MW), Unit 3 (320 MW), and Unit 6 (480 MW), except for 55.3 MW.

    $$[(231.197 \text{ MW-gross/ CTG}) * (2 \text{ CTGs}) + 230.557 \text{ MW-gross/steam turbine}]_{\text{combined cycle}} + [(100.438 \text{ MW-gross/ CTG}) * (4 \text{ CTGs})]_{\text{simple-cycle}} = 692.951 \text{ MW} + 401.75 \text{ MW} = 1094.7 \text{ MW-gross (case 12)}$$

    Condition E448.1 limits the total electrical output from AEC to 1094.7 MW-gross at 59 ºF, as follows:

    > The total electrical output on a gross basis from Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 (Devices D165 and D173, respectively), common Steam Turbine Generator, and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Device D185, D191, D197, and D203, respectively) shall not exceed 1094.7 MW-gross at 59 deg F.

  - **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**

    Table 2 is updated to incorporate the following:

    1) Redondo Beach Energy Project (RBEP) - The South Coast AQMD cancelled the applications for the RBEP on March 4, 2017. AES has not submitted new applications for a repowering project.

    2) Revised dates are provided by the revised retirement plans for the Huntington Beach Energy Project (HBEP) and the Alamitos Energy Center (AEC), as described in the table footnotes.

Table 2 – AES Rule 1304(a)(2) Offset Plan

Project	Phase	First Fire or Shutdown Date	MW-gross
Huntington Beach Energy Project (HBEP)	Combined-Cycle Block[a]	~~10/1/2019~~ **10/3/2019[f]**	693.822
	HBGS Unit 1 Retired	~~11/1/2019~~ **12/31/2019[f]**	215
	RBGS Unit 7 Retired	~~10/1/2019~~ **9/30/2019[f]**	480
	Simple-Cycle Block[b]	11/1/2023	201.628
	HBGS Unit 2 Retired	12/31/2020	215
	MW Installed		895.45
	MW Retired		910
	Surplus MW		14.55
~~Redondo Beach Energy Project (RBEP)~~ **NOTE: REPOWERING PROJECT IS CANCELLED.**	~~Combined-Cycle Block[e]~~	~~11/1/2019~~	~~546.4~~
	~~RBGS Unit 5 Retired~~	~~12/31/2019~~	~~175~~
	~~RBGS Unit 8 Retired~~	~~12/31/2019~~	~~480~~
	~~MW Installed~~		~~546.4~~
	~~MW Retired~~		~~655~~
	~~Surplus MW (HBEP & RBEP)~~		~~123.15~~
Alamitos Energy Center (AEC)	Combined-Cycle Block[c]	~~10/1/2019~~ **10/3/2019[g]**	692.951
	AGS Unit 1 Retired	~~12/29/2019~~ **12/31/2019[g]**	175
	AGS Unit 2 Retired	~~12/29/2019~~ **12/31/2019[g]**	175
	AGS Unit 6 Retired	~~12/29/2019~~ **12/31/2019[g]**	480
	AGS Unit 3 Retired	12/31/2020	320
	Simple-Cycle Block[d]	~~6/1/2021~~ **11/1/2023[g]**	401.751
	MW Installed		1,094.702
	MW Retired		1150
Total MWs	Total MW Installed		~~2,536.552~~ **1990.152**
Installed and Retired	Total MW Retired		~~2,715.00~~ **2060.00**

[a] Based on 65.8 F with evaporative coolers operating.
[b] ~~Based on 65.8 F with evaporative coolers operating.~~
[c] Based on 59 F without evaporative coolers operating.
[d] Based on 59 F without evaporative coolers operating.
[e] Based on 33 F without evaporative coolers operating.

[f] **Letter dated 5/10/19 from Stephen O'Kane to Sr. Manager Bhaskar Chandan re revised Boiler Retirement Schedule for the Huntington Beach Energy Project (Facility ID 115389).**

[g] **Letter dated 5/10/19 from Stephen O'Kane to Sr. Manager Bhaskar Chandan re revised Boiler Retirement Schedule for the Alamitos Energy Center (Facility ID 115394).**

- ***Proposed Schedule***
  For the ***Application****, the proposed schedule is updated in Table 3 below pursuant to the AES e-mails and letter cited in the revised table footnotes.*

  Construction activities are anticipated to last 56 months, from ~~first~~ **third** quarter 2017 until ~~third quarter 2021~~ **fourth quarter 2023**. The project will commence with site preparation and the removal of the remaining components of Unit 7, comprised of six peaking turbines that were shut down in 2003, and other ancillary structures to make room for the construction of AEC CCGT and SCGT power blocks. Site preparation ~~will~~ commence**d** on ~~January~~ **July 1,** 2017 and construction on the AEC CCGT is expected to be completed by the ~~first~~ **fourth** quarter of ~~2020~~ **2019**. The AEC SCGT power block construction is scheduled to commence in the ~~second quarter of 2020~~ **third quarter of 2022** and be completed by the ~~third quarter of 2021~~ **fourth quarter of 2023**. Construction overlap is not expected between the AEC CCGT and AEC SCGT power blocks.

  Major project milestones are listed in the following table. The table below shows updates to *Table 3* in the FDOC.

Table 3 - AEC Schedule Major Milestones

Activity	Dates	Commercial Operation
Demolition of Unit 7	January 2017 – May 2017	Not Applicable
Auxiliary Boiler Commissioning	~~January 2020~~ **August 1, 2019**[a]	Not Applicable
Construction of AEC CCGT.	~~June 2017~~ **August 7, 2017**[b] – ~~March 2020~~ **Fourth Quarter 2019**[b]	~~Second~~ **First Quarter** 2020 ~~(April 1, 2020)~~
Construction of AEC SCGT.	~~May 2020~~ **Third Quarter 2022**[c]– ~~August 2021~~ **December 2023**[c]	~~Third Quarter 2021~~ **First Quarter 2024**[d]

[a] **E-mail, dated 8/1/19, from Jeff Miller, AES, to Vicky Lee regarding auxiliary boiler first fire.**
[b] **Letter, dated 3/15/19, from Stephen O'Kane to Sr. Manager Bhaskar Chandan re Permit to Construct Extension (Facility ID 115394).**
[c] **Letter dated 5/10/19 from Stephen O'Kane to Sr. Manager Bhaskar Chandan re revised Boiler Retirement Schedule for the Alamitos Energy Center (Facility ID 115394).**
[d] **E-mail dated 8/12/19 from Stephen O'Kane to Vicky Lee in response to request for updates to Table 3.**

- ***New South Coast AQMD Applications Submitted***
  AES submitted four sets of applications in 2018 – 2019. The applications and fees are described in Table 4A (A/N 604013-604015, 604018, 604020), Table 4B (A/N 608431-608433), Table 4C (A/N 610354-610360), and Table 4D (A/N 613323) below.

As discussed below, on 4/4/19, AES submitted a *Petition for Post-Certification Amendment, Modification of Gas Turbine Operating Hours and Combined Cycle Gas Turbine (CCGT) Stack Height* to amend the CEC License. The CEC and AES are proceeding on incorporating the other pending application changes that had been submitted to the South Coast AQMD into the CEC license.

NOTE: A/N 604015, 604018, 604020, 608431-608433, 610354-610360 *("Application")* will be consolidated in this engineering evaluation.

A/N 604014, 613323, and 604013 for the Auxiliary Boiler, Auxiliary Boiler SCR, and RECLAIM/Title V Revision, respectively, were evaluated in a separate engineering evaluation because the auxiliary boiler and SCR will be started up prior to the turbines. After expedited EPA review, the permits were issued on 7/10/19.

Table 4A – Administrative Applications

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
604013	5/11/18	5/29/18	RECLAIM/Title V Revision	$2,247.02
604014	5/11/18	5/29/18	Auxiliary Boiler (A/N 579158)**—Converted to Change of Condition Application, Fee of $6,063.52.**	$920.48
604015	5/11/18	5/29/18	Combined-Cycle Turbine, CCGT-1 (A/N 579142)	$920.48
604018	5/11/18	5/29/18	Combined-Cycle Turbine, CCGT-2 (A/N 579143)	$920.48
604020	5/11/18	5/29/18	Aqueous Ammonia Tank-1 for Combined-Cycle Turbines (A/N 579167)	$920.48
			Total Fees	**$5,928.94**

Table 4B – Change of Condition Applications

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
608431	11/9/18	1/9/19	SCR/CO Catalyst for Combined-Cycle Turbine, CCGT-1 (A/N 579160)	$2,763.20
608432	11/9/18	1/9/19	SCR/CO Catalyst for Combined-Cycle Turbine, CCGT-2 (A/N 579161)	$2,763.20 * 0.5 (identical) = $1,381.60
608433	11/9/18	1/9/19	RECLAIM/Title V Revision	$2,496.24
			Total Fees	**$6,641.04**

Table 4C – Modification Applications

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
610354	2/8/19	5/23/19	Combined-Cycle Turbine (A/N 579142)	$19,779.97 * 1.5 (XPP) = $29,669.96

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
610355	2/8/19	5/23/19	Combined-Cycle Turbine (A/N 579143)	[$19,779.97 * 0.5 (identical)] * [1.5 (XPP)] = $14,834.99
610356	2/8/19	5/23/19	Simple-Cycle Turbine (A/N 579145)	$19,779.97 * 1.5 (XPP) = $29,669.96
610357	2/8/19	5/23/19	Simple-Cycle Turbine (A/N 579147)	[$19,779.97 * 0.5 (identical)] * [1.5 (XPP)] = $14,834.99
610358	2/8/19	5/23/19	Simple-Cycle Turbine (A/N 579150)	[$19,779.97 * 0.5 (identical)] * [1.5 (XPP)] = $14,834.99
610359	2/8/19	5/23/19	Simple-Cycle Turbine (579152)	[$19,779.97 * 0.5 (identical)] * [1.5 (XPP)] = $14,834.99
610360	2/8/19	5/23/19	RECLAIM/Title V Revision	$2,496.24
			Total Fees	**$121,176.12**

Table 4D – Change of Condition Application

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
613323	6/6/19	6/12/19	SCR for Auxiliary Boiler (A/N 579166)	$2672.34
			Total Fee	**$2672.34**

On 5/15/19, Stephen O'Kane sent an e-mail to the South Coast AQMD detailing additional proposed changes resulting from a comprehensive review of the permits with the operators. The South Coast AQMD response e-mails, dated 5/23/19 & 5/30/19, indicated that five of the six proposed changes can be incorporated into previously submitted pending applications but a new condition change application will be required for the Auxiliary Boiler SCR. A/N 613323 was submitted for the Auxiliary Boiler SCR on 6/6/19.

The table below summarizes (1) the proposed changes requested in the applications, and (2) the proposed changes requested in Stephen O'Kane's e-mail, dated 5/15/19. An expanded Discussion of AES Proposed Changes and South Coast AQMD Conclusions, including the analysis for the administrative changes, follow the table.

Table 4E - Summary of Proposed Changes for Applications

Application No.	Equipment Description (Current Permit)	Proposed Changes
604013	RECLAIM/ Title V Revision--For Auxiliary Boiler and Auxiliary Boiler SCR, A/N 604014 and 613323, respectively.	RECLAIM/TV Rev
604014	Auxiliary Boiler (A/N 579158, Device D181) **NOTE: A/N 604014, 613323, and 604013 for the Auxiliary Boiler, Auxiliary Boiler SCR, and RECLAIM/Title V Revision, respectively, were evaluated in a separate engineering evaluation. P/Cs were issued on 7/10/19.**	Administrative - Update manufacturer and model for the boiler and the burner to reflect equipment installed. Stephen O'Kane e-mail, 5/15/19 - Condition E193.10—Revise commissioning period from 30 hr to 100 hr. Appx. 6/12/19 – In a telephone conversation, Mr. O'Kane informed the South Coast AQMD that a CO CEMS would be installed on the auxiliary boiler at the Huntington Beach Energy Center. The process and equipment are the same at the AEC. **Administrative application converted to Change of Condition to incorporate the commissioning and CO CEMS revisions.**
604015	Combined-Cycle Turbine, CCGT-1 (A/N 579142, Devices D165, S172)	Administrative – Update stack height from 140 ft. to 150 ft. to reflect as-built conditions. Consolidate with A/N 610354. Cancel A/N 604015 and approve A/N 610354.
604018	Combined-Cycle Turbine, CCGT-2 (A/N 579143, Devices D173, S180)	Administrative – Update stack height from 140 ft. to 150 ft. to reflect as-built conditions. Consolidate with A/N 610355. Cancel A/N 604018 and approve A/N 610355.
604020	Aqueous Ammonia Tank-1 for Combined-Cycle Turbines (A/N 579167, Device D163)	Administrative – Update capacity and dimensions of tank to reflect equipment installed.
608431	SCR/CO Catalyst for Combined-Cycle Turbine, CCGT-1 (A/N 579160, Devices C170/C169)	Change of Condition – Revise condition D12.10 to update exhaust temperature range at inlet of SCR/CO catalyst from 570 – 692 deg F to 600 – 775 deg F. **Note: Subsequently, the requested range was increased to 450 - 800 deg F.** Stephen O'Kane e-mail, 5/15/19 – Revise condition D12.9 to update the ammonia injection rate range for SCR from 44 - 242 lb/hr to 20 – 242 lb/hr.
608432	SCR/CO Catalyst for Combined-Cycle Turbine, CCGT-2 (A/N 579161, Devices C178, C177)	Same as A/N 608431.
608433	RECLAIM/ Title V Revision	RECLAIM/TV Rev – Consolidate with A/N 610360. Cancel A/N 608433 and approve A/N 610360.
610354	Combined-Cycle Turbine, CCGT-1 (A/N 579142, Devices D165, S172)	Modification – Increase annual operating hours by 1905 hours. Stephen O'Kane e-mail, 5/15/19 – Revise condition A63.2 from requiring the use of the CO emission factor to calculate

		compliance with the monthly and annual CO emissions limits to requiring the use of the CEMS readings after the CO CEMS certification.
610355	Combined-Cycle Turbine, CCGT-2 (A/N 579143, Devices D173, S180)	Same as A/N 610354.
610356	Simple-Cycle Turbine, SCGT-1 (A/N 579145, Devices D185, S190)	Modification – Reduce annual operating hours by 1300 hours. Stephen O'Kane e-mail, 5/15/19 – Revise condition A63.3 from requiring the use of the CO emission factor to calculate compliance with the monthly and annual CO emissions limits to requiring the use of the CEMS readings after the CO CEMS certification.
610357	Simple-Cycle Turbine, SCGT-2 (A/N 579147, Devices D191, S196)	Same as A/N 610356.
610358	Simple-Cycle Turbine, SCGT-3 (A/N 579150, Devices D197, S202)	Same as A/N 610356.
610359	Simple-Cycle Turbine, SCGT-4 (A/N 579152, Devices D203, S208)	Same as A/N 610356.
610360	RECLAIM/ Title V Revision—For all applications <u>except</u> A/N 604014 and 613323, Auxiliary Boiler and Auxiliary Boiler SCR, respectively.	RECLAIM/TV Rev—Consolidate all facility permit condition changes. From A/N 604013--Revise facility condition F52.1 to update the permanent shutdown date for Boilers No. 1, 2, and 6 from December 29, 2019 to January 2, 2020. In a letter dated 5/10/19, Stephen O'Kane submitted a revised "Boiler Retirement Plan for the Alamitos Energy Center (Facility ID 115394)." The revised retirement plan changed the permanent shutdown date from January 2, 2020 (proposed by A/N 604013) to December 31, 2019. Stephen O'Kane e-mail, 5/15/19 – Revise facility condition F52.2 to clarify that the requirements for "all circuit breakers at the facility utilizing SF6" refers to the new AEC facility with the turbines, not the existing AGS facility with the utility boilers.
613323	SCR for Auxiliary Boiler (A/N 579166, Device C183) **NOTE: See A/N 604013 & 604014 above.**	Stephen O'Kane e-mail, 5/15/19 – Revise condition D12.15 to update the ammonia injection rate to the SCR from 0.3 – 1.1 lb/hr to 0.3 – 3.9 lb/hr.

Note: A/N 604013, 604014, and 613323 for the RECLAIM/Title V Revision, Auxiliary Boiler, and Auxiliary Boiler SCR were evaluated in a separate engineering evaluation because the auxiliary boiler and SCR will be started up prior to the turbines. **After expedited EPA review, the permits were issued on 7/10/19.**

1. 604013 - RECLAIM/ Title V Revision, submitted 5/11/18

   This RECLAIM/Title V revision application was originally submitted for (1) A/N 604014, Auxiliary Boiler; (2) A/N 604015, Combined-Cycle Turbine CCGT-1; (3) A/N 604018, Combined-Cycle Turbine CCGT-2; and (4) A/N 604020, Aqueous Ammonia Tank for Combined-Cycle Turbines.

   Because the auxiliary boiler commissioning will take place before the commissioning for the turbines, A/N 604013 was the RECLAIM/Title V revision application for A/N 604014 and 613323 (submitted 6/6/19) only.

   The remaining applications, A/N 604015, A/N 604018, A/N 604020, will be consolidated in this engineering evaluation, with A/N 610360 as the RECLAIM/Title V revision application.

   A/N 604013 proposes to revise facility condition F52.1 to update the permanent shutdown date for Boilers No. 1, 2, and 6 from December 29, 2019 to January 2, 2020. (In a letter dated 5/10/19, Stephen O'Kane submitted a revised "Boiler Retirement Plan for the Alamitos Energy Center (Facility ID 115394)." The revised retirement plan changed the permanent shutdown date for Boilers No. 1, 2, and 6 from January 2, 2020 (proposed by A/N 604013) to December 31, 2019.) All proposed facility condition changes, including to condition F52.1, will be consolidated in this engineering evaluation, with A/N 610360 as the RECLAIM/Title V revision application. See A/N 610360 below for further discussion.

2. A/N 604014 - Auxiliary Boiler (A/N 579158), submitted 5/11/18

16. A/N 613323 - Auxiliary Boiler SCR (A/N 579166), submitted 6/6/19 (16th application submitted)

    A/N 604014 is the master file for A/N 604013 & A/N 613323.

    The auxiliary boiler is included in this evaluation for the **Application** (A/N 604015, 604018, 604020, 608431-608433, 610354-610360) for the facility-wide analyses. The

    auxiliary boiler will be included in the post-modification facility emissions for the purpose of rule applicability in the Rule Evaluation section, as well as in the facility-wide air dispersion modeling and health risk assessment evaluation in support of the CEC's analysis of the *Petition for Post-Certification Amendment.*

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MASTER FILE: A/N 610354 submitted to increase the annual operating hours for Combined-Cycle Turbine No. 1 will be the MASTER FILE for the Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360).

3. A/N 604015 – Combined-Cycle Turbine CCGT-1 (A/N 579142)
4. A/N 604018 – Combined-Cycle Turbine CCGT-2 (A/N 579143)

The Yorke Engineering application letter, dated 5/9/18, proposes to increase the height of the combined-cycle turbine exhaust stacks from 140 ft. to 150 ft.

From the *Petition for Post-Certification Amendment, Modification of Gas Turbine Operating Hours and Combined Cycle Gas Turbine (CCGT) Stack Height*, the permitted stack height of 140 ft. was identified as the lowest height that would allow the project to comply with the ambient air quality standards as analyzed through a dispersion modeling analysis while minimizing visual impacts. During detailed design, the applicant determined that the height is required to be raised to 150 ft. to accommodate stack dampers for noise attenuation to satisfy the noise limits of CEC Condition of Certification NOISE-4.

The increase in the permitted stack height to the as-built 150 ft. is incorporated in the air dispersion modeling performed for A/N 610354 and A/N 610355. As discussed below, these applications propose to increase the total annual operating hours for the combined-cycle turbines by 1905 hours/turbine, from the permitted 4640 hr/turbine to 6545 hr/turbine, with no changes to the number of annual startups and shutdowns per turbine.

This Application evaluation concludes:

(A) For Turbine No. CCGT-1, A/N 604015 will be consolidated with A/N 610354. For Turbine No. CCGT-2, A/N 604018 will be consolidated with A/N 610355. The consolidation procedure is that the earlier applications, A/N 604015 and 604018, will be cancelled. The later applications, A/N 610354 and 610355, will be approved after evaluation.

(B) The stack heights in the equipment descriptions for the Turbine No. CCGT-1 Stack (S172) and Turbine No. CCGT-2 (S180) will be revised from 140 ft. to 150 ft.

5. A/N 604020 – Aqueous Ammonia Tank-1 for Combined-Cycle Turbines (A/N 579167)

The Yorke Engineering application letter, dated 5/9/18, proposes to update the capacity and dimensions for the ammonia tank from 40,000 gallons, 13 ft. diameter, and 45 ft. long to 22,000 gallons, 10 ft. diameter, and 36 ft. length. AES indicated that no changes to the ammonia percent by weight content, number of deliveries, filling operations, monitoring parameters, or operating schedule are requested.

From the FDOC, no ammonia emissions are expected because the filling losses will be controlled by a vapor return line and the breathing losses by the 50 psig pressure valve. Thus the emissions will not change regardless of the tank capacity.

This Application evaluation concludes:
The equipment description for the Ammonia Storage Tank (D163) will be updated as follows:

STORAGE TANK, TANK-1 (COMBINED-CYCLE TURBINES), AQUEOUS AMMONIA 19 PERCENT, ~~40,000~~ **22,290** GALS; DIAMETER: ~~13~~ **10** FT; LENGTH: ~~45~~ **36** FT

A/N 608431-608433 - Change of Condition Applications, Submitted 11/9/18

6. A/N 608431 - SCR/CO Catalyst for Combined-Cycle Turbine, CCGT-1 (A/N 579160)
7. A/N 608432 - SCR/CO Catalyst for Combined-Cycle Turbine, CCGT-2 (A/N 579161)

The Yorke Engineering application letter, dated 5/9/18, for these applications is included in A/N 608431. Also included are the AES/South Coast AQMD e-mail strings regarding the changes to conditions D12.10 and D12.9.

(A) The applications propose to revise condition D12.10 to update the exhaust temperature range at inlet of SCR/CO catalyst from 570 – 692 deg F (FDOC) to 600 – 775 deg F.

In an e-mail dated 10/16/18, Stephen O'Kane stated: "We have been informed by the catalyst vendor [Haldor Topsoe] that the guaranteed operating temperature range is 636 degrees to 738 degrees F, (with NOx reduction capable between 450 to 800 degrees F). As there are assumptions and an expected variation in the guaranteed temperature, AES requests that the minimum operating temperature, as specified in condition D12.10 be 600 degrees F and the maximum 775 degrees F. I have attached our vendor's letter confirming this data."

The applications included a Haldor Topsoe letter, dated September 7 2017, addressed to Vogt Power International. The letter stated: "The catalyst is designed for the operating temperature range found in referenced datasheet, 636 F to 738 F, and the flow conditions that correspond to those temperatures. This is to confirm that the SCR catalyst to be provided for VPI projects VI7505 Huntington Beach and V17506 Alamitos is capable of NOx reduction from 450 ºF to 800 ºF. Operation during startup could even begin as low as 300 ºF in certain cases."

Since the Haldor Topsoe letter, dated 9/7/17, stated that the SCR catalyst "is capable of NOx reduction from 450 ºF to 800 ºF," a wider range of 450 deg F to 800 deg F may be more appropriate. In an e-mail dated 8/2/19 to Stephen O'Kane, the South Coast AQMD asked whether AES wished to change to the wider range of 450 ºF to 800 ºF. In an e-mail dated 8/12/19, Mr. O'Kane responded in the affirmative.

This Application evaluation concludes:
Since the Haldor Topsoe letter provides sufficient explanation to support the wider range and since AES requested the wider range, condition D12.10 will be revised as follows:

> The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between ~~570~~ **450** degrees F and ~~692~~ **800** degrees F, except during startups and shutdowns.

(B) Stephen O'Kane's e-mail, dated 5/15/19, indicated condition D12.9 is required to be updated to revise the ammonia injection rate range for SCR from 44 - 242 lb/hr (FDOC) to 20 – 242 lb/hr. In an e-mail dated 5/31/19, Mr. O'Kane provided the following explanation:

> For condition D12.9, our operators and vendors for both the gas turbine and SCR have explained that at minimum turn down we will need less than half the originally stated ammonia injection rate. Primarily this is due to the fact that the dry low NOx burners in the combustion canisters can maintain a steady 9 ppm emission rate all the way down to the minimum turn down of the gas turbine. This is accomplished by reducing the number of combustion canisters firing (there are 16 canisters around the turbine). It was originally assumed that our NOx emission rate out of the gas turbine would go up at minimum load and a higher ammonia injection rate would be required to maintain 2.0 ppm at the stack exhaust. At 44 lbs/hr we would likely exceed the ammonia slip rate of 5.0 ppm, therefore we are requesting a lower value for minimum ammonia injection.

This Application evaluation concludes:
Since the explanation provided is sufficient to support the proposed decrease, condition D12.9 will be revised as follows:

> The operator shall maintain the ammonia injection rate between ~~44~~ **20** and 242 pounds per hour, except during startups and shutdowns.

8. A/N 608433 - RECLAIM/ Title V Revision

A/N 608433 will be consolidated with A/N 610360, which was submitted later for A/N 610354-610360 to increase the annual operating hours for the combined-cycle turbines and decrease the annual operating hours for the simple-cycle turbines. The consolidation procedure is that A/N 608433 will be cancelled, and A/N 610360 will be approved after evaluation.

As discussed below, A/N 610360 will be the RECLAIM/Title V revision application for the Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360) evaluated here.

A/N 610354-610360 - Modification Applications, Submitted 2/8/19

Overview: Yorke Engineering submitted, on behalf of AES, an application document entitled *Applications for Modification* for A/N 610354 – 610360. These applications propose to increase the annual operating hours for the combined-cycle turbines and to decrease the annual operating hours for the simple-cycle turbines to better reflect expected demand and to optimize operational capability. The selection of the specific increase in CCGT operating hours and reduction in SCGT operating hours, further discussed below, was designed to yield no net change in annual $PM_{2.5}$ emissions due to offset considerations, in accordance with Condition F2.1 and Rule 1325. **After the installation and startup of the combined-cycle and simple-cycle turbines, the facility-wide $PM_{2.5}$ emissions will remain below 70 tons/yr. The commencement of the actual construction of Phase 2 (simple-cycle turbines and associated equipment) has been postponed from May 2020 (FDOC) to Third Quarter 2022 (Application).**

The air dispersion modeling and health risk assessment (HRA) analyses performed for the FDOC are required to be revised on a permit unit basis, unless a modeling exemption is applicable, to incorporate the requested changes in the annual emissions for the combined-cycle and simple-cycle turbines for the South Coast AQMD evaluation. Further, the modeling and HRA are required to be revised on a facility-wide basis in support of the CEC's analysis of the *Petition for Post-Certification Amendment*.

Prior to the submittal of the *Applications for Modification*, Yorke Engineering submitted a letter protocol, dated 11/7/18, for proposed revisions to the modeling and HRA performed for the FDOC (**Yorke Protocol, 11/7/18**). South Coast AQMD Engineering and Sr. Meteorologist Melissa Sheffer reviewed the protocol. On 12/20/18, the South Coast AQMD provided comments on the letter protocol (**South Coast AQMD Comments on Yorke Protocol, 12/20/18**). The Yorke Protocol and the South Coast AQMD Comments will be discussed under the air dispersion modeling and health risk assessment analyses below.

Differences in Requested Changes in Annual Operating Hours for Combined-Cycle and Simple-Cycle Turbines between Yorke Protocol, 11/7/18, and Yorke *Applications for Modification: Turbine Emission Limits*, 2/8/19

- The **Yorke Protocol, 11/17/18,** proposes an increase of 1960 hr/yr for each combined-cycle turbine and a decrease of 1340 hr/yr for each simple-cycle turbine.

- The Yorke *Applications for Modification: Turbine Emission Limits,* submitted on 2/8/19, proposes an increase of 1905 hr/yr for each combined-cycle turbine and a decrease of 1300 hr/yr for each simple-cycle turbine in the application write-up. However, the *Appendix B – Emissions Calculations* was based on the superseded increase of 1960 hr/yr for each combined-cycle turbine and the superseded decrease of 1340 hr/yr for each simple-cycle turbine that were proposed in the Yorke letter protocol, dated 11/7/18. (The same *Appendix B* was included in the *Petition for Post-Certification Amendment* submitted to the CEC.)

  In an e-mail dated 5/22/19, the South Coast AQMD requested an updated *Appendix B* that reflects an increase of 1905 hr/yr for each combined-cycle turbine and a decrease of 1300 hr/yr for each simple-cycle turbine. In a response e-mail dated 5/28/19, Yorke Engineering provided the updated *Appendix B.*

9. <u>A/N 610354 - Combined-Cycle Turbine (A/N 579142)</u>
10. <u>A/N 610355 - Combined-Cycle Turbine (A/N 579143)</u>

The *Applications for Modification: Turbine Emission Limits* propose to increase the total annual operating hours by 1905 hours/turbine, from the permitted 4640 hr/turbine to 6545 hr/turbine, with no changes to the number of annual startups and shutdowns per turbine. The breakdown becomes (1) ~~4100~~ **<u>6005</u>** hours of normal operation, (2) 80 cold starts (80 hr), (3) 420 non-cold starts (210 hr), and (5) 500 shutdowns (250 hr) for a total ~~4640~~ **<u>6545</u>** hours for maximum annual emissions per turbine.

In an e-mail dated 5/15/19, Stephen O'Kane also requested the revision of condition A63.2 from requiring the use of the CO emission factor to calculate compliance with the monthly and annual CO emissions limits to requiring the use of the CEMS readings after the CO CEMS certification.

<u>This Application evaluation concludes</u>:

(A) The evaluation provided below concludes that the increase in annual normal operating hours from 4100 hr (FDOC) to 6005 hours for each combined-cycle turbine will not result in significant air quality impacts and will comply with all applicable federal, state and local air quality rules and regulations.

(B) Condition A63.2 will be revised to remove the CO emission factor for normal operation and add the following:

<u>For normal operation, the CO emissions shall be measured with the certified CO CEMS. For the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the emission factor shall be CO, 15.28 lb/mmcf.</u>

11. <u>A/N 610356 - Simple-Cycle Turbine (A/N 579145)</u>
12. <u>A/N 610357 - Simple-Cycle Turbine (A/N 579147)</u>

13. A/N 610358 - Simple-Cycle Turbine (A/N 579150)
14. A/N 610359 - Simple-Cycle Turbine (A/N 579152)

The *Applications for Modification: Turbine Emission Limits* proposes to decrease the total annual operating hours by 1300 hours per turbine, from an assumed 2360 hours per turbine to 1060 hours per turbine, with no changes in the number of annual startups and shutdowns per turbine.

The 2360 hr/yr assumed by Yorke Engineering was based on 0.22 hr/shutdown. The FDOC, however, was permitted for 2358 hr/yr per turbine based on 0.2167 hr/shutdown. The 2358 hr/yr per turbine was used throughout the FDOC, including for the Rule 1304.1 fees. ***Therefore, this evaluation will be based on a decrease from the permitted 2358 hr/yr to 1058 hr/yr***.

The breakdown becomes (1) ~~2000~~ **700** hours of normal operation, (2) 500 startups (250 hr), and (3) 500 shutdowns (108 hr), for a total of ~~2358~~ **1058** hours for maximum annual emissions per turbine.

In an e-mail dated 5/15/19, Stephen O'Kane also requested that condition A63.3 be revised from requiring the use of the CO emission factor to calculate compliance with the monthly and annual CO emissions limits to requiring the use of the CEMS readings after the CO CEMS certification.

This Application evaluation concludes:

(A) The evaluation provided below concludes that the decrease in annual normal operating hours from 2000 hr (FDOC) to 700 hours for each simple-cycle turbine will not result in significant air quality impacts and will comply with all applicable federal, state and local air quality rules and regulations.

(B) Condition A63.3 will be revised to remove the CO emission factor for normal operation and add the following:

> **For normal operation, the CO emissions shall be measured with the certified CO CEMS. For the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the emission factor shall be CO, 8.84 lb/mmcf.**

15. A/N 610360 - RECLAIM/ Title V Revision

A/N 610360 will be the RECLAIM/Title V revision application for all applications, except A/N 604014 and A/N 613323 for the Auxiliary Boiler and Auxiliary Boiler SCR, respectively, as discussed above.

In addition, all facility permit condition revisions will be consolidated in A/N 610360.

(A) From A/N 604013--Revise facility condition F52.1 to update the permanent shutdown date for Boilers No. 1, 2, and 6 from December 29, 2019 to January 2, 2020.

As requested by the South Coast AQMD, in a letter dated 5/10/19, Stephen O'Kane submitted a revised "Boiler Retirement Plan for the Alamitos Energy Center (Facility ID 115394)," and a revised "Boiler Retirement Schedule for the Huntington Beach Energy Project (Facility ID 115389.)" The revised retirement plan for the AEC changed the permanent shutdown date for Boilers No. 1, 2, and 6 from the January 2, 2020 (proposed by A/N 604013) to December 31, 2019. The December 31, 2019 date is correct because the first fire of CCGT-1 on 10/3/19 plus 90 days will be January 1, 2020. (*Rule 1313(d*) states: "For a new source or modification which will be a replacement, in whole or part, for an existing source on the same or contiguous property, a maximum of 90 days may be allowed as a start-up period for simultaneous operation of the subject sources.") Further, the revised retirement plan changed the date that AES will provide a notarized statement that Boilers Nos. 1, 2, and 6 are permanently shut down from December 29, 2019 (FDOC) to January 10, 2020. Still further, the date that AES will provide a notarized statement that Boiler No. 3 is permanently shut down was changed from December 31, 2020 (FDOC) to January 10, 2021.

This Application evaluation concludes:
Condition F52.1 will be revised as requested by the proposed retirement plan.

> Within 30 calendar days of actual shutdown but no later than ~~December 29, 2019~~ **January 10, 2020**, AES shall provide ~~SCAQMD~~ **South Coast AQMD** with a notarized statement that Boilers Nos. 1, 2, and 6 are permanently shut down….
>
> AES shall notify ~~SCAQMD~~ **South Coast AQMD** 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boilers Nos. 1, 2, and 6, or advise ~~SCAQMD~~ **South Coast AQMD** as soon as practicable should AES undertake permanent shutdown prior to ~~December 29, 2019~~ **December 31, 2019**.
>
> Within 30 calendar days of actual shutdown but no later than ~~December 31, 2020~~ **January 10, 2021 (unless the December 31, 2020 OTC compliance date is extended by SWRCB)**, AES shall provide ~~SCAQMD~~ **South Coast AQMD** with a notarized statement that Boiler No. 3 is permanently shut down and that any re-start or operation of the boiler shall require a new Permit to Construct and be subject to all requirements of Nonattainment New Source Review and the Prevention Of Significant Deterioration Program.
>
> **In the event that the State Water Resources Control Board (SWRCB) extends the December 30, 2020 Once Through Cooling Policy compliance date for Boiler No. 3, AES shall: (1) Notify South Coast AQMD within 3 months of the approval of an extension, and (2) Within 30 calendar days of actual shutdown of Boiler No. 3, provide South Coast AQMD with a notarized statement that Boiler No. 3 is permanently shut down and that any re-start or operation of the boiler shall**

require a new Permit to Construct and be subject to all requirements of Nonattainment New Source Review and the Prevention of Significant Deterioration Program.

(B) In an e-mail dated 5/15/19, Stephen O'Kane indicated that the condition F52.2 limits on SF6 are facility wide and not limited to any device ID. They have 12 existing and much larger SF6 breakers, which are meeting the leak rate in the ARB rule, however, total SF6 from the site is already well above this limit. This condition and annual total SF6 limit is acceptable for the new breakers installed, but can't accommodate the leaks from the existing breakers (which are not listed in their existing Title V permit). In an e-mail dated 5/30/19, the South Coast AQMD responded that the Condition F52.2 requirements are for the new turbines and steam turbine generator at the Alamitos Energy Center. Because F52.2 is a facility condition, the facility permit program shows the condition in both Sections D (Permits to Operate) and H (Permits to Construct) with the implication that the facility includes the Alamitos Generating Station and the utility boilers. Condition F52.2 to define the "facility" as the Alamitos Energy Center.

This Application evaluation concludes:
Condition F52.2 will be revised to add the following clarification:

The "facility" is defined as the Alamitos Energy Center. The equipment includes Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2, common Steam Turbine Generator, and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4.

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SOUTH COAST AQMD CONDITION UPDATES

1. Pursuant to current agency requirements, references to "SCAQMD," "District" or "AQMD" in the existing conditions will be updated to "South Coast AQMD" in the engineering evaluation. Depending on how the condition is programmed in the facility permit program, the engineer may not be able to make some of the updates in the facility permit program until the facility permit program is re-programmed in the future. (Remaining references to "SCAQMD," "District" or "AQMD" in the facility permit that have not been updated in conjunction with the evaluation of applications will be updated as part of the Title V renewal application, A/N 612392, submitted on 5/2/19.)

2. Condition D29.2 provides initial source test requirements for the combined-cycle and simple-cycle turbines, including the ammonia slip testing. Condition D29.4 provides periodic

(compliance) source test requirements for the SCRs for the combined-cycle and simple-cycle turbines, including the ammonia slip testing.

The source test method on the current permit is "District method 207.1 and 5.3 or EPA method 17." The "and 5.3 or EPA method 17" will be removed. On 3/23/18, then Source Test Engineering Supervising Engineer Mike Garibay was consulted regarding the correct source test method for ammonia testing. Mike explained that South Coast AQMD Method 5.3 or EPA Method 17 were formerly specified as the ammonia sampling methods for a draft ammonia test method using ion chromatography. Subsequently, District Method 207.1 was developed, which included provisions for sampling. When the standard source test method became District Method 207.1, the use of South Coast AQMD Method 5.3 or EPA Method 17 for sampling was no longer appropriate.

3. Condition A63.2 sets forth monthly and annual emissions limits for CO, VOC, PM_{10}, and SOx, with associated emission factors, for the combined-cycle turbines. Condition A63.3 is the analogous condition for simple-cycle turbines. To clarify that $PM_{2.5}$ emissions are conservatively assumed to be equal to PM_{10} emissions, $PM_{2.5}$ is added as a contaminant, with the same emission factor as PM_{10}, to conditions A63.2 and 63.3. The $PM_{2.5}$ emission factors that will be added to these conditions are the same as the emission factors in existing condition F2.1. Condition F2.1 limits the facility-wide $PM_{2.5}$ emissions to below the applicability limit 70 tpy set forth in *Rule 1325—Federal PM2.5 New Source Review Program, amended 1/4/19.* ***Update: Pursuant to the Rule 1325 analysis in this evaluation, the PM2.5 emission limit in condition F2.1 will be corrected to 100 tpy.***

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 AEC will be rated at greater than 50 megawatts, it is subject to the CEC's certification process.

As discussed above, on 12/27/13, AES submitted an *Application for Certification (AFC)* for the original AEC to the CEC. On 10/26/15, AES submitted a *Supplemental Application for Certification (SAFC)* (13-AFC-01) for the amended AEC. On 4/12/16, AES submitted revised sections for Air Quality, Biological Resources, and Public Health Assessment. On 4/12/17, the CEC approved the *Supplemental*

Application for Certification for the amended AEC on 4/12/17 by adopting the Energy Commission Order.

On 4/4/19, AES submitted the *Petition for Post-Certification Amendment, Modification of Gas Turbine Operating Hours and Combined Cycle Gas Turbine (CCGT) Stack Height* to amend the CEC License. The CEC and AES are proceeding on incorporating the other pending application changes that had been submitted to the South Coast AQMD into the CEC license.

PROCESS DESCRIPTION

1. **A/N 604015 & A/N 610354, A/N 604018 & 610355—Combined-Cycle Combustion Turbine Generators Nos. CCGT-1, CCGT-2 (A/N 579142, 579143)**
   - **FDOC Summary**

     The 2-on-1 combined-cycle gas turbine power block will consist of the following equipment:

     - Two General Electric (GE) 7FA.05 natural-gas fired combustion turbine generators (CTGs). Each combustion turbine generator is rated 236.645 MW-gross and 235.907 MW-net, at 28 ºF, and 231.197 MW-gross and 230.459 MW- net, at 59 ºF ambient temperature. The CTGs will be equipped with evaporative coolers on the inlet air system and dry low NOx combustors, GE DLN 2.6. The use of the evaporative coolers is not intended as power augmentation (i.e., to produce additional power above rated nominal net capacity), but rather will be employed to mitigate CTG ambient condition degradation and to maintain the facility at or near the nominal generating capacity. The dry low-NOx combustors reduces the NOx concentrations to 9 ppm.

     - One, single-flow, impulse, down exhaust condensing steam turbine generator (STG) rated 219.615 MW-gross and 208.965 MW-net, at 28 ºF, and 230.557 MW-gross and 215.402 MW-net, at 59 ºF.

     - Two heat recovery steam generators (HRSGs) of the horizontal gas flow, triple-pressure, natural-circulation type. Each HRSG is equipped with an emission reduction system consisting of a CO catalyst and SCR in the outlet ductwork. The HRSGs will not employ supplemental firing.

     - One air-cooled condenser and one closed-loop fin fan cooler.

     - One 230-kV interconnection to the existing SCE switchyard, which is adjacent to the site.

     Combustion air will flow through the inlet air filters, evaporative inlet air coolers, associated air inlet ductwork, and silencers before being compressed in the CTG's compressor section and then entering the CTG's combustion sections. Natural gas will be mixed with the compressed air prior to being introduced to the combustion sections and ignited. The hot combustion gases will expand through the power turbine section of the CTGs, causing them to rotate and drive the CTG compressors and two electric generators. The CTG exhaust gases of approximately 1,100 ºF will be used to generate steam in the HRSGs. The hot combustion exhaust gases will exit the turbine sections and enter the HRSGs where they will heat water (feed water), converting it to superheated steam. The HRSGs will use a triple pressure design reheat system. High-pressure, intermediate-pressure, and low-pressure steam will be delivered to the steam turbine. As the steam expands as it passes through the steam turbine, the thermal energy is converted to mechanical energy as the turbine rotates and then converted to electrical energy as the steam turbine turns a third generator (STG). The low-pressure steam exiting the steam turbine will enter the air-cooled condenser, which will remove heat from the low-pressure steam (causing the steam to condense to water) and release the heat to the ambient air. The condensed water, or condensate will be returned to the HRSG feed water system for reuse. The combustion gases exiting the HRSG will enter the control equipment consisting of the oxidation catalyst and selective catalytic reduction system.

The use of an air-cooled condenser to condense exhaust steam from the STG will eliminate the significant water demand required for condensing STG exhaust steam in a conventional surface condenser/cooling tower arrangement. To condense steam in an air-cooled condenser, large fans blow ambient air across finned tubes through which low-pressure steam flows. The low-pressure steam is cooled until it condenses. The condensate is collected in a receiver located under the air-cooled condenser. Condensate pumps will return the condensate from the receiver back to the HRSGs for reuse.

AES reviewed electrical production rates over a range of site-specific ambient conditions and operating profiles for the combined-cycle turbines, which are summarized in *Table 15 - Combined-Cycle Turbine Operating Scenarios* (cases 1 - 14), below. For the AEC site, the maximum gross output for the equipment (two combined-cycle turbines and steam generator) occurs at 59 °F ambient conditions, without evaporative coolers operating (case 12). The maximum electrical production rates are incorporated in *Table 2 – AES Rule 1304(a)(2) Offset Plan*, above.

- **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
  The proposed increase in annual operating hours does not change the process description for the combined-cycle turbines.

2. **A/N 608431, 608432--Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. CCGT-1, CCGT-2 (Combined-Cycle Turbines) (A/N 579160, 579161)**
   - **FDOC Summary**
     Each HRSG will be equipped with an oxidation catalyst and a selective catalytic reduction system located in the HRSG evaporator region.

     - *CO Oxidation Catalyst*

The CO oxidation catalyst, located between the HRSG and the SCR, will be used to control CO and VOC emissions. For the PDOC, the catalyst was required to reduce CO emissions from 7 - 8 ppm to 2 ppmv, all 1-hr averages, dry basis at 15% O_2. For the FDOC, the CO catalyst will be required to reduce the CO emissions to 1.5 ppmv, 1-hr average, dry basis at 15% O_2, in accordance with the reduction in the BACT limit from 2 ppmv to 1.5 ppmv. The catalyst will reduce the VOC from approximately 2.6 ppm to 2 ppmv, all 1-hour averages, dry basis at 15% O_2.

- *Selective Catalytic Reduction*
  The SCR catalyst will use ammonia injection in the presence of the catalyst to further reduce the NOx 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 NOx to elemental nitrogen and water, resulting in NOx concentrations in the exhaust gas decreasing from 9 ppm to 2.0 ppmv, all 1-hour averages, dry basis at 15% O_2. The ammonia slip will be limited to 5 ppmvd at 15% O_2. Each SCR will be vented through a dedicated stack, which is 20 feet diameter and 140 feet high.

  The exhaust temperature is required to be between 570 and 692 ºF, as specified in condition no. D12.10. 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 1.6 inches water column, as required by condition no. D12.11. The ammonia flow rate shall be between 44 and 242 pounds per hour, as required by condition no. D12.9.

- **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
  Condition D12.9 will be revised to change the ammonia injection rate range for SCR from the current 44 - 242 lb/hr to 20 – 242 lb/hr. Also, condition D12.10 will be revised to change the exhaust temperature range at the inlet of SCR/CO catalyst from the current 570 – 692 deg F to 450 – 800 deg F. Each stack will increase from 140 feet to 150 feet. There are no other changes to the process description.

3. **A/N 604014--Auxiliary Boiler (for Combined-Cycle Turbines) (A/N 579158)**
4. **A/N 613323--Selective Catalytic Reduction for Auxiliary Boiler (A/N 579166)**
   See separate engineering evaluation for A/N 604013, 604014, and 613323 for the RECLAIM/ Title V Revision, Auxiliary Boiler, and Auxiliary Boiler SCR, respectively. **After expedited EPA review, the permits were issued on 7/10/19.**

5. **A/N 610356, 610357, 610358, 610359—Simple-Cycle Combustion Turbine Generators Nos. SCGT-1, SCGT-2, SCGT-3, SCGT-4 (A/N 579145, 579147, 579150, 579152)**
   - **FDOC Summary**
     The simple-cycle power block will consist of the following equipment:

- Four General Electric LMS-100 PB natural-gas fired combustion turbine generators equipped with dry low NOx combustors, GE DLN 2.6. Each combustion turbine generator is rated 100.438 MW-gross and 99.087 MW-net, at 59 ºF.

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

- Each CTG will include an inlet air filter house with evaporative cooler, turbine inter-cooler and associated intercooler circulating pumps.

- Two CTGs will share one fin-fan heat exchanger.

- One 230-kV interconnection to the existing onsite SCE 230-kV switchyard.

Combustion air will flow through the inlet air filters, evaporative inlet air coolers, and associated air inlet ductwork before being compressed and cooled in the intercooler and CTG compressor section and then entering the CTG combustion sections. Natural gas will be mixed with the cool compressed air prior to being introduced to the combustion sections and ignited. The hot combustion gases will expand through the power turbine section of the CTG, causing the section to rotate and drive the electric generator and CTG compressor. The hot combustion gases will exit the turbine section and enter the control equipment consisting of the oxidation catalyst and selective catalytic reduction system.

The LMS-100 PB is a 3-spool gas turbine prime mover that uses an intercooler between the Low Pressure Compressor (LPC) and the High Pressure Compressor (HPC). Intercooling provides significant benefits to the Brayton cycle by reducing the work of compression for the HPC. This allows for higher pressure ratios, thus increasing overall efficiency. The reduced inlet temperature for the HPC allows increased mass flow resulting in higher specific power. One air-cooled closed loop fluid cooler per two CTGs will be employed to reject waste heat from the intercooler and other gas turbine auxiliaries. The air-cooled heat exchangers will use large fans to blow ambient air across finned tubes through which the closed-loop cooling water will flow.

AES reviewed electrical production rates over a range of site-specific ambient conditions and operating profiles for the simple-cycle turbines, which are summarized in *Table 31 - Simple-Cycle Turbine Operating Scenarios* (cases 1 - 14), below. For the AEC site, the maximum gross output occurs at 59 °F ambient conditions, without evaporative coolers operating (case 12). The maximum electrical production rates are incorporated in *Table 2 – AES Rule 1304(a)(2) Offset Plan*, above.

- **<u>Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)</u>**

The proposed decrease in annual operating hours does not change to the process description for the simple-cycle turbines.

7. **A/N 604020--Ammonia Storage Tank, No. Tank-1 (Combined-Cycle Turbines) (A/N 579167)**
   - **FDOC Summary**
     This 40,000-gallon ammonia tank will provide ammonia to the two SCRs for the combined-cycle turbines and the SCR for the auxiliary boiler. Aqueous ammonia, 19% by weight, will be delivered by tanker truck. The maximum number of deliveries is estimated to be four per month, with each shipment approximately 7000 gallons. The filling will take approximately 90 minutes, assuming a 3-inch filling connection between the tanker truck and the AEC ammonia filling system.

     To control the filling losses, the tanker truck will connect a filling line and a vapor return line to the AEC 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.

     The tank will be a pressure vessel with a pressure relief valve set at 50 psig. Breathing losses are not expected under normal operating conditions, because the total vapor pressure of 19% aqueous ammonia at 80 °F is 5.85 psia.

     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 in injected, it will mix with the exhaust gases upstream of the SCR catalyst.

   - **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
     The **Application** proposes to update the capacity and dimensions for the ammonia tank from 40,000 gallons, 13 ft. diameter, and 45 ft. long to 22,000 gallons, 10 ft. diameter, and 36 ft. length. AES indicated that no changes to the ammonia percent by weight content, number of deliveries, filling operations, monitoring parameters, or operating schedule are requested. Thus there is no change to the process description.

EMISSIONS CALCULATIONS

Alamitos Generating Station—Existing Equipment

- **Potential to Emit Calculations**
  *For the **Application**, the potential to emit calculations for the AGS remain the same as for the FDOC.*

  Potential to emit emissions for the AGS are required to evaluate compliance with certain rules and regulations, as discussed in the *Rule Evaluation* section below. The potential to emit emissions calculations for existing Utility Boilers Units 1 – 6 are set forth below.

1. Boiler No. 1, 1785 MMBtu/hr
2. Boiler No. 2, 1785 MMBtu/hr
   Operating schedule: 52 wk/yr, 7 days/wk, 24 hr/day = 8760 hr/yr

CO: 500 ppm CO per Rule 1303(b)(2) (permit limit)
NOx: 7 ppmv NOx per Rule 2009 (permit limit)
ROG: 5.5 lb/mmscf per annual emissions reporting (AER) default emission factors for natural gas fired boiler
SOx: 0.6 lb/mmscf per AER default emission factors for natural gas fired boiler
PM/PM_{10}: 7.6 lb PM/mmscf per AER default emission factor for natural gas fired boiler
$PM_{2.5}$: 0.00113 lb/MMBTU—Emission factor approved by the South Coast AQMD Source Testing Dept., 9/2/15

CO = (1,785,000,000 Btu/hr) (8710 dscf/10^6 Btu)(500 ppm CO/10^6)
(20.9/(20.9-3.0)) (28 lbs CO/379 scf) (8760 hr/yr)(ton/2000 lb)
= 2937.06 tpy

NOx = (1,785,000,000 Btu/hr) (8710 dscf/10^6 Btu) (7 ppm/10^6)(20.9/(20.9-3.0))
(46 lbs NOx/385 scf for NOx RECLAIM) (8760 hr/yr)(ton/2000 lb) = 66.5 tpy

For combustion emissions, the standard assumption is PM_{10} = PM.
PM_{10} = (1,785,000,000 Btu/hr) (cf/1050 Btu) (7.6 lb PM_{10}/10^6 cf)
(8760 hr/yr) (ton/2000 lb) = 56.6 tpy

$PM_{2.5}$ = (1,785 MMBtu/hr) (0.00113 lb $PM_{2.5}$/MMBtu) (8760 hr/yr) (ton/2000 lb)
= 8.83 tpy

ROG = (1,785,000,000 Btu/hr) (cf/1050 Btu) (5.5 lb ROG AER/10^6 cf)
(8760 hr/yr)(ton/2000 lb) = 41.0 tpy

SOx = (1,785,000,000 Btu/hr) (cf/1050 Btu) (0.6 lb SOx AER/10^6 cf)
(8760 hr/yr) (ton/2000 lb) = 4.5 tpy

Combustion of natural gas in the turbines will result in greenhouse gas emissions of CO_2, CH_4, and N_2O. Emission factors for CO_2, CH_4, and N_2O are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised April 4, 2014.

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

CO_2 = (1785 MMBtu/hr)(8760 hr/yr)(53.06 kg/MMBtu)(2.2046 lb/kg)(ton/2000 lb)
= 914,554.06 tpy

CH_4 = (1785 MMBtu/yr)(8760 hr/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g) (ton/2000 lb)
= 17.24 tpy

N_2O = (1785 MMBtu/hr)(8760 hr/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g)(ton/2000 lb)
= 1.7 tpy

CO_2e emissions are equal to the sum of the mass emission of each individual GHG adjusted for its global warming potential. Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as amended by 79 FR 73779, 12/11/14: *(1)* CH_4 is equivalent to 25 times the global warming potential of CO_2, and *(2)* N_2O is equivalent to 298 times of CO_2.

CO_2e = (914,554.06 tpy CO_2)(1 lb CO_2e/lb CO_2) + (17.24 tpy CH_4)
(25 lb CO_2e/lb CH_4) + (1.7 tpy N_2O)(298 lb CO_2e/lb N_2O) = 915,491.66 tpy

3. <u>Boiler No. 3, 3350 MMBtu/hr</u>
4. <u>Boiler No. 4, 3350 MMBtu/hr</u>

Operating schedule: 52 wk/yr, 7 days/wk, 24 hr/day = 8760 hr/yr

CO:	300 ppm CO per Rule 1303(b)(2) (permit limit)
NOx:	7 ppmv NOx per Rule 2009 (permit limit)
ROG:	5.5 lb/mmscf per AER default emission factors for natural gas fired boiler
SOx:	0.6 lb/mmscf per AER default emission factors for natural gas fired boiler
PM/PM_{10}:	7.6 lb PM/mmscf per AER default emission factor for natural gas fired boiler
$PM_{2.5}$:	0.00113 lb/MMBTU—Emission factor approved by the South Coast AQMD Source Testing Dept., 9/2/15

CO = (3,350,000,000 Btu/hr) (8710 dscf/10^6 Btu)(300 ppm CO/10^6)
(20.9/(20.9-3.0)) (28 lbs CO/379 scf)(8760 hr/yr)(ton/2000 lb)
= 3307.28 tpy

NOx = (3,350,000,000 Btu/hr) (8710 dscf/10^6 Btu) (7 ppm/10^6)(20.9/(20.9-3.0))
(46 lbs NOx/385 scf for NOx RECLAIM) (8760 hr/yr)(ton/2000 lb) =
124.80 tpy

For combustion emissions, the standard assumption is PM_{10} = PM.
PM_{10} = (3,350,000,000 Btu/hr) (cf/1050 Btu) (7.6 lb PM_{10}/10^6 cf) (8760 hr/yr)
(ton/2000 lb) = 106.20 tpy

$PM_{2.5}$ = (3,350.0 MMBtu/hr) (0.00113 lb $PM_{2.5}$/MMBtu) (8760 hr/yr) (ton/2000 lb)

= 16.58 tpy

ROG = (3,350,000,000 Btu/hr) (cf/1050 Btu) (5.5 lb ROG AER/10^6 cf) (8760 hr/yr)(ton/2000 lb) = 76.86 tpy

SOx = (3,350,000,000 Btu/hr) (cf/1050 Btu) (0.6 lb SOx AER/10^6 cf) (8760 hr/yr) (ton/2000 lb) = 8.38 tpy

CO_2 = (3,350 MMBtu/hr)(8760 hr/yr)(53.06 kg/MMBtu)(2.2046 lb/kg) (ton/2000 lb) = 1,716,389.96 tpy

CH_4 = (3,350 MMBtu/yr)(8760 hr/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g) (ton/2000 lb) = 32.35 tpy

N_2O = (3,350 MMBtu/hr)(8760 hr/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g) (ton/2000 lb) = 3.24 tpy

CO_2e = (1,716,389.96 tpy CO_2)(1 lb CO_2e/lb CO_2) + (32.35 tpy CH_4) (25 lb CO_2e/lb CH_4) + (3.24 tpy N_2O)(298 lb CO_2e/lb N_2O) = 1,718,164.23 tpy

5. <u>Boiler No. 5, 4750 MMBtu/hr</u>
6. <u>Boiler No. 6, 4752.2 MMBtu/hr</u>

Operating schedule: 52 wk/yr, 7 days/wk, 24 hr/day = 8760 hr/yr

CO: 300 ppm CO per Rule 1303(b)(2) (permit limit)
NOx: 5 ppmv NOx per Rule 2009 (permit limit)
ROG: 5.5 lb/mmscf per AER default emission factors for natural gas fired boiler
SOx: 0.6 lb/mmscf per AER default emission factors for natural gas fired boiler
PM/PM_{10}: 7.6 lb PM/mmscf per AER default emission factor for natural gas fired boiler
$PM_{2.5}$: 0.00113 lb/MMBTU— Emission factor approved by the South Coast AQMD Source Testing Dept., 9/2/15

CO = (4,752,200,000 Btu/hr) (8710 dscf/10^6 Btu)(300 ppm CO/10^6) (20.9/(20.9-3.0)) (28 lbs CO/379 scf)(8760 hr/yr)(ton/2000 lb) = 4691.59 tpy

NOx = (4,752,200,000 Btu/hr) (8710 dscf/10^6 Btu) (5 ppm/10^6)(20.9/(20.9-3.0)) (46 lbs NOx/385 scf for NOx RECLAIM) (8760 hr/yr)(ton/2000 lb) = 126.5 tpy

For combustion emissions, the standard assumption is PM_{10} = PM.

PM_{10} = (4,752,200,000 Btu/hr) (cf/1050 Btu) (7.6 lb $PM_{10}/10^6$ cf) (8760 hr/yr) (ton/2000 lb) = 150.7 tpy

$PM_{2.5}$ = (4,752.2 MMBtu/hr) (0.00113 lb $PM_{2.5}$/MMBtu) (8760 hr/yr) (ton/2000 lb) = 23.52 tpy

ROG = (4,752,200,000 Btu/hr) (cf/1050 Btu) (5.5 lb ROG AER/10^6 cf) (8760 hr/yr)(ton/2000 lb) = 109.0 tpy

SOx = (4,752,200,000 Btu/hr) (cf/1050 Btu) (0.6 lb SOx AER/10^6 cf) (8760 hr/yr) (ton/2000 lb) = 11.9 tpy

CO_2 = (4,752.2 MMBtu/hr)(8760 hr/yr)(53.06 kg/MMBtu)(2.2046 lb/kg) (ton/2000 lb) = 2,434,814.44 tpy

CH_4 = (4,752.2 MMBtu/yr)(8760 hr/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g) (ton/2000 lb) = 45.9 tpy

N_2O = (4,752.2 MMBtu/hr)(8760 hr/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g) (ton/2000 lb) = 4.59 tpy

CO_2e = (2,434,814.44 tpy CO_2)(1 lb CO_2e/lb CO_2) + (45.9 tpy CH_4) (25 lb CO_2e/lb CH_4) + (4.59 tpy N_2O)(298 lb CO_2e/lb N_2O) = 2,437,329.76 tpy

Table 13 - Alamitos Generating Station Potential to Emit Emissions

	Boiler No. 1	**Boiler No. 2**	**Boiler No. 3**	**Boiler No. 4**	**Boiler No. 5**	**Boiler No. 6**	**AGS Total**
CO (tpy)	2937.06	2937.06	3307.28	3307.28	4691.59	4691.59	21,871.86
NO_x (tpy)	66.5	66.5	124.80	124.80	126.5	126.5	635.60
PM_{10} (tpy)	56.6	56.6	106.20	106.20	150.7	150.7	627.0
$PM_{2.5}$ (tpy)	8.83	8.83	16.58	16.58	23.52	23.52	97.86
ROG (tpy)	41	41	76.86	76.86	109	109	453.72
SO_2 (tpy)	4.5	4.5	8.38	8.38	11.9	11.9	49.56
CO_2 (tpy)	914,554.06	914,554.06	1,716,389.96	1,716,389.96	2,434,814.44	2,434,814.44	10,131,516.92
CH_4 (tpy)	17.24	17.24	32.35	32.35	45.9	45.9	190.98
N_2O (tpy)	1.7	1.7	3.24	3.24	4.59	4.59	19.06
CO_2e (tpy)	915,491.66	915,491.66	1,718,164.23	1,718,164.23	2,437,329.76	2,437,329.76	10,141,971.30

- **Actual Emissions**
  *For the **Application**, the baseline actual emissions for the AGS remain the same as for the FDOC.*

Baseline actual emissions for the AGS are required to evaluate compliance with federal regulations, as discussed in the Rule Evaluation section below.

Table 14 – Alamitos Generating Station Actual Emissions (2013 & 2014)

		NOx	CO	ROG	PM_{10}/ $PM_{2.5}$	SOx	CO_2e
Year	**Unit**	**lb/year (tpy)**					**tpy**
2013	**1**	2,647	23,163	441	227	132	13,145
	2	4,433	64,091	457	830	249	24,677
	3	29,338	108,183	7,289	6,905	2,302	219,554
	4	18,576	14,976	3,298	4,656	2,328	219,662
	5	22,645	430,872	4,005	6,084	3,042	310,231
	6	17,642	72,405	1,786	2,848	1,553	154,020
2014	**1**	2,296	43,095	621	320	186	18,702
	2	9,794	252,396	1,350	2,454	736	73,661
	3	39,237	42,794	9,796	9,281	3,094	309,806
	4	29,729	1,743	4,938	6,972	3,486	349,018
	5	2,798	75,627	603	916	458	45,880
	6	10,750	22,257	1,347	2,148	1,171	117,162
Total 2013		95,284	713,690	17,276	21,550	9,606	941,292
Total 2014		94,604	437,913	18,656	22,090	9,131	914,231
2-Year Average		94,944 (47.47)	575,802 (287.90)	17,966 (8.98)	21,820 (10.91)	9,369 (4.68)	927,761

NOx, CO, ROG, PM_{10}/$PM_{2.5}$, and SOx are based on AGS's Annual Emissions Reports. CO_2e emissions are based on actual gas usage.

EMISSIONS CALCULATIONS

1. **A/N 604015/A/N 610354, A/N 604018/610355—Combined-Cycle Combustion Turbine Generators Nos. CCGT-1, CCGT-2 (A/N 579142, 579143)**

   The combined-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 engineering estimates.

   A. **Criteria Pollutants**

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

   - Worst Case Operating Scenario

To determine the worst case operating scenario that yields the highest controlled emissions, the applicant provided fourteen 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%, 75%, and approximately 45%) at four ambient temperatures (28 ºF, 59.0 ºF, 65.3 ºF, and 107 ºF), and with or without evaporative cooling of the inlet air to the turbines.

The following table summarizes the operating scenarios data and is the same as *Table 15* in the FDOC.

Table 15 – Combined-Cycle Turbine Operating Scenarios

Case No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
CTG Load Level (%)	100	75	45	100	100	75	44	100	100	75	48	100	75	44
CTG Inlet Air Cooling	Off	Off	Off	On	Off	Off	Off	On	Off	Off	Off	Off	Off	Off
Ambient Conditions														
Ambient Temperature (°F)	28.0	28.0	28.0	65.3	65.3	65.3	65.3	107	107	107	107	59.0	59.0	59.0
Ambient Relative Humidity (%)	76%	76%	76%	87%	87%	87%	87%	11%	11%	11%	11%	60%	60%	60%
Combustion Turbine Performance														
Gross GTG Output, kW (one CTG)	236,645	177,484	106,017	229,659	227,708	170,781	101,102	217,778	194,136	145,602	92,797	231,197	173,398	101,727
Net CTG Output, kW (one CTG)	235,907	176,746	105,279	228,921	226,970	170,043	100,364	217,040	193,398	144,864	92,059	230,459	172,660	100,989
CTG Heat Input, MMBtu/hr (LHV) (one CTG)	2,052	1,619	1,245	2,029	2,019	1,568	1,179	1,942	1,754	1,403	1,126	2,032	1,582	1,182
CTG Heat Input, MMBtu/hr (HHV) (one CTG)	2,275	1,795	1,380	2,250	2,239	1,739	1,307	2,153	1,945	1,556	1,249	2,253	1,755	1,310
CTG Exhaust Temperature, ºF (one CTG)	1,104	1,112	1,215	1,142	1,142	1,153	1,215	1,119	1,162	1,204	1,215	1,139	1,144	1,215
Gross 2x1 Combined-Cycle, kW	692,905	529,868	355,002	688,980	684,653	519,700	342,082	628,950	569,016	435,703	307,722	692,951	524,659	342,458
Net 2x1 Combined-Cycle, kW	680,779	516,621	344,352	672,444	668,221	505,408	331,820	612,912	554,506	423,721	297,721	676,320	510,231	332,184
Gross STG Output, kW	219,615	174,900	142,968	229,662	229,237	178,138	139,878	193,394	180,744	144,499	122,128	230,557	177,863	139,004
Stack Parameters														
Stack Exit Temperature, °F	216	178	170	213	215	175	170	221	223	198	184	209	174	170
Stack Diameter, ft.	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Stack Exit Velocity, ft/sec	67.0	51.2	40.0	66.0	66.2	48.9	38.8	66.3	59.9	46.0	39.9	65.6	49.3	38.7
CTG Outlet/Catalyst Inlet concentrations														
NOx, ppmvd (dry, 15% O_2)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
CO, ppmvd (dry, 15% O_2)	7.08	7.27	7.52	6.97	7.01	7.10	7.59	7.24	7.31	7.28	8.12	7.02	7.17	7.62
VOC, ppmvd (dry, 15% O_2)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Catalyst Outlet/Stack Emissions Rates														
NOx, 2.0 ppmvd (dry, 15% O_2) BACT, lb/hr as NO_2	16.5	13.0	10.0	16.3	16.2	12.6	9.47	15.6	14.1	11.3	9.05	16.3	12.7	9.49

CO, 1.5 ppmvd (dry, 15% O_2) BACT, lb/hr	7.53	5.94	4.57	7.44	7.41	5.76	4.33	7.13	6.44	5.15	4.13	7.46	5.81	4.34
VOC, 2.0 ppmvd (dry, 15% O_2) BACT, lb/hr	5.75	4.54	3.49	5.68	5.66	4.39	3.30	5.44	4.92	3.93	3.16	5.69	4.43	3.31
$PM_{10}/PM_{2.5}$, lb/hr (including ammonium sulfate, assuming 100% conversion from SO_3)[1]	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50
SO_2 short-term rate (0.75 grains/100 scf), lb/hr[2]	4.86	3.84	2.95	4.81	4.78	3.72	2.79	4.60	4.16	3.33	2.67	4.82	3.75	2.80
SO_2 long-term rate (0.25 grains/100 scf), lb/hr	1.62	1.28	0.98	1.60	1.59	1.24	0.93	1.53	1.39	1.11	0.89	1.61	1.25	0.93
SCR NH_3 slip, 5.0 ppmvd (dry, 15% O_2) BACT, lb/hr	15.3	12.0	9.26	15.1	15.0	11.7	8.77	14.4	13.0	10.4	8.38	15.1	11.8	8.79

1 A percentage of the SO_2 in the turbine exhaust is assumed to oxidize to SO_3 in the CO catalyst and SCR. The SO_3 reacts with ammonia in the SCR to form ammonium sulfate particulates. Total PM_{10} is comprised of the ammonium sulfate particulates and the PM_{10} 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.

Case 1, based on 100% load, 28 °F ambient temperature, and without inlet cooling, is the worst case operating scenario that yields the highest controlled emissions. The emissions rates for NOx, CO, VOC, $PM_{10}/PM_{2.5}$, and the short-term SO_2 rate (0.75 grains/100 scf) were used to calculate the normal operation emissions component for the maximum daily emissions and maximum monthly emissions. Since Case 1 is the scenario that yields the highest Btu/hr consumption for each turbine, it is also the basis for the equipment description on the facility permit.

Case 4, based on 100% load, 65.3 °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 NOx, CO, VOC, $PM_{10}/PM_{2.5}$, and the long-term SO_2 rate (0.25 grains/100 scf) were used to calculate the normal operation emissions component for maximum annual emissions. Condition B61.1 requires testing to confirm the long-term SO_2 rate of 0.25 grains/100 scf, which is expected to be the average content.

Case 12, based on 100% load, 59 °F ambient temperature, and without inlet cooling, yields the maximum gross output for the equipment (two combined-cycle turbines and the steam generator). This maximum rating is used for the purposes of Rule 1304(a)(2) compliance demonstration and Rule 1304.1 fee calculation.

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

- <u>Four Operational Modes</u>
  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. In AES Response Letter, dated 12/11/15, the applicant has clarified that the combustors are not expected to require tuning after commissioning.

  <u>Commissioning</u>
  *The **FDOC** provided the following analysis. For the **Application** under evaluation here, the analysis remains the same as for the FDOC because AES did not request any changes to commissioning emissions or schedule.*

  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, HRSGs, SCR/CO catalysts, and STG.

The NOx, 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 $PM_{10}/PM_{2.5}$ and SO_2 emission rates are the same as during normal operation, because these pollutants are not controlled by the SCR/CO catalysts.

The following table provides a summary of the commissioning activity parameters and emissions and is the same as *Table 16* in the FDOC.

Table 16 - Combined-Cycle Turbine Commissioning Activity Parameters and Emissions

					Reduction (%)			Total Controlled Emissions, lb				
Activity	**Duration (hr)**	**CTG Load (%)**	**Fuel Use (MMSCF/hr)**	**Fuel Use (MMSCF/ Activity)**	**NOx (SCR)**	**CO (OxCat)**	**VOC (OxCat)**	**NOx**	**CO**	**VOC**	**SOx**	**$PM_{10}/PM_{2.5}$**
CTG Testing (Full Speed No Load, FSNL)	48	10	0.6866	32.9581	0%	0%	0%	6,240	91,200	12,960	233	408
Steam Blows	120	40	1.2694	152.3331	0%	0%	0%	8,190	3,888	360	583	1,020
Set Unit HRSG & Steam Safety Valves	12	40	1.2694	15.2333	0%	0%	0%	819	389	36.0	58.3	102
Steam Blows – Restoration												
DLN Emissions Tuning	12	50	1.3541	16.2487	0%	0%	0%	567	285	24.0	58.3	102
Emissions Tuning	12	60	1.4913	17.8956	0%	0%	0%	630	298	24.0	58.3	102
Emissions Tuning	12	80	1.8323	21.9881	0%	0%	0%	756	350	30.0	58.3	102
Restart CTGs and run HRSG in Bypass Mode. STG Bypass Valve Tuning. HRSG Blow Down and Drum Tuning												
Verify STG on Turning Gear, Establish Vacuum in ACC Ext Bypass Blowdown to ACC (Combined Blows). Commence Tuning On ACC Controls. Finalize Bypass Valve Tuning. ACC Cleaning.	168	80	1.8323	307.8339	78%	78%	35%	2,328	1,078	273	816	1,428
CT Base Load Testing/Tuning	24	100	2.1734	52.1613	78%	78%	35%	388	182	46.8	117	204
Load Test STG / Combined-Cycle (2 x 1) Tuning	48	50	1.3541	64.9947	78%	78%	35%	499	251	62.4	233	408
STG Load Test/ Combined-Cycle Tuning	96	80	1.8323	175.9051	78%	78%	35%	1,331	616	156	467	816
RATA/ Pre-Performance Testing/Source Testing	84	80	1.8323	153.9170	78%	78%	35%	1,164	539	137	408	714
Source Testing & Drift Test Day 1	24	50	1.3541	32.4973	78%	78%	35%	249	125	31.2	117	204
Source Testing & Drift Test Day 2	24	50	1.3541	32.4973	78%	78%	35%	249	125	31.2	117	204
Source Testing & Drift Test Day 3	24	50	1.3541	32.4973	78%	78%	35%	249	125	31.2	117	204
Source Testing & Drift Test Day 4	24	50	1.3541	32.4973	78%	78%	35%	249	125	31.2	117	204
Source Testing & Drift Test Day 5	24	50	1.3541	32.4973	78%	78%	35%	249	125	31.2	117	204
Source Testing & Drift Test Day 6	24	50	1.3541	32.4973	78%	78%	35%	249	125	31.2	117	204
Source Testing & Drift Test Day 7	24	50	1.3541	32.4973	78%	78%	35%	249	125	31.2	117	204
Performance Testing	132	100	2.1734	286.8873	78%	78%	35%	2,134	1,004	257	642	1,122
CALISO Certification & Testing/PPA Testing	60	75	2.1734	130.4033	78%	78%	35%	804	371	97.5	292	510
Total for One CTG	**996**			**1656.24**				**27,597**	**101,328**	**14,682**	**4,841**	**8,466**

The applicant requested 996 hours of fired operation for the commissioning of each combined-cycle turbine, as indicated in the table above. The commissioning for each turbine is expected to extend over a period of six months.

<u>*Startup of Combined-Cycle Turbines*</u>
*For the **Application** under evaluation here, the analysis remains the same as for the FDOC because AES did not request any changes to the annual number of startups per turbine.*

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 NOx, CO, and VOC due to the phased-in effectiveness of the SCR and CO oxidation catalysts.

Two startup scenarios have been developed for the combined-cycle turbines.

1) For a **cold start event**, the combustion turbine and the steam generation system are all at ambient temperature at the time of the startup, which occurs when 48 hours or more has elapsed between a shutdown event and a system startup event. For the cold start event, the time from fuel initiation until reaching the baseload operating rate is expected to take up to 60 minutes.

2) A **non-cold start event** occurs less than 48 hours from a shutdown event. The time from fuel initiation until reaching the baseload operating rate is expected to take up to 30 minutes.

   Non-cold starts include (a) **warm start events** that occur 10 hours or more but less than 48 hours from a shutdown event and (b) **hot start events** that occur less than 10 hours of a shutdown event. Emissions and duration are the same for warm start events and hot start events.

For daily emissions (for modeling) and monthly emissions, the **Application** did not request any changes to the daily and monthly number of startups per turbine.

For annual emissions, the **Application** did not request any changes to the annual number of startups per turbine. The modification under evaluation will continue to be based on a maximum of 80 cold starts and 420 non-cold starts per turbine, the same as for the FDOC.

<u>*Shutdown of Combined-Cycle Turbines*</u>
*For the **Application** under evaluation here, the analysis remains the same as for the FDOC because AES did not request any changes to the annual number of shutdowns per turbine.*

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 greater than during normal operation because the ammonia injection into the SCR reactor 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 30 minutes.

For daily emissions (for modeling) and monthly emissions, the **Application** did not request any changes in the daily and monthly number of shutdowns per turbine.

For annual emissions, the **Application** did not request any changes in the annual number of shutdowns per turbine. The modification under evaluation will continue to be based on a maximum of 500 shutdowns per turbine, the same as for the FDOC.

- *Startup/Shutdown Emissions*
  The following table provides the durations and emissions for the three types of startup events and the shutdown event. The only change to *Table 17* in the FDOC is that the warm starts and hot starts are now collectively designated as "non-cold starts" for the **Application**.

Table 17 – Combined-Cycle Turbine Start-up/Shutdown Emission Rates

	Duration Minutes (hr)	NOx lb/event	CO lb/event	VOC lb/event	PM_{10} lb/hr (lb/event)	$PM_{2.5}$ lb/hr (lb/event)	SO_2 lb/hr (lb/event)
Cold Start	60 (1.0)	61.0	325	36.0	< 8.50 (8.50)	< 8.50 (8.50)	Short-term: < 4.86 (4.86) Long-term: < 1.62 (1.62)
~~Warm~~ **<u>Non-Cold</u>** Start	30 (0.5)	17.0	137	25.0	< 8.50 (4.25)	< 8.50 (4.25)	Short-term: < 4.86 (2.43) Long-term: < 1.62 (0.81)
~~Hot Start~~	~~30 (0.5)~~	~~17.0~~	~~137~~	~~25.0~~	~~< 8.50 (4.25)~~	~~< 8.50 (4.25)~~	~~Short-term: < 4.86 (2.43)~~ ~~Long-term: < 1.62 (0.81)~~
Shutdown	30 (0.5)	10.0	133	32.0	< 8.50 (4.25)	< 8.50 (4.25)	Short-term: < 4.86 (2.43) Long-term: < 1.62 (0.81)

- *Startup/Shutdown Conditions*
  For the ***Application*** *under evaluation here, the following analysis remains the same as for the FDOC.*

  In lieu of requiring steady state BACT at all times, EPA accepted an alternative BACT which limits and minimizes emissions during periods when steady state BACT is not achievable, such as during startups and shutdowns. Condition no. C1.3 provides limits for startups, and condition no. C1.4 provides limits for shutdowns. The limits are necessary because condition nos. A195.8, A195.9, and A195.10 state that BACT for NO_x, CO, and VOC, respectively, shall not apply during startups and shutdowns. The startup limits include: (1) number of cold starts per calendar month and year; (2) number of non-cold starts per calendar month and year; (3) number of starts per day; (4) duration of cold starts and non-cold starts; and (5) NOx, CO, and VOC emission limits per cold start and non-cold start. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdowns; and (3) NOx, CO, and VOC emission limits per shutdown. Condition nos. C1.3 and C1.4 will remain the same as in the FDOC.

<u>Normal Operation</u>
*For the **Application** under evaluation here, the following analysis remains the same as for the FDOC.*

Normal operation occurs after the CTGs, HRSGs, SCR/CO catalysts, and STG are working optimally. The emissions during normal operations are assumed to be fully controlled to BACT levels, and exclude emissions due to commissioning, startup and shutdown periods, which are not subject to BACT levels. NOx is controlled to 2.0 ppmvd, CO to 1.5 ppmvd, and VOC to 2.0 ppmvd, all 1-hr averages, at 15% O2.

- *<u>Maximum Daily, Monthly, Annual, NSR Emissions Calculations</u>*
  *For the **Application** under evaluation here, the analysis for the maximum daily emissions, maximum monthly emissions, and associated emission factors and permit condition limits will remain the same as for the FDOC, as discussed below.*

  - *<u>Maximum Daily Emissions per Turbine</u>*
    Maximum daily emissions during normal operations are calculated to determine whether BACT/LAER for non-RECLAIM pollutants are applicable. The BACT/LAER analysis under *Regulation XIII—New Source Review* below explains that the applicability threshold is an increase of 1 lb/day of uncontrolled emissions for non-RECLAIM pollutants. This maximum daily emissions are based on realistic maximum daily emissions, not the 30-day average. The 30-day average is used for offsets, not BACT/LAER applicability.

    - <u>Commissioning Month</u>
      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.

    - <u>Normal Operating Month</u>
      For the **Application**, the maximum daily emissions for all criterial pollutants will remain the same as for the FDOC because the (1) number of normal operating hours, (2) normal operating emission rates for all pollutants, (3) emissions for cold starts, non-cold starts

and shutdowns for all pollutants, and (4) number of cold, noncold, and shutdowns all remain the same as for the FDOC. The normal operating emission rates are from *Table 15* (case 1) above, and the startup and shutdown emissions per event are from *Table 17 above.* The SO_x emission rates are based on the short-term rate (0.75 grains/100 scf).

For strict BACT/LAER applicability for non-RECLAIM pollutants, the increase in daily emissions are based on uncontrolled emissions. As it is already known that the installation of a combined-cycle turbine requires BACT/LAER, the maximum controlled daily emissions for normal operations are shown in the table below for informational purposes. The only change to *Table 18* in the FDOC is that the "warm" startups have been updated to "non-cold" startups.

Table 18 - Combined-Cycle Turbine Maximum Daily Emissions

Pollutants	No. of Normal Operating Hr	Normal Operation Emission Rate, lb/hr (Case 1)	No. of Cold Startups	Lb/cold Startup	No. of ~~Warm~~ Non-Cold Startups	Lb/~~Warm~~ Non-Cold Startup	No. of Shutdowns	Lbs/ Shutdown	Maximum Daily Emissions lb/day
NOx	21	16.5	2	61	0	17	2	10	488.50
CO	21	7.53	2	325	0	137	2	133	1074.13
VOC	21	5.75	2	36	0	25	2	32	256.75
$PM_{10}/PM_{2.5}$	21	8.50	2	8.50	0	4.25	2	4.25	204.00
SOx	21	4.86	2	4.86	0	2.43	2	2.43	116.64

No. of normal operating hours = 24 hr/day – (2 cold start/day)(1.0 hr/cold start) - (0 non-cold start/day) (0.5 hr/non-cold start) - (2 shutdowns/day)(0.5 hr/shutdown) = 21 hr

Maximum Daily Emissions, lb/day = (no. normal operating hours) (normal emission rate, Case 1) + (no. starts, cold) (lb/startup, cold) + (no. startups, non-cold) (lb/startup, non-cold) + (no. shutdowns) (lb/shutdown)

- *Maximum Monthly Emissions and Emission Factors per Turbine*
  Condition A63.2 specifies the monthly emissions limits for CO, VOC, PM_{10}/**$PM_{2.5}$**, and SOx. Monthly limits are required to establish a basis for calculating offset requirements and ensure compliance with BACT requirements. RECLAIM rules do not allow a monthly limit for NOx. The monthly emissions for NOx, however, are indirectly limited by the monthly emissions limits for CO, VOC, PM_{10}/**$PM_{2.5}$**, and SOx. The number of RECLAIM RTCs required are determined on an annual basis and reflected in conditions I297.1 and I297.2.

  The maximum monthly emissions and 30-day averages 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. AES indicated there will be no combination commissioning/normal operating month. Therefore, the FDOC evaluated the maximum commissioning month(s) emissions and maximum normal operating month emissions only. In addition, the commissioning emission factors and normal operating emission factors are included in condition A63.2 for CO, VOC, PM_{10}/**$PM_{2.5}$**, and SOx. The commissioning emission factor and the post-commissioning/pre-CEMS certification emission factor are included in conditions A99.1 and A99.2, respectively, for NOx.

- Commissioning Months
  - Maximum Monthly Emissions, Commissioning
    For the **Application**, the maximum monthly emissions for commissioning for all criterial pollutants will remain the same as for the FDOC because the applicant has not requested any changes to the commissioning.

    For the FDOC, the applicant indicated that the commissioning period would extend over a period of six full months, and would not overlap with steady-state operation of the CTGs. The number of commissioning hours per month per turbine would be 166 hours.

    The table below summarizes the maximum monthly emissions for each pollutant from any one of the six months of commissioning. The table is the same as *Table 19* in the FDOC.

Table 19 – Combined-Cycle Turbine Maximum Monthly Emissions, Commissioning

Pollutants	Month	Commissioning Emissions, lb/month
NOx	One	14,293.5
CO	One	95,023.2
VOC	One	13,314.0
$PM_{10}/PM_{2.5}$	All months	1411
SOx	Five	809

  - Commissioning Emission Factors
    For the **Application**, the commissioning period emission factors in condition no. A63.2 for CO (61.18 lb/mmcf), VOC (8.86 lb/mmcf) , PM_{10}/**$PM_{2.5}$** (5.11 lb/mmcf), and SOx (2.92 lb/mmcf), and in condition no. A99.1 for NOx (16.66 lb/mmscf) will remain the same as for the FDOC. As explained in the Rule 2012 analysis below, condition no. A99.1 specifies the interim emission factor for NOx for the commissioning period (no certified CEMS), during which the CTGs are assumed to be operating at uncontrolled and partially controlled levels. For each pollutant, the emission factor is calculated as the total emissions for the commissioning period divided by the total fuel usage for the commissioning period, both of which are shown in *Table 16 - Combined-Cycle Turbine Commissioning Activity Parameters and Emissions* above and both of which will remain the same as for the FDOC.

- Normal Operating Month
  - Maximum Normal Operating Month Emissions

    For the FDOC, the applicant indicated that the normal operating month will begin in the first month following completion of commissioning activities, with no commissioning carry-over.

    For the **Application**, the maximum normal operating month emissions per combined-cycle turbine will remain the same as for the FDOC, because the (1) number of normal operating hours, (2) normal operating emission rates for all pollutants, (3) emissions for cold starts, non-cold starts and shutdowns for all pollutants, and (4) number of cold, noncold, and shutdowns will remain the same as for the FDOC.

    For the FDOC, the applicant requested (1) 674.5 normal operating hours, (2) 15 cold starts (15 hr total), (3) 12 warm starts (6 hr total), (4) 35 hot starts (17.5 hr total), and (5) 62 shutdowns (31 hr total), for a total of 744 hours per month. The normal operating emission rates are from *Table 15* (case 1) above, and the startup and shutdown emissions per event are from *Table 17 above.* The SO_x emission rates are based on the short-term rate (0.75 grains/100 scf). **(In an e-mailed dated 2/2/16, AES clarified that 0.75 grains/100 scf will be used for daily and monthly emissions, instead of the 0.25 grains/100 scf initially proposed.)**

    The table below shows the maximum normal operating month emissions. The only change to *Table* 21 in the FDOC is that the hot starts and warm starts have been combined and updated to non-cold starts.

Table 21 - Combined-Cycle Turbine Maximum Monthly Emissions, Normal Operations

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr (Case 1)	No. of Cold Starts	Lb/Cold Start	No. of Non-Cold Starts	Lb/Non-cold start	No. of Shut downs	Lb/Shutdown	Maximum Monthly Emissions lb/month (tons/month)
NOx	674.5	16.5	15	61	47	17	62	10	13,463.25 (6.73)
CO	674.5	7.53	15	325	47	137	62	133	24,638.99 (12.32)
VOC	674.5	5.75	15	36	47	25	62	32	7577.38 (3.79)
$PM_{10}/PM_{2.5}$	674.5	8.50	15	8.50	47	4.25	62	4.25	6324.00 (3.16)
SOx	674.5	4.86	15	4.86	47	2.43	62	2.43	3615.84 (1.81)

Maximum Monthly Emissions, lb/month = (no. normal operating hours) (normal emission rate, Case 1) + (no. startups, cold) (lb/startup, cold) + (no. startups, non-cold) (lb/startup, non-cold) + (no. shutdowns) (lb/shutdown)

- Normal Operating Emission Factors

  For the **Application**, the normal operating emission factors in condition no. A63.2 for ~~CO (15.28 lb/mmcf)~~, VOC (4.70 lb/mmcf), PM_{10}/**$PM_{2.5}$** (3.92 lb/mmcf), and SOx (2.24 lb/mmcf), and in condition no. A99.2 for NOx (8.35 lb/mmscf)will remain the same as for the FDOC.

The normal operating emission factors are calculated as shown in the table below.

Table 22 - Combined-Cycle Turbine Normal Operating Emission Factors - Monthly Limits

Pollutants	Maximum Monthly Emissions, lb/month	Emission Factors, lb/mmcf
NOx	13,463.25	8.35
CO	24,638.99	15.28
VOC	7577.38	4.70
PM_{10}/**<u>$PM_{2.5}$</u>**	6324.0	3.92
SOx	3615.84	2.24

Emission factor, lb/mmcf = (lb/month) (month/1612 mmscf)

Where max monthly fuel usage = (744 hours, incl. startups/shutdowns) (2275 MMBtu/hr, Case 1) (mmscf/1050 MMBtu) = 1612 mmscf/month

However, for the CO emission factor, the condition will be revised to add: **<u>For normal operation, the CO emissions shall be measured with the certified CO CEMS. For the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the emission factor shall be CO, 15.28 lb/mmcf.</u>**

As explained in the Rule 2012 analysis below, condition no. A99.2 specifies the interim emission factor for NOx for the normal operating period after commissioning has been completed but before the CEMS is certified, during which the CTGs are assumed to be operating at BACT levels. For each pollutant, the emission factor is calculated as the maximum normal operating month emissions divided by the total fuel usage for the month, both of which will remain the same as for the FDOC.

- <u>Permit Conditions—Monthly Emissions Limits</u>
  Condition no. A63.2 specifies the maximum monthly emissions limits per turbine for CO, VOC, PM_{10}/**<u>$PM_{2.5}$</u>**, and SOx. For each pollutant, the maximum monthly emissions and 30-day averages for each pollutant are based on the higher of the emissions for a commissioning month (*Table 19*) or a normal operating month (*Table 21*). The condition A63.2 monthly emissions limits per turbine will remain the same as in the FDOC because the maximum commissioning month emissions and the maximum normal operating month emissions will remain the same.

  The table below compares the maximum commissioning month emissions with the maximum normal operating month emissions (higher values in bold font) to determine the maximum monthly emissions limits and associated 30-day averages. There are no changes from *Table 23* in the FDOC. (Although condition no. A63.2 will not include a monthly limit for NOx, it is included in the table below because the determination of 30-day averages for all pollutants is required for the internal NSR Data Summary Sheet.)

Table 23 – Combined-Cycle Turbine Maximum Monthly Emissions and Thirty-Day Averages

Pollutants	Maximum Commissioning Month Emissions, lb/month (lb/day)	Maximum Normal Operating Month Emissions, lb/month (lb/day)	Maximum Monthly Emissions, lb/month	30-Day Averages, lb/day
NOx	**14,293.5 lb/month (476.45 lb/day)**	13,463.25 lb/month (448.78 lb/day)	14,294	476.45
CO	**95,023.2 lb/month (3167.44 lb/day)**	24,638.99 lb/month (821.30 lb/day)	95,023	3167.44
VOC	**13,314.0 lb/month (443.8 lb/day)**	7577.38 lb/month (252.58 lb/day)	13,314	443.8
PM_{10}/**$\underline{PM_{2.5}}$**	1411 lb/month (47.03 lb/day)	**6324.0 lb/month (210.8 lb/day)**	6324	210.8
SOx	809 lb/month (27.0 lb/day)	**3615.84 lb/month (120.53 lb/day)**	3616	120.53

For the **Application**, condition A63.2 will continue to limit CO emissions to 95,023 lb/month, VOC to 13,314 lb/month, PM_{10}/**$\underline{PM_{2.5}}$** to 6324 lb/month, SOx to 3616 lb/month, the same as in for the FDOC.

- *Maximum Annual Emissions per Turbine*

The *Applications for Modification: Turbine Emission Limits* for A/N 610354 – 610360 proposes to increase the total annual operating hours by 1905 hours/turbine, from the permitted 4640 hr/turbine to 6545 hr/turbine, with no changes to the number of annual startups and shutdowns per turbine. The breakdown becomes (1) ~~4100~~ 6005 hours of normal operation, (2) 80 cold starts (80 hr), (3) 420 non-cold starts (210 hr), and (5) 500 shutdowns (250 hr) for a total ~~4640~~ 6545 hour for maximum annual emissions per turbine.

The maximum annual emissions for the commissioning year and a normal operating year are calculated below, with the changes to the FDOC shown.

- Commissioning Year

  For the FDOC, the maximum annual emissions for CO, VOC, PM_{10}/**$\underline{PM_{2.5}}$**, and SOx set forth in condition A63.2 were based on a normal operating year. The condition specifies that compliance with the annual emission limits shall be based on a 12-operating month-rolling-average basis, following completion of the commissioning period.

  The maximum commissioning year emissions was used only to determine the NOx RTC holding for the first year of operation as set forth in conditions I297.1 and I297.2. The NOx RTC holding requirement is not an enforceable emission limit because a RECLAIM facility has the flexibility to exceed the RTC holding requirement.

As discussed under the Rule 2005(c)(2) analysis below, the appropriate RTC holding condition is I297. This condition specifies the pounds of NOx RTCs that are required to be held in the facility's allocation account to offset the annual emissions for the first year of operation only. The first year of operation is the commissioning year.

For the FDOC, the maximum commissioning year emissions were calculated by adding the total emissions for the six months of commissioning from *Table 16* above to six months of maximum monthly normal operating emissions from *Table 21* above. AES response e-mail dated 4/6/16 had indicated that the combined-cycle power block commissioning will require six months to complete. The calculations were shown in *Table 24 – Combined-Cycle Turbine Maximum Annual Emissions, Commissioning Year*. *Table 24* indicated that the maximum commissioning year NOx emissions will be 108,377 lb/yr, which were reasonably higher than the 83,850 lb/yr derived for a maximum normal operating year in *Table 25 - Combined-Cycle Turbine Maximum Annual Emissions, Normal Operating Year*. NOx emissions are typically higher for a commissioning year than for a normal operating year because of the uncontrolled emissions during the commissioning period. Accordingly, FDOC conditions I297.1 and I297.2 required each turbine to hold 108,377 pounds of RTCs per year.

For the **Application**, *Table 24* below is the same as for the FDOC and shows the maximum annual emissions for a commissioning year. The maximum commissioning year emissions will remain the same as for the FDOC because both (1) the total emissions for the 6-month commissioning period and (2) the six months of maximum monthly normal operating emissions will remain the same as for the FDOC.

Table 24 – Combined-Cycle Turbine Maximum Annual Emissions, Commissioning Year

Pollutants	Commissioning Year Emissions, lb/yr (tpy)
NOx	(27,597 lb/commissioning) + (13,463.25 lb/month)(6 normal operating months) = 108,377 lb/yr (54.19 tpy)
CO	(101,328 lb/commissioning) + (24,638.99 lb/month)(6 normal operating months) = 249,161.94 lb/yr (124.58 tpy)
VOC	(14,682 lb/commissioning) + (7577.38 lb/month)(6 normal operating months) = 60,146.28 lb/yr (30.07 tpy)
PM_{10}/**$PM_{2.5}$**	(8,466 lb/commissioning) + (6324.0 lb/month)(6 normal operating months) = 46,410.0 lb/yr (23.21 tpy)
SOx	(4,841 lb/commissioning) + (3615.84 lb/month)(6 normal operating months) = 26,536.04 lb/yr (13.27 tpy)

For the **Application**, conditions I297.1 and I297.2 will continue to require each turbine to hold 108,377 pounds of RTCs the first year.

- Normal Operating Year
  Because the monthly emissions limits in condition A63.2 are applicable each and every month, the annual emissions limits are the monthly emissions multiplied by twelve months, unless limited by permit condition. For power plants, the electric power demand is seasonal. The maximum monthly emissions are determined based on summer months when electric power demand is high. However, the same high demand is not required the rest of the year.

  For the FDOC, the applicant requested (1) 4100 hours of normal operation, (2) 80 cold starts, (3) 88 warm starts, (4) 332 hot starts, and (5) 500 shutdowns, for a total of 4640 hours for maximum annual emissions per turbine. When warm starts and hot starts are updated to the term "non-cold starts," the itemization becomes (1) 4100 hours of normal operation, (2) 80 cold starts (80 hr), (3) 420 non-cold starts (warm and hot) (210 hr), and (5) 500 shutdowns (250 hr), for a total of 4640 hours. The normal operation emission rates are from *Table 15* (case 4) above, and the startup and shutdown emissions per event from *Table 17* above. The SOx emission rates are based on the long-term rate (0.25 grains/100 scf).

  The **Application** proposes to increase the total annual operating hours by 1905 hours per turbine, from the permitted 4640 hr per turbine to 6545 hr per turbine, with no changes to the number of annual startups and shutdowns per turbine. The breakdown becomes (1) ~~4100~~ **6005** hours of normal operation, (2) 80 cold starts (80 hr), (3) 420 non-cold starts (210 hr), and (5) 500 shutdowns (250 hr) for a total ~~4640~~ **6545** hour for maximum annual emissions per turbine.

  The table below shows the revised maximum annual emissions per turbine for the **Application**. The changes shown are to *Table 25 - Combined-Cycle Turbine Maximum Annual Emissions, Normal Operations* in the FDOC. Hot starts and warm starts are updated to non-cold starts.

Table 25 - Combined-Cycle Turbine Maximum Annual Emissions, Normal Operating Year

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr (Case 4)	No. of Cold Starts	lb/cold start	No. of Non-Cold Starts	lb/non-cold start	No. of Shut downs	lb/shutdown	Maximum Annual Emissions lb/yr (tpy)
NOx	~~4100~~ **6005**	16.3	80	61	420	17	500	10	~~83,850 (41.93 tpy)~~ **114,901.5 (57.45 tpy)**
CO	~~4100~~ **6005**	7.44	80	325	420	137	500	133	~~180,544.00 (90.27 tpy)~~ **194,717.2 (97.36)**
VOC	~~4100~~ **6005**	5.68	80	36	420	25	500	32	~~52,668 (26.33 tpy)~~ **63,488.4 (31.74 tpy)**
$PM_{10}/PM_{2.5}$	~~4100~~ **6005**	8.50	80	8.50	420	4.25	500	4.25	~~39,440 (19.72 tpy)~~ **55,632.5 (27.82 tpy)**
SOx	~~4100~~ **6005**	1.60	80	1.62	420	0.81	500	0.81	~~7434.80 (3.72)~~ **10,482.8 (5.24 tpy)**

Maximum Annual Emissions, lb/yr = (no. normal operating hours) (normal emission rate, Case 4) + (no. startups, cold) (lb/startup, cold) + (no. startups, non-cold) (lb/startup, non-cold) + (no. shutdowns) (lb/shutdown)

- Permit Conditions—Annual Emissions Limits
  For the **Application**, the annual emission limits for a normal operating year currently set forth in condition A63.2 for CO, VOC, PM_{10}/**$PM_{2.5}$**, and SOx will be revised to reflect the revised annual emissions in *Table 25* above. **The annual emissions limits will be increased from 180,544 lb/yr to 194,717 lb/yr for CO; 52,668 lb/yr to 63,488 lb/yr for VOC; 39,440 lb/yr to 55,633 lb/yr for PM_{10}/$PM_{2.5}$; 7435 lb/yr to 10,483 lb/yr for SOx in condition A63.2.**

  The annual limits ensure that the annual PM_{10}/$PM_{2.5}$ and NO_2 emissions will not exceed the PM_{10}/$PM_{2.5}$ and NO_2 modeled emission rates for the annual averaging period provided in *Table 51--Modeled Emission- Rates - Normal Operation for AEC CCGT* below. In addition, the annual limits for PM_{10}/$PM_{2.5}$ emissions will ensure compliance with condition F2.1, which limits the facility-wide $PM_{2.5}$ emissions to below the applicability limit 70 tpy set forth in *Rule 1325—Federal PM2.5 New Source Review Program, amended 1/4/19.* ***Update: Pursuant to the Rule 1325 analysis in this evaluation, the PM2.5 emission limit in condition F2.1 will be corrected to 100 tpy.***

  As with the monthly limits, an annual emissions limit may not be added for NOx because AEC will be a RECLAIM facility and such a limit is not allowed by RECLAIM rules. The annual emissions for NOx, however, are indirectly limited by the annual emissions limits for CO, VOC, PM_{10}/**$PM_{2.5}$**, and SOx. Additionally, the toxic pollutants and greenhouse gases are indirectly limited by the annual emissions limits.

  The emission factors for the monthly emission limits (VOC, PM_{10}/$PM_{2.5}$) shall be used to demonstrate compliance with the annual emission limits, but not SOx. AES requested that the maximum monthly emissions be based on 0.75 grains/100 scf, but the annual emissions be based on 0.25 grains/100 scf. The table below shows the calculation of the annual SOx emission factor. The changes shown are to *Table 25A* in the FDOC.

Table 25A - Combined-Cycle Turbine Normal Operating Emission Factor - Annual Limit

Pollutants	Maximum Annual Emissions, lb/year	Emission Factors, lb/mmcf
SOx	~~7434.8~~ **10,482.8**	0.75

Emission factor, lb/mmcf = (lb/yr) (yr / ~~9942.86~~ **14,025** mmscf)

Where max annual fuel usage = (~~4640~~ **6545** hours, incl. startups/shutdowns) (2250 MMBtu/hr, Case 4) (mmscf/1050 MMBtu) = ~~9942.86~~ **14,025** mmscf/yr

For the **Application**, the annual SOx emission factor remains 0.75 lb/mmcf.

- *New Source Review (NSR) Database Entries*
  The 30-day averages for the ***Application*** *remain the same as for the FDOC.*

  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 23*. 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.

NOx

R2 = (476.45 lb/day)(day/24 hr) = 19.85 lb/hr

R1 = (19.85 lb/hr)(9 ppm uncontrolled/2 ppm controlled per case 1) = 89.33 lb/hr

30-DA = 476.45 lb/day

CO

R2 = (3167.44 lb/day)(day/24 hr) = 131.98 lb/hr

R1 = (131.98 lb/hr)(7.08 ppm uncontrolled/ 1.5 ppm controlled per case 1)
= 622.95 lb/hr

30-DA = 3167.44 lb/day

ROG

R2 = R1 (Appx. 0% control efficiency per case 1)

R2 = R1 = (443.8 lb/day)(day/24 hr) = 18.49 lb/hr

30-DA = 443.8 lb/day

PM_{10}

R2 = R1 = (210.8 lb/day)(day/24 hr) = 8.78 lb/hr

30-DA = 210.8 lb/day

SOx

R2 = R1 = (120.53 lb/day)(day/24 hr) = 5.02 lb/hr

30-DA = 120.53 lb/day

B. <u>Toxic Pollutants</u>

The toxic air pollutant (TAC) and hazardous air pollutant (HAP) emissions rates will be used for the Rule 1401 health risk assessment (HRA) below. For the **Application**, the FDOC emission rates are required to be revised to reflect the proposed increase in annual operating hours from the permitted 4640 hr/yr to 6545 hr/yr per turbine.

On p. 15 of the Yorke *Applications for Modification: Turbine Emission Limits* for A/N 610354 – 610360, *Table 3-7: Toxic Air Contaminant Emissions for Each CCGT* provides the TAC and HAP emissions rates for each combined-cycle turbine based on the increase to 6545 hr/yr proposed. In *Appendix B – Emissions Calculations*, the table for *Each CCGT Hazardous Air Pollutants Emissions* shows the emissions calculations. (The *Appendix B* provided with the Yorke *Applications for Modification: Turbine Emission Limit,* was erroneously based on the superseded increase to 6600 hr that had been proposed earlier in the Yorke Protocol, 11/7/18. On 5/28/19, Yorke e-mailed a revised *Appendix B* based on the increase to 6545 hr/yr.)

For the **Application**, FDOC *Table 26* is revised below to reflect the proposed increase in annual operating hours from the permitted 4640 hr/yr to 6545 hr/yr per turbine.

- The hourly emission rates in revised *Table 26* below are the same as for the FDOC, with very minor differences from the hourly emission rates shown by Yorke Engineering in *Table 3-7*. The exception is <u>ammonia</u>. The **FDOC** was based on the 15.3 lb/hr from *Table 15* (case 1) above as proposed by AES, instead of the calculated 15.74 lb/hr (case 1). In *Table 3-7*, Yorke Engineering based the hourly ammonia rate on the more conservative calculated 15.74 lb/hr (case 1), which is acceptable and incorporated in revised *Table 26* below.

- The annual emission rates in revised *Table 26* below reflect the increase to 6545 hr/yr. The basis for the annual ammonia emissions rate in *Table 3-7* is different from the FDOC. The **FDOC** was based on the 15.1 lb/hr from *Table 15* (case 4) as proposed by AES. In *Table 3-7*, Yorke Engineering based the annual ammonia rate on the more conservative calculated emission rate of 15.566 lb/hr (case 4), which is acceptable and incorporated in revised *Table 26* below.

Table 26 - Combined-Cycle Turbine Toxic Air Contaminants/Hazardous Air Pollutants

Compound	CAS	TAC/HAP	Emission Factor [1] (Lb/MMBtu)	Lb/hr	Lb/yr	TPY
Ammonia[5]	766417	TAC		~~15.3~~ <u>**15.74**</u>	~~70,004~~ <u>**101,879.79**</u>	~~35.0~~ <u>**50.94**</u>
Acetaldehyde[2]	75070	TAC & HAP	1.76E-04	0.39	~~1789~~ <u>**2591.25**</u>	~~0.89~~ <u>**1.30**</u>

Compound	CAS	TAC/HAP	Emission Factor [1] (Lb/MMBtu)	Lb/hr	Lb/yr	TPY
Acrolein[2]	107028	HAP & TAC	3.62E-06	0.008	~~36.7~~ **53.30**	~~0.018~~ **0.03**
Benzene[2]	71432	HAP & TAC	3.26E-06	0.0072	~~33.1~~ **48.0**	~~0.017~~ **0.024**
1,3-Butadiene	106990	HAP & TAC	4.3E-07	0.0010	~~4.36~~ **6.33**	~~0.0022~~ **0.0032**
Ethylbenzene	100414	HAP & TAC	3.2E-05	0.071	~~324~~ **471.14**	~~0.16~~ **0.24**
Formaldehyde[2]	50000	HAP & TAC	3.6E-04	0.80	~~3648~~ **5300.27**	~~1.82~~ **2.65**
Hexane	110543	HAP & TAC	Not available	--		--
Naphthalene	91203	HAP & TAC	1.3E-06	0.0029	~~13.2~~ **19.14**	~~0.0066~~ **0.0096**
PAHS (excluding naphthalene)[3, 4]	1151	HAP & TAC	(2.2E-06 – 1.3E-06) * 0.5 = 0.45E-06	0.0010	~~4.56~~ **6.63**	~~0.0023~~ **0.0033**
Propylene (propene)[5]	115071	TAC	Not available			--
Propylene Oxide	75569	HAP & TAC	2.9E-05	0.063	~~290~~ **426.97**	~~0.15~~ **0.21**
Toluene	108883	HAP & TAC	1.3E-04	0.29	~~1322~~ **1913.99**	~~0.66~~ **0.96**
Xylene	1330207	HAP & TAC	6.4E-05	0.14	~~649~~ **942.27**	~~0.32~~ **0.47**
Total Annual HAPS Emissions per Combined-Cycle Turbine, TPY					~~8113.92~~ **11,779.29**	~~4.05~~ **5.90**
Total Annual Toxic Air Contaminants Emissions per Combined-Cycle Turbine, TPY						~~39.05~~ **56.84**

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.

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 Per Section 3.1.4.3 of AP-42, PAH emissions were assumed to be controlled by 50 percent by the oxidation catalyst.

5 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:

<u>For compounds other than ammonia</u>
Hourly emissions, lb/hr = (Emission Factor) (maximum hourly heat input rate of 2275 MMBtu/hr (Case 1))

Annual emissions, lb/yr = (Emission Factor) (average annual heat input rate of ~~10,437,686~~ **<u>14,722,986</u>** MMBtu/yr)

Where average annual heat input = (~~4640~~ **<u>6545</u>** hr/yr)(2249.5013 MMBtu/hr (Case 4)
= ~~10,437,686~~ **<u>14,722,986</u>** MMBtu/yr

Note: Case 4 in Table 15 shows 2250 MMBtu/hr, but AES used the more precise value of 2249.5013 MMBtu/hr for the FDOC.

<u>Ammonia</u>
Maximum hourly emissions, lb/hr = (2275 MMBtu/hr (case 1)) (8710 dscf/MMBtu) (5 ppm NH_3 /10^6) (20.9/(20.9-15.0)) (17 lbs NH_3/379 scf) = 15.74 lb /hr

<u>Note</u>:
For the **FDOC**, AES used the 15.3 lb/hr from *Table 15* (case 1) instead of the calculated 15.74 lb/hr (case 1), which was acceptable as the difference appeared to be due to rounding differences. For the **Application**, AES used the calculated 15.74 lb/hr (case 1).

Maximum annual emissions, lb/yr = (~~4640~~ **<u>6545</u>** hr/yr) ~~(15.1 lb/hr (case 4))~~ **<u>(2249.5013 MMBtu/hr (case 4)) (8710 dscf/MMBtu)(5 ppm NH_3 /10^6) (20.9/(20.9-15.0)) (17 lbs NH_3/379 scf)</u>** = (**<u>6545 hr/yr)(15.566 lb/hr) =</u>** ~~70,004~~ **<u>101,879.79</u>** lb/yr = ~~35.0~~ **<u>50.94</u>** tpy

<u>Note</u>:
For the **FDOC**, AES used the 15.1 lb/hr from *Table 15* (case 4). For the **Application**, AES used the calculated emission rate of 15.566 lb/hr (case 4).

C. <u>Greenhouse Gases (GHG)</u>

- *<u>Combustion: CO_2, CH_4, N_2O</u>*
  Combustion of natural gas in the turbines will result in emissions of CO_2, CH_4, and N_2O.

  As shown above for the toxic pollutants emissions calculations, for the **Application**, the average annual heat input rate will be increased to ~~10,437,686~~ **<u>14,722,986</u>** MMBtu/yr, based on the proposed increase from the permitted 4640 hr/turbine to 6545 hr/turbine.

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

For each combined-cycle turbine:

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

CO_2 = (~~10,437,686~~ **14,722,986** MMBtu/yr)(53.06 kg/MMBtu)(2.2046 lb/kg)
= ~~1,220,959,551~~ **1,722,237,129** lb/yr = ~~610,479.78~~ **861,118.56** tpy

CH_4 = (~~10,437,686~~ **14,722,986** MMBtu/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= ~~23,015.10~~ **32,464.18** lb/yr = ~~11.51~~ **16.23** tpy

N_2O = (~~10,437,686~~ **14,722,986** MMBtu/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= ~~2301.51~~ **3246.42** lb/yr = ~~1.15~~ **1.62** tpy

Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as amended by 79 FR 73779, 12/11/14: *(1)* CH_4 is equivalent to 25 times the global warming potential of CO_2, and *(2)* N_2O is equivalent to 298 times of CO_2.

CO_2e, tpy = (~~1,220,959,551~~ **1,722,237,129** lb/yr CO_2)(1 lb CO_2e/lb CO2) + (~~23,015.10~~ **32,464.18** lb/yr CH_4)(25 lb CO2e/lb CH_4) + ~~2301.51~~ **3246.42** lb/yr N_2O) (298 lb CO_2e/lb N_2O) = ~~1,222,220,778~~ **1,724,016,167** lb/yr = ~~611,110.39~~ **862,008.08** tpy = ~~50,925.87~~ **71,834.01** tons/month

- *Circuit Breakers: SF6*
  For the **Application**, the SF6 emissions calculations are the same as the FDOC. The increase in annual operating hours for the combined-cycle turbines will not affect the SF6 leakage rate. Thus condition F52.2 will continue to specify a CO_2e facility-wide annual limit for SF_6 (74.55 tpy) to enforce the BACT requirements for the circuit breakers located at the CCGT (17.44 tpy) and SCGT (57.11 tpy) power blocks.

  CCGT: 34,884 lb/yr = 17.44 tpy = 1.45 tons/month CO_2e

- *New Source Review (NSR) Database Entries*
  This section develops the internal NSR Data Summary Sheet entries. For the **Application**, the entries are revised to reflect the increase to 6545 hr/yr per turbine.

Operating Schedule: 52 wks/yr, 7 days/wk, 24 hrs/day (annualized schedule)
→ 8736 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.

CO_2 = (~~1,220,959,551~~ **1,722,237,129** lb/yr) (yr /8736 hr) = ~~139,761.85~~ **197,142.53** lb/hr

CH_4 = (~~23,015.10~~ **32,464.18** lb/yr) (yr /8736 hr) = ~~2.63~~ **3.72** lb/hr

N_2O = (~~2301.51~~ **3246.42** lb/yr) (yr /8736 hr) = ~~0.26~~ **0.37** lb/hr

SF_6 = (34,884 lb/yr) (yr /8736 hr) = 3.99 lb/hr

2. A/N 608431, 608432—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. CCGT-1, CCGT-2 (Combined-Cycle Turbines) (A/N 579160, 579161)

A. Criteria Pollutants

NOx = CO = VOC = PM_{10} = SOx = 0 lb/hr = 0 lb/day

B. Toxic Pollutants

From *Table 26* above, the annual ammonia emission rate, based on the 5 ppmvd BACT level, increased as a result of the requested increase in the annual operating hours per turbine and the revised ammonia emission rate.

~~70,004~~ **101,879.79** lb/yr = ~~35~~ **50.94** tons/yr = ~~2.92~~ **4.25** tons/month (avg)

To calculate R1 and R2 for annualized operating schedule (52 wk/yr, 7 days/wk, 24 hr/day, same as CTGs):

NH_3, lb/day = (~~70,004~~ **101,879.79** lb/yr) (yr/52 wk) (wk/7 days) = ~~192.32~~ **279.89** lb/day
lb/hr = (~~192.32~~ **279.89** lb/day) (day/24 hr) = ~~8.01~~ **11.66** lb/hr

Note: Ammonia is not a federal HAP.

3. A/N 604014—Auxiliary Boiler (Combined-Cycle Turbines), 70.8 MMBtu/hr (A/N 579158)

The separate engineering evaluation for A/N 604014 and 613323 for the Auxiliary Boiler and SCR concluded the criteria pollutants and toxic pollutants will remain the same as for the FDOC.

Table 30 is reproduced below for use in the facility-wide health risk assessment for *Rule 1401* in support of CEC's analysis of the *Petition for Post-Certification Amendment* for this evaluation.

Table 30 - Auxiliary Boiler Toxic Air Contaminants/Hazardous Air Pollutants

Compound	**CAS**	**TAC/HAP**	**Emission Factor (lb/MMcf)**	**Emission Factor (lb/MMBtu)[1]**	**Lb/hr**	**Lb/yr**	**TPY**
Ammonia[2]	766417	TAC			0.16	423	0.212
Acetaldehyde	75070	TAC & HAP	0.0031	2.95E-06	2.09E-04	0.558	2.79E-04
Acrolein	107028	HAP & TAC	0.0027	2.57E-06	1.82E-04	0.486	2.43E-04
Benzene	71432	HAP & TAC	0.0058	5.52E-06	3.91E-04	1.04	5.22E-04
Ethylbenzene	100414	HAP & TAC	0.0069	6.57E-06	4.65E-04	1.24	6.22E-04
Formaldehyde	50000	HAP & TAC	0.0123	1.17E-05	8.29E-04	2.22	1.11E-03
Hexane	110543	HAP & TAC	0.0046	4.38E-06	3.10E-04	0.829	4.14E-04
Naphthalene	91203	HAP & TAC	0.0003	2.86E-07	2.02E-05	0.054	2.70E-05
PAHS (excluding naphthalene)	1151	HAP & TAC	0.0001	9.5E-08	6.74E-06	0.018	9.01E-06
Propylene[2]	115071	TAC	0.5300	5.05E-04	3.57E-02	95.5	4.77E-02
Toluene	108883	HAP & TAC	0.0265	2.52E-05	1.79E-03	4.77	2.39E-03
Xylene	1330207	HAP & TAC	0.0197	1.88E-05	1.33E-03	3.55	1.77E-03
Total Annual HAPS Emissions, TPY							**0.0074**
Total Annual Toxic Air Contaminants Emissions, TPY							**0.27**

5. **<u>A/N 610356, 610357, 610358, 610359—Simple-Cycle Combustion Turbine Generators Nos. SCGT-1, SCGT-2, SCGT-3, SCGT-4 (A/N 579145, 579147, 579150, 579152)</u>**

➢ **<u>Proposed Revisions to the FDOC</u>**

The Yorke *Applications for Modification: Turbine Emission Limits* for A/N 610354 – 610360 proposes to decrease the total annual operating hours by 1300 hours per turbine, from 2360 hours per turbine to 1060 hours per turbine, with no changes in the number of annual startups and shutdowns per turbine.

The 2360 hr/yr assumed by Yorke Engineering was based on 0.22 hr/shutdown. The FDOC, however, was permitted for 2358 hr/yr per turbine based on 0.2167 hr/shutdown. The 2358 hr/yr per turbine was used throughout the FDOC, including for the Rule 1304.1 fees. <u>Therefore, this evaluation will be based on a decrease from the permitted 2358 hr/yr to 1058 hr/yr.</u> The breakdown becomes (1) ~~2000~~ <u>700</u> hours of normal operation, (2) 500 startups (250 hr), and (3) 500 shutdowns (108 hr), for a total of ~~2358~~ <u>1058</u> hours for maximum annual emissions per turbine.

The simple-cycle CTGs will emit combustion emissions consisting of criteria pollutants, toxic pollutants, and greenhouse gases. The four CTGs will have identical emissions. Emissions are based on manufacturer data and engineering estimates.

A. <u>Criteria Pollutants</u>

As with the combined-cycle turbines, emissions from the four operational modes must be considered.

- <u>Worst Case Operating Scenario</u>
  To determine the worst case operating scenario that yields the highest controlled emissions, the applicant provided fourteen operating scenarios. The operating scenarios are for three load conditions (100%, 75%, and 50%) at four ambient temperatures (28 ºF, 59.0 ºF, 65.3 ºF, and 107 ºF), and with or without evaporative cooling of the inlet air to the turbines.

  The following table summarizes the operating scenarios data and is the same as *Table 31* in the FDOC.

Table 31 – Simple-Cycle Turbine Operating Scenarios

Case No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
CTG Load Level (%)	100	75	50	100	100	75	50	100	100	75	50	100	75	50
CTG Inlet Air Cooling	Off	Off	Off	On	Off	Off	Off	On	Off	Off	Off	Off	Off	Off
Ambient Conditions														
Ambient Temperature (°F)	28.0	28.0	28.0	65.3	65.3	65.3	65.3	107	107	107	107	59.0	59.0	59.0
Ambient Relative Humidity (%)	76.3%	76.3%	76.3%	86.8%	86.8%	86.8%	86.8%	10.7%	10.7%	10.7%	10.7%	60%	60%	60%
Combustion Turbine Performance														
Gross GTG Output, kW (one CTG)	100,317	75,011	49,671	99,215	98,788	73,878	48,916	82,840	70,821	52,867	34,887	100,438	75,030	49,740
Net CTG Output, kW (one CTG)	98,966	73,661	48,321	97,864	97,437	72,527	47,565	81,489	69,470	51,516	33,536	99,087	73,679	48,389
CTG Heat Input, MMBtu/hr (LHV) (one CTG)	792	645	498	789	786	637	493	689	619	514	404	795	645	498
CTG Heat Input, MMBtu/hr (HHV) (one CTG)	879	715	553	876	873	707	547	764	688	570	449	882	715	553
CTG Exhaust Temperature, ºF (one CTG)	789	816	888	797	798	814	883	837	868	908	981	794	815	885
4 LMS-100 PB Gross, kW	401,268	300,045	198,686	396,860	395,152	295,511	195,663	331,360	283,284	211,467	139,549	401,751	300,120	198,958
4 LMS-100 PB Net, kW	386,261	286,924	187,440	381,903	380,226	282,485	184,485	317,669	270,480	200,014	129,478	386,712	286,998	187,711
Stack Parameters														
Stack Exit Temperature, °F	789	816	888	797	798	814	883	837	868	908	981	794	815	885
Stack Diameter, ft.	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Stack Exit Velocity, ft/sec	109	94.0	78.0	109	108	93.3	77.4	99.2	91.8	80.3	67.4	109.3	94.1	78.0
CTG Outlet/Catalyst Inlet concentrations														
NOx, ppmvd (dry, 15% O2)	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
CO, ppmvd (dry, 15% O2)	100	100	125	100	100	100	125	100	100	100	125	100	100	125
VOC, ppmvd (dry, 15% O2)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Catalyst Outlet/Stack Emissions Rates														
NOx, 2.5 ppmvd (dry, 15% O_2) BACT, lb/hr as NO_2	8.23	6.70	5.18	8.20	8.17	6.62	5.12	7.15	6.44	5.34	4.20	8.26	6.70	5.18
CO, 2.0 ppmvd (dry, 15% O_2) BACT, lb/hr	4.01	3.26	2.52	3.99	3.98	.22	2.50	49	3.14	2.60	2.05	4.03	3.26	2.52

VOC, 2.0 ppmvd (dry, 15% O_2) BACT, lb/hr	2.30	1.87	1.44	2.29	2.28	1.85	1.43	2.00	1.80	1.49	1.17	2.30	1.87	1.44
PM_{10}/$PM_{2.5}$, lb/hr (including ammonium sulfate, assuming 100% conversion from SO_3)[1]	6.23	6.23	6.23	6.23	6.23	6.23	6.23	6.23	6.23	6.23	6.23	6.23	6.23	6.23
SO_2 short-term rate (0.75 grains/100 scf), lb/hr[2]	1.62	1.32	1.02	1.62	1.61	1.31	1.01	1.41	1.27	1.05	0.83	1.63	1.32	1.02
SO_2 long-term rate (0.25 grains/100 scf), lb/hr	0.54	0.44	0.34	0.54	0.54	0.44	0.34	0.47	0.42	0.35	0.28	0.54	0.44	0.34
SCR NH_3 slip, 5.0 ppmvd (dry, 15% O2) BACT, lb/hr	6.09	4.96	3.83	6.07	6.05	4.90	3.79	5.30	4.77	3.95	3.11	6.12	4.96	3.83

1 A percentage of the SO_2 in the turbine exhaust is assumed to oxidize to SO_3 in the CO catalyst and SCR. The SO_3 reacts with ammonia in the SCR to form ammonium sulfate particulates. Total PM_{10} is comprised of the ammonium sulfate particulates and the PM_{10} 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.

Case 1, based on 100% load, 28 °F ambient temperature, and without inlet cooling, is the worst case operating scenario that yields the highest controlled emissions. The emissions rates for NOx, CO, VOC, PM_{10}/$PM_{2.5}$, and the short-term SO_2 rate (0.75 grains/100 scf) were used to calculate the normal operation emissions component for the maximum daily emissions and maximum monthly emissions.

Case 4, based on 100% load, 65.3 °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 NOx, CO, VOC, PM_{10}/$PM_{2.5}$, and the long-term SO_2 rate (0.25 grains/100 scf) were used to calculate the normal operation emissions component for maximum annual emissions. Condition B61.1 requires testing to confirm the long-term SO_2 rate of 0.25 grains/100 scf, which is expected to be the average content.

Case 12, based on 100% load, 59 °F ambient temperature, and without inlet cooling, yields the maximum gross output for each turbine. This maximum rating is used for the purposes of Rule 1304(a)(2) compliance demonstration and Rule 1304.1 fee calculation. Since Case 12 is the scenario that yields the highest Btu/hr consumption for each turbine, it is also the basis for the equipment description on the facility permit.

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

- Four Operational Modes

  The simple-cycle 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 the proposed parameters and emissions associated with each mode. In AES Response Letter, dated 12/11/15, the applicant has clarified that the combustors are not expected to require tuning after commissioning.

  Commissioning

  *The **FDOC** provided the following analysis. For the **Application** under evaluation here, the analysis remains the same as for the FDOC because AES did not request any changes to commissioning emissions or schedule.*

  Commissioning is a one-time event and the NOx, CO, and VOC emission rates are expected to be higher during the commissioning period than during normal operations.

  The following table summarizes the operating scenarios data and is the same as *Table 32* in the FDOC.

Table 32 - Simple-Cycle Turbine Commissioning Activity Parameters and Emissions

					Reduction (%)			Total Controlled Emissions, lb				
Activity	**Duration (hr)**	**CTG Load (%)**	**Fuel Use MMscf/hr)**	**Fuel Use (MMscf/ Activity)**	**NOx (SCR)**	**CO (OxCat)**	**VOC (OxCat)**	**NOx**	**CO**	**VOC**	**SOx**	**$PM_{10}/PM_{2.5}$**
Unit Testing (Full Speed No Load, FSNL)	4	5	0.1848	0.7390	0%	0%	0%	160	976	20.3	6.48	24.9
Unit DLN Emissions Tuning	12	100	0.8381	10.0571	75%	75%	33%	246	1,080	36.7	19.4	74.8
Unit Emissions Tuning	12	75	0.6143	7.3714	75%	75%	33%	198	869	32.2	19.4	74.8
Unit Base Load Testing	12	75	0.6143	7.3714	75%	75%	33%	198	869	13.7	19.4	74.8
No Operation												
Install Temporary Emissions Test Equipment												
Refire Unit	12	100	0.8381	10.0571	75%	75%	33%	246	1,080	36.7	19.4	74.8
Unit Source Testing & Drift Test Day 1-5; RATA/Pre-performance Testing/Part 60/75 Certification and Source Testing	168	100	0.8381	140.800	75%	75%	33%	3,444	15,120	513	272	1,047
Unit Water Wash & Performance Preparation	24	100	0.8381	20.1143	75%	75%	33%	492	2,160	73.3	38.9	150
Unit Performance Testing	24	100	0.8381	20.1143	75%	75%	33%	492	2,160	73.3	38.9	150
Install Temporary Emissions Test Equipment												
Unit CALISO Certification	12	100	0.8381	10.0571	75%	75%	33%	246	1,080	36.7	19.4	74.8
Total for One CTG	**280**			**226.68**				**5,722**	**25,395**	**836**	**454**	**1,744**

The applicant requested 280 hours of fired operation for the commissioning of each simple-cycle turbine, as indicated in the table above. The commissioning for each turbine is expected to extend over a period of three months.

<u>*Startup of CTGs*</u>
*The **FDOC** provided the following analysis. For the **Application** under evaluation here, the analysis remains the same as for the FDOC because AES did not request any changes to the annual number of startups per turbine.*

A startup event occurs each time a simple-cycle CTG is started up.

One startup scenario has been developed for the simple-cycle turbines. The time from fuel initiation until reaching the baseload operating rate is expected to take up to 30 minutes.

For daily emissions (for modeling) and monthly emissions, the **Application** did not request any changes to the daily and monthly number of startups per turbine.

For annual emissions, the **Application** did not request any changes to the annual number of startups per turbine. The modification under evaluation will continue to be based on a maximum of 500 starts per turbine, the same as for the FDOC.

<u>*Shutdown of CTGs*</u>
*The **FDOC** provided the following analysis. For the **Application** under evaluation here, the analysis remains the same as for the FDOC because AES did not request any changes to the annual number of shutdowns per turbine.*

A shutdown event occurs each time a simple-cycle CTG is shut down.

The duration of a shutdown event is expected to take up to 13 minutes.

For daily emissions (for modeling) and monthly emissions, the **Application** did not request any changes in the daily and monthly number of shutdowns per turbine.

For annual emissions, the **Application** did not request any changes in the annual number of shutdowns per turbine. The modification under evaluation will continue to be based on a maximum of 500 shutdowns per turbine, the same as for the FDOC.

- <u>*Startup/Shutdown Emissions*</u>
  The following table provides the durations and emissions for the startup event and shutdown event and is the same as *Table 33* in the FDOC, except that the duration of a shutdown has been corrected from the 0.22 hr in the table to the 0.2167 hr used in the emissions calculations for the FDOC.

Table 33 – Simple-Cycle Turbine Start-up/Shutdown Emission Rates

	Duration Minutes (hr)	NOx lb/event	CO lb/event	VOC lb/event	PM_{10} lb/hr (lb/event)	$PM_{2.5}$ lb/hr (lb/event)	SO_2 lb/hr (lb/event)
Startup	30 (0.5)	16.6	15.4	2.80	< 6.23 (3.12)	< 6.23 (3.12)	Short-term: < 1.62 (0.82) Long-term: < 0.54 (0.27)
Shutdown	13 (~~0.22~~) (**0.2167**)	3.12	28.1	3.06	< 6.23 (1.35)	< 6.23 (1.35)	Short-term: < 1.62 (0.35) Long-term: < 0.54 (0.12)

- *Startup/Shutdown Conditions*
  For the ***Application*** *under evaluation here, the following analysis remains the same as for the FDOC.*

  In lieu of requiring steady state BACT at all times, EPA accepted an alternative BACT which limits and minimizes emissions during periods when steady state BACT is not achievable, such as during startups and shutdowns. Condition no. C1.5 provides limits for startups, and condition no. C1.6 provides limits for shutdowns. The limits are necessary because condition nos. A195.11, A195.17, and A195.10 state that BACT for NO_x, CO, and VOC, respectively, shall not apply during startups and shutdowns. 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, CO, and VOC emission limits per start. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdowns; and (3) NOx, CO, and VOC emission limits per shutdown. Condition nos. C1.5 and C1.6 will remain the same as for the FDOC.

Normal Operation
For the ***Application*** *under evaluation here, the following analysis remains the same as for the FDOC.*

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, and exclude emissions due to commissioning, startup and shutdown periods, which are not subject to BACT levels. NOx is controlled to 2.5 ppmvd, CO to 2.0 ppmvd, and VOC to 2.0 ppmvd, all 1-hr averages, at 15% O2.

- *Maximum Daily, Monthly, Annual, NSR Emissions Calculations*
  For the ***Application*** *under evaluation here, the analysis for the maximum daily emissions, maximum monthly emissions, and associated emission factors and permit condition limits will remain the same as for the FDOC, as discussed below.*

- *Maximum Daily Emissions per Turbine*
  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
  For the **Application**, the maximum daily emissions for all criterial pollutants will remain the same as for the FDOC because the (1) number of normal operating hours, (2) normal operating emission rates for all pollutants, (3) emissions for cold starts, non-cold starts and shutdowns for all pollutants, and (4) number of cold, noncold, and shutdowns all remain the same as for the FDOC. The normal operating emission rates are from *Table 31* (case 1) above, and the startup and shutdown emissions per event are from *Table 33 above.* The SO_x emission rates are based on the short-term rate (0.75 grains/100 scf). **(In an e-mailed dated 2/2/16, AES clarified that 0.75 grains/100 scf will be used for daily and monthly emissions, instead of the 0.25 grains/100 scf initially proposed.)**

  For strict BACT/LAER applicability for non-RECLAIM pollutants, the increase in daily emissions are based on uncontrolled emissions. As it is already known that the installation of a combined-cycle turbine requires BACT/LAER, the maximum controlled daily emissions for normal operations are shown in the table below for informational purposes and is the same as *Table 34* in the FDOC.

Table 34 - Simple-Cycle Turbine Maximum Daily Emissions

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr (Case 1)	No. of Startups	Lb/ Startup	No. of Shutdowns	Lbs/ Shutdown	Maximum Daily Emissions lb/day
NOx	22.56	8.23	2	16.6	2	3.12	**225.11**
CO	22.56	4.01	2	15.4	2	28.1	**177.47**
VOC	22.56	2.30	2	2.80	2	3.06	**63.61**
$PM_{10}/PM_{2.5}$	22.56	6.23	2	3.12	2	1.35	**149.49**
SOx	22.56	1.62	2	0.82	2	0.35	**38.89**

No. of normal operating hours = 24 hr/day – (2 startups/day)(0.5 hr/start) - (2 shutdowns/day) (0.22 hr/shutdown) = 22.56 hr

Maximum Daily Emissions, lb/day = (no. normal operating hours) (normal emission rate, Case 1) + (no. startups, cold) (lb/startup, cold) + (no. startups, warm) (lb/startup, warm) + (no. shutdowns) (lb/shutdown)

- *Maximum Monthly Emissions and Emission Factors per Turbine*
  Condition A63.3 specifies the monthly emissions limits for CO, VOC, PM_{10}/**$PM_{2.5}$**, and SOx. Monthly limits are required to establish a basis for calculating offset requirements and ensure compliance with BACT requirements. RECLAIM rules do not allow a monthly limit for NOx. The monthly emissions for NOx, however, are indirectly limited by the

monthly emissions limits for CO, VOC, PM_{10}/**<u>$PM_{2.5}$</u>**, and SOx. The number of RECLAIM RTCs required are determined on an annual basis and reflected in conditions I297.3 - I297.6.

The maximum monthly emissions and 30-day averages 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. AES indicated there will be no combination commissioning/normal operating month. Therefore, the FDOC evaluated the maximum commissioning month(s) emissions and maximum normal operating month emissions only. In addition, the commissioning emission factors and normal operating emission factors are included in condition A63.3 for CO, VOC, PM_{10}/**<u>$PM_{2.5}$</u>**, and SOx. The commissioning emission factor and the post-commissioning/pre-CEMS certification emission factor are included in conditions A99.1 and A99.2, respectively, for NOx.

- <u>Commissioning Months</u>
  - <u>Maximum Monthly Emissions, Commissioning</u>
    For the **Application**, the maximum monthly emissions for commissioning for all criterial pollutants will remain the same as for the FDOC because the applicant has not requested any changes to the commissioning.

    For the FDOC, the applicant indicated that the commissioning period would extend over a period of three full months, and would not overlap with steady-state operation of the CTGs. The number of commissioning hours per month per turbine would be 93.33 hours.

    The table below summarizes the maximum monthly emissions for each pollutant from any one of the three months of commissioning and is the same as *Table 35* in the FDOC.

Table 35 – Simple-Cycle Turbine Maximum Monthly Emissions, Commissioning

Pollutants	Month	Commissioning Emissions, lb/month
NOx	Three	1913.27
CO	One	8593.7
VOC	Three	285.08
$PM_{10}/PM_{2.5}$	Three	582.5
SOx	Three	151.16

  - <u>Commissioning Emission Factors</u>
    For the **Application**, the commissioning period emission factors in condition no. A63.3 for CO, VOC, PM_{10}/**<u>$PM_{2.5}$</u>**, and SOx, and in condition no. A99.3 for NOx

will remain the same as for the FDOC. As explained in the Rule 2012 analysis below, condition no. A99.3 specifies the interim emission factor for NOx for the commissioning period (no certified CEMS), during which the CTGs are assumed to be operating at uncontrolled and partially controlled levels. For each pollutant, the emission factor is calculated as the total emissions for the commissioning period divided by the total fuel usage for the commissioning period, both of which are shown in *Table 32 - Simple-Cycle Turbine Commissioning Activity Parameters and Emissions* above and both of which will remain the same as for the FDOC.

- Normal Operating Month
  - Maximum Normal Operating Month Emissions

    For the FDOC, the applicant indicated that the normal operating month will begin in the first month following completion of commissioning activities, with no commissioning carry-over.

    For the **Application**, the maximum normal operating month emissions per simple-cycle turbine will remain the same as for the FDOC, because the (1) number of normal operating hours, (2) normal operating emission rates for all pollutants, (3) emissions for cold starts, non-cold starts and shutdowns for all pollutants, and (4) number of cold, noncold, and shutdowns will remain the same as for the FDOC.

    For the FDOC, the applicant requested (1) 700 normal operating hours (Case 1), (2) 62 startups (31 hr), and (3) 62 shutdowns (13.4 hr), for a total of 744 hours. The normal operating emission rates are from *Table 32* (case 1) above, and the startup and shutdown emissions per event are from *Table 33* above. The SO_x emission rates are based on the short-term rate (0.75 grains/100 scf). **(In an e-mailed dated 2/2/16, AES clarified that 0.75 grains/100 scf will be used for daily and monthly emissions, instead of the 0.25 grains/100 scf initially proposed.)**

    The table below shows the maximum normal operating month emissions and is the same as *Table 37 - Simple-Cycle Turbine Maximum Monthly Emissions, Normal Operations* in the FDOC.

Table 37 - Simple-Cycle Turbine Maximum Monthly Emissions, Normal perations

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr (Case 1)	No. of Startups	lb/startup	No. of Shut downs	lb/shutdown	Maximum Monthly Emissions lb/month (tons/month)
NOx	700	8.23	62	16.6	62	3.12	**6983.64 (3.49)**
CO	700	4.01	62	15.4	62	28.1	**5504.00 (2.75)**
VOC	700	2.30	62	2.80	62	3.06	**1973.32 (0.99)**
$PM_{10}/PM_{2.5}$	700	6.23	62	3.12	62	1.35	**4638.14 (2.32)**
SOx	700	1.62	62	0.82	62	0.35	**1206.54 (0.60)**

Maximum Monthly Emissions, lb/month = (no. normal operating hours) (normal emission rate, Case 1) + (no. startups, cold) (lb/startup, cold) + (no. startups, warm) (lb/startup, warm) + (no. startups, hot) (lb/startup, hot) + (no. shutdowns) (lb/shutdown)

- Normal Operating Month Emission Factors

For the **Application**, the normal operating emission factors in condition no. A63.3 for ~~CO (8.84 lb/mmcf)~~, VOC (3.17 lb/mmcf), PM_{10}/**$PM_{2.5}$** (7.44 lb/mmcf), and SOx (1.94 lb/mmcf), and in condition no. A99.3 for NOx (25.24 lb/mmcf) will remain the same as for the FDOC.

The normal operating month emission factors are calculated as shown in the table below.

Table 38 - Simple-Cycle Turbine Normal Operating Emission Factors - Monthly

Pollutants	Maximum Monthly Emissions, lb/month	Emission Factors, lb/mmcf
NOx	6983.64	11.21
CO	5504.00	8.84
VOC	1973.32	3.17
PM_{10}/**$PM_{2.5}$**	4638.14	7.44
SOx	1206.54	1.94

Emission factor, lb/mmcf = (lb/month) (month/622.83 mmscf)

Where max monthly fuel usage = (744 hours, incl. startups/shutdowns) (879 MMBtu/hr, Case 1) (mmscf/1050 MMBtu) = 622.83 mmscf/month

However, for the CO emission factor, the condition will be revised to add: **For normal operation, the CO emissions shall be measured with the certified CO CEMS. For the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the emission factor shall be CO, 8.84 lb/mmcf.**

As explained in the Rule 2012 analysis below, condition no. A99.4 specifies the interim emission factor for the normal operating period after commissioning has been completed but before the CEMS is certified, during which the CTGs are assumed to be operating at BACT levels. For each pollutant, the emission factor is calculated as the maximum normal operating month emissions divided by the total fuel usage for the month, both of which will remain the same as for the FDOC.

- Permit Conditions—Monthly Emissions Limits
  The table below compares the maximum commissioning month emissions with the maximum normal operating month emissions (higher values in bold font) to determine the maximum monthly emissions limits and associated 30-day averages. The table is the same as *Table 39* in the FDOC. (Although condition no. A63.3 will not include a monthly limit for NOx, it is included in the table below because the determination of 30-day averages for all pollutants is required for the internal NSR Data Summary Sheet.)

Table 39 – Simple-Cycle Turbine Maximum Monthly Emissions and Thirty-Day Averages

Pollutants	Maximum Commissioning Month Emissions, lb/month (lb/day)	Maximum Normal Operating Month Emissions, lb/month (lb/day)	Maximum Monthly Emissions, lb/month	30-Day Averages, lb/day
NOx	1913.27 lb/month (63.78 lb/day)	**6983.64 lb/month (232.79 lb/day)**	6983.64	232.79
CO	**8593.7 lb/month (286.46 lb/day)**	5504 lb/month (183.47 lb/day)	8593.7	286.46
VOC	285.08 lb/month (9.50 lb/day)	**1973.32 lb/month (65.78 lb/day)**	1973.32	65.78
PM_{10}/**$PM_{2.5}$**	582.5 lb/month (19.42 lb/day)	**4638.14 lb/month (154.60 lb/day)**	4638.14	154.60
SOx	151.16 lb/month (5.04 lb/day)	**1206.54 lb/month (40.22 lb/day)**	1206.54	40.22

For the **Application**, condition A63.3 will continue to limit CO emissions to 8594 lb/month, VOC to 1973 lb/month, PM_{10} to 4638 lb/month, and SOx to 1207 lb/month.

- *Maximum Annual Emissions per Turbine*
  The Yorke *Applications for Modification: Turbine Emission Limits* for A/N 610354 – 610360 proposes to decrease the total annual operating hours by 1300 hours per turbine, from 2360 hours per turbine to 1060 hours per turbine, with no changes in the number of annual startups and shutdowns per turbine.

  The assumed 2360 hr/yr was based on 0.22 hr/shutdown. The FDOC, however, was permitted for 2358 hr/yr per turbine based on 0.216 hr/shutdown. The 2358 hr/yr per

turbine was used throughout the FDOC, including for the Rule 1304.1 fees. Therefore, this evaluation will be based on a decrease from the permitted 2358 hr/yr to 1058 hr/yr.

The breakdown becomes (1) ~~2000~~ 700 hours of normal operation, (2) 500 startups (250 hr), and (3) 500 shutdowns (108 hr), for a total of ~~2358~~ 1058 hours for maximum annual emissions per turbine.

The annual emissions for the commissioning year and a normal operating year are calculated below, with the changes to the FDOC shown.

- Commissioning Year

  For the FDOC, the maximum annual emissions for CO, VOC, PM_{10}/**$PM_{2.5}$**, and SOx set forth in condition A63.3 were based on a normal operating year. The condition specifies that compliance with the annual emission limits shall be based on a 12-operating month-rolling-average basis, following completion of the commissioning period.

  The maximum commissioning year emissions were used only to determine the NOx RTC holding for the first year of operation set forth in conditions I297.3 - I297.6. The NOx RTC holding requirement is not an enforceable emission limit because a RECLAIM facility has the flexibility to exceed the RTC holding requirement.

  As discussed under the Rule 2005(c)(2) analysis below, the appropriate RTC holding condition is I297. This condition specifies the pounds of NOx RTCs that are required to be held in the facility's allocation account to offset the annual emissions for the first year of operation only. The first year of operation is the commissioning year.

  For the FDOC, the maximum commissioning year emissions was calculated by adding the total emissions for the three months of commissioning from *Table 32* above to nine months of maximum monthly normal operating emissions from *Table 37* above. Based on the same methodology as used for the combined-cycle turbines in *Table 24* above, the calculations for the simple-cycle turbines were shown in *Table 40 – Simple-Cycle Turbine Maximum Annual Emissions, Commissioning Year*. *Table 40* indicated that the maximum commissioning year NOx emissions will be 68,574.76 lb/yr, which were conservatively higher than the 26,260.00 lb/yr derived for the maximum normal operating year in *Table 41 - Simple-Cycle Turbine Maximum Annual Emissions, Normal Operating Year*. Although NOx emissions are typically higher for a commissioning year than for a maximum normal operating year because of the uncontrolled emissions during the commissioning period, the maximum commissioning year NOx emissions were conservatively higher because of the low maximum normal operating year schedule and emissions. As the above methodology provided reasonable commissioning year emissions for the combined-cycle turbines, the same methodology was used for the simple-cycle turbines for consistency. Accordingly, FDOC conditions I297.3, I297.4, I297.5, and I297.6 required each turbine to hold 68,575 pounds of RTCs the first year.

After incorporating the proposed decrease in annual normal operating hours from 2000 hr/yr to 700 hr/yr for the **Application**, revised *Table 41 -Simple-Cycle Turbine Maximum Annual Emissions, Normal Operating Year* below shows that the maximum annual NOx emissions will decrease from 26,260 lb/yr to 15,600 lb/yr per turbine.

If conditions I297.3, I297.4, I297.5, and I297.6 were to continue to require each turbine to hold 68,575 pounds of RTCs per turbine for the commissioning year, the 68,575 lb/yr will be significantly higher than the proposed maximum normal operating year emissions of 15,600 lb/yr per turbine. Due to the proposed significant reduction in maximum normal operating year emissions, Yorke Engineering proposed on p. 11 of the *Applications for Modification: Turbine Emission Limits* to revise the methodology for determining the commissioning year emissions for the simple-cycle turbines. The proposed methodology is to add the total emissions for the three months of commissioning from *Table 32* above to the proposed maximum normal operating year emissions from revised *Table 41- Simple-Cycle Turbine Maximum Annual Emissions, Normal Operations* below, because all of the permitted annual emissions could occur in the nine months after commissioning. The proposed methodology is acceptable because it would provide a reasonable estimate of the commissioning year emissions.

For the **Application**, FDOC *Table 40* is revised below to implement the revised methodology for calculating the commissioning year emissions.

Table 40 – Simple-Cycle Turbine Maximum Annual Emissions, Commissioning Year

Pollutants	Commissioning Year Emissions, lb/yr
NOx	(5722 lb/commissioning) + ~~(6983.64 lb/month)(9 normal operating months)~~ **15,600 lb/yr** = ~~68,574.76~~ **21,322** lb/yr (~~34.29~~ **10.66** tpy)
CO	(25,395 lb/commissioning) + ~~(5504 lb/month)(9 normal operating months)~~ **24,543 lb/yr** = ~~74,931~~ **49,938** lb/yr (~~37.47~~ **24.97** tpy)
VOC	(836 lb/commissioning) + ~~(1973.32 lb/month)(9 normal operating months)~~ **4533.0 lb/yr** = ~~18,595.88~~ **5369** lb/yr (~~9.30~~ **2.68** tpy)
PM_{10}/**$PM_{2.5}$**	(1744 lb/commissioning) + ~~(4638.14 lb/month)(9 normal operating months)~~ **6596.0 lb/yr** = ~~43,487.26~~ **8340** lb/yr (~~21.74~~ **4.17** tpy)
SOx	(454 lb/commissioning) + ~~(1206.54 lb/month)(9 normal operating months)~~ **573.0 lb/yr** = ~~11,312.86~~ **1027** lb/yr (~~5.66~~ **0.51** tpy)

For the **Application**, conditions I297.3, I297.4, I297.5, and I297.6 will be revised to require each turbine to hold ~~68,575~~ **21,322** pounds of RTCs the first year.

- <u>Normal Operating Year</u>
  Because the monthly emissions limits in condition A63.3 are applicable each and every month, the annual emissions limits are the monthly emissions multiplied by twelve months, unless limited by permit condition. For power plants, the electric power demand is seasonal. The maximum monthly emissions are determined based on summer months when electric power demand is high. However, the same high demand is not required the rest of the year.

  For the FDOC, the applicant requested: (1) 2000 hours of normal operation (Case 4), (2) 500 startups (250 hr), and (3) 500 shutdowns (110 hr), for a total of 2358 hours for maximum annual emissions per turbine. The normal operation emission rates from *Table 31* (case 4) above, and the startup and shutdown emissions per event are from *Table 33* above. The SOx emission rates are based on the long-term rate (0.25 grains/100 scf).

  The **Application** proposes to decrease the total annual operating hours by 1300 hours per turbine, from the permitted 2358 hours per turbine to 1058 hours per turbine, with no changes in the number of annual startups and shutdowns per turbine. The breakdown becomes (1) ~~2000~~ <u>**700**</u> hours of normal operation, (2) 500 startups (250 hr), and (3) 500 shutdowns (108 hr), for a total of ~~2358~~ <u>**1058**</u> hours for maximum annual emissions per turbine.

  The table below shows the revised maximum annual emissions per turbine for the **Application**. The changes shown are to *Table 41* in the FDOC.

Table 41 - Simple-Cycle Turbine Maximum Annual Emissions, Normal Operations

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr (Case 4)	No. of Startups	lb/ startup	No. of Shut downs	lb/shutdown	Maximum Annual Emissions lb/yr (tpy)
NOx	~~2000~~ <u>**700**</u>	8.20	500	16.6	500	3.12	~~26,260.0 (13.13)~~ <u>**15,600 (7.80 tpy)**</u>
CO	~~2000~~ <u>**700**</u>	3.99	500	15.4	500	28.1	~~29,730.0 (14.87)~~ <u>**24,543 (12.27 tpy)**</u>
VOC	~~2000~~ <u>**700**</u>	2.29	500	2.80	500	3.06	~~7510.0 (3.76)~~ <u>**4533.0 (2.27 tpy)**</u>
$PM_{10}/PM_{2.5}$	~~2000~~ <u>**700**</u>	6.23	500	3.12	500	1.35	~~14,695 (7.35)~~ <u>**6596.0 (3.30 tpy)**</u>
SOx	~~2000~~ <u>**700**</u>	0.54	500	0.27	500	0.12	~~1275.0 (0.64)~~ <u>**573.0 (0.29 tpy)**</u>

- <u>Permit Conditions—Annual Emissions Limits</u>
  For the **Application**, the annual emission limits for a normal operating year currently set forth in condition A63.3 for CO, VOC, PM_{10}/<u>**$PM_{2.5}$**</u>, and SOx will be revised to reflect the revised annual emissions in *Table 41* above. <u>**The annual emissions limits**</u>

will be decreased from 29730 lb/yr to 24543 lb/yr for CO; 7510 lb/yr to 4533 lb/yr for VOC; 14695 lb/yr to 6596 lb/yr for $PM_{10}/PM_{2.5}$; and 1275 lb/yr to 573 lb/yr for SOx in condition A63.3.

The annual limits ensure that the annual $PM_{10}/PM_{2.5}$ and NO_2 emissions will not exceed the $PM_{10}/PM_{2.5}$ and NO_2 modeled emission rates for the annual averaging period provided in *Table 53* below. In addition, the annual limits for $PM_{10}/PM_{2.5}$ emissions will ensure compliance with condition F2.1, which limits the facility-wide $PM_{2.5}$ emissions to below the applicability limit of 70 tpy set forth in *Rule 1325—Federal PM2.5 New Source Review Program, amended 1/4/19.* ***Update: Pursuant to the Rule 1325 analysis in this evaluation, the PM2.5 emission limit in condition F2.1 will be corrected to 100 tpy.***

As with the monthly limits, an annual emissions limit may not be added for NOx because AEC will be a RECLAIM facility and such a limit is not allowed by RECLAIM rules. The annual emissions for NOx, however, are indirectly limited by the annual emissions limits for CO, VOC, PM_{10}**/$PM_{2.5}$**, and SOx. Additionally, the toxic pollutants and greenhouse gases are indirectly limited by the annual emissions limits.

The emission factors for the monthly emission limits (VOC, $PM_{10}/PM_{2.5}$) shall be used to demonstrate compliance with the annual emission limits, except for SOx. AES requested that the maximum monthly emissions be based on 0.75 grains/100 scf, but that the annual emissions be based on 0.25 grains/100 scf. The table below shows the calculation of the annual SOx emission factor. The changes shown are to *Table 41A* in the FDOC.

Table 41A – Simple-Cycle Turbine Normal Operating Emission Factor – Annual Limit

Pollutants	Maximum Annual Emissions, lb/year	Emission Factors, lb/mmcf
SOx	~~1275~~ **573.00**	0.65

Emission factor, lb/mmcf = (lb/yr) (yr / ~~1967.25~~ **882.67** mmscf)

Where max annual fuel usage = (~~2358~~ **1058** hours, incl. startups/shutdowns) (876 MMBtu/hr, Case 4) (mmscf/1050 MMBtu) = ~~1967.25~~ **882.67** mmscf/yr

For the **Application**, the annual SOx emission factor remains 0.65 lb/mmcf.

- <u>*New Source Review (NSR) Database Entries*</u>
  The 30-day averages for the ***Application*** *remain the same as for the FDOC.*

  This section develops the internal NSR Data Summary Sheet entries.

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

  The 30-day averages per turbine are from *Table 39*. 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.

  <u>NOx</u>
  R2 = (232.79 lb/day)(day/24 hr) = 9.70 lb/hr

  R1 = (9.70 lb/hr)(25 ppm uncontrolled/2.5 ppm controlled per case 1) = 97.0 lb/hr

  30-DA = 232.79 lb/day

  <u>CO</u>
  R2 = (286.46 lb/day)(day/24 hr) = 11.94 lb/hr

  R1 = (11.94 lb/hr)(100 ppm uncontrolled/ 2 ppm controlled per case 1) = 597.0 lb/hr

  30-DA = 286.46 lb/day

  <u>ROG</u>
  R2 = (65.78 lb/day)(day/24 hr) = 2.74 lb/hr

  R1 = (2.74 lb/hr)(4 ppm uncontrolled/2 ppm controlled per case 1) = 5.48 lb/hr

  30-DA = 65.78 lb/day

  <u>PM_{10}</u>
  R2 = R1 = (154.60 lb/day)(day/24 hr) = 6.44 lb/hr

  30-DA = 154.60 lb/day

  <u>SOx</u>
  R2 = R1 = (40.22 lb/day)(day/24 hr) = 1.68 lb/hr

  30-DA = 40.22 lb/day

B. Toxic Pollutants

The toxic air pollutant (TAC) and hazardous air pollutant (HAP) emissions rates are for use in the Rule 1401 health risk assessment (HRA) below. For the **Application**, the FDOC emission rates are required to be revised to reflect the proposed decrease in annual operating hours from the permitted 2358 hr/turbine to 1058 hr/turbine.

On p. 15 of the Application, *Table 3-8: Toxic Air Contaminant Emissions for Each SCGT* provides the TAC and HAP emissions rates for each combined-cycle turbine. In *Appendix B – Emissions Calculations*, the table for *Each SCGT Hazardous Air Pollutants Emissions* shows the emissions calculations. (The *Appendix B* provided with the Yorke *Applications for Modification: Turbine Emission Limit,* was erroneously based on the superseded increase to 1020 hours that had been proposed earlier in the Yorke Protocol, 11/7/18. On 5/28/19, Yorke e-mailed a revised *Appendix B* based on the increase to 1060 hr/yr.)

For the **Application**, FDOC *Table 42* is revised below to reflect the corrected proposed decrease in annual operating hours from the permitted 2358 hr/yr to 1058 hr/yr per turbine.

Table 42 - Simple-Cycle Turbine Toxic Air Contaminants/Hazardous Air Pollutants

Compound	CAS	TAC/HAP	Emission Factor [1] (Lb/MMBtu)	Lb/hr	Lb/yr	TPY
Ammonia[5]	766417	TAC		6.09	~~14,309~~ **6422.84**	~~7.15~~ **3.21**
Acetaldehyde[2]	75070	TAC & HAP	1.76E-04	0.15	~~354~~ **163.36**	~~0.18~~ **0.08**
Acrolein[2]	107028	HAP & TAC	3.62E-06	0.0031	~~7.26~~ **3.36**	~~0.0036~~ **0.0017**
Benzene[2]	71432	HAP & TAC	3.26E-06	0.0028	~~6.55~~ **3.03**	~~0.0033~~ **0.0015**
1,3-Butadiene	106990	HAP & TAC	4.3E-07	0.00037	~~0.86~~ **0.40**	~~0.00043~~ **0.0002**
Ethylbenzene	100414	HAP & TAC	3.2E-05	0.027	~~64.1~~ **29.70**	~~0.032~~ **0.015**
Formaldehyde[2]	50000	HAP & TAC	3.6E-04	0.31	~~722~~ **334.15**	~~0.36~~ **0.17**
Hexane	110543	HAP & TAC	Not available	--	--	--
Naphthalene	91203	HAP & TAC	1.3E-06	0.0011	~~2.62~~ **1.21**	~~0.0013~~ **0.00061**
PAHS (excluding naphthalene)[3, 4]	1151	HAP & TAC	(2.2E-06 – 1.3E-06) * 0.5 = 0.45E-06	0.00038	~~0.90~~ **0.42**	~~0.00045~~ **0.00021**
Propylene (propene)[5]	115071	TAC	Not available	--	--	--
Propylene Oxide	75569	HAP & TAC	2.9E-05	0.025	~~58.22~~ **26.92**	~~0.029~~ **0.013**
Toluene	108883	HAP & TAC	1.3E-04	0.11	~~262~~ **120.66**	~~0.13~~ **0.060**

Compound	CAS	TAC/HAP	Emission Factor [1] (Lb/MMBtu)	Lb/hr	Lb/yr	TPY
Xylene	1330207	HAP & TAC	6.4E-05	0.055	~~128~~ **59.40**	~~0.064~~ **0.030**
Total Annual HAPS Emissions per Turbine, TPY					~~1606.51~~ **742.61**	~~0.80~~ **0.372**
Total Annual Toxic Air Contaminant Emissions per Turbine, TPY						~~7.95~~ **3.58**

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.

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 Per Section 3.1.4.3 of AP-42, PAH emissions were assumed to be controlled by 50 percent by the oxidation catalyst.

5 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 879 MMBtu/hr (Case 1))

Annual emissions, lb/yr = (Emission Factor) (average annual heat input rate of ~~2,065,608~~ **926,434.24** MMBtu/yr)

Where average annual heat input = (~~2358~~ **1058** hr/yr)(875.64673 MMBtu/hr)
= ~~2,064,775~~ **926,434.24** MMBtu/yr

Note: Case 4 in Table 31 shows 876 MMBtu/hr, but AES used the more precise value of 875.64673 MMBtu/hr.

Ammonia

Maximum hourly emissions, lb/hr = (879 MMBtu/hr (case 1)) (8710 dscf/10^6 Btu) (5 ppm NH_3 /10^6) (20.9/(20.9-15.0)) (17 lbs NH_3/379 scf) = 6.09 lb /hr

This is the same as the 6.09 lb/hr from *Table 31* (case 1)

Maximum annual emissions, lb/yr = (~~2358~~ **1058** hr/yr)(6.07 lb/hr (case 4)) = ~~14,313~~ **6422.06** lb/yr = ~~7.16~~ **3.21** tpy

C. Greenhouse Gases (GHG)

- *Combustion: CO_2, CH_4, N_2O*

  Combustion of natural gas in the turbines will result in emissions of CO_2, CH_4, and N_2O.

  As shown above for the toxic pollutants emissions calculations, the average annual heat input rate will be ~~2,064,775~~ **926,434.24** MMBtu/yr, based on the increase in proposed decrease in annual operating hours from the permitted 2358 hr/yr to 1058 hr/yr per turbine.

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

  For each simple-cycle turbine:

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

  CO_2 = (~~2,064,775~~ **926,434.24** MMBtu/yr)(53.06 kg/MMBtu)(2.2046 lb/kg)
  = ~~241,529,277.3~~ **108,370,642.1** lb/yr = ~~120,764.64~~ **54,185.32** tpy

  CH_4 = (~~2,064,775~~ **926,434.24** MMBtu/yr)(1 g/MMBtu)(2.205×10^{-3} lb/g)
  = ~~4552.83~~ **2042.79** lb/yr = ~~2.28~~ **1.02** tpy

  N_2O = (~~2,064,775~~ **926,434.24** MMBtu/yr)(0.1 g/MMBtu)(2.205×10^{-3} lb/g)
  = ~~455.28~~ **204.28** lb/yr = ~~0.23~~ **0.10** tpy

  Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as amended by 79 FR 73779, 12/11/14: *(1)* CH_4 is equivalent to 25 times the global warming potential of CO_2, and *(2)* N_2O is equivalent to 298 times of CO_2.

  CO_2e = (~~241,529,277.3~~ **108,370,642.1** lb/yr CO_2)(1 lb CO_2e/lb CO2) + (~~4552.83~~ **2042.79** lb/yr CH_4)(25 lb CO2e/lb CH_4) + (~~455.28~~ **204.28** lb/yr N_2O) (298 lb CO_2e/lb N_2O) = ~~241,778,771.5~~ **108,482,587.3** lb/yr = ~~120,889.39~~ **54,241.29** tpy per turbine = ~~10,074.12~~ **4520.11** tons/month

- *Circuit Breakers: SF6*

  For the **Application**, the SF6 emissions calculations are the same as the FDOC. The decrease in annual operating hours for the simple-cycle turbines will not affect the SF6 leakage rate. Condition F52.2 will continue to specify a CO_2e facility-wide annual limit for SF_6 (74.55 tpy) to enforce the BACT requirements for the circuit breakers located at the CCGT (17.44 tpy) and SCGT (57.11 tpy) power blocks.

SCGT: 114,228.0 lb/yr = 57.11 tpy = 4.76 ton/month CO_2e

- *New Source Review (NSR) Database Entries*
  This section develops the internal NSR Data Summary Sheet entries. For the **Application**, the entries are revised to reflect the decrease to 1058 hr/yr per turbine.

  Operating Schedule: 52 wks/yr, 7 days/wk, 24 hrs/day (annualized schedule)
  → 8736 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.

  CO_2 = (~~241,529,277.3~~ **108,370,642.1** lb/yr) (yr /8736 hr) = ~~27,647.58~~ **12,405.06** lb/hr

  CH_4 = (~~4552.83~~ **2042.79** lb/yr) (yr /8736 hr) = ~~0.52~~ **0.23** lb/hr

  N_2O = (~~455.28~~ **204.28** lb/yr) (yr /8736 hr) = ~~0.05~~ **0.02** lb/hr

  SF_6 = (114,228 lb/yr) (yr /8736 hr) = 13.08 lb/hr

7. A/N 604020--Ammonia Storage Tank, No. Tank-1 (Combined-Cycle Turbines) (A/N 579167)

The **Application** proposes to update the capacity and dimensions for the ammonia tank from 40,000 gallons to 22,000 gallons. The change in tank capacity will not change the FDOC emissions.

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

Emissions are not expected because the filling losses will be controlled by a vapor return line and the breathing losses by the 50 psig pressure valve.

NH_3 = 0 lb/hr = 0 lb/day

11. Facility Maximum Monthly and Annual Emissions, Normal Operation

a. Maximum Monthly Emissions, Normal Operations

For the **Application**, the facility maximum monthly emissions are the same as for the FDOC.

Table 43 - Facility Maximum Monthly Emissions, Normal Operations

	Tons/Month						
Equipment	**NOx**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**	**SOx**	**NH_3**	**CO_2e**
Combined-Cycle Turbine	6.73	12.32	3.79	3.16	1.81		50,925.87
Combined-Cycle Turbine	6.73	12.32	3.79	3.16	1.81		50,925.87
Circuit Breakers for Combined-Cycle Turbine Power Block							1.45
Simple-Cycle Turbine	3.49	2.75	0.99	2.32	0.60		10,074.12
Simple-Cycle Turbine	3.49	2.75	0.99	2.32	0.60		10,074.12
Simple-Cycle Turbine	3.49	2.75	0.99	2.32	0.60		10,074.12
Simple-Cycle Turbine	3.49	2.75	0.99	2.32	0.60		10,074.12
Circuit Breakers for Simple-Cycle Turbine Power Block							4.76
Auxiliary Boiler	0.057	0.30	0.051	0.057	0.016		922.72
SCR/CO Catalyst for Combined-Cycle Turbine						2.92	
SCR/CO Catalyst for Combined-Cycle Turbine						2.92	
SCR/CO Catalyst for Simple-Cycle Turbine						0.60	
SCR/CO Catalyst for Simple-Cycle Turbine						0.60	
SCR/CO Catalyst for Simple-Cycle Turbine						0.60	
SCR/CO Catalyst for Simple-Cycle Turbine						0.60	
SCR for Auxiliary Boiler						0.018	
Ammonia Tank for Combined-Cycle Turbines						0	
Ammonia Tank for Simple-Cycle Turbines						0	
Oil/Water Separator for Combined-Cycle Turbines			0.0000075				
Oil/Water Separator for Simple-Cycle Turbines			0.0000011				
Facility Total	**27.48**	**35.94**	**11.59**	**15.66**	**6.04**	**8.26**	**143,077.15**

b. Maximum Daily Emissions, Normal Operations
For the FDOC, the facility maximum daily emissions were calculated for the public notice required for Rule 212(c)(2) and significant Title V revision. For that purpose only, the daily emissions were the monthly emissions from the table above, divided by 30 days. For the **Application**, public notice is not required by Rule 212 but is required for this significant Title V revision.

c. Maximum Annual Emissions, Normal Operations
The facility maximum annual emissions are calculated for the purpose of rule applicability in the *Rule Evaluation* section below. For the **Application**, the changes shown are to *Table 45* in the FDOC.

Table 45 - Facility Maximum Annual Emissions, Normal Operations

	Tons/Year						
Equipment	**NOx**	**CO**	**VOC**	**PM_{10}/ $PM_{2.5}$**	**SOx**	**NH_3**	**CO_2e**
Combined-Cycle Turbine	~~41.93~~ **57.45**	~~90.27~~ **97.36**	~~26.33~~ **31.74**	~~19.72~~ **27.82**	~~3.72~~ **5.24**		~~611,110.39~~ **862,008.08**
Combined-Cycle Turbine	~~41.93~~ **57.45**	~~90.27~~ **97.36**	~~26.33~~ **31.74**	~~19.72~~ **27.82**	~~3.72~~ **5.24**		~~611,110.39~~ **862,008.08**
Circuit Breakers for Combined-Cycle Turbine Power Block							17.44
Simple-Cycle Turbine	~~13.13~~ **7.80**	~~14.87~~ **12.27**	~~3.76~~ **2.27**	~~7.35~~ **3.30**	~~0.64~~ **0.29**		~~120,889.39~~ **54,241.29**
Simple-Cycle Turbine	~~13.13~~ **7.80**	~~14.87~~ **12.27**	~~3.76~~ **2.27**	~~7.35~~ **3.30**	~~0.64~~ **0.29**		~~120,889.39~~ **54,241.29**
Simple-Cycle Turbine	~~13.13~~ **7.80**	~~14.87~~ **12.27**	~~3.76~~ **2.27**	~~7.35~~ **3.30**	~~0.64~~ **0.29**		~~120,889.39~~ **54,241.29**
Simple-Cycle Turbine	~~13.13~~ **7.80**	~~14.87~~ **12.27**	~~3.76~~ **2.27**	~~7.35~~ **3.30**	~~0.64~~ **0.29**		~~120,889.39~~ **54,241.29**
Circuit Breakers for Simple-Cycle Turbine Power Block							57.11
Auxiliary Boiler (A/N 604014 & 613323 Evaluation)	0.68	3.60	0.61	0.68	0.19		11,072.68
SCR/CO Catalyst for Combined-Cycle Turbine						~~35.0~~ **50.94**	
SCR/CO Catalyst for Combined-Cycle Turbine						~~35.0~~ **50.94**	
SCR/CO Catalyst for Simple-Cycle Turbine (*Table 42*)						~~7.16~~ **3.21**	
SCR/CO Catalyst for Simple-Cycle Turbine						~~7.16~~ **3.21**	
SCR/CO Catalyst for Simple-Cycle Turbine						~~7.16~~ **3.21**	
SCR/CO Catalyst for Simple-Cycle Turbine						~~7.16~~ **3.21**	
SCR for Auxiliary Boiler (A/N 604014 & 613323 Evaluation)						0.21	
Ammonia Tank for Combined-Cycle Turbines						0	
Ammonia Tank for Simple-Cycle Turbines						0	
Oil/Water Separator for Combined-Cycle Turbines			0.00009				
Oil/Water Separator for Simple-Cycle Turbines			0.000013				
Facility Total	~~137.06~~ **146.78**	~~243.62~~ **247.40**	~~68.31~~ **73.17**	69.52	~~10.19~~ **11.83**	~~98.85~~ **114.93**	~~1,716,925.57~~ **1,952,128.55**
Post-Modification – Pre-Modification	**+ 9.72**	**+ 3.78**	**+ 4.86**	**+ 0.00**	**+ 1.64**	**+16.08**	**+ 235,202.98**

RULE EVALUATION

The modified AEC project is expected to comply with all applicable South Coast AQMD rules and regulations, and federal and state regulations, as follows:

DISTRICT RULES AND REGULATIONS

Rule 205—Expiration of Permit to Construct

Section 70.6 of 40 CFR Part 70 and South Coast AQMD Rule 3004(a) and (b) require each Title V permit to include emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements, at the time of permit issuance.

Rule 205, 40 Part 52.21(r)(2), and Rule 1713(c) provide expiration requirements for permits to construct.

Rule 205—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. This requirement is set forth in condition 1.b in Section E: Administrative Conditions of the facility permit. Section E is comprised of a standard list of operating conditions that apply to all permitted equipment at the facility unless superseded by condition(s) listed elsewhere in the permit.

40 Part 52.21--Rule 1714(c) incorporates by reference the provisions of 40 Part 52.21--Prevention of Significant Deterioration of Air Quality. Part 52.21(r)(2) states: "Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date."

§52.21(j)(4) states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

Rule 1713, adopted 10/7/88--Rule 1713(c) states: "A permit to construct shall become invalid if construction is not commenced within 24 months after receipt of such approval, if construction is discontinued for a period of 24 months or more, or if construction is not completed within a reasonable time. The Executive Officer may extend the 24-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 24 months of the projected and approve commencement date."

The requirements for Rule 205, 40 Part 52.21, and Rule 1713 are consolidated in conditions E74.1 and E193.5.

Analysis:
Condition E74.1 requires BACT/LAER determination for Phase II to be reviewed and modified by the South Coast AQMD no later than 18 months prior to the commencement of construction of Phase II. Phase II consists of the four simple-cycle turbines, as well as the aqueous ammonia tank and oil/water separator for the simple-cycle turbines. The PSD BACT determination for NOx, PM_{10}, and CO for the Phase II equipment is discussed below under Rules 1703(a)(2) and 1703(a)(3)(B).

Because the AEC project is a multi-year, multi-phase project, condition E193.5 sets forth requirements for the extension of the expiration date for the Permits to Construct. Condition E193.5 states in part: "The Permit to Construct shall expire one year from the issuance date, unless an 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." On 4/17/18, the South Coast AQMD extended the expiration date of all Permits to Construct to 4/17/19. On 4/12/19, the South Coast AQMD extended the expiration date of all Permits to Construct to 4/17/20. Since the construction of the combined-cycle units (Power Block 1, Phase 1) was initiated on 8/7/17, which is within one year of the date of issuance of the Permits to Construct on 4/18/17, condition E193.5 did not require the Permits to Construct for Phase 1 to be extended. AES requested the one-year extensions as recommended by the South Coast AQMD.

For the **FDOC**, *Table 3 - AEC Schedule Major Milestones* indicated the construction of AEC SCGT will start in May 2020. For the **Application**, the letter dated 5/10/19 from Stephen O'Kane to Sr. Manager Bhaskar Chandan regarding the revised Boiler Retirement Schedule for the Alamitos Energy Center (Facility ID 115394), indicated the AEC SCGT construction start date has been moved to July 2022. Accordingly, *Table 3* will be updated to indicate AEC SCGT construction date has been changed to Third Quarter 2022. In addition, condition E193.5 will be revised as follows:

> Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D164, and oil water separator D210) shall commence within 18 months of ~~May 31, 2020~~ **June 30, 2022** unless an extension is granted by the Permitting Authority.

Rule 212—Standards for Approving Permits, as amended 3/1/19
Rule 2005(h) –Public Notice for RECLAIM *(requires compliance with 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 (RECLAIM), or equipment under Regulation XXX (Title V) 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: For the **Application**, although the facility-wide emissions will increase, this paragraph will **not** require public notice because the closest combined-cycle turbine will **no longer** be located within 1000 feet of the outer boundary of a school.

For the **FDOC**, the nearest K-12 school—Rosie the Riveter Charter High School, 690 N. Studebaker Road, Long Beach, CA 90803-- was located 971 feet away from the closest combined-cycle turbine. Consequently, Rule 212(c)(1) public notice was required. For the **Application**, public notice is not required. In an e-mail dated 8/12/19**,** Stephen O'Kane indicated that the school is no longer on site. The building has been repurposed for AES use. (On 8/2/19, Jeff Miller, Compliance Manager, had stated this occurred in late spring 2019.)

Planning, Rule Development & Area Sources (PRDAS) staff was requested to use Google Earth and a map of the AGS facility to provide an accurate distance from the combined-cycle turbine to the outer boundary of the next closest K-12 school. In an e-mail dated 8/9/19, PRDAS staff indicated the distance from the outer boundary of Kettering Elementary School, 550 Silvera Avenue, Long Beach, CA 90803, to the nearest combined-cycle turbine is 2021 feet, which is farther than 1000 ft threshold.

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

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

Table 47 - Rule 212(c)(2) Applicability

	VOC	NOx	PM_{10}	SOx	CO	Lead
AEC 30-day averages, lb/day	0	0	0	0	0	0
Rule 212(c)(2) Daily Maximum, lbs/day	30	40	30	60	220	3
Increase Exceed Daily Maximum?	No	No	No	No	No	No

- ***Rule 212(c)(3)***
  Public notice is required for any new or modified permit unit, source under Regulation XX or equipment under 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 maximum individual cancer risk greater than, or equal to one in a million (1 x 10^{-6}), per guidelines published by the Executive Officer under Rule 1401(e), for facilities with more than one permitted unit, source, or equipment, 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 x 10^{-6}) using the risk assessment procedures and toxic air contaminants specified under Rule 1402.

  Analysis:
  This paragraph will **not** require public notice. The increases in annual toxic emissions from the combined-cycle turbines due to the proposed increase in the annual operating schedule will not expose a person to a maximum individual cancer risk (MICR) that is greater than or equal to one in a million, as shown in *Table 68--Model Results for HRA for Combined-Cycle Turbine* below. The decreases in annual toxic emissions from the simple-cycle turbines due to the proposed decrease in the annual operating schedule will result in a lower MICR, as shown in *Table 70--Model Results for HRA for Simple-Cycle Turbine* below.

Rule 218 – Continuous Emission Monitoring
The combined- and simple-cycle turbines are each 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 emission limit. In accordance with paragraphs (c), (e), (f), the facility is required to submit an "Application for CEMS" for each CO CEMS and to adhere to retention of records requirements and reporting requirements once approval to operate the CO CEMS is granted. Subsequent to the issuance of the permits to construct on 4/18/17, AES submitted a CEMS application on 8/22/18 for a CO CEMS (Rule 218) and a NOx CEMS (RECLAIM) for the combined-cycle and simple-cycle turbines. In a letter dated 2/20/19, South Coast AQMD Source Test Engineering granted initial approval for both CEMS for the turbines.

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 during normal operation because they will be firing exclusively on pipeline quality natural gas.

Update: The facility received 45 public complaints (44 received from 10/5/19 – 11/7/19) during the uncontrolled first fire phase of the commissioning of the two new combined-cycle turbines. The public complaints, consisting of visible emissions (smoke), noise and chemical odor, resulted in two Notices of Violation, P67928 and P67929. The facility filed a Variance petition to allow the facility to complete the uncontrolled phase of the startup operation of the CCGTs. The Variance was granted by the South Coast AQMD Hearting Board. The uncontrolled startup phase has now concluded, and the facility is no longer operating under a Variance. The facility is currently in compliance with the opacity requirements of the permit.

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. Update: See Rule 401.

Rule 403 – Fugitive Emissions

The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule includes the prohibition of fugitive dust emissions that remains visible in the atmosphere beyond the property line of the emission source.

During normal operations, fugitive emissions are not expected from the operation of the turbines and other equipment. Compliance with Rule 403 is expected.

Rule 407 – Liquid and Gaseous Air Contaminants

This rule limits the gas turbines to 2000 ppmv CO. The CO emissions from the combined-cycle turbines will be controlled by an oxidation catalyst to the BACT limit of 1.5 ppmvd at 15% O_2. The CO emissions from the simple-cycle turbines will be controlled by an oxidation catalyst to the BACT limit of 2 ppmvd at 15% O_2.

The SO_2 portion of the rule does not apply per subdivision (c)(2), because the natural gas fired in the CTGs will comply with the sulfur limit in Rule 431.1. Therefore, compliance with this rule is expected.

Rule 409 – Combustion Contaminants

This rule restricts the combustion generated PM emissions from combustion equipment to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12% CO_2, averaged over 15 minutes.

The **FDOC** provided the following analysis which indicated the combined-cycle and simple-cycle turbines will be in compliance with Rule 409. The **Application** analysis remains the same because the

PM_{10} hourly emission rates for the combined-cycle and simple-cycle turbines remain the same as the FDOC.

- Combined-Cycle Turbines
  Each combined-cycle 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 0.007 gr/scf.

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

  where:

  A = Maximum PM_{10} emission rate during normal operation, 8.5 lb/hr (case 1)
  B = Rule specified percent of CO_2 in the exhaust (12%)
  C = Percent of CO_2 in the exhaust (approx. 4.29% for natural gas)
  D = Stack exhaust flow rate, scf/hr

  $$D = F_d * \frac{20.9}{(20.9 - \%\ O_2)} * TFD = 8710 * \frac{20.9}{17.9} * 2275 = 23.1E+06 \text{ scf/hr}$$

  where:

  F_d = Dry F factor for fuel type, 8710 dscf/MMBtu
  O_2 = Rule specific dry oxygen content in the effluent stream, 3%
  TFD = Total fired duty measured at HHV, 2275 MMBTU/hr (case 1)

  Grain Loading = [(8.5 * 12) / (4.29) (23.1E+06)] * 7000 = 0.007 gr/scf < 0.1 gr/scf limit

- Simple-Cycle Turbines
  Each simple-cycle 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 0.01 gr/scf.

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

  where:

  A = Maximum PM_{10} emission rate during normal operation, 6.23 lb/hr (case 1)
  B = Rule specified percent of CO_2 in the exhaust (12%)
  C = Percent of CO_2 in the exhaust (approx. 4.29% for natural gas)
  D = Stack exhaust flow rate, scf/hr

  $$D = F_d * \frac{20.9}{(20.9 - \%\ O_2)} * TFD = 8710 * \frac{20.9}{17.9} * 879 = 8.94E+06 \text{ scf/hr}$$

where:

F_d = Dry F factor for fuel type, 8710 dscf/MMBtu
O_2 = Rule specific dry oxygen content in the effluent stream, 3%
TFD = Total fired duty measured at HHV, 879 MMBTU/hr (case 1)

Grain Loading = [(6.23 * 12) / (4.29) (8.94E+06)] * 7000 = 0.01 gr/scf < 0.1 gr/scf limit

Rule 431.1 – Sulfur Content of Gaseous Fuels

The natural gas supplied to the gas turbines is expected to comply with the 16 ppmv sulfur limit (calculated as H_2S) 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, amended 12/4/81

As Rule 474 was last amended on 12/4/81, this rule continues to be superseded by NOx RECLAIM pursuant to *Rule 2001--Applicability,* amended ***10/5/18****, Table 1—Rules Not Applicable To RECLAIM Facilities For Requirements Pertaining To NOx Emissions If Rule Was Adopted Or Amended Prior To October 5, 2018.*

Rule 475 – Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976, and establishes a limit for combustion contaminants (particulate matter) of 11 lbs/hr or 0.01 grains/scf. Compliance is achieved if either the mass limit or the concentration limit is met.

The **FDOC** provided the following analysis which indicated the combined-cycle and simple-cycle turbines will be in compliance with Rule 475. The **Application** analysis remains the same because the PM_{10} emission rates for the combined-cycle and simple-cycle turbines remain the same as the FDOC.

- Combined-Cycle Turbines
  Each CTG is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the concentration is expected to be 0.0026 gr/scf.

  Combustion Particulate (gr/scf) = (PM_{10}, lb/hr / Stack Exhaust Flow, scf) * 7000 gr/lb

  PM_{10} = 8.5 lb/hr (case 1)

  Stack exhaust flow = 23.1E+06 scf/hr (see Rule 409 analysis, above)

  Combustion Particulate = (8.5 / 23.1E+06) * 7000 = 0.0026 gr/scf < 0.01 gr/scf limit

- Simple-Cycle Turbines
  Each CTG is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the concentration is expected to be 0.005 gr/scf.

Combustion Particulate (gr/scf) = (PM_{10}, lb/hr / Stack Exhaust Flow, scf) * 7000 gr/lb

PM_{10} = 6.23 lb/hr (case 1)

Stack exhaust flow = 8.94E+06 scf/hr (see Rule 409 analysis, above)

Combustion Particulate = (6.23 / 8.94E+06) * 7000 = 0.005 gr/scf < 0.01 gr/scf limit

***Rule 1134 – Emissions of NOx from Stationary Gas Turbines**, as amended 4/5/19*

For the FDOC, Rule 1134, amended 8/8/97, was superseded by NOx RECLAIM pursuant to *Rule 2001--Applicability*, amended ***12/4/15,*** *Table 1--Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.*

For the **Application**, Rule 1134, amended 4/5/19, is not superseded by *Rule 2001--Applicability,* amended ***10/5/18,*** *Table 1—Rules Not Applicable To RECLAIM Facilities For Requirements Pertaining To NOx Emissions If Rule Was Adopted Or Amended Prior To October 5, 2018.*

This amended rule will not be applicable to the AEC because subdivision (b) was revised as follows:

(b) Applicability
The provisions of this rule shall apply to all ~~existing~~ stationary gas turbines, 0.3 megawatt (MW) and larger~~, as of August 4, 1989~~. The rule does not apply to stationary gas turbines subject to Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities, located at petroleum refineries, landfills, or publicly owned treatment works or fueled by landfill gas.

As the turbines are subject to Rule 1135, they will not be subject to Rule 1134.

~~***Rule 1135 – Emissions of NOx from Electric Power Generating Systems**, as amended 7/19/91*~~
***Rule 1135—Emissions of Oxides of Nitrogen from Electricity Generating Facilities**, as amended 11/2/18*

For the FDOC, Rule 1135, amended **7/19/91**, was superseded by NOx RECLAIM pursuant to *Rule 2001*, amended ***12/4/15,*** *Table 1.*

For the **Application**, Rule 1135, amended **11/2/18**, is not superseded by *Rule 2001--Applicability,* amended ***10/5/18,*** *Table 1—Rules Not Applicable To RECLAIM Facilities For Requirements Pertaining To NOx Emissions If Rule Was Adopted Or Amended Prior To October 5, 2018.* The analysis is provided below.

(b) Applicability
This rule shall apply to electric generating units at electricity generating facilities.

(c) Definitions

(7) ELECTRIC GENERATING UNIT means a boiler that generates electric power, gas turbine that generates electric power with the exception of cogeneration turbines, or diesel internal combustion engine that generates electric power and is located on Santa Catalina Island with the exception of emergency internal combustion engines.

(8) ELECTRICITY GENERATING FACILITY means a facility that is owned or operated by an investor-owned electric utility; is owned or operated by a publicly owned electric utility; or has electric generating units with a combined generation capacity of 50 megawatts or more of electrical power for distribution in the state or local electrical grid system. Electricity generating facility does not include landfills, petroleum refineries, or publicly owned treatment works.

Analysis: The simple-cycle and combined-cycle gas turbines are electric generating units at an electricity generating facility and are subject to this rule.

(d) Emissions Limitations Limits

(1) Emissions Limits for Boilers and Gas Turbines
Notwithstanding the exemptions contained in Rule 2001 – Applicability, subdivision (j) – Rule Applicability and its accompanying Table 1: Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions, **on and after January 1, 2024**, or when required by a permit to operate issued to effectuate the requirements in this rule, whichever occurs first, the owner or operator of an electricity generating facility shall not operate, a boiler or gas turbine in a manner that exceeds the NOx and ammonia emissions limits listed in Table 1: Emissions Limits for Boilers and Gas Turbines, where:

(B) Boilers and gas turbines installed or for which the owner or operator has applied for permits to construct prior to November 2, 2018 shall:

(i) Average the NOx and ammonia emissions limits in Table 1 over a 60 minute rolling average; or

(ii) Retain the averaging time requirements specified on the SCAQMD permit as of November 2, 2018.

Table 1: Emissions Limits for Boilers and Gas Turbines

Equipment Type	NOx (ppmv)[1]	Ammonia (ppmv)	Oxygen Correction (%, dry)
Combined Cycle Gas Turbine and Associated Duct Burner	2	5	15
Simple Cycle Gas Turbine	2.5	5	15

[1] – The NOx emission limits in Table 1 shall not apply during start-up, shutdown, and tuning.

Analysis: Subparagraph (d)(1)(B) is applicable because the initial applications for P/Cs for the simple-cycle and combined-cycle turbines were submitted on 10/23/15.

Combined-Cycle Turbines: As condition A195.8 limits NOx to 2.0 ppmv and condition A195.15 limits ammonia to 5 ppmv, both averaged over 1 hour at 15% O2, the turbines will be in compliance with (d)(1)(B).

Simple-Cycle Turbines: As condition A195.11 limits NOx to 2.5 ppmv and condition A195.15 limits ammonia to 5 ppmv, both averaged over 1 hour at 15% O2, the turbines will be in compliance with (d)(1)(B).

(3) Start-up, Shutdown, and Tuning Requirements
The owner or operator of an electricity generating facility shall meet start-up, shutdown, and tuning requirements in the SCAQMD permit for each electric generating unit. On and after January 1, 2024, the SCAQMD permit shall include limitations for duration, mass emissions, and number of start-ups, shutdowns, and, if applicable, tunings.

Analysis: The turbine permits are in compliance with (d)(3) for startups and shutdowns. In AES Response Letter, dated 12/11/15, the applicant clarified that the turbine combustors are not expected to require tuning after commissioning.

Combined-Cycle Turbines: Condition C1.3 provides startup limits, including: (1) number of starts per calendar month and year; (2) number of starts per day; (3) duration of starts, and (4) NOx, CO, and VOC emissions per start. Condition C1.4 provides shutdown limits, including (1) number of shutdowns per calendar month and year; (2) duration of shutdowns; and (3) NOx, CO, and VOC emissions per shutdown.

Simple-Cycle Turbines: Condition C1.5 provides startup limits, and C1.6 provides shutdown limits. These conditions are analogous to conditions C1.3 and C1.4 for the combined-cycle turbines.

(e) Monitoring, Recordkeeping, and Reporting

(1) RECLAIM NOx Source

The owner or operator of each RECLAIM NOx source subject to Rule 1135 shall comply with SCAQMD Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions to demonstrate compliance with the NOx emissions limits of this rule.

Analysis: The facility is currently in RECLAIM and required to comply with Rule 2012.

(6) Ammonia Emissions Limits

(A) The owner or operator of each electric generating unit with catalytic control devices shall conduct quarterly source tests to demonstrate compliance with the ammonia emission limit according to SCAQMD Method 207.1 – Determination of Ammonia Emissions from Stationary Sources during the first twelve months of operation of the catalytic control device and annually thereafter when four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit. If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the ammonia emissions limits prior to resuming annual source tests.

Analysis: Condition D29.4 will be revised to incorporate the more stringent Rule 1135(e)(6)(A) quarterly source testing requirements as follows:

~~The test(s) shall be conducted at least quarterly during the first 12 months of operation and at least annually thereafter~~. **The test(s) shall be conducted quarterly during the first twelve months of operation of the catalytic control device and annually thereafter when four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit. If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the ammonia emissions limits prior to resuming annual source tests.**

In addition to the existing rule tags for Rule 1303(a)(1)—BACT, 5-10-1996 and 12-6-2002, add Rule 1135, 11-2-2018, as a rule tag.

REGULATION XIII—NEW SOURCE REVIEW (NSR)

The South Coast AQMD new source review rules are based on both the National Ambient Air Quality Standards (NAAQS) and the California Ambient Air Quality Standards (CAAQS). The primary NAAQS are the levels of air quality necessary, with an adequate margin of safety, to protect the public health.

- ***Rule 1303(a)(1)—BACT/LAER (PM_{10}, SOx, VOC, CO)***
- ***Rule 2005(c)(1)(A)—BACT/LAER (NOx)***

Rule 1303(a)(1) requires Best Available Control Technology (BACT) for a new or modified source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia, with the South Coast AQMD interpreting the emission increase to be 1 lb/day or greater of uncontrolled emissions.

The South Coast AQMD is not in attainment for PM10 (California 24-hr and annual standards) and ozone, but is in attainment for PM10 (national 24-hr standard), CO, NOx, and SOx. Since NOx, SOx, and VOC (no attainment standards for VOC) are precursors to non-attainment pollutants, they are treated as non-attainment pollutants as well. Specifically, NOx and VOC are precursors to ozone. NOx and SOx are precursors to PM10 and PM2.5. Thus, this rule requires BACT for NOx (non-RECLAIM), PM10, SOx, VOC, and ammonia. As discussed below, Rules 1701(b)(1) and 1703(a)(2) require BACT for CO. Rule 2005(c)(1)(B) requires BACT for NOx for RECLAIM facilities.

Rule 1303(a)(2) provides that BACT for sources located at major polluting facilities shall be at least as stringent as Lowest Achievable Emissions Rate (LAER) as defined in the federal Clean Air Act Section 171(3). Rule 1302(s) (as amended 11/4/16) defines a "major polluting facility" (same as major stationary source) located in the South Coast Air Basin as any facility which emits, or has the potential to emit, a criteria air pollutant at a level that equals or exceeds the following emission thresholds: (1) VOC, 10 tpy; (2) NOx, 10 tpy; (3) SOx, 70 tpy; (4) CO, 50 tpy; and (5) PM10, 70 tpy. **Note**: The Rule 1302(s) major source thresholds for SOx, CO, and PM10 are required to be updated. As these pollutants that are in federal attainment, the thresholds are 100 tpy. If a threshold for any one criteria pollutant is equaled or exceeded, the facility is a major polluting facility, and will be subject to LAER for all pollutants subject to NSR. The existing Alamitos Generating Station is a major polluting facility because *Table 13* indicates the PTEs for VOC (453.72 tpy), NOx (635.60 tpy), CO (21,871.86 tpy), and PM10 (627 tpy) exceed the applicable thresholds.

Rule 1302(h) defines BACT as "the most stringent emission limitation or control technique which:

(1) has been achieved in practice [AIP] for such category or class of source; or

(2) is contained in any state implementation plan (SIP) approved by the US EPA approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or

(3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific

source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board."

The first two requirements in the BACT definition above are required by federal law as LAER for major sources. The third part of the definition is unique to South Coast AQMD and some other areas in California, and allows for more stringent controls than LAER. For major polluting facilities, LAER is determined on a permit-by-permit basis.

The FDOC provided a New Source Review BACT/LAER analyses for VOC, SO_2, and NH_3 which are not PSD pollutants for the proposed facility. As required by PSD, top-down BACT analyses were performed under *Rule 1703(a)(2)* for NOx, PM_{10}, and CO below.

1. **A/N 604015 & A/N 610354, A/N 604018 & 610355—Combined-Cycle Combustion Turbine Generators Nos. CCGT-1, CCGT-2 (A/N 579142, 579143)**
2. **A/N 608431, 608432--Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. CCGT-1, CCGT-2 (Combined-Cycle Turbines) (A/N 579160, 579161)**

- **FDOC Summary**

BACT/LAER for VOC Emissions
VOCs are formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. Effective combustor design and post-combustion control using an oxidation catalyst are two technologies for controlling VOC emissions from a combustion turbine. The FDOC concluded that BACT/LAER is the installation of dry low NOx combustors and an oxidation catalyst to meet 2.0 ppm at 15% O_2 (1-hr averaging) based on modified South Coast AQMD Method 25.3.

BACT/LAER for SO_2 Emissions
Emissions of SOx are dependent on the sulfur content in the fuel rather than any combustion variables. During the combustion process, almost all of the sulfur in the fuel is oxidized to SO_2. The AEC will be supplied with natural gas from the Southern California Gas pipeline, which is limited by Tariff Rule No. 30 to a maximum total fuel sulfur content of less than 0.75 grain of sulfur per 100 scf. The FDOC concluded the use of pipeline-quality natural gas with low sulfur content is BACT/LAER for SO_2.

BACT/LAER for Ammonia Emissions
A very small amount of ammonia used in the SCR systems to control NOx from the turbine exhaust stream is not consumed by the reaction in the SCR systems. The FDOC concluded that BACT/LAER for the ammonia slip is 5.0 ppm at 15% O_2 (1-hr averaging).

Alternative BACT/LAER for Commissioning, Startups and Shutdowns
Condition nos. A195.8, A195.9, and A195.10 provide that the BACT limits of 2.0 ppmvd NOx, 1.5 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, EPA accepted an alternative BACT which limits and minimizes emissions during periods when steady state BACT is not achievable, such as during commissioning, startups and shutdowns.

During commissioning, it is not technically feasible for the CTGs to meet BACT limits during the entire period because the dry low-NOx combustors may not be optimally tuned 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 no. E193.8 limits the commissioning period to 996 hours of fired operation per turbine, including a maximum of 216 hours without control.

During startups, it is not technically feasible for the CTGs to meet 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 C1.3 specifies limits for cold and non-cold startups.

During shutdowns, it is not technically feasible for the turbines to meet BACT limits during the entire shutdown because ammonia injection into the SCR reactor has ceased operation. The SCR and CO catalysts, however, are still above ambient temperatures and continue to operate for a portion of the shutdown. Condition C1.4 specifies limits for shutdowns.

- **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
  For the **Application**, *Table 18 - Combined-Cycle Turbine Maximum Daily Emissions* shows that the maximum daily emissions will not increase for VOC, SO_2, and ammonia. As daily emissions will not increase, a BACT/LAER analysis is not required. Further, there will be no changes to the commissioning , startup, and shutdown durations and emissions. Therefore, the limits set forth in conditions E193.8, C1.3, and C1.4 are not required to be revised.

5. A/N 610356, 610357, 610358, 610359—Simple-Cycle Combustion Turbine Generators Nos. SCGT-1, SCGT-2, SCGT-3, SCGT-4 (A/N 579145, 579147, 579150, 579152)

- **FDOC Summary**
  BACT/LAER for VOC Emissions
  The discussion on VOC formation and technologies for VOC control are the same as for the combined-cycle turbines.

  The FDOC concluded that BACT/LAER is the installation of dry low NOx combustors and an oxidation catalyst to meet 2.0 ppm at 15% O_2 (1-hr averaging) based on modified South Coast AQMD Method 25.3.

BACT/LAER for SO_2 Emissions
As with the combined-cycle turbines, the FDOC concluded the use of pipeline-quality natural gas with low sulfur content is BACT/LAER for SO_2.

BACT/LAER for Ammonia Emissions
As with the combined-cycle turbines, the FDOC concluded that BACT/LAER for ammonia slip is 5.0 ppm at 15% O_2 (1-hr averaging).

Alternative BACT for Commissioning, Startups and Shutdowns
Condition nos. A195.11, A195.17, and A195.10 provide that the BACT limits of 2.5 ppmvd NOx, 2.0 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, EPA accepted an alternative BACT which limits and minimizes emissions during periods when steady state BACT is not achievable, such as during commissioning, startups and shutdowns.

During commissioning, it is not technically feasible for the CTGs to meet BACT limits during the entire period because the dry low-NOx combustors may not be optimally tuned 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 no. E193.9 limits the commissioning period to 280 hours of fired operation per turbine, including a maximum of four hours without control.

During startups, it is not technically feasible for the CTGs to meet 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 C1.5 specifies limits for startups.

During shutdowns, it is not technically feasible for the turbines to meet BACT limits during the entire shutdown because ammonia injection into the SCR reactor has ceased operation. The SCR and CO catalysts, however, are still above ambient temperatures and continue to operate for a portion of the shutdown. Condition C1.6 specifies limits for shutdowns.

- **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
  For the **Application**, *Table 34 - Simple-Cycle Turbine Maximum Daily Emissions* shows that the maximum daily emissions will not increase for VOC, SO_2, and ammonia. As daily emissions will not increase, a BACT/LAER analysis is not required. Further, there will be no changes to the commissioning , startup, and shutdown durations and emissions.

Therefore, the limits set forth in conditions E193.9, C1.5, and C1.6 are not required to be revised.

7. A/N 604020--Ammonia Storage Tank, No. Tank-1 (Combined-Cycle Turbines) (A/N 579167)

- **FDOC Summary**
  For an ammonia storage tank, BACT/LAER for ammonia requires the use of a pressure vessel for storage and a vapor return line for transfer, which are required by conditions C157.1 and E144.1, respectively. The tanks will be pressure vessels with a pressure relief valve set at 50 psig to control breathing losses. The filling losses will be controlled by a vapor return line to the delivery vehicle. No ammonia emissions are expected during normal operation.

- **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
  For the **Application, a**s daily emissions will not increase, a BACT/LAER analysis is not required.

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- ***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 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 South Coast AQMD. As discussed for the BACT/LAER requirements above, the South Coast AQMD is not in attainment for PM_{10} (California 24-hr and annual standards) and ozone, but is in attainment for PM_{10} (national 24-hr standard), CO, NOx, and SOx. Since NOx, SOx, and VOC (no attainment standards for VOC) are precursors to non-attainment pollutants, they are treated as non-attainment pollutants as well.

  Rule 1303 requires modeling for NO_2 (non-RECLAIM), CO, PM_{10}, and SO_2. Rule 2005(c)(1)(B) requires modeling for NO_2 for RECLAIM facilities. (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, NO_2, CO, SO_2, PM_{10} (federal standard), the modeled peak impacts plus the worst-case background concentrations shall not exceed the most stringent air quality standard. For non-attainment pollutants where the background concentrations exceed the ambient air quality standards, the modeled peak impacts shall not cause an exceedance of the Rule 1303 significant change thresholds. The South Coast Air Basin is designated non-attainment for the state PM_{10} standard, and state and federal $PM_{2.5}$ standards.

Rule 1304(a) provides an exemption from the modeling requirements of Rule 1303(b)(1) and the offset requirement of Rule 1303(b)(2) for:

(2) Electric Utility Steam Boiler Replacement
The source is replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The new equipment must have a maximum electrical power rating (in megawatts) that does not allow basin wide electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset.

Page 11 of the Final Staff Report for Proposed Rule 1304.1—Electrical Generating Facility Fee for Use of Offset Exemption, dated 9/6/13, clarifies: "Currently, pursuant to Rule 1304(a)(2), replacement of an electrical steam boiler at an EGF [Electric Generating Facility] that does not increase basin wide MW capacity at that utility (now interpreted as owner) is exempt from the modeling and offset requirements of Rule 1303(b)(2)." Rule 1304(a)(2) provides an exemption for new qualifying equipment, such as combined-cycle turbines and simple-cycle turbines with intercoolers, that have a maximum electrical rating (in megawatts) that is less than or equal to the maximum electrical rating (in megawatts) of the electric utility steam boiler(s) that the new equipment replaces. Both the new equipment and the existing electric utility boiler(s) must have the same owner and be located in the basin. For example, this exemption allows the transfer of 480 MW credit from the Redondo Beach Generating Station (retirement of Utility Boiler No. 7) to the Huntington Beach Energy Project (new combined- and simple-cycle turbines), as listed in *Table 2 – AES Rule 1304(a)(2) Offset Plan* above. Offsets are provided from the South Coast AQMD internal offset accounts, as discussed in the Rule 1304.1 analysis below.

AES proposes to replace existing Utility Boiler No. 1 (175 MW-gross), No. 2 (175 MW-gross), Unit 6 (480 MW-gross), and No. 3 (320 MW-gross) for a total of 1150 MW-gross. The replacement equipment are two combined-cycle turbines (692.951 MW-gross total at 59 ºF) and four simple-cycle turbines (401.751 MW-gross total at 59 ºF) for a total of 1094.7 MW-gross total. At this time, AES has not identified plans for the surplus 55 MWs from the permanent retirements. Condition E448.1 limits the total electrical output from AEC to 1094.7 MW-gross at 59 ºF.

Therefore, Rule 1303 (CO, PM_{10}, SO_2) provides an exemption from the modeling requirements for the combined- and simple-cycle turbines, but not the auxiliary boiler. Rule 2005 (NO_2), Rule 1401 (health risk assessment for toxics) and Rule 1703 PSD (NO_2, PM_{10}, CO) do not provide any exemptions for the project.

Overview of Modeling Required for the Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)

FDOC Analysis

Pursuant to South Coast AQMD procedure, Planning, Rule Development & Area Sources (PRDAS) staff was requested to review the dispersion modeling analysis, including the health risk assessment results, provided by the applicant for the **FDOC**. PRDAS staff Melissa Sheffer reviewed the applicant's dispersion modeling analysis, by independently reproducing the modeling analysis, to verify compliance with South Coast AQMD rules and in support of the CEC's analysis of the *Supplemental Application for Certification*. The modeling review memo, dated 5/20/16, from Planning & Rules Manager Ian MacMillan, to Sr. Engineering Manager Andrew Lee provided comments on the applicant's modeling analyses, as well as PRDAS's independent modeling results, which were incorporated into the **FDOC**.

The **FDOC** provided a modeling analysis for the normal operation of the auxiliary boiler that demonstrated compliance with the ambient air quality standards for Rule 1303 (CO, PM_{10}, SO_2) and Rule 2005 (NO_2), as set forth in *Table 57A - Modeled Results - Normal Operation for Auxiliary Boiler*. The **FDOC** also provided facility-wide modeling for the normal operation of the two combined-cycle turbines, four simple-cycle turbines, and the auxiliary boiler in *Table 57 - Modeled Results - Normal Operation for Total Project*, in support of the CEC's analysis of the *Supplemental Application for Certification*.

Application Analysis

For the **Application**, the air dispersion modeling and health risk assessment (HRA) analysis performed for the FDOC are required to be revised on a permit unit basis, unless a modeling exemption is applicable, to incorporate the requested changes in the annual emissions for the combined-cycle and simple-cycle turbines for the South Coast AQMD evaluation. Further, the modeling and HRA are required to be revised on a facility-wide basis in support of the CEC's analysis of the *Petition for Post-Certification Amendment*.

- **Prior PRDAS Guidance regarding Modeling Requirements**
  Then Program Supervisor Jillian Baker (now Manager Jillian Wong) provided guidance regarding modeling requirements for a similar project modification for the City of Colton (Agua Mansa Power Plant) (ID 172077), A/N 570811, 570812, 570807 in 2015. That project proposed an increase in annual startups, shutdowns, and operating hours, in addition to other proposed revisions not affecting modeling. In an e-mail, dated 1/14/15, to Engineer Ken Laird, Jillian Baker stated: "This approach is consistent with what we have done previously, where we would only analyze the pollutants and averaging periods where the emission rate has increased or if new standards have been adopted which need to get evaluated." Subsequently, Ms. Baker verbally clarified to Engineer Vicky Lee that the new standard of concern is the federal 1-hr NO_2 standard, not any new PM_{10} or SOx standards. For the **Application**, revised air dispersion

modeling is only required for the annual averaging period for NO_2 and $PM_{10}/PM_{2.5}$, because modeling for the federal 1-hr NO_2 standard was performed for the FDOC.

On 12/6/18, Sr. Meteorologist Melissa Sheffer requested and received clarification from Manager Jillian Wong regarding modeling requirements for a modification project. Both the air dispersion modeling and HRA are required to be performed based on the emissions increases per permit unit, provided the stack parameters (height, diameter, location, flow rates, temperature) remain the same and the monitors for the background concentrations are located sufficiently close to the facility to capture the existing emissions from the facility. For the **Application**, both the air dispersion modeling and HRA are required to be based on total emissions, not on the emissions increases, because the equipment is under construction and has not contributed to the measured background concentrations.

- **Yorke Protocol, 11/7/18, and South Coast AQMD Comments on Yorke Protocol, 12/20/18**
  Prior to the submittal of A/N 610354-610360 (annual schedule changes for turbines) on 2/8/19, Yorke Engineering submitted a letter protocol, dated 11/7/18, detailing its proposed revisions to the modeling and HRA performed for the FDOC (**Yorke Protocol, 11/7/18**). Engineering staff and Sr. Meteorologist Melissa Sheffer reviewed the protocol. On 12/20/18, the South Coast AQMD provided comments on the proposed letter protocol (**South Coast AQMD Comments on the Yorke Protocol, 12/20/18**).

  a. The proposed **Yorke Protocol** stated that although Rule 1304 provides an exemption for Rule 1303 modeling, the FDOC applications compared the total facility annual NO_2 modeled concentration plus a representative ambient background NO_2 concentration to the annual NO_2 NAAQS. This analysis showed that the annual concentration predicted from the total facility emissions added minimally to the high background and would not cause an exceedance of the annual NO_2 NAAQS. Therefore, the minimal NOx annual emission increase, resulting from the proposed changes in annual operating hours for the combined-cycle and simple-cycle turbines, is not expected to cause an exceedance of the NAAQS, and this analysis will not be included in the revised modeling for the applications under preparation. Further, the proposed **Protocol** stated that the FDOC applications included an examination of the annual PM_{10} NAAQS (project plus background) [federal standard], and a comparison to the annual Rule 1303 significant change threshold for PM_{10} [state standard] since South Coast AQMD is non-attainment for the annual PM_{10} CAAQS. The NAAQS analysis showed that the annual concentration predicted from the total facility PM_{10} emissions added minimally to the high background and would not cause an exceedance of the NAAQS. The Rule 1303 analysis presented in the FDOC applications showed the total facility annual PM_{10} concentration was well below the significant change threshold. The proposed modification for the changes in annual operating hours for the combined-cycle and simple-cycle turbines is not expected to change the total facility annual PM_{10} concentration such that it would cause an exceedance of the NAAQS or the Rule 1303 significant change threshold, thus these analyses will not be included in the revised modeling for the applications under preparation.

South Coast AQMD Comments responded that, for the FDOC, the combined- and simple-cycle turbines were exempt from the modeling requirements of Rule 1303(b)(1) pursuant to the Rule 1304(a)(2) exemption for utility boiler repower projects. However, the FDOC applications provided a Rule 1303 modeling analysis of impacts for the entire project in support of the CEC's analysis of the *Supplemental Application for Certification*. The South Coast AQMD's understanding is that AES will submit a *Petition for Post-Certification Amendment* to the CEC for the modification project. The qualitative reasoning provided in the Protocol indicating that the changes in annual emissions for NOx and PM_{10} will not result in total predicted concentrations that will exceed the CAAQS, NAAQS, or Rule 1303 thresholds is not sufficient reason to avoid remodeling. The South Coast AQMD requested re-modeling for NO_2, PM_{10} and $PM_{2.5}$ based on the total emissions from each turbine and the auxiliary boiler for the annual averaging period to update FDOC *Table 57--Modeled Results - Normal Operation for Total Project* in support of the CEC's analysis of the *Petition for Post-Certification Amendment.*

b. The **Protocol** proposed to revise the dispersion modeling that had been accepted by the South Coast AQMD for the FDOC to incorporate the proposed operating hour revisions for the combined-cycle and simple-cycle turbines. **South Coast AQMD Comments** clarified that the air dispersion modeling and health risk assessment analysis are required to be updated to the most recent background concentrations, MET data, AERMOD version (air quality modeling), and AERMOD with HARP version (HRA).

c. The **Protocol** proposed that the maximum modeled annual NO_2 concentrations will include the NO_2 to NO_x conversion ratio of 0.75 (ARM method), as approved by EPA and South Coast AQMD for the FDOC. **South Coast AQMD Comments** clarified that, at the time the FDOC was approved on 1/3/17, the ARM method was still a regulatory option for NO_2 modeling. However, as this option has not been allowed by the EPA since October 2017, this is no longer an approved method. Therefore, the revised modeling is required to use the ARM2 method within the AERMOD model for all annual NO_2 modeling.

- **Planning, Rule Development & Area Sources (PRDAS) Staff Modeling Review for Application**

  Pursuant to South Coast AQMD procedure, Planning, Rule Development & Area Sources (PRDAS) staff was requested in a Modeling Review Request Memo, dated 5/30/19, to review the dispersion modeling analysis, including the health risk assessment results, provided by the applicant for the **Application**. PRDAS staff reviewed the applicant's dispersion modeling analysis, by independently reproducing the modeling analysis, to verify compliance with South

Coast AQMD rules and in support of the CEC's analysis of the *Petition for Post-Certification Amendment*.

The Modeling Review Memo, dated 7/30/19, from the Health Effects Officer Jo Kay Ghosh, to Sr. Engineering Manager Bhaskar Chandan provided comments on the applicant's modeling analyses and presented PRDAS's independent modeling results. **The maximum modeled concentrations and updated background levels provided by PRDAS staff are incorporated in the modeling results tables for Rules 1303, 1703, 1401, and 2005, below.** The comments and changes provided by PRDAS staff are identified as from the *PRDAS Memo*, which is included in the Appendix to this evaluation.

- **AERMOD, METEOROLOGICAL DATA, BACKGROUND DATA**
The Yorke *Applications for Modification: Turbine Emission Limits* for A/N 610354 – 610360 provided the analysis for the revised modeling and HRA on pp. 18 – 30. The FDOC modeling was the starting point for the modeling. The revised modeling followed the methodology proposed in the **Yorke Protocol, 11/17/18**, and the requested changes to the proposed methodology provided in **the South Coast AQMD Comments on Yorke Protocol, 12/20/18**.

In response to the **South Coast AQMD Comments**, the applicant utilized the most recent AERMOD (version 18081) for the air dispersion modeling. This is an update from the AERMOD (version 15181) used in the FDOC. The *PRDAS Memo* confirmed version 18081 is the current U.S. EPA approved model. The applicant used meteorological data are from the South Coast AQMD's Long Beach meteorological station for the years 2012 – 2016. Prior to the submittal of the Modeling Review Request Memo, dated 5/30/19, to PRDAS, Sr. Meteorologist Melissa Sheffer responded to Engineering staff on 5/22/19 that this was the correct set of MET data and the applicant will not need to revise the modeling to correct the MET data. The *PRDAS Memo* confirmed the use of the MET data from the ASOS Long Beach station (KLGB) for the years 2012-2016 is appropriate for this analysis.

The applicant used the same modeling receptor grid for the AERMOD modeling as used for the FDOC. The grid consists of receptors that are placed at the ambient air boundary (i.e., the project's property boundary) and Cartesian-grid receptors that are placed beyond the project's site boundary at spacing that increases with distance from the origin. Property boundary receptors were placed at 30-meter intervals. Beyond the project's property boundary, receptor spacing was as follows:

- 50-meter spacing from property boundary to 500 meters from the origin
- 100-meter spacing from beyond 500 meters to 3 km from the origin
- 500-meter spacing from beyond 3 km to 10 km from the origin
- 1,000-meter spacing from beyond 10 km to 25 km from the origin
- 5,000-meter spacing from beyond 25 km to 50 km from the origin

The *PRDAS Memo* confirmed that the receptor grid selection remains appropriate to capture the maximum impacts from the project

In response to the **South Coast AQMD Comments** and pursuant to EPA's 2017 Guideline on Air Quality Models, the applicant based the annual NO_2 annual modeling on the Ambient Ratio Method 2 (ARM2) to convert NOx to NO_2, an update from the ARM method used for the FDOC. The *PRDAS Memo* stated the minimum and maximum NO2/NOx ratios were the U.S. EPA default values (0.5 and 0.9, respectively), which is appropriate.

In response to the **South Coast AQMD Comments**, the most recent background data from the same monitoring stations as the FDOC were used. Data are from are the South Coastal Los Angeles County 1 – North Long Beach, South Coastal Los Angeles County 2 – South Long Beach, and South Coastal Los Angeles County 3 – 2425 Webster Street, Long Beach. On p. 22 of the *Applications for Modification*, *Table 4-2: Background Ambient Air Quality Data in Long Beach* presents the annual NO_2, PM_{10}, and $PM_{2.5}$ ambient data collected at these stations from 2014 to 2016. The maximum concentration measured for each pollutant from any of the stations was used in the dispersion modeling. On 5/22/19, Ms. Sheffer responded to Engineering staff that the background data for the years from 2014 to 2016 are acceptable because the 2017 background data were not posted by the South Coast AQMD until the end of January 2019, right before the submittal of the applications for the annual operating schedule changes, A/N 610354 – 610360, on 2/8/19. Instead of requiring Yorke Engineering to update the background data and resubmit the modeling, Ms. Sheffer indicated that PRDAS staff will update the background data for 2015 to 2017 as part of their review of the air dispersion modeling and HRA analysis submitted by the applicant for the project. Subsequently, the *PRDAS Memo* indicated that the applicant used the monitoring data from SRA 4, South Coastal Los Angeles County No. 3 monitoring station for the last three years (2014-2016) to determine the NO_2 background concentration. Years 2014-2016 are acceptable because 2017 data were not posted by the South Coast AQMD until the end of January 2019 and is more conservative than the years 2015-2017. Consequently, the *PRDAS Memo* did not update the background data to 2015-2017.

*****<u>PRDAS Correction to Yorke Modeling</u>**

The *PRDAS Memo* stated that the applicant used the URBAN dispersion option in AERMOD, with a population of 9,862,049 for Los Angeles County. The current South Coast dispersion modeling guidelines require a population of 9,818,605. AERMOD test runs by PRDAS confirmed that this discrepancy in urban population does not affect the modeling results at the precision reported. In an e-mail dated 8/30/19, the South Coast AQMD forwarded this PRDAS staff comment regarding the Rule 1303 modeling, and two comments regarding the Rule 1401 health risk assessment discussed below, to AES.

- **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. Because these meteorological phenomena do not persist for long periods, only the shorter averaging periods, less than or equal to 8 hours, should be considered. Therefore, the fumigation analysis for the **Application** is the same as the FDOC because fumigation is not evaluated for an annual averaging period.

- **NORMAL OPERATION IMPACTS**
  Turbine emissions and stack parameters, such as flow rate and exit temperature, exhibit some variation with ambient temperature and operating load. Therefore, to evaluate the worst-case impacts, the applicant performed a dispersion modeling analysis at three different load scenarios at three temperature conditions for each turbine type (combined- and simple-cycle) for the FDOC.

  For combined-cycle turbines, the three loads (45%, 75%, 100%) and three temperatures (28 ºF, 65.3 ºF, and 107 ºF) are from *Table 15 - Combined-Cycle Turbine Operating Scenarios*, above. For simple-cycle turbines, the loads (50%, 75%, 100%) and temperatures (28 ºF, 65.3 ºF, and 107 ºF) are from *Table 31 - Simple-Cycle Turbine Operating Scenarios*, above. The applicant's load analysis also included the operation of auxiliary boiler. The applicant's load analysis results were used to select the worst-case impacts for each criteria pollutant and averaging period for the **FDOC**.

1. **Combined-Cycle Gas Turbines Modeled Rates and Stack Parameters**
   As shown in *Table 51 - Modeled Emission - Rates - Normal Operation for AEC CCGT* below, the modeling is required to be revised for only the annual averaging period for the **Application**. The proposed revision to the annual number of normal operating hours from 4100 to 6005 hours for each combined-cycle turbine will affect the annual emission rates (NO_2, $PM_{10}/PM_{2.5}$) but not the Worst-Case Emission Scenario for the annual averaging period.

   Modeling is not required to be revised for the 1-hour, 3-hour, 8-hour, and 24-hour averaging periods. The emission rates and the worst-case emission scenarios for these short-term averaging periods will not change because the proposed change to the annual number of operating hours will not affect these other averaging periods.

   The NOx and $PM_{10}/PM_{2.5}$ emission rates for modeling for the annual averaging period are calculated as follows:

   For the Emissions Calculations section above, the normal operating rates for the maximum monthly emissions are based on Case 1 in *Table 15 - Combined-Cycle Turbine Operating Scenarios*. Case 1, based on 100% load, 28 °F ambient temperature, and without inlet cooling, is the worst case operating scenario that yields the highest controlled emissions. The normal operating rates for the maximum annual emissions are based on Case 4. Case 4, based on 100% load, 65.3 °F ambient temperature, and with inlet cooling, is the worst case operating scenario that yields the highest emission rates for the average annual temperature.

For Modeling, the normal operating rates for the worst-case emission scenario for the annual averaging period are based on Case 7 in *Table 15*. The maximum annual turbine impacts were predicted using the exhaust parameters for the 65.3 ºF, minimum load case, which represents the turbine exhaust parameters associated with the maximum predicted annual ground-level impact in the dispersion modeling. The **South Coast AQMD Comments on the Yorke Protocol, 12/20/18,** did not request Yorke Engineering to confirm that Case 7 remains the worst case scenario because the proposed changes in annual operating hours for the turbines were not expected to change the worst case scenario.

NO_x: [(**6005** hr/yr)(9.47 lb/hr, Case 7) + (80 cold starts)(61 lb/cold start) + (420 non-cold starts)
(17 lb/non-cold start) + (500 shutdowns)(10 lb/shutdown)] / 8760-hr averaging =
8.43 lb/hr → 1.06 g/sec

The modeling provided by applicant was based on 8.49 lb/hr (1.071 g/sec) pursuant to the superseded 6060 normal operating hrs proposed in the Yorke Protocol, 11/17/18. The small discrepancy will not affect the modeling results.

$PM_{10}/PM_{2.5}$: [(**6005** hr/yr)(8.5 lb/hr, Case 7) + (80 cold starts)(8.5 lb/cold start) + (420 non-cold starts)(4.25 lb/non-cold start) + (500 shutdowns)(4.25 lb/shutdown)] / 8760-hr averaging =
6.35 lb/hr → 0.800 g/sec

The modeling provided by applicant was based on 6.49 lb/hr (0.808 g/sec) pursuant to the superseded 6060 normal operating hrs proposed in the Yorke Protocol, 11/17/18. The small discrepancy will not affect the modeling results.

Table 51 - Modeled Emission- Rates - Normal Operation for AEC CCGT

Averaging Time	Worst-Case Emission Scenario	Pollutant	Emissions Per Turbine, lbs/hr
1-hour	NO_2: Both turbines in cold start-up mode, 28 °F ambient temperature. CO: Both turbines in cold start-up mode, 28 °F ambient temperature. SO_2: Both turbines in cold start-up mode, 28 °F ambient temperature.	**Modeling is not required to be revised for the 1-hour, 3-hour, 8-hour, and 24-hour averaging periods, but is required for the annual averaging period.**	
1-hour (federal)	NO_2: Both turbines in cold start-up mode, 28 °F ambient temperature. SO_2: Both turbines in cold start-up mode, 65.3 °F ambient temperature.		
3-hour	SO_2: Both turbines continuous average (75%) load operation, 65.3 °F ambient temperature.		
8-hour	CO: Both turbines complete two cold starts, 2 shutdowns, and balance of period at minimum (45%) load, 28 °F ambient temperature.		
24-hour	PM_{10}, $PM_{2.5}$: Both turbines continuous minimum (44%) load operation, 65.3 °F ambient temperature. SO_2: Both turbines continuous average (75%) load operation, 65.3 °F ambient temperature.		
Annual	NO_2, PM_{10}, $PM_{2.5}$: Both turbines operate at minimum (44%) load for ~~4100~~ **<u>6005</u>** normal operating hours, 80 cold starts, 420 non-cold starts, and 500 shutdowns, for total of ~~4640~~ **<u>6545</u>** hours, 65.3 °F ambient temperature. (Condition A63.2 limits annual CO, VOC, PM_{10}**<u>/$PM_{2.5}$</u>**, and SOx emissions, which also indirectly limits annual NOx emissions.)	NOx	~~6.24~~ **<u>8.43</u>**
		PM_{10}, $PM_{2.5}$	~~4.50~~ **<u>6.35</u>**

For the **Application**, FDOC *Table 52* is revised below to remove the 1-hour, 3-hour, 8-hour, and 24-hour averaging period data because revised modeling is required only for the annual averaging period. *Table 4-1: Stack Parameters and Emission Rates for Annual Modeling* on p. 21 of the Yorke *Applications for Modification* for A/N 610354 – 610360 was reviewed to confirm that modeling is based on the same stack parameters as the FDOC, except the stack height is increased.

As discussed above, A/N 604015 & A/N 604018 propose to increase the height of the combined-cycle turbine exhaust stacks from 140 ft. to 150 ft. During detailed design, AES determined that the height is required to be raised from 140 ft. to 150 ft. to accommodate stack dampers for noise attenuation to satisfy the noise limits of CEC Condition of Certification NOISE-4. The modeling is based on 150 ft. (45.7 m).

Table 52 - Modeled Stack Parameters - Normal Operation for AEC CCGT

	Averaging Period	**Stack Diameter (m)**	**Stack Height (m)**	**Exhaust Temp (°F (°K))**	**Exhaust velocity (ft/s (m/s))**	**Scenario**
NO_2	Annual	6.10	~~42.7~~ **45.7**	170 (350)	38.8 (11.8)	CC07
PM_{10}, $PM_{2.5}$	Annual	6.10	~~42.7~~ **45.7**	170 (350)	38.8 (11.8)	CC07

2. **Simple Cycle Gas Turbines Modeled Rates and Stack Parameters**
Regarding FDOC *Table 53 - Modeled Emission Rates - Normal Operation for AEC SCGT*, the modeling is required to be revised only for the annual averaging period for the **Application**. The proposed revision to the annual number of normal operating hours from 2000 to 700 hours for each simple-cycle turbine will affect the annual emission rates (NO_2, PM_{10}/$PM_{2.5}$) but not the Worst-Case Emission Scenario for the annual averaging period.

Modeling is not required to be revised for the 1-hour, 3-hour, 8-hour, and 24-hour averaging periods. The emission rates and the worst-case emission scenarios for these short-term averaging periods will not change because the proposed change to the annual number of operating hours will not affect these averaging periods.

The NOx and PM_{10}/$PM_{2.5}$ emission rates for modeling for the annual averaging period are calculated as follows:

For the Emissions Calculations section above, the normal operating rates for the maximum monthly emissions are based on Case 1 in *Table 31 – Simple-Cycle Turbine Operating Scenarios*. Case 1, based on 100% load, 28 °F ambient temperature, and without inlet cooling, is the worst case operating scenario that yields the highest controlled emissions. The normal operating rates for the maximum annual emissions are based on Case 4. Case 4, based on 100% load, 65.3 °F ambient temperature, and with inlet cooling, is the worst case operating scenario that yields the highest emission rates for the average annual temperature.

For Modeling, the normal operating rates for the worst-case emission scenario for the annual averaging period are based on Case 7 in *Table 31*. The maximum annual turbine impacts were predicted using the exhaust parameters for the 65.3 ºF, minimum load case, which represents the turbine exhaust parameters associated with the maximum predicted annual ground-level impact in the dispersion modeling.

NOx: [(**700** hr/yr)(5.12 lb/hr, Case 7) + (500 starts)(16.6 lb/start) +

(500 shutdowns)(3.12 lb/shutdown)] / 8760-hr averaging = 1.53 lb/hr --> 0.193 g/sec

The modeling provided by applicant was based on 1.51 lb/hr (0.191 g/sec) pursuant to the superseded 660 normal operating hrs proposed in the Yorke Protocol, 11/17/18. The small discrepancy will not affect the modeling results.

$PM_{10}/PM_{2.5}$: [(**<u>700</u>** hr/yr)(6.23 lb/hr, Case 7) + (500 starts)(3.12 lb/start) + (500 shutdowns)(1.35 lb/shutdown)] / 8760-hr averaging = 0.75 lb/hr → 0.095 g/sec

The modeling provided by applicant was based on 0.72 lb/hr (0.091 g/sec) pursuant to the superseded 660 normal operating hrs proposed in the Yorke Protocol, 11/17/18. The small discrepancy will not affect the modeling results.

Table 53 - Modeled Emission Rates - Normal Operation for AEC SCGT [1]

Averaging Time	Worst-Case Emission Scenario	Pollutant	Emissions Per Turbine, lbs/hr [1]
1-hour	NO_2: Four turbines in startup, shutdown, and balance of period at minimum (50%) load, 28 °F ambient temperature. CO: Four turbines in startup, shutdown, and balance of period at minimum (50%) load, 28 °F ambient temperature. SO_2: Four turbines in startup, shutdown, and balance of period at minimum (50%) load, 28 °F ambient temperature.	**Modeling is not required for the 1-hour, 3-hour, 8-hour, and 24-hour averaging periods, but is required for the annual averaging period.**	
1-hour (federal)	NO_2: Four turbines in startup, shutdown, and balance of period at minimum (50%) load, 28 °F ambient temperature. SO_2: Four turbines in startup, shutdown, and balance of period at minimum (50%) load, 65.3 °F ambient temperature.		
3-hour	SO_2: Four turbines continuous maximum (100%) load operation, 65.3 °F ambient temperature.		
8-hour	CO: Four turbines complete 2 starts, 2 shutdowns, and balance of period at minimum (50%) load, 28 °F ambient temperature.		
24-hour	PM_{10}, $PM_{2.5}$: Four turbines continuous minimum (50%) load operation, 65.3 °F ambient temperature. SO_2: Four turbines continuous maximum (100%) load operation, 65.3 °F ambient temperature.		
Annual	NO_2, PM_{10}, $PM_{2.5}$: Four turbines operate at minimum (50%) load for ~~2000~~ **<u>700</u>** normal operating hours, 500 starts, and 500 shutdowns, for total of ~~2358~~ **<u>1058</u>** hours, 65.3 °F ambient temperature. Condition A63.3 limits annual CO, VOC, PM_{10}/**<u>$PM_{2.5}$</u>**, and SOx emissions, which also indirectly limits annual NOx emissions.	NO_x PM_{10}, $PM_{2.5}$	~~2.29~~ **<u>1.53</u>** ~~1.68~~ **<u>0.75</u>**

For the **Application**, FDOC *Table 54* is revised below to show only the annual averaging period. *Table 4-1: Stack Parameters and Emission Rates for Annual Modeling* on p. 21 of the Yorke *Applications for Modification* for A/N 610354 – 610360 was reviewed to confirm that modeling is based on the same stack parameters as the FDOC.

Table 54 - Modeled Stack Parameters - Normal Operation for AEC SCGT

	Averaging Period	**Stack Diameter (m)**	**Stack Height (m)**	**Exhaust Temp (°F (°K))**	**Exhaust velocity (ft/s (m/s))**	**Scenario**
NO_2	Annual	4.11	24.4	883 (746)	77.4 (23.6)	SC07
PM_{10}, $PM_{2.5}$	Annual	4.11	24.4	883 (746)	77.4 (23.6)	SC07

3. **Auxiliary Boiler Modeled Rates and Stack Parameters**

The separate engineering evaluation for A/N 604014 and 613323 for the Auxiliary Boiler and SCR concluded that re-modeling on a permit unit basis is not required because the condition changes did not change the emissions. The worst-case emission scenarios and emission rates for all averaging periods will remain the same as for the FDOC. For the **Application**, however, the boiler will be included in the modeling with the combined-cycle and simple-cycle turbines for the annual averaging period for the facility-wide Rule 1303 modeling in support CEC's analysis of the *Petition for Post-Certification Amendment*.

FDOC *Table 55* is revised below to show only the annual averaging period. The NO_2 and PM_{10}/$PM_{2.5}$ emission rates remain the same as the FDOC.

Table 55 - Modeled Emission Rates - Normal Operation for Auxiliary Boiler

Averaging Period	**Worst-case Emission Scenario**	**Pollutant**	**Emissions Per Turbine, lbs/hr**
Annual	NO_2, PM_{10}, $PM_{2.5}$: Boiler operate at 30% of maximum firing rate for 8760 hours total, including 24 cold starts, 48 warm starts, 48 hot starts. (Condition A63.4 limits annual CO, VOC, PM_{10}, and SOx emissions, which also indirectly limits annual NOx emissions.)	NO_x	0.15 (0.019 g/sec)
		PM_{10}, $PM_{2.5}$	0.15 (0.019 g/sec)

FDOC *Table 56* is revised to show only the annual averaging period. *Table 4-1: Stack Parameters and Emission Rates for Annual Modeling* on p. 21 of the Yorke *Applications for Modification* for A/N 610354 – 610360 was reviewed to confirm that modeling is based on the same stack parameters as the FDOC.

Table 56 - Modeled Stack Parameters - Normal Operation for Auxiliary Boiler

	Averaging Period	Stack Diameter (m)	Stack Height (m)	Exhaust Temp (°F (°K))	Exhaust velocity (ft/s (m/s))	Scenario
NO_2	Annual	0.91	24.4	318 (432)	69.5 (21.2)	AB
PM_{10}, $PM_{2.5}$	Annual	0.91	24.4	318 (432)	69.5 (21.2)	AB

4. <u>Modeled Results –Normal Operation for AEC</u>

The combined- and simple-cycle turbines, but not the auxiliary boiler, are exempt from the modeling requirements of Rule 1303(b)(1) pursuant to the Rule 1304(a)(2) exemption. Therefore the state and federal ambient air quality standards and Rule 1303 thresholds in the table below do not apply and are shown for informational purposes only. Because the South Coast Air Basin is designated non-attainment for the state PM_{10} standard, and state and federal $PM_{2.5}$ standards, project increments are compared to the significant change thresholds in Rule 1303.

For the **FDOC**, the applicant provided a modeling analysis of impacts for the entire project in support of the CEC's analysis of the *Supplemental Application for Certification* for the amended AEC, submitted on 10/26/15, and the revised sections for Air Quality, Biological Resources, and Public Health Assessment, submitted on 4/12/16. The dispersion modeling analysis for the maximum AEC operational impacts included the operation of the two combined-cycle turbines, four simple-cycle turbines, and the auxiliary boiler. The maximum AEC operational impacts, including changes and updates provided by PRDAS staff, were presented in *Table 57 - Modeled Results - Normal Operation for Total Project* in the FDOC.

As discussed above**, South Coast AQMD Comments on Yorke Protocol, 12/20/18,** requested re-modeling for NO_2, PM_{10} and $PM_{2.5}$ based on the total emissions from each turbine and the auxiliary boiler for the annual averaging period to update FDOC *Table 57* for the **Application**. The update is required to support of the CEC's analysis of the *Petition for Post-Certification Amendment.*

On p. 23 of the Yorke *Applications for Modification*, *Table 4-3: Modeled Results – Annual Operations for Total Facility* shows the results of the facility-wide operational impacts based on background data and meteorological data for 2014 to 2016. **PRDAS staff has independently reproduced the applicant's analysis and summarized the results in the *PRDAS Memo*. FDOC *Table 57* is updated below to incorporate PRDAS' modeling results for the Application. The modeled impacts are below all thresholds in Rule 1303 for NO_2, PM_{10}, and $PM_{2.5}$.**

Table 57 - Modeled Results - Normal Operation for Total Project

Pollutant	Averaging Period	Maximum Predicted Impact (µg/m³)	Background Concentration (µg/m³) [2]	Total Predicted Concentration (µg/m³)	State Standard CAAQS (µg/m³)	Federal Standard, Primary NAAQS (µg/m³)	Rule 1303 Thresholds (µg/m³)	Exceeds Any Threshold?
NO_2 [1]	Annual	~~0.2~~ **0.4**	~~47.6~~ **39.6**	~~47.8~~ **40.0**	57	100		No
PM_{10}	Annual	~~0.2~~ **0.3**			20		1	No
$PM_{2.5}$	Annual	~~0.2~~ **0.3**			12	12	1	No

1 The NO_2 concentration included conversion of NO_x to NO_2 using ARM2.
2 Maximum value for NO_2 from SRA 4, South Coastal LA County 3 (No. 033) monitoring station for the last three years available prior to application submittal (2014-2016) was used.

5. **Modeled Results - Rule 2005**
   See Rule 2005 analysis below.

- **COMMISSIONING IMPACTS**
  The **Application** did not propose any changes to the commissioning of the combined-cycle turbines or the simple-cycle turbines. Therefore, revised modeling is not required for the commissioning of the turbines.

- ***Rule 1303(b)(2)—Offsets***
  Rule 1303(b)(2) requires a net emission increase in emissions of any nonattainment air contaminant (PM_{10}, ROG, and SOx) 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 and any device at a RECLAIM facility."

  Unless exempt, 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.

- **Combined-Cycle Turbines, A/N 579142, 579143**
- **Simple-Cycle Turbines, A/N 579145, 579147, 1549150, 579152**
  - VOC, SOx, and PM_{10}
    South Coast AQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler repower projects. The exemption applies to: "The source is replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-

recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The new equipment must have a maximum electrical power rating (in megawatts) that does not allow basinwide electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset." This exemption applies to the combined-cycle turbines and simple-cycle turbines equipped with intercoolers. Offsets are provided from the South Coast AQMD internal offset accounts, as discussed in the Rule 1304.1 analysis below.

- NOx
  For the **Application**, FDOC Table 63 is revised below to show only the combined-cycle and simple-cycle turbines and the revised NOx RTCs required. The first-year operation for the combined-cycle turbines and auxiliary boiler will have ended prior to the first-year operation for the simple-cycle turbines.

  See *Rule 2005(c)(2)* analysis below for the NOx RTC requirements.

Table 63 - Post-Modification ~~ERCs and~~ RTCs Required

A/N	Equipment	NOx RTCs, lb/yr (first year)
610354	Combined-Cycle Turbine	108,377
610355	Combined-Cycle Turbine	108,377
604013	Auxiliary Boiler	1351
610356	Simple-Cycle Turbine	~~68,575~~ **21,322**
610357	Simple-Cycle Turbines	~~68,575~~ **21,322**
610358	Simple-Cycle Turbines	~~68,575~~ **21,322**
610359	Simple-Cycle Turbines	~~68,575~~ **21,322**
	Total Project, lbs/day	First year: 218,105 lb for combined-cycle turbines & boiler. First year: ~~274,300~~ **85,288** lb for simple-cycle turbines.

- ***Rule 1303(b)(3)-Sensitive Zone Requirements***
- ***Rule 2005(e)-Trading Zone Restrictions***
  Both rules provide that credits shall be obtained from the appropriate trading zone. A facility located in zone 1, such as AES Alamitos, may obtain ERCs originated in zone 1 only, and RTCs originated in zone 1 only.

- ***Rule 1303(b)(4)-Facility Compliance***
  AEC is expected to comply with all applicable rules and regulations of the South Coast AQMD, as required by this rule.

- ***Rule 1303(b)(5)-Major Polluting Facilities***
- ***Rule 2005(g)—Additional Federal Requirements for Major Stationary Sources***

Rule 1303(b)(5)--In addition to the above requirements, any new major polluting facility or major modification at an existing major polluting facility shall comply with the following requirements, Rule 1303(A) – (D) (see below).

Rule 2005(g)—The Executive Officer shall not approve the application for a Facility Permit or an Amendment to a Facility Permit for a new, relocated or modified major stationary source, unless the applicant complies with Rule 2005(g)(1) – (g)(4).

- **Rule 1302(s)** defines "major polluting facility" to mean any facility located in the South Coast Air Basin (SOCAB) which emits or has the potential to emit the following amounts or more: VOC, 10 tpy; NOx, 10 tpy; SOx, 70 tpy; PM10, 70 tpy, CO 50 tpy. **Note**: The Rule 1302(s) major source thresholds for SOx, CO, and PM10 are required to be updated. As these pollutants that are in federal attainment, the thresholds are 100 tpy.

- **Rule 1302(r)** and **Rule 2005(c)(44)** define "major modification" to mean any modification at an existing major polluting facility that will cause the facility's potentials to emit to increase: (1) 1 lb/day or more of NOx or VOC for a facility located in the South Coast Air Basin; (2) 40 tpy or more of SOx; (3) 15 tpy or more of PM10; or (4) 50 tpy or more of CO.

The AGS is a major polluting facility because *Table 13* indicates the PTEs for VOC (453.72 tpy), NOx (635.60 tpy), CO (21,871.86 tpy), and PM_{10} (627 tpy) exceed the applicable thresholds.

The **Application** project to revise the annual operating hours for the combined-cycle and simple-cycle turbines will constitute a major modification. *Table 45* indicates the facility's potentials to emit will increase for NOx by 9.72 tpy and VOC by 4.86 tpy, with both increases exceeding the 1 lb/day threshold. As the existing AGS facility is a major polluting facility undergoing a major modification, the following provisions are applicable.

- ***Rule 1303(b)(5)(A) – Alternative Analysis***
- ***Rule 2005(g)(2)—Alternative Analysis***
- ***Rule 1303(b)(5)(D) – Compliance through CEQA***
- ***Rule 2005(g)(3)—Compliance through CEQA***

  Rule 1303(b)(5)(A) requires an analysis of alternative sites, sizes, production processes and environmental control techniques, and a demonstration that the benefits of the proposed project outweigh the environmental and social costs associated with that project. Rule 2005(g)(2) requires an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source which demonstrates that the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of its location, construction, and modification.

Rule 1303(b)(5)(D) specifies the requirements of subparagraph (b)(5)(A) may be met through compliance with CEQA. Rule 2005(g)(3) specifies the requirements of paragraph (g)(2) may be met through CEQA analysis.

Since the AEC is a permitted project undergoing initial construction and since AES is applying for revised annual operating schedules for the combined-cycle and simple-cycle turbines, an analysis of alternative sites, sizes, production processes, and environmental controls is not applicable.

The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger. The CEC's 12-month permitting process is a certified regulatory program under CEQA and includes various opportunities for public and inter-agency participation. CEQA is designed to assure that all potential environmental impacts are reviewed prior to permitting a major project, and CEQA environmental review is fully integrated into the CEC siting process. Under state law, the preparation of the CEQA analysis is undertaken by CEC for a project subject to CEC jurisdiction. The CEC is in the process of evaluating the *Petition for Post-Certification Amendment* submitted by AES for this project.

- ***Rule 1303(b)(5)(B) – Statewide Compliance***
- ***Rule 2005(g)(1) – Statewide Compliance***

Rule 1303(b)(5)(B) requires a demonstration that all major stationary sources are owned or operated by such person in the state are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Rule 2005(g)(1) requires the applicant to certify that all other major stationary sources in the state which are controlled by the applicant are in compliance or on a schedule for compliance with all applicable federal emission limitations or standards.

In a letter dated 8/14/19, Weikko Wirta, Director Plant Operations, AES Alamitos, LLC, certified that he, as a corporate officer and Director of Plant Operations of AES Alamitos, LLC, AES Redondo Beach, LLC, and AES Huntington Beach, LLC, certify that all major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by AES in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance for all applicable emission limitations and standards under the Clean Air Act.

The South Coast AQMD website provides up-to-date compliance status, including for Notices of Violation and Notices to Comply, on the Facility Information Detail (FIND) web page (http://www3.aqmd.gov/webappl/fim/prog/search.aspx). By entering the South Coast AQMD facility ID and selecting the Compliance tab, the status of the Notices of Violation (NOVs) and of Notices to Comply (NCs) are provided for the selected facility.

For AES Alamitos (ID 115394), the status shown for all Notices to Comply for violation dates occurring in the last five years is "In Compliance." The disposition shown for all Notices of Violation issued in the last five years is "Closed Case," except for P67929 and P67928. These NOVs were issued during the uncontrolled first fire phase of the commissioning of the two new combined-cycle turbines) and are summarized below.

NOV No.	Issued Date	Violation Date	Summary	Final Action
P67929	10/8/19	10/6/19	Opacity greater than R1 (20%) for greater than 3 minutes in an hour. Opacity greater than R2 (40%) for greater than 3 minutes in an hour. Failure to operate permitted equipment in compliance with all terms specified in Title V permit at all times. Discharge of air contaminants causing detriment, nuisance, or annoyance to a considerable amount of person or to the public.	Variance
P67928	10/3/19	10/3/19	Opacity greater than R1 (20%) for greater than 3 minutes in an hour. Opacity greater than R2 (40%) for greater than 3 minutes in an hour. Failure to operate permitted equipment in compliance with all terms specified in Title V permit at all times.	In compliance.

For AES Huntington Beach (ID 115389), The status shown for all Notices to Comply for violation dates occurring in the last five years is "In Compliance." The disposition shown for all Notices of Violation issued in the last five years is "Closed Case," except for P69259 and P67930. These NOVs were issued during the uncontrolled first fire phase of the commissioning of the two new combined-cycle turbines) and are summarized below.

NOV No.	Issued Date	Violation Date	Summary	Final Action
P67930	10/8/19	10/6/19	Opacity greater than R1 (20%) for greater than 3 minutes in an hour. Failure to operate permitted equipment in compliance with all terms specified in Title V permit at all times. Discharge of air contaminants causing detriment, nuisance, or annoyance to a considerable amount of person or to the public.	Variance
P69259	10/4/19	10/4/19	Opacity greater than R1 (20%) and R2 (40%) for greater than 3 minutes in an	In compliance

NOV No.	Issued Date	Violation Date	Summary	Final Action
			hour. Failure to operate permitted equipment in compliance with all terms, requirements, and conditions specified in Title V permit at all times.	

In response to the above NOVs, the facility filed Variance petitions to allow them to complete the uncontrolled phase of the startup operation of the CCGTs. The Variance petitions were granted by the South Coast AQMD Hearting Board. The uncontrolled startup phase for both the Alamitos and Huntington Beach facilities has now concluded, and the facilities are no longer operating under a Variance; both facilities are currently in compliance with the opacity requirements of the permit.

For AES Redondo Beach (ID 115536), the status shown for all Notices to Comply for violation dates occurring in the last five years is “In Compliance.” The disposition shown for all Notices of Violation issued in the last five years is “Closed Case.”

Prior to issuance of the revised Permits to Construct, the South Coast AQMD will confirm that the compliance status of AES has not changed.

- ***Rule 1303(b)(5)(C) –Protection of Visibility***
- ***Rule 2005(g)(4)—Protection of Visibility***

Rule 1303(b)(5)(C) requires a modeling analysis for plume visibility if the net emission increases from a new or modified sources exceed 15 tpy of PM_{10} or 40 tpy of NOx; and the location of the source, relative to the closest boundary of a specified Federal Class I area, is within the distance specified in Table C-1 of the rule. Rule 2005(g)(4) imposes the same requirements for NOx, with the Federal Class I areas and distances listed in Table 4-1 of the rule (same as Table C-1).

For the **FDOC**, *Table 71 – Prevention of Significant Deterioration Applicability* showed that the net emissions increases (AEC PTE – AGS actual) exceeded 15 tpy PM_{10} and 40 tpy NOx. The applicant had identified the San Gabriel Wilderness, approximately 53 km from the AEC site, as the nearest Class I area. Tables C-1 and 4-1 would require a visibility analysis if the AEC site is within 29 km of the closest boundary of San Gabriel Wilderness. Since the AEC is not within 29 km, a visibility analysis was not required.

For the **Application**, revised *Table 71* shows that the net emissions increases continue to exceed 15 tpy PM_{10} and 40 tpy NOx. However, a visibility study is not required because the AEC is not located within 29 km of San Gabriel Wilderness.

Rule 1304.1—Electrical Generating Facility Fee for Use of Offset Exemption, adopted 9/6/13
The relevant sections are presented below, followed by the rule analysis and fee calculations.

(a) Purpose and Applicability
The purpose of this rule is to require Electrical Generating Facilities (EGFs) which use the specific offset exemption described in Rule 1304(a)(2) [Electric Utility Steam Boiler Replacement] to pay fees for up to the full amount of offsets provided by the SCAQMD… . Notwithstanding Rule 1301(c)(1), this rule applies to all permits issued to EGFs electing to use Rule 1304(a)(2) and receiving the applicable permit to construct on or after September 6, 2013.

(b) Definitions
(2) COMMENCEMENT OF OPERATION means to have begun the first fire of the unit(s), or to generate electricity for sale, including the sale of test generation.

(c) Requirements
(l) Any EGF operator electing to use the offset exemptions provided by Rule 1304(a)(2) shall pay a fee, the Offset Fee (F_i), calculated pursuant to paragraph (c)(2), for each pound per day of each pollutant (i), for which the SCAQMD provides offsets. This fee may be paid on an annual basis or as a single payment or a combination of both at the election of the applicant.

(2) The Offset Fee (F_i), for a specific pollutant (i), shall be calculated by multiplying the applicable pollutant specific Annual Offset Fee Rate (R_i) or Single Payment Offset Fee Rate (L_i) and Offset Factor in Table A1 or A2, as applicable, by the fraction of the potential to emit level(s) of the new replacement unit(s). This fraction is calculated as the product of the potential to emit of the new replacement unit ($PTErep_i$) multiplied by the new replacement to existing unit generation annual capacity ratio. This annual capacity ratio which is defined as the maximum permitted annual megawatt hour (MWh) generation of the new replacement unit(s) (C_{rep}) minus the most recent twenty-four (24) months average of the megawatt hour (MWh) generation (megawatt utilization) of the unit(s) to be replaced (C2YRAvgExisting) divided by the maximum permitted annual megawatt hour (MWh) generation of the new replacement unit(s) (C_{rep}).

The offset fee calculation described above is governed by equations in subparagraphs A and B:

(A) Annual Payment Option

(ii) Repowering more than 100MW cumulatively at a facility subsequent to September 6, 2013 with offsets debited from the SCAQMD internal offset accounts:

$$\text{Annual } Offset\ Fee\ (F_i) = \left(\left[R_{iA1} \times \left(\frac{100}{MW}\right)\right] + \left[R_{iA2} \times \left(\frac{MW - 100}{MW}\right)\right]\right) \times OF_i \times PTErep_i \times \left(\frac{C_{rep} - C_{2YRAvgExisting}}{C_{rep}}\right)$$

Where;

F_i	=	Offset Fee for pollutant (i).
R_{iA1}	=	Table A1, Annual Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, annually.
R_{iA2}	=	Table A2, Annual Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, annually.
MW	=	MW rating of new replacement unit(s).
OF_i	=	offset factor pursuant to Rule 1315(c)(2) for extreme non-attainment pollutants and their precursors, (see Table A1 or A2, as applicable, for factors).
$PTErep_i$	=	permitted potential to emit of new replacement unit(s) for pollutant i, in pounds per day. (Maximum permitted monthly emissions ÷ 30 days).
C_{rep}	=	maximum permitted annual megawatt hour (MWh) generation of the new replacement unit(s). (Maximum rated capacity (MW) x Maximum permitted annual operating hours (h)).
$C_{2YRAvgExisting}$	=	the average annual megawatt-hour (MWh) generation of the existing unit(s) to be replaced using the last twenty-four (24) month period immediately prior to issuance of the permit to construct.

(3) The owner/operator of an EGF electing to use the offset fee exemption of Rule 1304(a)(2) shall remit the offset fees as follows:

(A) For the annual payment option:

(i) The owner/operator must remit the first year annual offset fee payment prior to the issuance of the permit to construct and such fees shall be based on the total amount of the repowered MW capacity for which a permit to construct is being issued by SCAQMD for the facility. Subsequent payments shall be remitted annually based on the cumulative total of MW capacity that commenced operation, on or before the anniversary date of the original commencement of operation of such MW capacity at the fee rates in effect at the time the fee is due.

(ii) If the owner/operator of an EGF fails to pay the applicable Annual Offset Fee (F_i) amount, for each applicable pollutant (i), within thirty (30) days after the due date, the associated permit(s) will expire and no longer be valid. Such permit(s) may be reinstated within sixty (60) days with an additional penalty of 50%.

(iii) The owner/operator of an EGF that has elected the annual fee payment option may switch to the single payment option upon submittal of a written request to the Executive Officer for such a change in payment method. The amount of the single payment offset fee due shall be based on offset fee rates applicable at the time the written request for the change in payment method is submitted to the Executive Officer. The sum of the annual offset fees remitted prior to the submittal of a request for change to a single payment option shall be credited towards the single payment offset fee due.

(B) For the single payment option, the owner/operator must remit the entire fee prior to issuance of the permit to construct.

(5) Refunds of First Year of Annual Payment or Single Payment

(A) The full amount of any payments made in satisfaction of the requirements of the rule shall be refunded if a written request by the facility owner/operator is received prior to the commencement of operation. Such a request for refund shall automatically trigger cancellation of the Permit to Construct and/or Operate.

(B) Prior to the commencement of construction of each new electrical generating unit, an owner/operator can request the Executive Officer to have their permit amended to limit the permitted maximum monthly and/or annual generation capacity and can seek a refund for the fee adjustment corresponding to the requested reduction in capacity.

Analysis:

- ***First Year Annual Offset Fee Payment (Initial Payment Prior to Issuance of Permits to Construct)***

  The first year annual offset fee for the combined- and simple-cycle turbines that were estimated for the Final Determination of Compliance (FDOC) was very preliminary. The first year annual offset fee was subsequently updated based on the most recent operating data for the existing utility boilers, the most recent Rule 1304.1 annual offset fee rates, and other revisions discussed below. As required by Rule 1304.1(c)(3)(A)(i), AES remitted the first year annual offset fee payment prior to the issuance of the Permits to Construct for the AEC on 4/18/17. This is an estimated payment required for the South Coast AQMD to hold credits for the facility.

For the estimated First Year Annual Offset Fee, the updates and revisions to the analysis and fee in the FDOC are summarized below:

1) For the PDOC/FDOC, the Rule 1304.1 Excel calculator that is available on the South Coast AQMD website to calculate the annual or single fee for a repowering project was used to calculate the preliminary first year annual offset fee.

   The Board Package for the adoption of Rule 1304.1 at the 9/6/13 board meeting includes the Final Staff Report (Attachment F). P. 4 of Final Staff Report states: "Furthermore, an additional ~~50~~ 75% discount is proposed to be applied to the first 100 MW repowered cumulatively at the EGF [Electrical Generating Facility], applicable to all sources including smaller sources, to address concerns regarding reliability and the ability to obtain financing for projects, and to encourage smaller distributed generation."

   Although not stated in the Rule 1304.1 language, the calculator provides a 75% discount for the first 100 MW repowered cumulatively. As the Rule 1304.1 calculator was erroneously used separately for the combined-cycle turbines and the simple-cycle turbines for the PDOC/FDOC, the result was a 75% discount for the first 100 MW for the combined-cycle turbines and an additional 75% discount for the first 100 MW for the simple-cycle turbines, thereby resulting in an erroneously low first year annual offset fee for the project.

   For the final fee calculation set forth in a memo "Rule 1304.1 Annual Fees For Alamitos Energy Center (AEC)," dated 4/11/17, the first year annual offset fee was correctly calculated using the Rule 1304.1(c)(2)(A)(ii) equation to provide a 75% discount for the first 100 MW for <u>all</u> turbines at the AEC.

2) In Rule 1304.1, $C_{2YRAvgExisting}$ is defined as "the average annual megawatt-hour (MWh) generation of the existing unit(s) to be replaced using the last twenty-four (24) month period immediately prior to issuance of the permit to construct." For the PDOC, the preliminary fees were based on the 2013 and 2014 generation for Boilers Nos. 1, 2, 5, and 3. On 10/26/16, AES proposed that Unit 6 be retired instead of Unit 5. Since both units are identical, SCAQMD accepted this change for the FDOC. For the FDOC, the preliminary fees were based on the 2013 and 2014 generation for Boilers Nos. 1, 2, 6, and 3.

   On 4/3/17, Stephen O'Kane provided the monthly gross generation for Boilers Nos. 1, 2, 6, and 3 for the period from January 2015 through March 2017 for the calculation of the first year annual offset fee, as the Permits to Construct for the AEC were scheduled to be issued in April 2017.

3) For the PDOC/FDOC, the $C_{2YRAvgExisting}$ was based on the net average annual megawatt-hour (MWh) generation of the existing unit(s) to be replaced. The first year annual offset fee was corrected to be based on the gross average annual megawatt-hour (MWh) generation. The Planning, Rule Development & Area Sources (PRDAS) staff responsible for the development of Rule 1304.1 clarified that the $C_{2YRAvgExisting}$ is to be based on the gross generation because the MW rating of the new replacement units (*MW* in the Rule 1304.1(c)(2)(A)(ii) equation) is based on gross MW.

4) For the PDOC/FDOC, the South Coast AQMD made assumptions regarding the allocation of existing generation unit retirements to provide a preliminary estimate of the Rule 1304.1 fees. To offset the 1094.7 MW-gross for the installation of the combined- and simple-cycle turbines, the fee calculations assumed 175 MW was to be provided by the retirement of Unit 1, 175 MW from the retirement of Unit 2, 480 MW from the retirement of Unit 6, and 265 MW of 320 MW from the retirement of Unit 3. AES has not finalized plans for the surplus 55 megawatts from the retirement of Unit 3. AES had not provided any comments on the assumed allocation of existing generation unit retirements during its review of the PDOC and FDOC.

   In a letter dated April 6, 2017, the South Coast AQMD issued a letter to Stephen O'Kane indicating the first year annual offset fee due for this project. The fee was based on the assumed allocation of existing generation unit retirements from the PDOC/FDOC. Mr. O'Kane responded that AES has sole discretion over which units to retire and apply against the Rule 1304.1. Pursuant to AES, the allocation was revised as follows. To offset the 1094.7 MW-gross for the installation of the combined- and simple-cycle turbines, 120 MW of 175 MW was provided by the retirement of Unit 1, 175 MW from the retirement of Unit 2, 480 MW from the retirement of Unit 6, and 320 MW from the retirement of Unit 3. The first year annual offset fee was corrected to be based on the allocation of existing generation unit retirements provided by Mr. O'Kane.

5) For the PDOC/FDOC, the use of the Rule 1304.1 Excel calculator separately for the combined-cycle turbines and the simple-cycle turbines required the $C_{2YRAvgExisting}$ and C_{rep} to be divided between the combined-cycle and simple-cycle turbines, thereby resulting in an erroneous fee. The first year annual offset fee was correctly calculated using the Rule 1304.1(c)(2)(A)(ii) equation which is based on the total $C_{2YRAvgExisting}$ and total C_{rep}.

6) As shown in the (c)(2)(A)(ii) equation, the Annual Offset Fee (F_i), for a specific pollutant (i), is calculated by multiplying the applicable pollutant specific Annual Offset Fee Rate (R_i) and Offset Factor in Table A2, by the fraction of the potential to emit level(s) of the new replacement unit(s).

Table A2: Pollutant Specific Offset Fee Rates & Offset Factors applicable to the cumulative MW capacity in excess of 100 MW repowered at an EGF after September 6, 2013 with offsets debited from the SCAQMD internal offset accounts, footnote * states: "Offset Fees paid annually and adjusted annually by the CPI." Since Rule 1304.1 was adopted on 9/6/13, the Annual Offset Fee Rates in *Table A2* are effective for the fiscal year ending 6/30/14. For each successive fiscal year, the offset fee rates are required to be adjusted by the Governing Board-approved annual percent fee increase, effective each July 1, for the Regulation III fee rules.

For the PDOC/FDOC, the first year annual offset fee, calculated based on the Annual Offset Fee Rates (R_{iA1} and R_{iA2}) from *Table A2* for PM, SOx, and VOC, was adjusted by being multiplied by the Governing Board-approved annual percent fee increases for the three successive years (FY 2014 – 2015, FY 2015 – 2016, FY 2016 – 2017). Subsequently, PRDAS staff clarified that the Annual Offset Fee Rates, R_{iA1} and R_{iA2}, are required to be rounded off after every annual adjustment. The first year annual offset fee was corrected accordingly.

<u>First Year Annual Offset Fee Calculations (Initial Payment Prior to Issuance of Permits to Construct)</u>

The First Year Annual Offset Fee was calculated as shown below. The values for the variables are discussed following the calculations.

Annual Offset Fee (F_i) = [R_{iA1} x (100/MW) + R_{iA2} x (MW-100)/MW] x OF_i x PTE_{repi} x [(C_{rep} – $C_{2YRAvgExisting}$)/C_{rep}]

<u>PM_{10}</u>

[$1052 x (100/1094.7 MW) + $4206 x (1094.7-100)/1094.7] x 1.0 x 1040.0 lb/day
x [4,162,619 MWhr/yr – 650,693 MWh/yr]/4,162,619 MWh/hr]
= [3917.89] x 1.0 x 1040 x [0.844] = **$3,438,967.13**

<u>SOx</u>

[$837 x (100/1094.7 MW) + $3344 x (1094.7-100)/1094.7] x 1.0 x 401.9 lb/day
x [4,162,619 MWhr/yr – 650,693 MWh/yr]/4,162,619 MWh/hr]
= [3114.99] x 1.0 x 401.9 x [0.844] = **$1,056,615.82**

<u>VOC</u>

[$50 x (100/1094.7 MW) + $196 x (1094.7-100)/1094.7] x 1.2 x 1150.7 lb/day
x [4,162,619 MWhr/yr – 650,693 MWh/yr]/4,162,619 MWh/hr]
= [182.67] x 1.2 x 1150.7 x [0.844] = **$212,888.91**

TOTAL
\$3,438,967.13 + \$1,056,615.82 + \$212,888.91 = **\$4,708,472**

AES paid the \$4,708,472 prior to the issuance of the Permits to Construct for the AEC on 4/18/17.

Variables
R_{iA1} = Table A1, Annual Offset Fee Rate for Pollutant (i), in terms of dollars per pound per day, annually.
R_{iA2} = Table A2, Annual Offset Fee Rate for Pollutant (i), in terms of dollars per pound per day, annually.

Annual Offset Fee Rates (R_{iA1} and R_{iA2}) Adjusted Annual by the CPI
Since Rule 1304.1 was adopted on 9/6/13, the offset fee rates in the rule are effective for the fiscal year ending 6/30/14. For each successive fiscal year, the offset fee rates are required to be adjusted by the CPI. The fee increases to date were: (1) 1.6% effective 7/1/14 for FY 2014 - 2015, (2) 1.4% effective 7/1/15 for FY 2015 - 2016, and (3) 2.4% effective 7/1/16 for FY 2016 - 2017. **R_{iA1} and R_{iA2} were adjusted annually by the CPI through FY 2016 - 2017.**

Table A1
$R_{PM10\ A1}$: \$997 x 1.016 → \$1013 x 1.014 → \$1027 x 1.024 → \$1052
$R_{SOx\ A1}$: \$793 x 1.016 → \$806 x 1.014 → \$817 x 1.024 → \$837
$R_{VOC\ A1}$: \$47 x 1.016 → \$48 x 1.014 → \$49 x 1.024 → \$50

Table A2
$R_{PM10\ A2}$: \$3986 x 1.016 → \$4050 x 1.014 → \$4107 x 1.024 → \$4206
$R_{SOx\ A2}$: \$3170 x 1.016 → \$3221 x 1.014 → \$3266 x 1.024 → \$3344
$R_{VOC\ A2}$: \$185 x 1.016 → \$188 x 1.014 → \$191 x 1.024 → \$196

MW = MW rating of new replacement unit(s).

Discussion: 1094.7 MW

[(231.197 MW-gross/ CTG) * (2 CTGs) + 230.557 MW-gross/steam turbine]$_{\text{combined-cycle}}$
+ [(100.438 MW-gross/ CTG) * (4 CTGs)]$_{\text{simple-cycle}}$
= 692.951 MW $_{\text{combined-cycle}}$ + 401.75 MW $_{\text{simple-cycle}}$
= 1094.7 MW-gross (case 12)

OFi = offset factor pursuant to Rule 1315(c)(2) for extreme non-attainment pollutants and their precursors, (see Table A1 or A2, as applicable, for factors).

Discussion: The offset factor is 1.0 for PM_{10} and SO_x, and 1.2 for VOC.

PTErepi = permitted potential to emit of new replacement unit(s) for pollutant i, in pounds per day. (Maximum permitted monthly emissions ÷ 30 days).

Discussion:
$PTEr_{PM10}$: 1040.0 lb/day

Rule 1304(c)(2) defines PTE_{repi} as "the permitted potential to emit of new replacement unit(s) for pollutant I, in pounds per day. (Maximum permitted monthly emissions ÷ 30 days)." In the PDOC/FDOC, *Table 23* provides the 30-day averages per combined-cycle turbine, and *Table 39* provides the 30-day averages per simple-cycle turbine.

[210.8 lb/day-turbine * 2 turbines]$_{\text{combined-cycle}}$ +
[154.60 lb/day-turbine * 4 turbines]$_{\text{simple-cycle}}$
= 421.6 lb/day + 618.4 lb/day = 1040.0 lb/day

$PTEr_{SOx}$: 401.9 lb/day

[120.53 lb/day-turbine * 2 turbines]$_{\text{combined-cycle}}$ +
[40.22 lb/day-turbine * 4 turbines]$_{\text{simple-cycle}}$
= 241.06 lb/day + 160.88 lb/day = 401.94 lb/day

$PTEr_{VOC}$: 1150.7 lb/day

[443.8 lb/day-turbine * 2 turbines]$_{\text{combined-cycle}}$ +
[65.78 lb/day-turbine * 4 turbines]$_{\text{simple-cycle}}$
= 887.60 lb/day + 263.12 lb/day = 1150.72 lb/day

$PTEr_{NOx}$: Not applicable to RECLAIM facility.

Crep = maximum permitted annual megawatt hour (MWh) generation of the new replacement unit(s). (Maximum rated capacity (MW) x Maximum permitted annual operating hours (h)).

Discussion: 4,162,619.1 MWhr/yr

[(692.951 MW)(4640 hr/yr)]$_{\text{combined-cycle}}$ + [(401.75 MW)(2358 hr/yr)]$_{\text{simple-cycle}}$
= 4,162,619.1 MWhr/yr

Note: Startup and shutdown hours are included.

C2YRAvgExisting = the average annual megawatt-hour (MWh) generation of the existing unit(s) to be replaced using the last twenty-four (24) month period immediately prior to issuance of the permit to construct.

Discussion: 650,693 MW-gross

For a preliminary estimate for the PDOC/FDOC, the applicant provided the 2013 and 2014 generation for Boilers Nos. 1, 2, 6, and 3. For the First Year Annual Offset Fee, AES provided monthly gross generation for the existing utility boilers for the period from January 2015 through March 2017 because the Permits to Construct were scheduled to be issued in April 2017. (The AGS's megawatt-hours are reported to the EPA through the EPA's Acid Rain program and can be downloaded for the appropriate 24-month period.)

Table 64 - AGS 2-Year Average Electrical Production (April 2015 – March 2017)

			April 2015 – March 2016	April 2016 – March 2017	2-Year Average
Unit	Rating MW-gross	Shutdown Date	MWh- gross	MWh- gross	MWh- gross
1	175	12/29/2019	53,920	25,097	39,509
2	175	12/29/2019	103,994	55,316	79,655
6	480	12/29/2019	280,843	122,811	201,827
3	320	12/31/2020	375,220	309,017	342,119

Source: http://energyalmanac.ca.gov/electricity/web_qfer/

Pursuant to the e-mail dated 4/6/17, from Stephen O'Kane, to offset the 1094.7 MW-gross for the installation of the combined- and simple-cycle turbines, 120 MW of 175 MW was to be provided by the retirement of Unit 1, 175 MW from the retirement of Unit 2, 480 MW from the retirement of Unit 6, and 320 MW from the retirement of Unit 3. AES had not finalized plans for the surplus 55 megawatts from the retirement of Unit 1.

$C_{2YRAvgExisting}$ = (39,509 MW- gross, Unit 1) (120 MW/175 MW)
+ (79,655 MW-gross, Unit 2) + (201,827 MW-gross, Unit 6)
+ (342,119 MW-gross, Unit 3)
= 650,693 MW-gross

♦♦♦

- ***Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)***
  First Year Annual Offset Fee Payment (Actual Payment Required)
  As required by Rule 1304.1(c)(3)(A)(i), AES remitted the first year annual offset fee payment of $4,708,472 prior to the issuance of the Permits to Construct for the AEC on 4/18/17. This is an estimated payment required for the South Coast AQMD to hold credits for the facility.

  Rule 1304.1(c)(3)(A)(i) continues that subsequent payments shall be remitted annually based on the cumulative total of MW capacity that commenced operation, on or before the anniversary date of the original commencement of operation of such MW capacity at the fee rates in effect at the time the fee is due. As discussed below, the first fire of the first combined-cycle turbine will occur on October 3, 2019. **Therefore, the next annual payment for the two combined-cycle turbines will be due prior to October 3, 2020**. This annual fee is calculated below and will be deducted from the $4,708,472 previously paid to hold the credits.

  The Planning, Rule Development & Area Sources (PRDAS) staff responsible for the development of Rule 1304.1 was consulted regarding the correct implementation of Rule 1304.1 for subsequent payments. The following summarizes PRDAS staff's clarification.

  1) *Question*: For the next payment, does Rule 1304.1 allow AES to convert to a single payment for the combined-cycle turbines but continue with annual payments for the simple-cycle turbines?

     For the FDOC, AES selected the annual payment option for the first payment due prior to the issuance of the permits to construct, thereafter switching to the single payment option prior to the end of the first year of operation. However, the Yorke *Applications for Modification*, submitted on 2/8/19, provided an update: "AES will continue to pay the fees as annual payments for the emissions of VOC, PM, and SO_x." In an e-mail dated 8/14/19, Stephen O'Kane clarified: "AES plans to pay the Single Fee for the CCGT portion of the project in the first operating year (2020). Please let us know the fee broken out by CCGT phase and SCGT phase."

     PRDAS staff indicated that the language of paragraph (c)(1) provides for flexibility, contingent on Engineering & Permitting (E&P) organizational (permitting) constraints. E&P's determination is that since the combined-cycle and simple-cycle turbines were permitted as one project and since the first year annual offset fee payment of $4,708,472 was based on one project, both the simple-cycle and combined-cycle turbines should both be single payment or annual payment.

     On 9/19/19, E&P Staff met with Stephen O'Kane, AES Manager for Sustainability and Regulatory Compliance, and Charlene He, AES Environmental Manager, for a project update including for Rule 1304.1 fees. E&P suggested that both the combined-cycle and simple-cycle turbines remain on annual payments until AES makes a decision regarding whether to proceed with the construction of the simple-cycle turbines (Phase 2). As Rule 1304.1(c)(3)(A)(i) provides that subsequent payments shall be remitted annually based on the cumulative total of MW capacity that commenced operation, on or before the anniversary date of the original commencement of operation of such MW capacity at the fee rates in effect at the time the fee is due, the annual payments for the simple-cycle turbines will be $0.00 until the first annual payment due on or before the anniversary date of the original commencement of operation. Pursuant to *Table 2--AES Rule 1304(a)(2) Offset Plan* above, first fire for the simple-cycle turbines is scheduled for 11/1/2023. Further, Rule 1304.1(c)(3)(A)(iii) provides that the sum of the annual offset fees remitted for the combined-cycle turbines prior to the submittal of a request for change to a single payment option shall be credited towards the single payment offset fee due.

Mr. O'Kane agreed to remain on annual payments until AES decides whether to proceed with Phase 2. He indicated that the first fire of the first combined-cycle turbine will occur on October 3, 2019. Therefore, the next annual payment or a single payment for the combined-cycle turbines will be due prior to October 3, 2020. Mr. O'Kane indicated that AES will know by then whether they will proceed with Phase 2 for the simple-cycle turbines.

2) <u>Question</u>: If AES makes a decision to convert from annual payments to a single payment for the combined-cycle and simple-cycle turbines in the future, Rule 1304.1(c)(3)(A)(iii) provides that the sum of the annual offset fees remitted prior to the submittal of a request for change to a single payment option shall be credited towards the single payment offset fee due. Rule 1304.1(c)(3)(A)(iii) clearly specifies that the amount of the single payment offset fee due shall be based on offset fee rates applicable at the time the written request for the change in payment method is submitted to the Executive Officer. <u>The question is whether the sum of the annual offset fees remitted prior to the submittal of a request for change to a single payment option is required to be adjusted annually by the CPI to the time the written request for change is submitted.</u>

PRDAS staff indicated that **the fees are those in effect at the time an event occurs.** Therefore, there is no adjustment to the sum of the annual offset fees remitted. What was paid will be refunded or credited.

3) <u>Question</u>: Rule 1304.1(c)(5) provides for refunds. <u>The issue is whether the initial payment for the First Year Annual Offset Fee Payment is required to be adjusted annually by the CPI to the time of the request for refund</u>.

PRDAS staff indicated the fee rates are set forth in Tables A1 and A2 (Table A2 for this project). The fee rates on which all payments are based are date dependent. **Fees are those in effect at the time an event occurs**. Thus the initial payment for the First Year Annual Offset Fee Payment should not be recalculated or adjusted by the CPI, and remains $4,708,472 for all purposes.

4) *Question*: For the next annual payment, Rule 1304.1(c)(3)(A)(i) indicates that subsequent payments shall be remitted annually based on the cumulative total of MW capacity that commenced operation, on or before the anniversary date of the original commencement of operation of such MW capacity at the fee rates in effect at the time the fee is due.

The next annual payment will be due prior to October 3, 2020 for the operation of the two combined-cycle turbines only. PRDAS staff provided the following clarifications regarding the methodology to calculate the annual fee for the operation of the combined-cycle turbines, without including any simple-cycle turbines.

a) $C_{2YrAvgExisting}$ – The amount of offsets required for a project is calculated at the time of the issuance of permits to construct. The $C_{2YrAvgExisting}$ was used to calculate the amount of offsets required and was based on the last twenty-four month period immediately prior to the issuance of the Permits to Construct for the AEC. Thus, the $C_{2YrAvgExisting}$ remains a constant, even if the simple-cycle turbines are constructed years after the initial permits to construct are issued.

b) Crep—The increase in annual operating hours for the combined-cycle turbines and the decrease in the annual operating hours for the simple-cycle turbines are required to be included in the Crep.

c) Annual payment for combined-cycle turbines =

(Annual payment for simple-cycle and combined-cycle turbines) x

(Installed MW for combined-cycle turbines)
(Total MW for simple-cycle & combined-cycle turbines)

First Year Annual Offset Fee Calculations (Actual Payment Required)

The actual payment for the first year annual offset fee for the operation of the combined-cycle turbines will be due prior to October 3, 2020. This payment will be deducted from the initial payment of $4,708,472, required for the South Coast AQMD to hold the credits for the facility, paid prior to the issuance of the Permits to Construct for the AEC on 4/18/17.

For the *First Year Annual Offset Fee Payment (Actual Payment Required* for the *Project),* the only changes to the *First Year Annual Offset Fee Payment (Initial Payment Prior to Issuance of Permits to Construct)* shown above are the $\mathbf{R_{iA1}}$ **&** $\mathbf{R_{iA2}}$, $\mathbf{C_{rep}}$**, and installed MW**.

Actual Annual Offset Fee (F_i) = [R_{iA1} x (100/MW) + R_{iA2} x (MW-100)/MW] x OF_i x PTE_{repi} x [(C_{rep} – $C_{2YRAvgExisting}$)/C_{rep}] **x <u>692.95 MW combined-cycle turbines</u>**
1094.7 MW total turbines

<u>PM$_{10}$</u>
[~~$1052~~ **<u>$1154</u>** x (100/1094.7 MW) + ~~$4206~~ **<u>$4614</u>** x (1094.7-100)/1094.7] x 1.0 x 1040.0 lb/day x
[~~4,162,619~~ **<u>4,960,415.8</u>** MWhr/yr – 650,693 MWh/yr]/~~4,162,619~~ **<u>4,960,415.8</u>** MWh/hr]
x <u>692.95 MW combined-cycle turbines</u>
1094.7 MW total turbines

= [~~3917.89~~ **<u>4297.93</u>**] x 1.0 x 1040 x [~~0.844~~ **<u>0.869</u>**] x **<u>[0.633]</u>** = ~~$3,438,967.13~~
= **<u>$2,458,760.14</u>**

<u>SOx</u>
[~~$837~~ **<u>$918</u>** x (100/1094.7 MW) + ~~$3344~~ **<u>$3669</u>** x (1094.7-100)/1094.7] x 1.0 x 401.9 lb/day x
[~~4,162,619~~ **<u>4,960,415.8</u>** MWhr/yr – 650,693 MWh/yr]/~~4,162,619~~ **<u>4,960,415.8</u>** MWh/hr]
x <u>692.95 MW combined-cycle turbines</u>
1094.7 MW total turbines

= [~~3114.99~~ **<u>3417.70</u>**] x 1.0 x 401.9 x [~~0.844~~ **<u>0.869</u>**]] x **<u>[0.633]</u>** = ~~$1,056,615.82~~
= **<u>$755,571.26</u>**

<u>VOC</u>
[~~$50~~ **<u>$55</u>** x (100/1094.7 MW) + ~~$196~~ **<u>$215</u>** x (1094.7-100)/1094.7] x 1.2 x 1150.7 lb/day x
[~~4,162,619~~ **<u>4,960,415.8</u>** MWhr/yr – 650,693 MWh/yr]/~~4,162,619~~ **<u>4,960,415.8</u>** MWh/hr]
x <u>692.95 MW combined-cycle turbines</u>
1094.7 MW total turbines

= [~~182.67~~ **<u>200.38</u>**] x 1.2 x 1150.7 x [~~0.844~~ **<u>0.869</u>**]] x **<u>[0.633]</u>** = ~~$212,888.91~~
= **<u>$152,202.30</u>**

<u>NEXT ANNUAL OFFSET FEE</u>
$2,458,760.14 + $755,571.26 + $152,202.30 = $3,366,533.70

The $3,366,533.70 fee is adjusted annually_by the CPI through FY 2019 – 2020. Since the next annual payment will be due after June 30, 2020, the $3,366,533.70 is required to be adjusted by CPI for FY 2020 – 2021.

CREDIT
$4,708,472 (*First Year Annual Offset Fee Payment Prior to Issuance of Permits to Construct)* - $3,366,533.70 (*Next Annual Offset Fee, but needs to be further adjusted by CPI for 2020 – 2021*) is $1,341,938.30 credit that can be applied to the next annual or single payment, as selected by AES. The estimated $1,341,938.30 will be less after the $3,366,355.70 is adjusted by CPI for 2020 – 2021.

Variables
The values for the revised variables are discussed below.

R_{iA1} = Table A1, Annual Offset Fee Rate for Pollutant (i), in terms of dollars per pound per day, annually.
R_{iA2} = Table A2, Annual Offset Fee Rate for Pollutant (i), in terms of dollars per pound per day, annually.

Annual Offset Fee Rates (R_{iA1} and R_{iA2}) Adjusted for CPI
Since Rule 1304.1 was adopted on 9/6/13, the offset fee rates in the rule are effective for the fiscal year ending 6/30/14. For each successive fiscal year, the offset fee rates are required to be adjusted. The fee increases to calculate the *First Year Annual Offset Fee Paid* are: (1) 1.6% effective 7/1/14, (2) 1.4% effective 7/1/15, and (3) 2.4% effective 7/1/16. **The subsequent fee increases are: (4) 2.5% effective 7/1/17, (5) 3.4% effective 7/1/18, and (6) 3.5% effective 7/1/19, and (7) TBD % effective 7/1/20.**

Table A1

$R_{PM10\ A1}$: $997 x 1.016 → $1013 x 1.014 → $1027 x 1.024 → $1052 **x 1.025 → $1078 x 1.034 → $1115 x 1.035 → $1154**

$R_{SOx\ A1}$: $793 x 1.016 → $806 x 1.014 → $817 x 1.024 → $837 **x 1.025 → $858 x 1.034 → $887 x 1.035 → $918**

$R_{VOC\ A1}$: $47 x 1.016 → $48 x 1.014 → $49 x 1.024 → $50 **x 1.025 → $51 x 1.034 → $53 x 1.035 → $55**

Table A2

$R_{PM10\ A2}$: $3986 x 1.016 → $4050 x 1.014 → $4107 x 1.024 → $4206 **x 1.025 → $4311 x 1.034 → $4458 x 1.035 → $4614**

$R_{SOx\ A2}$: $3170 x 1.016 → $3221 x 1.014 → $3266 x 1.024 → $3344 **x 1.025 → $3428 x 1.034 → $3545 x 1.035 → $3669**

$R_{VOC\ A2}$: $185 x 1.016 → $188 x 1.014 → $191 x 1.024 → $196 **x 1.025 → $201 x 1.034 → $208 x 1.035 → $215**

Crep = maximum permitted annual megawatt hour (MWh) generation of the new replacement unit(s). (Maximum rated capacity (MW) x Maximum permitted annual operating hours (h)).

Discussion: ~~4,162,619.1~~ **4,960,415.8** MWhr/yr

The Application is proposing to increase the annual operating hours per combined-cycle turbine from the 4640 hr/yr to 6545 hr/yr, and to decrease the annual operating hours per simple-cycle turbine from 2358 hr/yr to 1058 hr/yr.

[(692.951 MW)$_{\text{2 turbines}}$ (~~4640~~ **6545** hr/yr)]$_{\text{combined-cycle}}$ + [(401.75 MW)$_{\text{4 turbines}}$ (~~2358~~ **1058** hr/yr)]$_{\text{simple-cycle}}$ = ~~4,162,619.1~~ **4,960,415.8** MWhr/yr

Note: Startup and shutdown hours are included.

Rule 1313—Permits to Operate

Section (d) is applicable to the retirement plan.

(d) For a new source or modification which will be a replacement, in whole or part, for an existing source on the same or contiguous property, a maximum of 90 days may be allowed as a start-up period for simultaneous operation of the subject sources.

Analysis: From revised *Table* 2 above, the schedule for AGS Boilers Nos. 1, 2, and 6 shutdown will be ~~12/29/2019~~ **12/31/19**. The combined-cycle block startup is scheduled for ~~11/1/2019~~ **10/3/2019**. The schedule for AGS Boiler No. 3 shutdown is 12/31/2020. The simple-cycle block startup is scheduled for ~~6/1/2021~~ **11/1/2023**.

Condition no. F52.1 limits simultaneous operation to 90 days, and sets forth a number of requirements for the retirement plan and the retirement of the AGS Boilers. As discussed above, this condition will be updated to incorporate the requested schedule changes.

(g) Emission Limitation Permit Conditions
Every permit shall have the following conditions:

(1) Identified BACT conditions
(2) Monthly maximum emissions from the permitted source

Analysis:

Combined-Cycle Turbines

BACT--Condition nos. A195.8, A195.9, and A195.10 set forth the BACT limits for NOx, CO, and VOC, respectively.

Monthly Emissions--Condition no. A63.2 sets forth the monthly limits for CO, VOC, PM_{10}, and SOx. These limits indirectly limit NOx.

Simple-Cycle Turbines

BACT-- Condition nos. A195.11, A195.17, and A195.10 set forth the BACT limits for NOx, CO, and VOC, respectively.

Monthly Emissions--Condition no. A63.3 sets forth the monthly limits for CO, VOC, PM_{10}, and SOx. These limits indirectly limit NOx.

Selective Catalytic Reduction

BACT—Condition nos. A195.15 and A195.16 set forth the BACT limit for the combined- and simple-cycle turbine SCRs (NH_3 at 15% O_2) and the auxiliary boiler SCR (NH_3 at 3% O_2), respectively.

Monthly Emissions—Monthly emission limits are applicable to basic equipment, not control equipment.

Ammonia Tanks

BACT—Condition 157.1 requires the tanks to be equipped with a pressure relief valve set at 50 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 valves and vapor return lines result in no ammonia emissions emitted from the tanks under normal operations.

Rule 1325—Federal PM2.5 New Source Review Program, adopted 6/3/2011, amended 12/5/14, 11/4/16, 1/4/19

- **Revision History of Rule 1325**

  The revision history of Rule 1325 is summarized below to provide background for the Rule 1325 analysis for the AEC project.

  Rule 1325 was adopted on June 3, 2011 to incorporate U.S. EPA requirements for PM2.5 into Regulation XIII – New Source Review (NSR). The rule mirrors federal requirements, including offset ratios, Lowest Achievable Emission Rate (LAER) compliance, and control of PM2.5 precursors.

Rule 1325 was amended on 12/5/14 to incorporate administrative changes to definitions, provisions and exclusions, based on comments received from the U.S. EPA regarding SIP approvability of Rule 1325. The amended rule was approved into the California State Implementation Plan on 5/1/15. The applicable requirements of 40 CFR Part 51, Appendix S, were necessary for permitting actions until Rule 1325 became SIP-approved.

Rule 1325 was amended on 11/4/16 to establish appropriate major stationary source thresholds for direct $PM_{2.5}$ and $PM_{2.5}$ precursors, including VOC and ammonia, in order to align with the recent reclassification of the South Coast Basin from a "moderate" $PM_{2.5}$ nonattainment area to a "serious" nonattainment area and with U.S. EPA's Fine Particulate Matter National Ambient Air Quality Standards implementation rule. The amendments were intended to facilitate SIP approval of the regulations. The amendment added ammonia and VOC as precursors to $PM_{2.5}$, per Clean Air Act Subpart 4 requirements. The major polluting facility thresholds were lowered from 100 tons per year per pollutant to 70 tons per year per pollutant. **These amendments were to be effective after August 14, 2017 or upon the effective date of EPA's approval of these amendments to this rule, whichever is later.** US EPA's Fine Particulate Matter National Ambient Air Quality Standards implementation rule states an area can rely on SIP-approved $PM_{2.5}$ New Source Review rule until the new rule is approved. 81 Fed Reg 58009 (August 24, 2016). US EPA's final implementation rule became effective on 10/24/16.

Rule 1325 was amended on 1/4/19 to address a deficiency in the 11/4/16 amendment in which the definition of "precursors" was expanded to add VOC and ammonia (NH3) to the existing list of PM2.5 precursors (oxides of nitrogen and sulfur dioxide), but the definition of "regulated NSR pollutant" was not expanded to explicitly reference VOC and NH_3. The 1/4/19 amendment addresses the deficiency by referencing "precursors" in the definition of "regulated NSR pollutant." In addition, the rule language was clarified and outdated language removed. ***Rule 1325, amended 1/4/19, is not applicable until a "major modification" occurs.***

- **FDOC Analysis**
  The FDOC provided an analysis for the **12/5/14** version of *Rule 1325*. The FDOC was not updated for the 11/4/16 version because the extended review period had been completed and the issuance of the FDOC on 1/25/17 was imminent. The analysis noted that the 11/4/16 amendments were to be effective after August 14, 2017 or upon the effective date of EPA's approval of these amendments to this rule, whichever is later.

- **Application Analysis**
*The relevant sections of the **11/4/16** version 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 $PM_{2.5}$.

With respect to major modifications, this rule applies on a pollutant-specific basis to emissions of $PM_{2.5}$ and its precursors in areas federally-designated as nonattainment for $PM_{2.5}$, for which (1) the source is major, (2) the modification results in a significant increase, and (3) the modification results in a significant net emissions increase.

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

(1) BASELINE ACTUAL EMISSIONS means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with the following:

(A) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Executive Officer shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

(3) MAJOR MODIFICATION means:

(A) Any physical change in or change in the method of operation of a major polluting facility that would result in: a significant emissions increase of a regulated NSR pollutant; and a significant net emissions increase of that pollutant from the major polluting facility.

(4) MAJOR POLLUTING FACILITY means, on a pollutant specific basis, any emissions source located in areas federally designated pursuant to 40 CFR 81.305 as non-attainment for 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 (NOx) and sulfur dioxide (SO_2), 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.

(12) SIGNIFICANT means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Nitrogen oxides: 40 tons per year
Sulfur dioxide: 40 tons per year
Volatile Organic Compounds: 40 tons per year
Ammonia: 40 tons per year
$PM_{2.5}$: 10 tons per year

(c) Requirements

(1) The Executive Officer shall deny the Permit for a new major polluting facility; or major modification to a major polluting facility; or any modification to an existing facility that would constitute a major polluting facility in and of itself, unless each of the following requirements is met:

(A) Lowest Achievable Emission Rate (LAER**)** is employed for the new or relocated source or for the actual modification to an existing source; and

(B) Emission increases shall be offset at an offset ratio of 1.1:1 for $PM_{2.5}$ and the ratio required in Regulation XIII or Rule 2005 for NOx and SO_2 as applicable; and

(C) Certification is provided by the owner/operator that all major sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act; and

(D) An analysis is conducted of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstration made that the benefits of the proposed project outweigh the environmental and social costs associated with that project.

(d) Emission Calculations

(1) Except as provided in subdivision (e) of this rule, and consistent with the definition of a major modification, a project is a major modification for a regulated NSR pollutant if it causes two types of emission increases—a significant emissions increase and a significant net emissions increase. The procedure for calculating whether a significant emissions increase will occur at the major polluting facility depends on the type of emissions units being modified, according to paragraphs (d)(2) through (d)(5). The procedure for calculating whether a significant net emissions increase will occur at the major polluting facility is contained in the definition of the term Net Emission Increase.

(2) Actual-to-projected-actual applicability tests for projects that only involve existing emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions and the baseline actual emissions [as defined in subparagraph (b)(1)(A) and (b)(1)(B), as applicable] for each existing emissions unit, equals or exceeds the significant amount for that pollutant.

(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:

Phase I (Combined-Cycle Turbines)

Pursuant to paragraph (b)(4) for the definition of MAJOR POLLUTING FACILITY, the lower threshold of 70 tons per year per pollutant is applicable if construction does not commence until "after August 14, 2017 or upon the effective date of U.S. EPA's approval of the 11/4/16 amendments to this rule, whichever is later." Subdivision (b) states: "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: …." Since "commence construction" is not defined in Rule 1325(b), we turn to 40 CFR 51.165(a)(1).

40 CFR 51.165 states:

(a) State Implementation Plan and Tribal Implementation Plan provisions satisfying sections 172(c)(5) and 173 of the Act shall meet the following conditions:

(1) All such plans shall use the specific definitions. Deviations from the following wording will be approved only if the State specifically demonstrates that the submitted definition is more stringent, or at least as stringent, in all respects as the corresponding definition below:

(xv) *Begin actual construction* means in general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying of underground pipework, and construction of permanent storage structures. With respect to a change in method of operating this term refers to those on-site activities other than preparatory activities which mark the initiation of the change.

(xvi) *Commence* as applied to construction of a major stationary source or major modification means that the owner or operator has all necessary preconstruction approvals or permits and either has:

(A) Begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or

(B) Entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time.

(xvii) *Necessary preconstruction approvals or permits* means those Federal air quality control laws and regulations and those air quality control laws and regulations which are part of the applicable State Implementation Plan.

(xviii) *Construction* means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions.

In an letter, dated 8/7/17, Stephen O'Kane, AES, provided confirmation that "actual construction" was commenced on 8/7/17. The letter states:

"On August 7, 2017 AES Alamitos, LLC began construction, as defined in 40CFR 51.165(a)(1)(xv), with the start of construction of the permanent foundation for gas turbine, Unit No. CCGT-1 (ID No. D165), heat recovery steam generator (HRSG), CO oxidation catalyst (ID No. C169), selective catalytic reduction control (ID No. C170) and the stack serving gas turbine Unit No. CCGT-1 (ID No. S172) at the AES Alamitos generating station, facility ID 115394. Auger in place, concrete and steel rebar support piles for the foundation of the gas turbine, HRSG, and stack have been installed in the area highlighted on the attached general arrangement drawing. A photograph of the subject permanent construction work, including completed concrete and steel rebar piles has also been provided."

For the **Application**, because the actual construction of Phase I (combined-cycle turbines and associated equipment) was commenced on or prior to 8/14/17 (earliest date that the 70 tpy threshold would become applicable), the analysis will continue to be based on a threshold of 100 tpy for major source. "Actual Emissions (2013 & 2014 Avg)" remains applicable as the "baseline actual emissions" because these years are within the 5-year period immediately preceding the commencement of actual construction of Phase I on 8/7/17. FDOC Table 67 is revised below to incorporate the revised AEC potential to emit resulting from the revised annual operating schedule for the turbines.

Update*: The PM2.5 emission limit was updated from 100 tpy (FDOC) to 70 tpy pursuant to the evaluation for Auxiliary Boiler (A/N 604014) and Auxiliary Boiler SCR (A/N 613323). See P/Cs issued on 7/10/19. Pursuant to the Rule 1325 analysis in this evaluation, the PM2.5 emission limit in condition F2.1 will be corrected to 100 tpy. The reason is that the actual construction of Phase I (combined-cycle turbines and associated equipment) was commenced on or prior to 8/14/17 (earliest date that the 70 tpy threshold would become applicable).

Table 67 – Rule 1325 Applicability

	NOx	**SO_2**	**$PM_{2.5}$**
Alamitos Generating Station Potential to Emit, TPY (*Table 13*)	635.60	49.56	97.86
Major Source for Particular Pollutant?	Yes, PTE is greater than 100 tpy.	No, PTE is less than 100 tpy.	No, PTE is less than 100 tpy.
Alamitos Generating Station (AGS) Actual Emissions (2013 & 2014 Avg) TPY (*Table 14*)	47.47	4.68	10.91
Alamitos Energy Center (AEC) Potential to Emit, TPY (*Table 45*)	~~137.06~~ **146.78**	~~10.19~~ **11.83**	69.52
Net Emissions Increase (AEC PTE – AGS actual)	~~89.59~~ **99.31**	~~5.51~~ **7.15**	58.61
If AGS is a major facility for particular pollutant, does the AEC result in a net significant emissions increase?	Yes, net increase is greater than 40 tpy.		

	NOx	SO_2	$PM_{2.5}$
If AGS is not a major facility for particular pollutant, does the AEC constitute a modification that would constitute a major polluting facility in and of itself?		No, net increase is less than 100 tpy.	No, net increase is less than 100 tpy.

The Application analysis below is the same as for the FDOC.

Rule 1325 is applicable to NOx. The AGS is a major polluting facility for NOx because the PTE is greater than 100 tpy, and the AEC constitutes a major modification because the net NOx increase is greater than 40 tpy. NOx meets the requirements of Rule 1325(c)(1)(A) – (D). For (c)(1)(A), the turbines meet LAER for NOx as discussed under the *Rule 1703(a)(2)—Top-Down BACT* analysis, below. For (c)(1)(B), the NOx emissions will be offset as discussed under the analysis for Rule 2005(c)(2)—Offsets, below. For (c)(1)(C), certification of statewide compliance is provided as discussed under Rule 2005(g)(1) for Statewide Compliance, below. For (c)(1)(D), the alternatives discussion is provided as discussed under the Rule 2005(g)(2) for Alternative Analysis, below.

Rule 1325 is not applicable to SO_2 and $PM_{2.5}$. The AGS is not a major polluting facility for SO_2 and $PM_{2.5}$ because the PTEs for both are less than 100 tpy. The AEC does not constitute a modification to an existing facility that would constitute a major polluting facility in and of itself, because the net increase for SO_2 and $PM_{2.5}$ are less than 100 tpy as enforced by the annual emissions limits for SOx and PM_{10} in conditions A63.2, A63.3, and A63.4.

Phase II (Simple-Cycle Turbines)

The commencement of construction for Phase II (simple-cycle turbines) did not occur on or prior to 8/14/17. Pursuant to *Table 3 - AEC Schedule Major Milestones*, the actual construction of Phase II has been revised to third quarter 2022.

Existing condition E74.1 requires a BACT/LAER determination for Phase II prior to the commencement of construction, pursuant to 40 CFR 52.2 – PSD. New analogous condition E74.2 will be added to require Rule 1325 evaluation and compliance prior to the commence of construction of Phase II.

E74.2 Notwithstanding the requirements of Section E conditions, the Operator may commence the construction of Phase II of this project if all the following condition(s) are met:

Rule 1325 compliance for the Phase II of this project shall be reviewed and required by South Coast AQMD as appropriate prior to the commencement of construction of Phase II of the project.

[Rule 1325, 11-4-16; RULE 1325, 1-4-19]

[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle), C187, C188, C193, C194, C199, C200, C205, C206 (simple-cycle control), D164 (ammonia tanks), D210 (oil-water separators)]

For A/N 604014 & 613323 for the condition changes for the auxiliary boiler and SCR, the condition F2.1 limit for PM2.5 was updated from 100 tpy to 70 tpy pursuant to paragraph (b)(4). See P/Cs issued 7/10/19. ***Update: Pursuant to the Rule 1325 analysis in this evaluation, the PM2.5 emission limit in condition F2.1 will be corrected to 100 tpy. The reason is that the actual construction of Phase I (combined-cycle turbines and associated equipment) was commenced on or prior to 8/14/17 (earliest date that the 70 tpy threshold would become applicable).***

Rule 1401—New Source Review of Toxic Air Contaminants, as amended 9/1/17
Rule 2005(i) – RECLAIM Rule 1401 Compliance, as amended 12/4/15

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 that emit toxic air contaminants listed in Table I of this rule. The rule establishes allowable risks for permit units requiring new permits pursuant to Rules 201 or 203. Rule 2005(i) requires compliance with Rule 1401 for NOx emissions at RECLAIM facilities.

Because the allowable risks are for each permit unit, the limits are for each turbine and the auxiliary boiler. 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.

(f) Emissions Calculations
(3) For the purpose of determining MICR, cancer burden and chronic HI due to a modified permit unit pursuant to this rule, the increase in emissions from the modified permit unit shall be calculated based on the difference between the total permitted emissions after the modification, calculated pursuant to the criteria established in subparagraphs (f)(1)(A), (B), (C), and (D), and: ….

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 South Coast AQMD 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.

- **Prior PRDAS Guidance regarding Modeling Requirements**
  On 8/14/18, Sr. Meteorologist Melissa Sheffer provided guidance for another project for which only the annual emissions would change. The consultant had concluded since the HIA is based on hourly emissions rates that would not change, the HIA would not be required to be evaluated in the revised HRA. Ms. Sheffer indicated that, as Rule 1401 provides limits for MICR, HIC, and HIA for a modified permit unit, the HRA analysis is required to provide the MICR, HIC, and HIA for each permit unit.

  As discussed above for the *Rule 1303(b)(1)*and *Rule 2005(c)(1)(B)* air dispersion modeling analysis, on 12/6/18, Sr. Meteorologist Melissa Sheffer requested and received clarification from

Manager Jillian Wong regarding modeling requirements for a modification project. Both the air dispersion modeling and HRA are required to be performed based on the emissions increases per permit unit, provided the stack parameters (height, diameter, location, flow rates, temperature) remain the same and the monitors for the background concentrations are located sufficiently close to the facility to capture the existing emissions from the facility. For the **Application**, both the air dispersion modeling and HRA are required to be based on total emissions, not on the emissions increases, because the equipment is under construction and has not contributed to the measured background concentrations.

- **Yorke Protocol, 11/7/18, and South Coast AQMD Comments on Yorke Protocol, 12/20/18**

a. The **Protocol** proposed to revise the dispersion modeling that was accepted by the South Coast AQMD for the FDOC to incorporate the proposed operating hour revisions for the combined-cycle and simple-cycle turbines. **South Coast AQMD Comments** clarified that the air dispersion modeling and health risk assessment analysis are required to be updated to the most recent background concentrations, MET data, AERMOD version (air quality modeling), and AERMOD with HARP version (HRA).

b. The **Protocol** stated the Rule 1401 HRA presented in the FDOC applications showed that the per unit and total facility cancer risk and chronic hazard indices were well below the South Coast AQMD thresholds of 10 in a million and 1, respectively. The cancer risk from the CCGTs contributed the largest percentage to the total facility cancer risk. Although the total facility TAC emissions will increase by 14% due to the operating hour changes, the TAC emissions from the CCGTs will increase by approximately 42% (or a scaling factor of 1.42) and the TAC emissions from the SCGTs will decrease by approximately 57% (or a scaling factor of 0.43). The Protocol provided a table that presented a scaled estimation of the revised potential cancer risk associated with the operating hour revisions for each unit (CCGT, SCGT, auxiliary boiler) and the total facility, which showed that the revised potential cancer risk for the total facility will remain well below the South Coast AQMD threshold of 10 in a million. The scaled estimation of the revised potential cancer risk per unit (CCGT, SCGT, auxiliary boiler) was calculated by multiplying the cancer risk per unit from the FDOC by the emissions scaling factor discussed above for the CCGTs and the SCGTs. The emissions scaling factor for the auxiliary boiler was 1.0 because there are no proposed changes in annual operating hours. The scaled estimation of the revised potential cancer risk for the total facility was estimated by summing the revised potential cancer risk per unit (CCGT, SCGT, auxiliary boiler). The Protocol indicated that this approach may overestimate the cancer risk, as the impacts may not occur at the same receptor. Likewise, the Protocol stated that the operating hour changes would have a similar effect on increasing the chronic hazard index, which was well below the South Coast AQMD threshold of one. Therefore, no additional HRA modeling was proposed for this permit modification.

South Coast AQMD Comments clarified the FDOC included *Table 68--Model Results for HRA for Combined-Cycle Turbine* that provided the MICR, HIC, HIA for each of two combined-cycle turbines. *Table 70--Model Results for HRA for Simple-Cycle Turbine* provided the MICR, HIC, and HIA for each of the four simple-cycle turbines. *Table 70A--Model Results for HRA for Facility* provided the MICR, HIC, HIA, and cancer burden for the facility, including the auxiliary boiler. AES had provided the facility-wide health risk assessment in support of CEC's analysis of the *Supplemental Application for Certification*. South Coast AQMD's understanding is that AES will submit a *Petition for Post-Certification Amendment* to the CEC for the modification project. The South Coast AQMD requested revised health risk assessments to update FDOC *Tables 68, 70,* and *70A* for the MICR, HIC, HIA, and cancer risk, based on the most recent risk values.

Yorke Engineering provided the evaluation for the revised modeling and HRA on pp. 18 – 30 of the *Applications for Modification* for A/N 610354 – 610360. The FDOC modeling was the starting point for the modeling. The revised modeling for the Application followed the methodology proposed in the **Yorke Protocol, 11/17/18**, and the requested changes to the proposed methodology provided in the **South Coast AQMD Comments on Yorke Protocol, 12/20/18**.

In response to **South Coast AQMD Comments**, the applicant provided HRA modeling based on the Office of Environmental Health Hazard Assessment (OEHHA) 2015 guidelines Tier 1 and South Coast AQMD Tier 4 techniques to estimate the health risk impacts for the closest residential, sensitive, and off-site worker receptors. The health risk calculations were performed using the HARP2 Air Dispersion Modeling and Risk Tool (ADMRT, version 18159). This is an update from the HARP 2, version 16088, used in the FDOC.

The ***PRDAS Memo*** indicated:

- The applicant performed the HRA with the Hot Spots Analysis and Reporting Program (HARP2, version 18159). The South Coast AQMD's HRA procedures require HARP to be used in Tier 4 risk assessments.

- The HRA used the same Cartesian receptor grid used for the Rule 1303 modeling analysis, plus additional receptors placed at known sensitive receptors and census block centroids, which is appropriate.

- <u>PRDAS Correction to Yorke Modeling</u>
  For the health risk impacts by permit unit, the applicant incorrectly reported the risks at the maximum receptors for the total facility instead of the maximum receptors for the permit unit, which are not necessarily in the same locations. This resulted in some underreported health risk impacts for the individual permit units. PRDAS corrected the results for each permit unit, which are shown in the *PRDAS Memo*.

- <u>PRDAS Correction to Yorke Modeling</u>

The applicant calculated the facility-wide cancer burden based on a Zone of Impact (ZOI) radius of 1,135 meters, a ZOI area of 4.045 km^2, and a default population density of 7,000 persons per km^2, which is appropriate. However, the applicant incorrectly used a facility-wide 70-year residential cancer risk of 1.0 in one million in the calculation. PRDAS staff determined the maximum facility-wide 70-year residential cancer risk is 2.0 in one million. Therefore, PRDAS staff recalculated the facility-wide cancer burden to be 4.045 x 7,000 x 2.0E-06 = 0.057.

<u>In an e-mail dated 8/30/19, the South Coast AQMD forwarded the above two PRDAS staff comments regarding the HRA, and a comment regarding the Rule 1303 modeling discussed above, to AES.</u>

- The closest school to the facility is Rosie the Riveter Charter High School, a privately owned and operated school located on the AES Alamitos site, approximately 971 feet northwest of the nearest proposed stack location (CCGT-1). The health risk impacts at this school are included for each turbine in the *PRDAS Memo*.

<u>Update</u>: In an e-mail dated 8/12/19**,** Stephen O'Kane indicated that the school is no longer on site. The building has been repurposed for AES use. (On 8/2/19, Jeff Miller, the Compliance Manager, had stated this occurred in late spring 2019.) The distance from the next closest school, Kettering Elementary School, 550 Silvera Avenue, Long Beach, CA 90803, to CCGT-1 is 2021 feet. Therefore, the health risk impacts provided for the school receptor type, based on the location of the former Rosie the Riveter Charter High School, are very conservative.

- <u>Combined-Cycle Turbines</u>

For the **Application**, the toxic air contaminants emissions calculations for determination of the maximum hourly and annual emissions rates are shown in revised *Table 26 - Combined-Cycle Turbine Toxic Air Contaminants/Hazardous Air Pollutants*, above. The maximum hourly emission rates are the same as for the FDOC, except for the ammonia emissions. The revised increased maximum annual emission rates in *Table 26* incorporate the increase in average annual heat input resulting from the proposed increase in total annual hours from 4640 hr/yr to 6545 hr/yr per turbine.

The modeled stack parameters for the hourly impacts and annual impacts will remain the same as for the FDOC, except the stack height has increased from 140 ft. to 150 ft., as set forth in new *Table 67A* below. The maximum hourly turbine impacts for the combined-cycle turbines will continue to be predicted using the exhaust parameters for the 65.3 ºF, minimum load case, which represents the turbine exhaust parameters associated with the maximum predicted 1-hour ground-level impact in the dispersion modeling (Case 7 in *Table 15*). The annual turbine impacts will continue to be predicted for the 65.3 ºF, minimum 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 7 in *Table 15*).

Table 67A--Modeled Stack Parameters for HRA for Combined-Cycle Turbines

Parameter	Hourly Impacts (Scenario CC07—65.3 °F, Minimum Load)	Annual Impacts (Scenario CC07—65.3 °F, Minimum Load)
Stack Diameter (m)	6.10	6.10
Stack Height (m)	~~42.7~~ **45.7**	~~42.7~~ **45.7**
Stack Temp (°K)	350	350
Stack Velocity (m/s)	11.8	11.8

The MICR limit is ten in one million for each combined- and simple-cycle turbine because Best Available Control Technology For Toxics (T-BACT) for combustion turbines is determined to be an oxidation catalyst (see discussion below).

On p. 28 of the Yorke *Applications for Modification*, *Table 4-9: HRA Results by Permit Unit* provides the HRA results for each combined-cycle turbine.

PRDAS staff has independently reproduced the applicant's analysis and summarized the results in the *PRDAS Memo*. FDOC *Table 68* is updated below to incorporate PRDAS' modeling results for the Application. The health risks for each combined-cycle turbine are less than the Rule 1401 cancer and non-cancer limits of 10 in one million (for permit units with T-BACT), and hazard indices (chronic and acute) of 1, respectively.

Table 68--Model Results for HRA for Combined-Cycle Turbines

Health Risk Index	Residential Receptor Risk	Sensitive (School) Receptor Risk [1]	Worker Receptor Risk [2]	Rule 1401 Thresholds (T-BACT)	Exceeds Any Threshold?
			CCGT-1		
MICR	~~0.48~~ **0.78** x 10^{-6}	**0.48 x 10^{-6}**	~~0.025~~ **0.04** x 10^{-6}	10 x 10^{-6}	No
HIC	~~0.0017~~ **0.0020**	**0.001**	~~0.0012~~ **0.003**	1	No
HIA	~~0.00657~~ **0.005**	**0.006**	~~0.00662~~ **0.006**	1	No
			CCGT-2		
MICR	~~0.49~~ **0.73** x 10^{-6}	**0.53 x 10^{-6}**	~~0.025~~ **0.04** x 10^{-6}	10 x 10^{-6}	No
HIC	~~0.00123~~ **0.002**	**0.001**	~~0.00171~~ **0.003**	1	No

HIA	~~0.00657~~ **0.005**	**0.006**	~~0.00672~~ **0.006**	1	No

[1] Health risk impacts were reported for the closest school, Rosie the Riveter Charter High School, located on the AES Alamitos site (971 ft. to CCGT-1). The school was evaluated with residential exposure assumptions.
Update: The school is no longer on site, and the building has been repurposed for AES use. The distance from the next closest school, Kettering Elementary School, 550 Silvera Avenue, Long Beach, CA 90803, to CCGT-1 is 2021 feet. Therefore, the health risk impacts provided for the school receptor type, based on the location of the Rosie the Riveter school, are very conservative.

[2] Work health risk impacts were evaluated at the maximum impacted receptor at or beyond the facility fenceline.

- Auxiliary Boiler

The separate engineering evaluation for A/N 604014 and 613323 for the Auxiliary Boiler and SCR concluded that an a revised HRA for the auxiliary boiler is not required because the condition changes did not change the toxic emissions. For the **Application**, however, the boiler is required to be included with the combined-cycle and simple-cycle turbines for the facility-wide Rule 1401 health risk assessment in support CEC's analysis of the *Petition for Post-Certification Amendment*.

The maximum hourly and annual emissions rates shown in *Table 30 - Toxic Air Contaminants/ Hazardous Air Pollutants for Auxiliary Boiler*, above, are the same as for the FDOC.

The modeled stack parameters for the hourly impacts and annual impacts remain the same as for the FDOC, as set forth in new *Table 68A* below. The maximum hourly and annual impacts for the auxiliary boiler are predicted based on the auxiliary boiler operating at 100 percent load for the hourly impacts and annual impacts.

Table 68A--Modeled Stack Parameters for HRA for Auxiliary Boiler

Parameter	Hourly Impacts	Annual Impacts
Stack Diameter (m)	0.91	0.91
Stack Height (m)	24.4	24.4
Stack Temp (°K)	432	432
Stack Velocity (m/s)	21.2	21.2

On p. 28 of the Yorke *Applications for Modification*, *Table 4-9: HRA Results by Permit Unit,* provides the HRA results for the auxiliary boiler. Although the hourly and annual emissions rates remain the same as in the FDOC, the HRA results are different than in FDOC *Table 69* because of the modeling mechanics updates, including the update to HARP2 Air Dispersion Modeling and Risk Tool (ADMRT, version 18159).

PRDAS staff has independently reproduced the applicant's analysis and summarized the results in the *PRDAS Memo*. FDOC *Table 69* is updated below to incorporate PRDAS' modeling results for the Application. The health risks from the auxiliary boiler are less than the Rule 1401 cancer and non-cancer limits of 1 in one million (for permit units without T-BACT), and hazard indices (chronic and acute) of 1, respectively.

Table 69--Model Results for HRA for Auxiliary Boiler

Health Risk Index	Residential Receptor Risk	Sensitive (School) Receptor Risk [1]	Worker Receptor Risk [2]	Rule 1401 Thresholds (No T-BACT)	Exceeds Any Threshold?
MICR	~~0.0091~~ **0.02** x 10^{-6}	**0.005 x 10^{-6}**	~~0.00091~~ **0.003** x 10^{-6}	1 x 10^{-6}	No
HIC	~~0.0000284~~ **0.00007**	**0.00002**	~~0.0000967~~ **0.0003**	1	No
HIA	~~0.000318~~ **0.0003**	**0.0001**	~~0.00049~~ **0.0005**	1	No

1 Health risk impacts were reported for the closest school, Rosie the Riveter Charter High School, located on the AES Alamitos site (971 ft. to CCGT-1). The school was evaluated with residential exposure assumptions.
Update: The school is no longer on site, and the building has been repurposed for AES use. The distance from the next closest school, Kettering Elementary School, 550 Silvera Avenue, Long Beach, CA 90803, to CCGT-1 is 2021 feet. Therefore, the health risk impacts provided for the school receptor type, based on the location of the Rosie the Riveter school, are very conservative.

2 Work health risk impacts were evaluated at the maximum impacted receptor at or beyond the facility fenceline.

- Simple-Cycle Turbines

For the **Application,** the toxic air contaminants emissions calculations for determination of the maximum hourly and annual emissions rates are shown in *Table 42 - Simple-Cycle Turbine Toxic Air Contaminants/Hazardous Air Pollutants*, above. The maximum hourly emission rates are the same as for the FDOC. The revised annual emissions in *Table 42* incorporate the decrease in average annual heat input resulting from the proposed decrease in total annual hours from 2358 hr/yr to 1058 hr/yr per turbine.

The modeled stack parameters for the hourly impacts and annual impacts remain the same as for the FDOC, as set forth in new *Table 69A* below. The maximum hourly turbine impacts for the simple-cycle turbines will continue to be predicted using the exhaust parameters for the 65.3 ºF, minimum load case, which represents the turbine exhaust parameters associated with the maximum predicted 1-hour ground-level impact in the dispersion modeling (Case 7 in *Table 31*). The annual turbine impacts will continue to be predicted for the 65.3 ºF, minimum 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 7 in *Table 31*).

Table 69A--Modeled Stack Parameters for HRA for Simple-Cycle Turbines

Parameter	Hourly Impacts (Scenario SC07-- 65.3 °F, Minimum Load)	Annual Impacts (Scenario SC07—65.3 °F, Minimum Load)
Stack Diameter (m)	4.11	4.11
Stack Height (m)	24.4	24.4
Stack Temp (°K)	746	746
Stack Velocity (m/s)	23.6	23.6

On p. 28 of the *Applications for Modification: Turbine Emission Limits, Table 4-9: HRA Results by Permit Unit* provides the HRA results for each simple-cycle turbine.

PRDAS staff has independently reproduced the applicant's analysis and summarized the results in the *PRDAS Memo*. FDOC *Table 70* is updated below to incorporate PRDAS' modeling results for the Application. The health risks from each simple-cycle turbine are less than the Rule 1401 cancer and non-cancer limits of 10 in one million (for permit units with T-BACT), and hazard indices (chronic and acute) of 1, respectively.

Table 70--Model Results for HRA for Simple-Cycle Turbines

Health Risk Index	Residential Receptor Risk	Sensitive (School) Receptor Risk [1]	Worker Receptor Risk [2]	Rule 1401 Thresholds (T-BACT)	Exceeds Any Threshold?
			SCGT-1		
MICR	~~0.049~~ **0.03** x 10^{-6}	**0.008 x 10^{-6}**	~~0.0019~~ **0.002** x 10^{-6}	10 x 10^{-6}	No
HIC	~~0.000126~~ **0.00008**	**0.00002**	~~0.000136~~ **0.0001**	1	No
HIA	~~0.00151~~ **0.001**	**0.002**	~~0.00237~~ **0.002**	1	No
			SCGT-2		
MICR	~~0.049~~ **0.03** x 10^{-6}	**0.007 x 10^{-6}**	~~0.0019~~ **0.002** x 10^{-6}	10 x 10^{-6}	No
HIC	~~0.000124~~ **0.00008**	**0.00002**	~~0.000137~~ **0.0001**	1	No
HIA	~~0.00153~~ **0.001**	**0.002**	~~0.00385~~ **0.002**	1	No
			SCGT-3		
MICR	~~0.048~~ **0.03** x 10^{-6}	**0.007 x 10^{-6}**	~~0.0019~~ **0.002** x 10^{-6}	10 x 10^{-6}	No
HIC	~~0.000122~~ **0.00007**	**0.00002**	~~0.000137~~ **0.0001**	1	No
HIA	~~0.00174~~ **0.001**	**0.001**	~~0.00242~~ **0.002**	1	No
			SCGT-4		
MICR	~~0.047~~ **0.03** x 10^{-6}	**0.007 x 10^{-6}**	~~0.0019~~ **0.002** x 10^{-6}	10 x 10^{-6}	No
HIC	~~0.00012~~ **0.00007**	**0.00002**	~~0.0000466~~ **0.0001**	1	No
HIA	~~0.00175~~ **0.001**	**0.001**	~~0.00239~~ **0.002**	1	No

[1] Health risk impacts were reported for the closest school, Rosie the Riveter Charter High School, located on the AES Alamitos site (971 ft. to CCGT-1). The school was evaluated with residential exposure assumptions.
Update: The school is no longer on site, and the building has been repurposed for AES use. The distance from the next closest school, Kettering Elementary School, 550 Silvera Avenue, Long Beach, CA 90803, to CCGT-1 is 2021 feet. Therefore, the health risk impacts provided for the school receptor type, based on the location of the Rosie the Riveter school, are very conservative.

[2] Work health risk impacts were evaluated at the maximum impacted receptor at or beyond the facility fenceline.

- Facility-wide

For the **FDOC**, the facility-wide health risk assessment was provided in support of CEC's analysis of the *Supplemental Application for Certification*. For the **Application**, the facility-wide health risk assessment is provided in support of CEC's analysis of the *Petition for Post-Certification Amendment.*

On p. 29 of the *Applications for Modification: Turbine Emission Limits*, *Table 4-10: Total Facility HRA Results* provides the results for the facility.

PRDAS staff has independently reproduced the applicant's analysis and summarized the results in the *PRDAS Memo*. FDOC *Table 70A* is updated below to incorporate PRDAS' modeling results for the Application. The health risks from the facility are less than the Rule 1401 cancer and non-cancer limits of 10 in one million (for permit units with T-BACT), and hazard indices (chronic and acute) of 1, respectively. Also, the cancer burden is less than the 0.5 limit.

Table 70A--Model Results for HRA for Facility

Health Risk Index	Residential Receptor Risk	Sensitive (School) Receptor Risk [1]	Worker Receptor Risk [2]	Rule 1401 Thresholds (T-BACT)	Exceeds Any Threshold?
MICR	~~1.1~~ **1.61** x 10^{-6}	**1.05 x 10^{-6}**	~~0.052~~ **0.09** x 10^{-6}	10 x 10^{-6}	No
HIC	~~0.0028~~ **0.004**	**0.003**	~~0.00364~~ **0.006**	1	No
HIA	~~0.0176~~ **0.01**	**0.02**	~~0.0188~~ **0.02**	1	No
Cancer Burden [3]	~~0.0097~~ **0.057**			0.5	No

1 Health risk impacts were reported for the closest school, Rosie the Riveter Charter High School, located on the AES Alamitos site (971 ft. to CCGT-1). The school was evaluated with residential exposure assumptions.
Update: The school is no longer on site, and the building has been repurposed for AES use. The distance from the next closest school, Kettering Elementary School, 550 Silvera Avenue, Long Beach, CA 90803, to CCGT-1 is 2021 feet. Therefore, the health risk impacts provided for the school receptor type, based on the location of the Rosie the Riveter school, are very conservative.

2 Work health risk impacts were evaluated at the maximum impacted receptor at or beyond the facility fenceline.

3 Cancer burden is based on a Zone of Impact (ZOI) radius of 1,135 meters, a ZOI area of 4.045 km2, a default population density of 7,000 persons per km2, and a facility-wide 70-year residential cancer risk of 2.0 in one million.

- Best Available Control Technology For Toxics (T-BACT) for Combustion Turbines
  The MICR limit is ten in one million for each combined- and simple-cycle turbine because T-BACT for combustion turbines is determined to be an oxidation catalyst.

  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 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. EPA identified stationary combustion turbines as major sources of hazardous air pollutants emissions, such as formaldehyde, toluene, benzene, and acetaldehyde.

Subpart YYYY requires an affected new or reconstructed stationary combustion turbine to comply with the emission limitation to reduce the concentration of formaldehyde in the exhaust to 91 parts per billion by volume (ppbvd) or less, at 15 percent O_2. The affected turbines are lean premix gas-fired, lean premix oil-fired, diffusion flame gas-fired, and diffusion flame oil-fired stationary combustion turbines. The oil-fired stationary combustion turbines must comply with the emissions limitations and operating limitations upon startup. The gas-fired stationary combustion turbines must comply with the Initial Notification requirements set forth in §63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance. Subpart YYYY was amended on August 18, 2004 (69 FR 51184) to stay the effectiveness of the standards in the lean premix gas-fired and diffusion flame subcategories, because, on April 7, 2004, EPA had proposed to delist four subcategories, including lean premix gas-fired turbines, from the Stationary Combustion Turbines source category (69 FR 18327). The delisting process remains pending.

EPA explained that, for new sources, the MACT floor is defined as the emission control that is achieved in practice by the best controlled similar source. (69 FR 10530) EPA considered using a surrogate for all organic HAP emissions in order to reduce the costs associated with monitoring while at the same time being relatively sure that the pollutants the surrogate is supposed to represent are also controlled. They 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 AEC, 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 combined- and simple-cycle turbines because AEC will not be a major source for HAP emissions.

REGULATION XVII – PREVENTION OF SIGNIFICANT DETERIORATION

*For the **Application**, the PSD analysis for the FDOC is revised below to incorporate the revised AEC potential to emit resulting from the revised annual operating schedule for the turbines.*

The federal Prevention of Significant Deterioration (PSD) has been established to protect deterioration of air quality in those areas that already meet the primary NAAQS. This regulation sets forth preconstruction review requirements for stationary sources to ensure that air quality in clean air areas do not significantly deteriorate while maintaining a margin for future industrial growth. Specifically, the PSD program establishes allowable concentration increases for attainment pollutants due to new or modified emission sources that are classified as major stationary sources.

Effective upon delegation by EPA, this regulation shall apply to preconstruction review of stationary sources that emit attainment air contaminants. On 3/3/03, EPA rescinded its delegation of authority to the South Coast AQMD. On 7/25/07, the EPA and South Coast AQMD signed a new "Partial PSD Delegation Agreement." The agreement is intended to delegate the authority and responsibility to the South Coast AQMD 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 South Coast AQMD Regulation XVII. The Partial Delegation agreement did not delegate authority and responsibility to South Coast AQMD 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 South Coast AQMD in accordance with the current requirements of Regulation XVII. AES has opted to apply to the South Coast AQMD.

The SCAB has been in attainment for NO_2, SO_2, and CO emissions. In addition, effective 7/26/13, the SCAB has been redesignated to attainment for the 24-hour PM_{10} national ambient air quality standard. Therefore, this regulation applies to these emissions.

- ***<u>RULES 1701, 1702, 1706--PSD APPLICABILITY</u>***

  The relevant PSD applicability rule sections are presented below, followed by the applicability analysis.

  <u>Rule 1701(b) Applicability</u>

  Effective upon delegation by EPA, this regulation shall apply to preconstruction review of stationary sources that emit attainment air contaminants.

  - ***Rule 1701(b)(1)*** provides: The BACT requirement applies to a net emission increase of a criteria air contaminant from a permit unit at any stationary source.

  - ***Rule 1701(b)(2)*** provides:
    All of the requirements of this regulation apply, except as exempted in Rule 1704, to the following stationary sources:

    (A) A new source or modification at an existing source where the increase in potential to emit is at least 100 or 250 tons of attainment air contaminants per year, depending on the source category; or

    (B) A significant emission increase at an existing major stationary source; or

    (C) Any net emission increase at a major stationary source located within 10 km of a Class I area, if the emission increase would impact the Class I area by 1.0 $\mu g/m^3$, (24-hours average).

  - ***Rule 1702*** provides definitions.

    (e) Best Available Control Technology (BACT) means the most stringent emission limitation or control technique which:

    (1) has been achieved in practice for such permit unit category or class of source. For permit units not located at a major stationary source, a specific limitation or control technique shall not apply if the owner or operator of the proposed sources demonstrates to the satisfaction of the Executive Officer

that such limitation or control technique is not attainable for that permit unit; or

(2) is contained in any State Implementation Plan (SIP) approved by the Environmental Protection Agency (EPA) for such permit unit category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer that such limitation or control technique is not presently achievable; or

(3) is any other emission control technique, including process and equipment changes of basic and control equipment, found by the Executive Officer to be technologically feasible and cost-effective for such class or category of sources or for a specific source….

(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.

(s) Significant Emission Increase means any attainment air contaminant for which the net cumulative emission increase of that air contaminant from a major stationary source is greater than the amount specified as follows:

Contaminant	Emissions Rate (tpy)
Carbon Monoxide	100
Sulfur Dioxide	40
Nitrogen Oxides	40
PM_{10}	15

- ***Rule 1706*** shall be used as the basis for calculating applicability for Regulation XVII as delineated in Rule 1703(a). **Rule 1706(c)** provides the emissions calculation methodology for determining a net emission increase.

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

(1)(B) The emissions for removal from service shall be calculated from:

(i) the sum of actual emissions, as determined from company records, which have occurred during the two-year period immediately preceding date of permit application, or a different two year time period within the past five (5) years upon a determination by the Executive Officer that it is more representative of normal source operation, except annual emission declarations pursuant to Rule 301 may be used if less than the actual emissions as determined above; and

(ii) the total emissions in those two years shall be calculated on an annual basis.

PSD Applicability Analysis:

The South Coast AQMD is presently in attainment for the primary NAAQS for NOx, CO, SOx, and PM_{10}. For proposed modifications at existing major sources, PSD applies to each regulated pollutant for which the proposed emissions increase resulting from the modification both is significant and results in a significant net emissions increase.

For the **FDOC**, the following table summarizes the Rule 1701(b)(2)(A) and (B) analysis to determine which pollutants are subject to PSD review for requirements other than BACT, such as modeling. Rules 1701(b)(1) and 1703(a)(2) require BACT for all permit units with a net emission increase of a criteria air contaminant. Rule 1701(b)(2)(C) is not applicable because the AEC is not located within 10 km of a Class I area. The nearest Class I area, San Gabriel Wilderness, is located 53 km away.

For the **Application**, this analysis continued to be for a new source because the applications were submitted on 2/8/19 and this analysis was initially drafted prior to the facility becoming an existing source. FDOC Table 67 is revised below to incorporate the revised AEC potential to emit resulting from the revised annual operating schedule for the turbines. "Actual Emissions (2013 & 2014 Avg)" remains applicable as the "emissions for removal from service" because the initial applications for the AEC were submitted in 10/13/15.

Table 71 – Prevention of Significant Deterioration Applicability

	CO	NOx	SO_2	PM_{10}
Alamitos Generating Station Potential to Emit, TPY (*Table 13*)	21,871.86	635.6	49.56	627.0
Major Source?	Yes, PTE is 100 tpy or more for CO, NOx, and PM_{10}. If a source is a major source for any one regulated pollutant, it is considered to be a major source for all regulated pollutants.			
Alamitos Generating Station (AGS) Actual Emissions (2013 & 2014 Avg), TPY (*Table 14*)	287.90	47.47	4.68	10.91

	CO	NOx	SO_2	PM_{10}
Alamitos Energy Center (AEC) Potential to Emit, TPY = Emissions Increase (*Table 45*)	~~243.62~~ **247.40**	~~137.06~~ **146.78**	~~10.19~~ **11.83**	69.52
Does the AEC result in a significant emissions increase?	Yes, increase is greater than 100 tpy.	Yes, increase is greater than 40 tpy.	No, increase is less than 40 tpy.	Yes, increase is greater than 15 tpy.
Net Emissions Increase (AEC PTE – AGS actual)	- ~~44.28~~ **- 40.5**	~~89.59~~ **99.31**	~~5.51~~ **7.15**	58.61
Does the AEC result in a net significant emissions increase?	No, there is a net decrease.	Yes, net increase is greater than 40 tpy.	No, net increase is less than 40 tpy.	Yes, net increase is greater than 15 tpy.
PSD Applicable?	No	Yes	No	Yes

As revised Table 71 shows, the PSD applicability for the ***Application*** *is the same as for the FDOC.*

Because the AGS is a fossil fuel-fired steam electric plant of more than 250 million BTU/hr input, the major source threshold for the facility is 100 tons per year. The AGS is an existing major stationary source as defined by Rule 1702(m)(1) because the potentials to emit for CO, NOx, and PM_{10} emissions all are 100 tpy or more. If a source is a major source for any one regulated pollutant, it is considered to be a major source for all regulated pollutants. The AEC will result in significant emissions increases for CO, NOx, and PM_{10}, but not SO_2. The AEC will result in net significant increases for NOx and PM_{10}, but not CO and SO_2. Therefore, CO is not subject to PSD requirements other than BACT, because the increase is significant but the net increase is a net decrease. SO_2 is not subject to PSD requirements other than BACT, because both the increase and net increase are less than the significant emissions threshold. **NOx and PM_{10} are subject to PSD review** for all PSD requirements because the emissions increases and net emissions increases for both constitute significant increases. For completeness, the following PSD review will include CO.

- ***RULE 1703—PSD REQUIREMENTS***
  The relevant PSD requirement sections are presented below, followed by the requirements analysis for each section. As determined above, the pollutants subject to PSD review for all PSD requirements are NOx and PM_{10}. For completeness, CO is only subject to BACT, but will be included in the following PSD review for all PSD requirements.

(a)(2) Each permit unit is constructed using BACT for each criteria air contaminant for which there is a net emission increase;

(a)(3) For each significant emission increase of an attainment air contaminant at a major stationary source:

(A) The applicant certifies in writing, prior to the issuance of the permit, that the subject stationary source shall meet all applicable limitations and standards under the Clean Air Act (42 U.S.C. 7401, et seq.) and all applicable emission limitations and standards which are part of the State Implementation Plan approved by the Environmental Protection Agency or is on a compliance schedule approved by appropriate federal, state, or District officials.

(B) The new source or modification will be constructed using BACT.

(C) The applicant has substantiated by modeling that the proposed source or modification, in conjunction with all other applicable emission increases or reductions (including secondary emissions) affecting the impact area, will not cause or contribute to a violation of:

(i) Any National or State Ambient Air Quality Standard in any air quality control region; or

(ii) Any applicable maximum allowable increase over the baseline concentration in any area.

(D) The applicant conducts an analysis of the ambient air quality in the impact area the new or modified stationary source would affect…. The applicant may rely on existing continuous monitoring data collected by the District if approved by the Executive Office…;

(E) The applicant provides an analysis of the impairment to visibility, soil, and vegetation that would occur as a result of the new or modified stationary source and the air quality impact projected for the baseline area as a result of general commercial, residential, industrial, and other growth associated with the source;

(F) The Executive Officer provides a copy of the complete application (within 10 days after being deemed complete by the District) to the EPA, the Federal Land Manager for any Class I area located within 100 km of the source, and to the federal official charged with direct responsibility for management of any lands within the Class I area….

<u>PSD REQUIREMENTS ANALYSES</u>:

1. *<u>Rule 1703(a)(2) & Rule 1703(a)(3)(B) Analysis—Top-Down BACT</u>*

Each permit unit is required to be constructed using BACT for each criteria air contaminant for which there is a net emission increase.

BACT 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 outlines 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 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. EPA has broken down this analytical process into the following five steps.

Step 1: Identify all available control technologies.
Step 2: Eliminate technically infeasible options.
Step 3: Rank remaining control technologies.
Step 4: Evaluate most effective controls and document results.
Step 5: Select the BACT.

As required by Rules 1701(b)(1) and 1703(a)(2), top-down BACT analyses are presented below for NOx, PM_{10}, and CO.

A. <u>Top-Down BACT Analysis for Combined-Cycle Gas Turbines and Simple-Cycle Gas Turbines for Nitrogen Oxide (NOx) Emissions</u>

- **<u>FDOC Summary</u>**

  <u>Combined-Cycle Turbines (Phase I)</u>

  Based on a review of the available control technologies for NOx emissions from natural gas-fired combined-cycle turbines, the conclusion is that BACT is the use of dry low-NOx combustors with SCR to control NOx emissions to 2.0 ppmvd (1-hour average) during normal operation.

Simple-Cycle Turbines (Phase II)
Based on a review of the available control technologies for NOx emissions from natural gas-fired simple-cycle turbines, the conclusion is that BACT is the use of dry low-NOx combustors with SCR to control NOx emissions to 2.5 ppmvd (1-hour average) during normal operation.

- **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
  Combined-Cycle Turbines (Phase I)
  Table 18 - Combined-Cycle Turbine Maximum Daily Emissions shows that the maximum daily emissions will not increase for NOx. Further, there will be no changes to the commissioning duration and emissions. As daily emissions will not increase, a PSD BACT analysis is not required pursuant to the South Coast AQMD applicability threshold of 1 lb/day increase.

  Simple-Cycle Turbines (Phase II)
  Table 34 - Simple-Cycle Turbine Maximum Daily Emissions shows that the maximum daily emissions will not increase for NOx. Further, there will be no changes to the commissioning duration and emissions. As daily emissions will not increase, a PSD BACT analysis is not required pursuant to the South Coast AQMD applicability threshold of 1 lb/day increase.

  However, *Rule 1714(c)* incorporates by reference the provisions of *40 Part 52.21--Prevention of Significant Deterioration of Air Quality*. §52.21(j)(4) states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." Accordingly, Condition E74.1 implements the requirements of §52.21(j)(4).

  - **PSD BACT Determination Review**:
    The PSD BACT determination for Phase II required by condition E74.1 indicates that BACT has not changed from the FDOC.

    Pending: The South Coast AQMD BACT Team, however, is in the process of evaluating whether BACT for simple-cycle turbines will be lowered from the current 2.5 ppmvd NOx (1-hour average). If the BACT level is lowered to less than 2.5 ppmvd, then the PSD BACT determination for NOx for the AES simple-cycle turbines (Phase II) will be re-evaluated at that time.

B. ***Top-Down BACT Analysis for Combined-Cycle Gas Turbines and Simple-Cycle Gas Turbines for Particulate Matter (PM_{10}) Emissions***

- **FDOC Summary**

  Combined-Cycle Turbines (Phase I)
  Based on the top-down review, the BACT for PM_{10} emissions is using pipeline-quality natural gas with low sulfur content, good combustion practice, and inlet air filtration for the turbines.

  Simple-Cycle Turbines (Phase II)
  BACT for PM_{10} is the same as for combined-cycle turbines.

- **Application (A/N 604015, 604018, *604020, 608431-608433, 610354-610360)***

  Combined-Cycle Turbines (Phase I) and Simple-Cycle Turbines (Phase II)
  Table 18 show the maximum daily emissions will not increase for PM_{10}. As daily emissions will not increase, a PSD BACT analysis is not required pursuant to the South Coast AQMD applicability threshold of 1 lb/day increase.

  Simple-Cycle Turbines (Phase II)
  Table 34 - Simple-Cycle Turbine Maximum Daily Emissions shows that the maximum daily emissions will not increase for PM_{10}.

  The PSD BACT determination for Phase II required by condition E74.1 indicates that BACT has not changed from the FDOC.

C. ***Top-Down BACT Analysis for Combined-Cycle Gas Turbines and Simple-Cycle Turbines for Carbon Monoxide (CO) Emissions***

- **FDOC Summary**

  Combined-Cycle Turbines (Phase I)
  Based on a review of the available control technologies for CO emissions from natural gas-fired combined-cycle turbines, the conclusion is that BACT is using good combustion practice and oxidation catalyst to control CO emissions to 1.5 ppm (1-hour average) during normal operation.

  Simple-Cycle Turbines (Phase II)
  Based on a review of the available control technologies for CO emissions from natural gas-fired simple-cycle turbines, the conclusion is that BACT is using good combustion practice and oxidation catalyst to control CO emissions to 2.0 ppm (1-hour average) during normal operation.

- **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
  Combined-Cycle Turbines (Phase I)
  Table 18 - Combined-Cycle Turbine Maximum Daily Emissions shows that the maximum daily emissions will not increase for CO. Further, there will be no changes to the commissioning duration and emissions. As daily emissions will not increase, a PSD BACT analysis is not required pursuant to the South Coast AQMD applicability threshold of 1 lb/day increase.

  Simple-Cycle Turbines (Phase II)
  Table 34 - Simple-Cycle Turbine Maximum Daily Emissions shows that the maximum daily emissions will not increase for CO.

  The PSD BACT determination for Phase II required by condition E74.1 indicates that BACT has not changed from the FDOC.

2. ***Rule 1703(a)(3)(A) Analysis—Certification of Compliance***
   For each significant emission increase of an attainment air contaminant at a major stationary source, the applicant is required to provide a certification of compliance. In a letter dated 8/14/19, Weikko Wirta, Director Plant Operations, AES Alamitos, LLC, certified that he, as a corporate officer and Director of Plant Operations of AES Alamitos, LLC, AES Redondo Beach, LLC, and AES Huntington Beach, LLC certify that all major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by AES in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance for all applicable emission limitations and standards under the Clean Air Act.

   See ***Rule 1303(b)(5)(B) – Statewide Compliance*** and ***Rule 2005(g)(1) – Statewide Compliance*** analysis above.

3. ***Rule 1703(a)(3)(F) Analysis—Copy of Application to EPA, Federal Land Manager, Forest Service***
   For the **FDOC**, as required for each significant emission increase of an attainment air contaminant, the South Coast AQMD mailed a copy of the original application package including the modeling CDs, submitted on 10/23/15, and subsequently a copy of the revisions to the original application package provided by AES on 3/30/16, to the National Park Service and the Forest Service. In an e-mail dated 5/6/16, Tonnie Cummings, National Park Service, indicated they agree the proposed controls represent BACT and do not anticipate the project would substantially affect any areas managed by National Park Service. Therefore, they have no need to provide further comments on the project. In an e-mail dated 8/4/16, Andrea Nick, Forest Service, indicated that after review of the project application package, she has no comments.

For the **Application**, the proposed changes to the annual operating hours for the combined-cycle and simple-cycle turbines constitute minor changes to the significant emission increases evaluated in the FDOC, which had already been reviewed by the National Park Service and the Forest Service. The revised modeling below confirms that (1) the facility-wide maximum predicted impacts for annual NO_2 and PM_{10} will remain below the respective Class II significant impact level (*Table 82*), (2) the facility-wide maximum predicted impacts for annual NO_2 and PM_{10} at 50 km will remain below the respective Class I significant impact levels (*Table 84*), and (3) the maximum predicted impact for annual NO_2 and background concentration will remain below the federal secondary NAAQS (*Table 85).*

4. ***Rule 1703(a)(3)(D), (a)(3)(C), (a)(3)(E) Analysis—Air Impacts***

The air impacts analysis, including modeling, were performed for CO, NO_2 and PM_{10}, as follows.

A. Rule 1703(a)(3)(D)--Pre-Construction Monitoring

- **FDOC Summary**

To ensure that the impacts from AEC will not cause or contribute to a violation of an ambient air quality standard or an exceedance of a PSD increment, an analysis of the existing air quality in the project area is necessary. Preconstruction ambient air quality monitoring data is required for the purposes of establishing background pollutant concentrations in the impact area (40 CFR 52.21(m)). However, a facility may be exempted from this requirement if the predicted air quality impacts are less than the significant monitoring concentrations.

Table 81 –Significant Monitoring Concentrations Compared to Maximum Predicted Impacts

Pollutant (Averaging Period)	Significant Monitoring Concentration (µg/m^3)	AEC Maximum Predicted Impact (µg/m^3) (FDOC *Table 57*)	Exempt?
NO_2 (1-hour)	N/A	N/A	N/A
NO_2 (annual)	14	0.20	Yes
CO (1-hour)	N/A	N/A	N/A
CO (8-hour)	575	44	Yes
PM_{10} (24-hour)	10	1.71	Yes
PM_{10} (annual)	N/A	N/A	N/A

For the **FDOC**, since the modeled impacts for NO_2, CO, and PM_{10} are below the respective monitoring thresholds, the project is exempt from the pre-construction monitoring requirement. Consequently, AES may rely on air quality monitoring data collected at South Coast AQMD monitoring stations. AES had proposed the use of the three most recent years of background CO and annual NO_2 data from the North Long Beach monitoring station (South Coastal Los Angeles County 1), and the three most recent years of background PM_{10} data from the South Long Beach monitoring station (South Coastal Los Angeles County 2) for background concentrations. PRDAS staff informed the applicant's consultant that their proposed background concentrations reflected the 2009-2013 period but were required to be updated to include the background concentrations for 2014. In its review, PRDAS staff used the monitoring data for South Coastal Los Angeles County monitoring stations (SRA No. 4) for the last three years (2012-2014) to determine the background concentrations. The modeling review memo, dated 5/20/16, incorporated these updated background concentrations.

- **<u>Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)</u>**
  The *PRDAS Memo* indicated that the applicant used the monitoring data from SRA 4, South Coastal Los Angeles County No. 3 monitoring station for the last three years (2014-2016) to determine the NO_2 background concentration. Years 2014-2016 are acceptable because 2017 data were not posted by the South Coast AQMD until the end of January 2019, immediately prior to the submittal of the applications for the turbine annual emissions changes. Further, the 2014-2016 data are more conservative than for the years 2015-2017.

B. ***<u>Rule 1703(a)(3)(C)—Air Quality Impacts Analysis</u>***

(1) <u>National and State Ambient Air Quality Standards</u>

- **<u>FDOC Summary</u>**
  As discussed under the Rule 1303(b)(1) and Rule 2005(c)(1)(B) modeling analyses above and the Rule 1703(a)(3)(C) PSD modeling analysis below, dispersion modeling demonstrates that CO, NO_2 and PM_{10} will be in compliance with the primary NAAQS and the CAAQS.

- **<u>Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)</u>**
  The revised dispersion modeling demonstrates that CO, NO_2 and PM_{10} will continue to be in compliance with the primary NAAQS and the CAAQS.

(2) <u>Class II PSD Increment</u>

- ***<u>Significance Impact Levels (SILs)</u>***
  A SIL is the ambient concentration resulting from the facility's emissions, for a given pollutant and averaging period, below which the source is considered to have an insignificant impact. If a significance impact level (SIL) is exceeded, an analysis is required to demonstrate that the maximum allowable increment will not be exceeded.

For CO, the SIL is 2000 μg/m^3 (1-hr) and 500 μg/m^3 (8-hr). For NO_2, the SIL is 1.0 μg/m^3 (annual). For PM_{10}, the SIL is 5.0 μg/m^3 ((24-hr) and 1.0 μg/m^3 (annual). For NO_2 (1-hr), the interim/proposed SIL is 7.52 μg/m^3, as recommended in "Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program" (EPA, 2010).

- ***Class II Increment Analysis***
  40 CFR 52.21(e) provides that international parks, national wilderness areas exceeding 5000 acres, national memorial parks exceeding 5000 acres, and national parks exceeding 6000 acres are designated as Class I areas. All other areas are designated as Class II areas. The AEC is located in a Class II area. 40 CFR 52.21(c) sets forth the increment standards for Class I, Class II, and Class III areas. The increments are the maximum increases in pollutant concentration that are allowed to occur above the baseline concentration.

  - **FDOC Summary**
    As shown in FDOC *Table 82 - Maximum Modeled Project Impacts Compared to Class II SILs and PSD Increment Standards*, the maximum predicted impacts for annual NO_2, 1-hr and 8-hr CO, and 24-hr and annual PM_{10} were below the respective Class II SILs. Therefore, these impacts were less than significant, and no additional PSD analysis was required. Although further analysis to demonstrate compliance with the increment standard was not required, the table included the increment standard comparison for informational purposes.

    The maximum predicted 1-hour NO_2 impact of 31.3 μg/m^3, however, exceeded the Class II SIL of 7.52 μg/m^3, with a radius of impact with predicted concentrations greater than 7.52 μg/m^3 of 1.5 km. Thus the cumulative impacts of the AEC and competing sources were required to be assessed for all receptors where the AEC impacts alone exceeded the 1-hour NO_2 SIL.

    Accordingly, the **FDOC** provided an analysis for the *Cumulative Impacts of the AEC and Nearby Sources*. As shown in FDOC *Table 83 - Competing Sources Results,* the 1-hour NO_2 impact from the project plus cumulative projects plus background is 251.3 μg/m^3, which exceeded the 1-hour NO_2 NAAQS of 188 μg/m^3. An examination of each facility's contributions to the modeled exceedances showed that Alamitos' maximum contributions to the modeled exceedances was 6.9

μg/m^3, which was less than the 1-hour NO_2 SIL of 7.52 μg/m^3. Therefore, Alamitos' impacts were less than significant and did not cause or contribute to the modeled exceedance.

- **<u>Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)</u>**
  - **<u>Yorke Protocol, 11/7/18, and South Coast AQMD Comments on Yorke Protocol, 12/20/18</u>**

    The **Yorke Protocol** indicated that, for compliance with Rule 1703 PSD, annual NO_2 modeling and annual PM_{10} modeling will be conducted for the entire facility (2 CCGTs, 4 SCGTs and auxiliary boiler) for comparison to the SIL [to update FDOC *Table 82 - Maximum Modeled Project Impacts Compared to Class II SILs and PSD Increment Standards]*.

    South Coast AQMD Comments responded that, for FDOC *Table 82 – Maximum Modeled Project Impacts Compared to Class II SILs and PSD Increment Standards*, the South Coast AQMD agreed with the **Yorke Protocol** that re-modeling for NO_2 and PM_{10} based on the total emissions from each turbine and the auxiliary boiler for the annual averaging period is required.

  On p. 24 of the Yorke *Applications for Modification*, *Table 4-6: Total Facility Model-Predicted Impacts Compared to Class II SILs and PSD Increments* presents the modeling results for the entire facility (two combined-cycle turbines, four simple-cycle turbines, and the auxiliary boiler) for comparison to the Class II Significant Impact Levels (SILs) to update *Table 82*.

  The *PRDAS Memo* stated the applicant conservatively used the maximum modeled concentrations of NO_2 and PM_{10} for Rule 1303, as set forth in updated *Table 57* above. PRDAS staff has independently reproduced the applicant's analysis and summarized the results in the *PRDAS Memo*. FDOC *Table 82* is updated below to incorporate PRDAS' modeling results for the Application.

Table 82 – Maximum Modeled Project Impacts Compared to Class II SILs and PSD Increment Standards

Pollutant	Averaging Time	AEC Maximum Predicted Impact [2] (μg/m³) *(Table 57)*	Class II Significant Impact Level (μg/m³)	Significant?	PSD Class II Increment Standard (μg/m³)	Exceeds Class II SIL?
NO_2 [1]	Annual	~~0.2~~ **0.4**	1.0	No	25	No
PM_{10}	Annual	~~0.2~~ **0.3**	1.0	No	17	No

[1] The NO_2 concentration included conversion of NOx to NO_2 using ARM2.
[2] Maximum modeled concentrations are predicted at the maximum receptor at or beyond the facility fenceline.

As shown in the table above, the maximum predicted impacts for annual NO_2 and annual PM_{10} are less than the respective Class II SILs. Therefore, these impacts are less than significant, and no additional PSD analysis is required. Although further analysis to demonstrate compliance with the increment standard is not required, the table includes the increment standard comparison for informational purposes.

(3) Class I Area Impact Analysis

A Class I impact analysis is required to demonstrate that the AEC will not adversely affect air quality-related values (AQRVs) and will not cause or contribute to an exceedance of the Class I Significant Impact Level (SIL) or PSD Class I Increment Standards.

- ***Air Quality Related Values***

  To evaluate the potential impacts on visibility and deposition at the nearest Class I area, the guidance provided in the Federal Land Manager's Air Quality Related Values Workgroup (FLAG) Phase I Report (revised 2010) allows an emissions/distance (Q/D) factor of 10 to be used as a screening criteria for sources located more than 50 km from a Class I area. This screening criterion includes all AQRVs. AQRVs are defined by the Federal Land Manager (FLM), and typically limit visibility degradation and the deposition of sulfuric acid and nitrogen. Emissions are calculated as the total SO_2, NO_x, PM_{10}, and sulfuric acid annual emissions (in tpy, based on 24-hour maximum allowable emissions multiplied by 365 days) unless an emission source is limited to time periods shorter than 1 year.

  - **FDOC Summary**

    Condition nos. A63.2, A63.3, and A63.4 provide annual emissions limits for PM_{10} and SO_2, for combined-cycle turbines, simple-cycle turbines, and the auxiliary boiler, respectively. These limits also indirectly limit the NOx emissions from the respective equipment.

On an annual equivalent basis, the combined AEC annual emissions of NOx (354.11 tpy), PM (184.36 tpy), SO_2 (23.74 tpy), and sulfuric acid (0 tpy) will be approximately 562.21 tpy. Therefore, the maximum Q/D for the project will be approximately 10.60 ton/km-year, where Q is 562.21 tpy and D is 53 km, the distance to the nearest Class I area, San Gabriel Wilderness.

Because the factor is greater than the federal Class I area air quality screening criteria of 10, visibility and deposition modeling is required for all Class I areas which exceed the screening criteria and any additional Class I areas requested by the FLM.

AES' consultant, CH_2M Hill, submitted the protocol and modeling for the AQRV directly to the appropriate FLM for review and approval. The FLM did not include the South Coast AQMD in its review.

- **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
  - **Yorke Protocol, 11/7/18, and South Coast AQMD Comments on Yorke Protocol, 12/20/18**

    The **Yorke Protocol** indicated that, other than annual modeling to update *Table 82*, as discussed above, no other PSD analyses, such as Class I SIL or AQRV analyses, will be conducted since the modeling for the FDOC applications predicted facility-related annual NO_2 and PM_{10} concentrations that were well below the appropriate thresholds. For the operating hour changes, the NOx annual emission increase is minimal, plus there is no annual PM_{10} increase.

    South Coast AQMD Comments did not comment on the AQRV analysis because, for the **FDOC**, the FLM did not include the South Coast AQMD in its review.

    The *Petition for Post-Certification Amendment* was subsequently prepared and submitted to the CEC by CH_2M Hill, the same consultant that had prepared the AQRV modeling for the FDOC. The *Petition* did not indicate a need for an updated AQRV analysis.

- ***Class I Increment Analysis***

  EPA requires an analysis addressing Class I increment impacts for the applicable pollutants regardless of the results of the Class I AQRV analysis.

- **FDOC Summary**
  To evaluate the potential impacts on Class I areas near the AEC site, all Class I areas within 300 km of AEC were identified. Based on this survey, the San Gabriel Wilderness, which is approximately 53 km from the AEC site, was identified as the nearest Class I area.

  For FDOC *Table 84 – Maximum Modeled Impacts Compared to Class I SILs*, the applicant performed an analysis by placing a radial receptor ring at a distance of 50 km from the project because 50 km is the maximum receptor distance of the AERMOD model. The predicted impacts from the operation of the AEC were below the SIL, therefore comparison with the increment standard was not required. Since the impact at 50 km is below the SIL, the project would have a negligible impact at the more distant Class I areas and actual ambient air quality impacts at Class I areas are not required to be determined.

- **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
  - **Yorke Protocol, 11/7/18, and South Coast AQMD Comments on Yorke Protocol, 12/20/18**
    The **Yorke Protocol** indicated that, other than annual modeling to update *Table 82*, as discussed above, no other PSD analyses, such as Class I SIL or AQRV analyses, will be conducted since the modeling for the FDOC applications predicted facility-related annual NO_2 and PM_{10} concentrations that were well below the appropriate thresholds. For the operating hour changes, the NOx annual emission increase is minimal, plus there is no annual PM_{10} increase.

    South Coast AQMD Comments requested re-modeling for the NO_2 and PM_{10} for the annual averaging period, using the ARM2 method to update FDOC *Table 84 – Maximum Modeled Impacts Compared to Class I SILs*.

  In response, on p. 24 of the Yorke *Applications for Modification*, *Table 4-7: Total Facility Model-Predicted Impacts Compared to Class I SILs* presents the modeling results for the entire facility (two combined-cycle turbines, four simple-cycle turbines, and the auxiliary boiler) for comparison to the Class I Significant Impact Levels (SILs).

PRDAS staff has independently reproduced the applicant's analysis and summarized the results in the *PRDAS Memo*. FDOC *Table 84* is updated below to incorporate PRDAS' modeling results for the Application.

Table 84 – Maximum Modeled Impacts Compared to Class I SILs

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)[2]	Class I Significance Impact Level ($\mu g/m^3$)	Exceeds Class I SIL?
NO_2 [1]	Annual	~~0.0047~~ **0.007**	0.1	No
PM_{10}	Annual	~~0.0046~~ **0.005**	0.2	No

[1] The NO_2 concentration included conversion of NOx to NO_2 using ARM2.
[2] Maximum modeled concentrations are predicted at 50 km from the facility.

As shown in the table above, the maximum predicted impacts for annual NO_2 and annual PM_{10} are less than the respective Class I SILs. Therefore, these impacts are less than significant, and no additional PSD analysis is required.

C. Rule 1703(a)(3)(E)—Additional Impacts: Visibility, Soil and Vegetation Impacts as Result of Growth

In addition to assessing the ambient air quality impacts expected for a proposed new source, the PSD regulations require the evaluation of other potential impacts on (1) growth, (2) soils and vegetation, and (3) visibility impairment. The depth of the analysis generally depends on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area.

(1) Growth

For the **Application,** the changes in annual operating hours for the turbines are not expected to affect the analysis in the FDOC.

(2) Soil and Vegetation Impacts

The additional impact analysis includes consideration of potential impacts to soils and vegetation associated with AEC.

- ***Nitrogen Deposition Impacts***
  For the **Application,** the changes in annual operating hours for the turbines are not expected to affect the analysis in the FDOC.

- ***Secondary NAAQS***

For most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS will not result in harmful effects, because the secondary NAAQS levels are set to protect public welfare, including animals, plants, soils, and materials.

- **<u>FDOC Summary</u>**
  The dispersion modeling performed to demonstrate compliance with the primary NAAQS shown in *Table 57* also demonstrated that NO_2 will be in compliance with the secondary NAAQS, as shown in FDOC *Table 85 - Model Results – Normal Operation for AEC - Compliance with Secondary NAAQS.*

- **<u>Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)</u>**
  FDOC *Table 85* is updated below to incorporate the modeling results from *Table 57* which is updated above to incorporate PRDAS' modeling results for the Application. Annual NO_2 will continue to be in compliance with the secondary NAAQS.

Table 85 - Model Results – Normal Operation for AEC - Compliance with Secondary NAAQS

Pollutant	Averaging Period	Maximum Predicted Impact (µg/m³) *(Table 57)*	Background Concentration (µg/m³)[2]	Total Predicted Concentration (µg/m³)	Federal Secondary NAAQS (µg/m³) [1]	Exceeds Any Threshold?
NO_2	Annual	~~0.20~~ **<u>0.4</u>**	~~47.6~~ **<u>39.6</u>**	~~47.8~~ **<u>40.0</u>**	100	No

[1] Federal and secondary NAAQS for NO_2 are the same.

(3) ***<u>Visibility Impairment--Class II Area Analysis</u>***
For the **Application,** the changes in annual operating hours for the turbines are not expected to affect the analysis in the FDOC.

- ***<u>Rule 1710—Analysis, Notice, and Reporting, amended 1/6/89, 3/1/19</u>***
  40 CFR §52.21 provides comprehensive applicability procedures for PSD public noticing, as analyzed below.

  40 CFR §52.21—Prevention of significant deterioration of air quality
  (a)(2) Applicability procedures.
  (i) The requirements of this section apply to the construction of any new major stationary source (as defined in paragraph (b)(1) of this section) or any project at an existing major

stationary source in an area designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act.

(ii) The requirements of paragraphs (j) through (r) of this section apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as this section otherwise provides.

Analysis: As shown below, paragraph (q) requires public participation pursuant to the applicable procedures of 40 CFR part 124 in processing applications for the construction of any new major stationary source or the major modification of any existing major stationary source. *§124.10 Public notice of permit actions and public comment period* provides the most recent noticing requirements, amended on 2/12/19.

(b) *Definitions.* For the purposes of this section:
(1)(i) *Major stationary source* means: ….

Analysis: Pursuant to the "*PSD Applicability Analysis*" above, the new AEC is a new major stationary source.

(2)(i) Major modification means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(40) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(50) of this section); and a significant net emissions increase of that pollutant from the major stationary source.

(23)(i) Significant means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Pollutant and Emissions Rate
Carbon monoxide: 100 tons per year (tpy)
Nitrogen oxides: 40 tpy
Sulfur dioxide: 40 tpy
Particulate matter: 25 tpy of particulate matter emissions
PM10: 15 tpy
PM2.5: 10 tpy of direct PM2.5 emissions; 40 tpy of sulfur dioxide emissions; 40 tpy of nitrogen oxide emissions unless demonstrated not to be a PM2.5 precursor under paragraph (b)(50) of this section

(40) Significant emissions increase means, for a regulated NSR pollutant, an increase in emissions that is significant (as defined in paragraph (b)(23) of this section) for that pollutant.

Analysis: From *Table 71—Prevention of Significant Deterioration Applicability* above, the increases in CO, NOx, SO2, and PM10 emissions resulting from the **Application** are shown below.

CO: 247.40 tpy (Application) – 243.62 tpy (FDOC) = 3.78 tpy < 100 tpy major modification threshold

NOx: 146.78 tpy (Application) – 137.06 tpy (FDOC) = 9.72 tpy < 40 tpy major modification threshold

SO2: 11.83 tpy (Application) – 10.19 tpy (FDOC) = 1.64 tpy < 40 tpy major modification threshold

PM10: 69.52 tpy (Application) – 69.52 tpy (FDOC) = 0 tpy < 15 tpy major modification threshold.

Therefore, the **Application** emissions increases do not constitute a major modification of an existing major stationary source.

(q) *Public participation.* The administrator shall follow the applicable procedures of 40 CFR part 124 in processing applications under this section.

FDOC—PSD NOTICING SUMMARY

Public notice requirements were completed for South Coast AQMD Rules 212 (Standards for Approving Permits), 1710 (PSD Analysis, Notice, And Reporting), 1714 (PSD Greenhouse Gases) And 3006 (Title V). The summary below describes the completion of PSD public notice requirements for a new major stationary source that did not coincide with the public noticing requirements of one or more of the other rules.

- ***PSD Public Notice Requirements Completion—Original Noticing***
  The South Coast AQMD issued the Preliminary Determination of Compliance (PDOC) and proposed revised Title V permit for the AEC project on 6/30/16. The original public notice was published on 7/8/16. *Pursuant to 40 CFR §124.10—Public notice of permit actions and public comment period*, the public notice was e-mailed or mailed, as requested, to the EPA PSD Mailing List and the South Coast AQMD PSD Mailing List for a 30-day comment period.

- ***PSD Public Notice Requirements Completion--Re-noticing***

The South Coast AQMD reissued the PDOC and proposed Title V permit for renotice on 11/10/16. The renotice was to provide interested parties the opportunity to review the PDOC concurrently with the CEC's Preliminary Staff Assessment (PSA) which was made available by CEC on July 13, 2016. The second public notice was published on 11/17/16. The second public notice was e-mailed or mailed, as requested, to the EPA PSD Mailing List and the South Coast AQMD PSD Mailing List for a 30-day comment period.

- ***Permits to Construct Issuance***
On 4/18/17, the South Coast AQMD issued an *Announcement of Final Permit Decision of Issue a Clean Air Act Title V and Prevention of Significant Deterioration Permit for AES Alamitos Energy Center* to the EPA PSD Mailing List and the South Coast AQMD PSD Mailing List. The Announcement stated:

> The Title V and PSD Permit, the Final Determination of Compliance, and South Coast AQMD's responses to comments received are available on the South Coast AQMD website at the link provided.
>
> Pursuant to 40 C.F.R. Section 124.15(b)(l), this PSD Permit becomes **effective May 22, 2017**, unless a petition for review is filed with the Environmental Appeals Board (EAB), as described below, by that date pursuant to 40 C.F.R. Section 124.19. In the event that a petition for review is filed with the EAB, construction of the facility is not authorized under this permit until resolution of the EAB petition(s). See 40 CFR 124.16.
>
> Within 30 days after the service of notice announcing this final permit decision, any person who filed comments on the proposed permit for the AEC Project may petition U.S. Environmental Protection Agency's (EPA) Environmental Appeals Board (EAB) to review any condition of the final PSD permit. Persons who did not file comments or participate in the public hearings may petition for administrative review only to the extent of changes from the proposed to the final PSD permit decision. The petition must include a statement of the reason(s) for requesting review by the EAB, including a demonstration that any issues being raised were raised during the public comment period to the extent required by the regulations at 40 CFR Part 124 and when appropriate, a showing that the conditions in question are based on 1) a finding of fact or conclusion of law which is erroneous, or 2) an exercise of discretion or an important policy consideration which the EAB should, in its discretion, review.

As no petition was filed with the EPA's EAB, the Permits to Construct became effective on 5/22/17.

APPLICATION (A/N 604015, 604018, 604020, 608431-608433, 610354-610360) —PSD NOTICING SUMMARY

The PSD noticing requirements for a new major stationary source had been completed for the FDOC. As the Application emission increases do not constitute a major modification of an existing major stationary source, PSD noticing is not required. The Title V and PSD Permit issued for the Application will be posted on the South Coast AQMD website.

Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases, amended 3/1/19

Rule 1714 was adopted into the SIP on 12/10/12, and became effective on 1/9/13. Upon the effective date, the South Coast AQMD became the Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permitting authority for sources located within the South Coast AQMD. The rule was subsequently amended on 3/1/19 to update the public participation requirements to ensure federal permitting rules are followed for permitting actions.

The relevant rule sections 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 the U.S. EPA to mean the air pollutant as an aggregate group of six GHGs: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. 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.

(b) Applicability
The provisions of this rule shall apply to any source and the owner or operator of any source subject to any GHG requirements under 40 Code of Federal Regulations Section 52.21 as incorporated into this rule.

(c) Incorporation by Reference
Except as provided below, the provisions of Title 40 of the Code of Federal Regulations (CFR) Part 52.21, are incorporated herein by reference and made part of the Rules and Regulations of the South Coast Air Quality Management District…

(d) Requirements
(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.

(e) Public Participation

For major stationary sources subject to Rule 1714, after receipt of a complete application, the Executive officer shall: …

In May 2010, EPA issued the GHG permitting rule officially known as the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (GHG Tailoring Rule), in which EPA defined six GHG pollutants (collectively combined and measured as carbon dioxide equivalent [CO_2e]) 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, March 2011, provide applicability criteria. Under Tailoring Rule Step 2, the PSD Applicability Test for GHGs in PSD Permits Issued on or after July 1, 2011 indicates that PSD applies to the GHG emissions from a proposed modification to an existing source if any of three sets of applicability criteria are met. The set of applicability criteria applicable to the AEC is as follows:

- Modification is otherwise subject to PSD (for another regulated NSR pollutant), and has a GHG emissions increase and net emissions increase:
  - Equal to or greater than 75,000 TPY CO_2e, and
  - Greater than -0- TPY mass basis

In *Utility Air Regulatory Group v. EPA* (No. 12-1146), issued 6/23/14, the Supreme Court issued a decision addressing the application of stationary source permitting requirements to greenhouse gases (GHG). The Court said that EPA may not treat greenhouse gases 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 said that that the EPA could continue to require that PSD permits, otherwise required based on emissions of conventional pollutants, to contain limitations on GHG emissions based on the application of BACT.

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:
The PDOC analysis is updated for the ***Application****.*

As discussed under the Rule 1703 analysis above, the modification is otherwise subject to PSD for other regulated NSR pollutants, NOx and PM_{10}. The following table summarizes the analysis to determine whether GHG emissions are subject to PSD review.

Table 87 – Prevention of Significant Deterioration Applicability for Greenhouse Gases

	CO_2e
GHG Emissions Increase = Alamitos Energy Center Potential to Emit *(Table 45)*	~~1,716,925.57~~ **1,952,128.55** TPY > 75,000 TPY and > 0 TPY mass basis
Alamitos Generating Station Actual Emissions (2013 & 2014 Avg) *(Table 14)*	927,761 TPY
GHG Net Emissions Increase = AEC PTE – AGS actual	~~789,164.57~~ **1,024,367.55** TPY > 75,000 TPY and > 0 TPY mass basis
PSD for Greenhouse Gases Applicable?	Yes

The greenhouse gases are subject to PSD review because the emissions increase and net emissions increase constitute significant increases.

PSD REQUIREMENTS ANALYSES:

The "PSD and Title V Permitting Guidance for Greenhouse Gases" explains that under the Clean Air Act and applicable regulations, a PSD permit must contain emissions limitations based on application of BACT for each PSD regulated NSR pollutant. A determination of BACT for GHGs should be conducted in the same manner as it is done for any other PSD regulated pollutant. EPA recommends that permitting authorities continue to use the Agency's five-step "top down" BACT process to determine BACT for GHGs. No other PSD requirements were enumerated.

For criteria pollutants, PSD requirements include pre-construction ambient monitoring, air impacts analyses, and other impacts analysis, as discussed under Rule 1703. As there are currently no NAAQS, CAAQS, SILs or PSD increments standards established for GHGs, the air impacts analysis requirement is not applicable. Further, EPA does not require pre-construction monitoring for GHGs in accordance with 40 CFR 52.21(i)(5)(iii) and 51.166(i)(5)(iii), or Class I areas impact analysis.

Top-Down BACT Analysis

1. Top-Down BACT Analysis for Combined-Cycle Gas Turbine Power Block and Simple-Cycle Gas Turbine Block for Carbon Dioxide (CO_2) Emissions

The primary sources of GHG emissions will be the natural-gas-fired combined-cycle and simple-cycle combustion turbines. The primary combustion emission is CO_2, because the CH_4 and N_2O emissions are insignificant.

- **FDOC Summary**

  The FDOC concluded that thermal efficiency is the only technically and economically feasible alternative for CO_2/GHG emissions control for the AEC project. The current design of the facility meets the BACT requirement for GHG emission reductions.

BACT also requires applicable GHG emission limits, implemented by permit conditions, as follows.

Combined-Cycle Turbines
Condition E193.14 limits the CO2 emissions to 610,480 tpy per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO2 emissions is limited to 937.88 pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations below.

Simple-Cycle Turbines
Condition E193.15 limits the CO2 emissions to 120,765 tpy per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO2 emissions is limited to 1356.03 pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations above.

- **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
  Thermal efficiency continues to be the only technically and economically feasible alternative for CO_2/GHG emissions control for the AEC project.

  BACT also requires applicable GHG emission limits, implemented by permit conditions. For the **Application**, the revised limits are shown below.

  Combined-Cycle Turbines
  Condition E193.14 limits the CO2 emissions to ~~610,480~~ **861,119** tpy per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO2 emissions is limited to ~~937.88~~ **916.01** pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations for 40 CFR Subpart TTTT below.

  Simple-Cycle Turbines
  Condition E193.15 limits the CO2 emissions to ~~120,765~~ **54,185** tpy per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO2 emissions is limited to ~~1356.03~~ **1506.98** pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations for 40 CFR Subpart TTTT below.

2. ***Top-Down BACT Analysis for Combined-Cycle Gas Turbine Power Block and Simple-Cycle Gas Turbine Power Block for Sulfur Hexafluoride (SF_6) Emissions***

The only GHG emitted from circuit breakers is sulfur hexafluoride (SF_6). SF_6 is used as a gaseous dielectric medium in electrical circuit breakers, switching equipment, and other high voltage electrical components. The circuit breakers for the combined-cycle gas turbine power block and the simple-cycle gas turbine power block will have a potential for fugitive emissions of SF_6 through leaks.

- **<u>FDOC Summary</u>**
  The FDOC concluded that BACT for the circuit breakers is the use of enclosed-pressure SF_6 circuit breakers with a maximum annual leakage rate of 0.5% by weight and a 10% by weight leak detection system, and an annual emission cap. The BACT determination was in agreement with the EPA's determination for the Pio Pico Energy Center. The Pio Pico PSD permit included conditions requiring the installation of enclosed-pressure SF_6 circuit breakers with a maximum annual leakage rate of 0.5% by weight. The circuit breakers were required to be equipped with a 10% by weight leak detection system, which was required to be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and records of all calibrations were required to be maintained on site. The CO_2e emissions from the circuit breakers were subject to an annual emissions limit. The SF6 emissions due to leakage from the circuit breakers are required to be calculated by using the mass balance in equation DD-1 at 40 CFR Part 98, Subpart DD, on an annual basis.

  Facility condition F52.2 enforces the BACT requirements for circuit breakers, using the same language as in the Pio Pico PSD permit. Annual CO_2e emissions from circuit breakers are limited to 74.55 tons per calendar year. The maximum CO_2e emissions from the combined-cycle turbine power block are 17.44 tpy, and from the simple-cycle turbine power block are 57.11 tpy. The CO_2e emissions are from the GHG emissions calculations above.

- **<u>Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)</u>**
  For the **Application**, BACT for SF6 emissions is the same as for the FDOC. The changes in annual operating hours for the combined-cycle and simple-cycle turbines will not affect the SF6 leakage rate.

<u>Regulation XX—RECLAIM</u>

- ***<u>Rule 2002—Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx)</u>***
  (c)(2)(C) specifies the applicable starting emission factor is found in Table 1—RECLAIM NOx Emission Factor. For Major NOx Sources, these emission factors are required to be used until the CEMS is certified, not to exceed one year after start of unit operation.

  - Turbines
    From Rule 2002, Table 1:

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor*	2000 (Tier I) Ending Emission Factor
Turbines	Natural Gas	mmcf	RV	61.450

* RV = Reported Value

"Reported Value" means the emissions factors are required to be calculated. For turbines, two NOx emission factors are required for use in the interim reporting period before the CEMS is certified.

- **FDOC Summary**
  Combined-Cycle Turbines: Condition A99.1 specifies the interim emission factor for the commissioning period during which the CTGs are assumed to be operating at uncontrolled levels. From *Table 20* above, the emission factor is 16.66 lb/mmcf. Condition A99.2 specifies the interim emission factor for the normal operating period after commissioning has been completed and before the CEMS is certified, during which the CTGs are assumed to be operating at BACT levels. From *Table 22* above, the emission factor is 8.35 lb/mmcf.

  Simple-Cycle Turbines: Condition A99.3 specifies the interim emission factor for the commissioning period during which the CTGs are assumed to be operating at uncontrolled levels. From *Table 36* above, the emission factor is 25.24 lb/mmcf. Condition A99.4 specifies the interim emission factor for the normal operating period after commissioning has been completed and before the CEMS is certified, during which the CTGs are assumed to be operating at BACT levels. From *Table 38* above, the emission factor is 11.21 lb/mmcf.

  As Rule 2012(h)(6) provides the Facility Permit holder which installs a new major source at an existing facility shall install, operate, and maintain all required or elected monitoring, reporting, and recording systems no later than 12 months after the initial startup of the major NOx source, the use of these interim emission factors shall not exceed one year after start of unit operation.

- **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
  Combined-Cycle Turbines: Condition A99.1 interim emission factor remains the same as the FDOC because AES has not requested any change to the commissioning duration or emissions. Condition A99.2 interim emission factor remains the same as the FDOC because the emission factor is calculated as the maximum normal operating month emissions divided by the total fuel usage for the month, both of which will remain the same as for the FDOC.

  Simple-Cycle Turbines: Condition A99.3 interim emission factor remains the same as the FDOC because AES has not requested any change to the commissioning duration or emissions. Condition A99.4 interim emission factor remains the same as the FDOC because the emission factor is calculated as the maximum normal operating month emissions divided by the total fuel usage for the month, both of which will remain the same as for the FDOC.

- ***Rule 2005—New Source Review for RECLAIM***
  This rule sets forth pre-construction review requirements for modifications to RECLAIM facilities.

  - ***(c)(1)(A)--BACT***
    As NOx is a PSD pollutant, see the *Rule 1703(a)(2)—Top-Down BACT* analysis above for the PSD BACT determination for the combined-cycle and simple-cycle turbines.

  - ***(c)(1)(B)--Modeling***
    For existing RECLAIM facilities, the Executive Offer shall not approve an application for a Facility Permit Amendment to authorize the installation of a new source which results in an emission increase, unless the applicant demonstrates that the operation of the source will not result in a significant increase in the air quality concentration for NO_2 as specified in Appendix A of the rule. Rule 2000(c)(71) defines “source” as “any individual unit, piece of equipment or process which may emit an air contaminant and which is identified, or required to be identified, in the RECLAIM Facility Permit.” Therefore, modeling is required on a per permit unit basis. Rule 1304(a) provides an exemption from the modeling requirements of Rule 1303(b)(1), but not Rule 2005(c)(1)(B). (The standards in Appendix A are outdated. The modeling analysis below is based on current ambient air quality standards.)

    - **FDOC Summary**
      For the FDOC, the applicant indicated that although each combustion emission unit was modeled, the results provided were only for the emission unit causing the highest modeled concentrations, which is one combined-cycle turbine. The maximum operational impacts, including changes and updates provided by PRDAS staff, were presented in *Table 88 – Rule 2005 Modeled Results – Normal Operation for a Single Combined-Cycle Turbine* in the FDOC.

    - **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
      - **Yorke Protocol, 11/7/18, and South Coast AQMD Comments on Yorke Protocol, 12/20/18**
        The **Protocol** stated that annual NOx emissions will increase by approximately 10 tons/yr. For compliance with Rule 2005, annual NO2 modeling will be conducted per permit unit for comparison to the significant change threshold, and presented for the units with revised operating hours, i.e., each CCGT and SCGT.

        South Coast AQMD Comments agreed with the Protocol. Revised modeling results are required for each combined-cycle and simple-cycle turbine.

      P. 23 of the Yorke *Applications for Modification* provides *Table 4-4: Rule 2005 Modeled Results – Annual Operations for a Single CCGT* and *Table 4-5: Rule 2005 Modeled Results – Annual Operations for a Single SCGT*.

PRDAS staff has independently reproduced the applicant's analysis and summarized the results for each of the two combined-cycle turbines and each of the four simple-cycle turbines in the *PRDAS Memo*. FDOC *Table 88* is updated below to incorporate PRDAS's modeling results for the two combined-cycle turbines. *Table 88A* is added below to present PRDAS' modeling results for the four simple-cycle turbines. As shown in Tables 88 and 88A below, the NO_2 maximum modeled concentration per turbine, when added to the highest background value, are below the applicable ambient air quality standards.

Table 88 – Rule 2005 Modeled Results – Normal Operation for ~~a Single~~ Combined-Cycle Turbines

Pollutant	Averaging Period	Maximum Predicted Impact (µg/m³)	Background Concentration (µg/m³) [2]	Total Predicted Concentration (µg/m³)	State Standard CAAQS (µg/m³)	Federal Standard, Primary NAAQS (µg/m³)	Exceeds Threshold?
			CCGT-1				
NO_2 [1]	Annual	~~0.1~~ **0.2**	~~47.6~~ **39.6**	~~47.7~~ **39.8**	57	100	No
			CCGT-2				
NO_2 [1]	Annual	~~0.1~~ **0.2**	~~47.6~~ **39.6**	~~47.7~~ **39.8**	57	100	No

1 The NO_2 concentration included conversion of NO_x to NO_2 using ARM2.
2 Maximum value for NO_2 from SRA 4, South Coastal LA County 3 (No. 033) monitoring station for the last three years available prior to application submittal (2014-2016) was used.

Table 88A – Rule 2005 Modeled Results – Normal Operation for Simple-Cycle Turbines

Pollutant	Averaging Period	Maximum Predicted Impact (µg/m³)	Background Concentration (µg/m³) [2]	Total Predicted Concentration (µg/m³)	State Standard CAAQS (µg/m³)	Federal Standard, Primary NAAQS (µg/m³)	Exceeds Threshold?
			SCGT-1				
NO_2 [1]	Annual	**0.02**	**39.6**	**39.6**	57	100	No
			SCGT-2				
NO_2 [1]	Annual	**0.02**	**39.6**	**39.6**	57	100	No
			SCGT-3				
NO_2 [1]	Annual	**0.02**	**39.6**	**39.6**	57	100	No
			SCGT-4				
NO_2 [1]	Annual	**0.02**	**39.6**	**39.6**	57	100	No

1 The NO_2 concentration included conversion of NO_x to NO_2 using ARM2.

2 Maximum value for NO_2 from SRA 4, South Coastal LA County 3 (No. 033) monitoring station for the last three years available prior to application submittal (2014-2016) was used.

- ***(c)(2)—Offsets***
Paragraph (c)(2) requires RECLAIM facilities to hold sufficient RTCs to offset the first year of operation's emissions increase from a new, relocated, or modified source before commencement of such operation. Before Rule 2005 was amended on 6/3/11, Rule 2005(f)(1) required RECLAIM facilities to hold RTCs for each subsequent compliance year prior to each compliance year for the same sources. Further, facilities subject to this NSR hold requirement were generally required to hold and not transfer out of their Allocation accounts the specified RTCs for each year until the compliance year was over.

  On 6/3/11, Rule 2005 was amended to remove existing facilities that do not have emissions greater than the level of their 1994 allocation plus non-tradable credits (NTCs) from section (f)(1). Per Rule 2000(c)(35), an existing facility is "any facility that submitted Emission Fee Reports pursuant to Rule 301 – Permit Fees, for 1992 or earlier years, or with valid District Permits to Operate issued prior to October 15, 1993, and continued to be in operation or possess valid District permits on October 15, 1993." Per Rule 2000(c)(51), a new facility is "any facility which has received all District Permits to Construct on or after October 15, 1993."

  Existing facilities that do not have emissions greater than the level of their 1994 allocation plus NTCs are only subject to the "hold" requirement for the first year of operation of each source with an emissions increase (the period commencing at the start of operation and concluding 364 days later; 365 days later if the period includes a leap day).

  - **FDOC Summary**
  The FDOC analysis is summarized and clarified below.

    A determination was made regarding whether AEC is subject to the RTC hold requirement the first year only (condition I297), or the first year and each subsequent year (condition I296). Southern California Edison (SCE) installed all six utility boilers by 1966, which is prior to 10/15/93. The AES Corporation purchased the power plant from SCE in 1998. Subsequently, the South Coast AQMD issued AES Alamitos change of operator permits for the power plant in 1999. Therefore, AES Alamitos is an existing facility.

    The NOx RTCs initially allocated was 704,485 pounds.

    First Year of Operation of AEC
    AES indicated that the first-year operation for the combined-cycle turbines and auxiliary boiler (commissioning year) will have ended prior to the first-year operation for the simple-cycle turbines (commissioning year).

The RTCs for the first year is estimated to be the commissioning year emissions for the two combined-cycle turbines and auxiliary boiler. The RTCs required will be 218,105 pounds. [(2 combined-cycle turbines)(108,377 lb/yr per turbine for commissioning yr, *Table 24*) + (1350.8 lb/yr for auxiliary boiler for commissioning yr, *Table 45*) = 218,104.8 lb]

<u>Second Year of Operation of AEC</u>
The RTCs for the second year of operation is estimated to be the commissioning year emissions for the four simple-cycle turbines, and the normal operating annual emissions for the two combined-cycle turbines and auxiliary boiler.

The RTCs required will be 443,350 pounds. [(4 simple-cycle turbines)(68,574.76 lb/yr per turbine for commissioning yr, *Table 40*) + (2 combined-cycle turbines)(83,850 lb/yr for normal operating yr, *Table 45*) + (1350.8 lb/yr for auxiliary boiler for normal operating yr, *Table 45*) = 443,349.84 lb]

<u>Third Year of Operation of AEC</u>
The RTCs for the third year of operation is estimated to be the normal operating year emissions for the turbines and auxiliary boiler. From *Table 45*, the facility-wide emissions for a normal operating year will be 274,120.0 pounds (137.06 tpy).

As shown above, the RTCs required for all years will be less than the initial allocation of 704,485 pounds. Therefore, since the AEC will be an existing facility that will not exceed the initial allocation, it will be required to hold RTCs for the first year of operation only per condition I297 for each NOx-emitting equipment. AEC is not required to hold a specific number of RTCs subsequent to the first year of operation. For subsequent years, Rule 2004(b)(1) specifies actual NOx emissions will determine the number of RTCs required to be held. Compliance with RECLAIM requirements is enforced by the Compliance & Enforcement Dept.

- **<u>Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)</u>**
  Rule 2005(d) specifies the RECLAIM credit calculation shall be based on the potential to emit or on a permit condition limiting the source's emissions.

  - <u>RTCs Required to Be Held the First Year of Operation</u>
    <u>Combined-Cycle Turbines</u>
    Conditions I297.1 and I297.2 will require each turbine to hold 108,377 pounds of RTCs the first year (revised *Table 24*).

    <u>Simple-Cycle Turbines</u>
    Conditions I297.3, I297.4, I297.5, and I297.6 will require each turbine to hold ~~68,575~~ **<u>21,322</u>** pounds of RTCs the first year (revised *Table 40*).

- RTCs Required to Be Purchased Prior to Issuance of Turbine Permits
  The commercial operation of the combined-cycle turbines and auxiliary boiler is scheduled for second quarter 2020. The commercial operation of the simple-cycle turbines is scheduled for first quarter 2024.

  Section B: RECLAIM Annual Emission Allocation, printed 9/11/19, indicates the NOx RTC holding for 1/2020 through 12/2020 is 430,540 lbs NOx, which is more than the 218,105 lbs required for the first year of operation for the two combined-cycle turbines and the auxiliary boiler.

- ***(e)--Trading Zone Restrictions***
  See Rule 1303(b)(3) analysis above.

- ***(g)—Additional Federal Requirements for Major Stationary Sources***
  For (g)(1) - (g)(4), see Rule 1303(b)(5) analysis above.

- ***(h)—Public Notice***
  See Rule 212 analysis above.

- ***(i)—Rule 1401 Compliance***
  See Rule 1401 analysis above.

- ***Rule 2012-RECLAIM Monitoring Recording and Recordkeeping Requirements***
  The purposes of this rule is to establish the monitoring, reporting and recordkeeping requirements for NOx emissions under the RECLAIM program.

  Classification as Major NOx Source
  - Combined-Cycle Turbines: Rule 2012(c)(1)(C) classifies any gas turbine rated greater than or equal to 2.9 megawatts excluding any emergency standby equipment or peaking unit as a major NOx source. The combined-cycle turbines are each rated at 236.645 MW-gross at 28 ºF. Therefore, these turbines are major NOx sources.

  - Simple-Cycle Turbines: The simple-cycle turbines are each rated at 100.438 MW-gross at 59 ºF. Rule 2012(e)(1)(D) classifies a “peaking unit” as a RECLAIM process unit, however. Rule 2012 Protocol, Attachment F--Definitions defines a “peaking unit” as “a turbine used intermittently to produce energy on a demand basis and does not operate more than 1300 hours per year.” The simple-cycle turbines are not peaking units because they are permitted to operate 2358 hours per year. Therefore, under Rule 2012(c)(1)(C), they are major NOx sources.

  Compliance Schedule

Rule 2012(h)(6) provides that the Facility Permit holder which installs a new major source at an existing facility shall install, operate, and maintain all required or elected monitoring, reporting, and recording systems no later than 12 months after the initial startup of the major NOx source. During the interim period between the initial startup of the major NOx source and the provisional certification date of the CEMS, the Facility Permit holder shall comply with the monitoring, reporting, and recordkeeping requirements of paragraphs (h)(2) and (h)(3) of this rule. (Condition D82.2 and D82.3 implement this requirement.)

Paragraph (h)(2) provides that interim reports shall be submitted monthly for major and large sources. Paragraph (h)(3) provides that the Facility Permit holder shall install, maintain, and operate a totalizing fuel meter for each major source. Rule 2012, Appendix A, Chapter 2 states on pg. Rule 2012A-2-1 that major sources shall be allowed to use an interim reporting procedure to measure and record NOx emissions on a monthly basis according to the requirements specified in Chapter 3 for large sources. Chapter 3 states on pg. Rule 2012A-3-1 that the interim reporting is specified in subdivision D, paragraph 1. Paragraph 1, in turn, provides that the interim reporting shall be based on fuel usage and emission factor(s).

See Rule 2002 above for further discussion on interim emission factors.

Regulation XXX—Title V Permits

- ***Rule 3000—General***

The proposed facility permit revision is considered as a "significant permit revision."

The "minor permit revision" analysis is performed first because a "de minimis significant permit revision" shall also meet the requirements of clauses (b)(15)(A)(i), (ii), (iii), (iv), (vii), (viii) and (ix) for a "minor permit revision."

The proposed revision is **not** a "minor permit revisions," as analyzed below.

(b) Definitions

(15) *MINOR PERMIT REVISION* means any Title V permit revision that:

(A)

(i) does not require or change a case-by-case evaluation of: reasonably available control technology (RACT) pursuant to Title I of the federal Clean Air Act; or maximum achievable control technology (MACT) pursuant to 40 CFR Part 63, Subpart B;

(ii) does not violate a regulatory requirement;

Analysis: Clauses (b)(15)(A)(i) – (ii) do not apply to the proposed administrative changes, changes of condition, and modifications (changes to annual operating hours for the turbines).

(iii) does not require any significant change in monitoring terms or conditions in the permit;

(iv) does not require relaxation of any recordkeeping, or reporting requirement, or term, or condition in the permit;

Analysis: All proposed changes of condition meet clauses (b)(15)(A)(iii) – (iv).

(v) does not result in an emission increase of RECLAIM pollutants over the facility starting Allocation plus nontradeable Allocations, or higher Allocation amount which has previously undergone a significant permit revision process;

Analysis: Revised *Table 45 - Facility Maximum Annual Emissions, Normal Operations*, shows the facility-wide annual emissions will increase by 9.72 tpy NOx to a total of 146.78 tpy (293,560 lb/yr). SECTION B: RECLAIM ANNUAL EMISSION ALLOCATION shows the "NOx RTC Initially Allocated" is 704485 lb/yr, which is higher than the increase to 293,560 tpy. Thus the proposed revision will meet clause (b)(15)(A)(v).

(vi) does not result in an increase in emissions of a pollutant subject to Regulation XIII - New Source Review or a hazardous air pollutant;

Analysis: Since the operation of turbines is seasonal, the annual emissions are limited by permit conditions to less than 12 months times the maximum monthly emissions. As shown in the emissions calculations above, the maximum monthly emissions and maximum daily emissions (interpreted as 30 day averages) for CO, VOC, and SOx will not increase as a result of the proposed changes in annual operating hours for combined-cycle turbines and the decrease in the annual operating hours for the simple-cycle turbines. However, as shown in revised *Table 45 - Facility Maximum Annual Emissions, Normal Operations*, the facility-wide annual emissions of pollutants subject to Regulation XIII will increase by 3.78 tpy CO, 4.86 lb/yr VOC; and 1.64 lb/yr SOx.

The facility-wide annual hazardous air pollutants will increase by 1.99 tpy. [(2 combined-cycle turbines)(5.90 - 4.05 tpy per turbine, *Table 26*) + (4 simple-cycle turbines) (0.372 - 0.80 tpy per turbine, *Table 42*) = 1.99 tpy]

As the annual CO, VOC, SOx, and HAP emissions will increase, the proposed revision does **not** meet clause (b)(15)(A)(vi).

(vii) does not result in an increase in GHG emissions of >75,000 tpy CO2e;

Analysis: As shown in revised *Table 45--Facility Maximum Annual Emissions, Normal Operations*, the facility-wide CO2e emissions will increase from 1,716,925.57 tpy to 1,952,128.55 tpy. As the increase of 235,202.98 tpy is greater than 75,000 tpy, the proposed revision does **not** meet clause (b)(15)(A)(vii).

(viii) does not establish or change a permit condition that the facility has assumed to avoid an applicable requirement;

(ix) is not an installation of a new permit unit subject to a New Source Performance Standard (NSPS) pursuant to 40 CFR Part 60, or a National Emission Standard for Hazardous Air Pollutants (NESHAP) pursuant to 40 CFR Part 61 or 40 CFR Part 63; and,

(x) is not a modification or reconstruction of an existing permit unit, resulting in new or additional NSPS requirements pursuant to 40 CFR Part 60, or new or additional NESHAP requirements pursuant to 40 CFR Part 61 or 40 CFR Part 63; or ….

Analysis: Clauses (b)(15)(A)(viii) – (A)(x) do not apply to the proposed administrative changes, changes of condition, and modifications (changes to annual operating hours for the turbines).

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The proposed revision is **not** a "de minimis permit revisions," as analyzed below.

(b) Definitions

(7) *DE MINIMIS SIGNIFICANT PERMIT REVISION* means any Title V permit revision where the cumulative emission increases of non-RECLAIM pollutants or hazardous air pollutants (HAP) from these permit revisions during the term of the permit are not greater than any of the following emission threshold levels:

Table 1 – De Minimis Emission Threshold Level

Air Contaminant	Daily Maximum (lbs/day)
HAP	30
VOC	30
NOx	40
PM10	30
SOx	60
CO	220

For the purposes of this paragraph, the de minimis levels for HAP and volatile organic compounds (VOC) are not additive if the HAP is a VOC. The de minimis levels for HAP and particulate matter with an aerodynamic diameter smaller than or equal to 10 microns (PM-10) are not additive if the HAP is a PM-10. The HAP de minimis level in this section shall be superseded by any lower HAP de minimis level promulgated by the United States Environmental Protection Agency (EPA) Administrator. De minimis significant permit revisions shall also meet the requirements of clauses (b)(15)(A)(i), (ii), (iii), (iv), (vii), (viii) and (ix) of this rule.

Analysis: Once the facility has exceeded the cumulative emission increase thresholds for de minimis significant revisions during a permit term (i.e., between renewals), the de minimis significant revision track is no longer available. Rather, the significant revision track must be used for all subsequent revisions that result in emission increases.

The history of permitting of the facility, starting with the most recent Title V renewal, is as follows.

- The second Title V Renewal, A/N 549420, was issued on 11/4/14.
- First Permit Revision, A/N 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170 for which the permits were issued on 4/18/17 for the new Alamitos Energy Center. The revision was a "**significant permit revision**." **All de minimis emission threshold levels for daily emissions were exceeded.**
- Second Permit Revision, A/N 604014, 613323, and 604013 for which the permits were issued on 7/10/19 for the *Auxiliary Boiler, Auxiliary Boiler SCR, and Title V/RECLAIM Revision.* The revision was a "minor permit revision" because the proposed condition changes did not result in an increase of criteria or toxic air contaminant emissions.

- Proposed--Third Permit Revision, A/N 604015, 604018, 604020; 608431-608433; 610354-610360, under evaluation here consist of proposed administrative changes, changes of condition, and modifications. The proposed modifications consist of increasing the annual operating schedule for the combined-cycle turbines and decreasing the annual operating schedule for the simple-cycle turbines.

- The third Title V Renewal, A/N 612392, was submitted on May 2, 2019. The Title V renewal evaluation will be submitted to EPA at the same time as the permit revision under evaluation here.

The following examines whether emissions have increased for VOC, PM_{10}, SOx, CO, or HAPs for the **Application**.

<u>VOC Emissions</u>
For the first revision, the permitting of the AEC exceeded the de minimis emission threshold level of 30 lb/day. For the applications under evaluation (third revision), the 30-day averages (daily emissions) will remain the same as for the first revision. The facility-wide annual emissions, however, will increase by 4.86 tpy VOC.

<u>PM_{10} Emissions</u>
For the first revision, the permitting of the AEC exceeded the de minimis emission threshold level of 30 lb/day. For the applications under evaluation (third revision), the 30-day averages (daily emissions) will remain the same as for the first revision. The facility-wide annual emissions will not increase.

<u>SOx Emissions</u>
For the AEC (first revision), the permitting of the AEC exceeded the de minimis emission threshold level of 60 lb/day. For the applications under evaluation (third revision), the 30-day averages (daily emissions) will remain the same as for the first revision. The facility-wide annual emissions, however, will increase by 1.64 tpy SOx.

<u>CO Emissions</u>
For the AEC (first revision), the permitting of the AEC exceeded the de minimis emission threshold level of 220 lb/day. For the applications under evaluation (third revision), the 30-day averages (daily emissions) will remain

the same as for the first revision. The facility-wide annual emissions, however, will increase by 3.78 tpy VOC.

Hazardous Air Pollutant Emissions
As discussed above under "minor permit revision," the facility-wide annual hazardous air pollutants will increase by 1.99 tpy HAPs.

CO_2e Emissions
De minimis significant permit revisions shall also meet the requirements of clauses (b)(15)(A)(i), (ii), (iii), (iv), (vii), (viii) and (ix) of this rule. As discussed above under "minor permit revision," the proposed revision does **not** meet (b)(15)(A)(vii), which states "does not result in an increase in GHG emissions of >75,000 tpy CO2e." As shown in revised *Table 45--Facility Maximum Annual Emissions, Normal Operations*, the facility-wide CO2e emissions will increase from 1,716,925.57 tpy to 1,952,128.55 tpy. As the increase of 235,202.98 tpy is greater than 75,000 tpy limit, the proposed revision does not meet (b)(15)(A).

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The proposed revision is a "**significant permit revision**," as analyzed below.

(b) Definitions

(31) ***SIGNIFICANT PERMIT REVISION*** means any facility permit revision that is not eligible for administrative permit revision, minor permit revision, or de minimis significant permit revision procedures. Such revisions include any of the following:

(A) relaxation of any monitoring, recordkeeping, or reporting requirement, term, or condition in the Title V permit;

(B) the addition of equipment or modification to existing equipment or processes that result in an emission increase of non-RECLAIM pollutants or hazardous air pollutants (HAP) in excess of any of the emission threshold levels in Table 1 of paragraph (b)(7) of this rule;

(C) cumulative emission increases of non-RECLAIM pollutants or hazardous air pollutants from de minimis significant permit revisions during the term of the permit, in excess of any of the emission threshold levels in Table 1 of paragraph (b)(7) of this rule.

For the purposes of this subparagraph, the de minimis levels for HAP and VOC are not additive if the HAP is a VOC. The de minimis levels for HAP and PM-10 are not additive if the HAP is a PM-10. The HAP de minimis level in this section shall be superseded by any lower HAP de minimis level promulgated by the EPA Administrator, or;

(D) any modification at a RECLAIM facility that results in an emission increase of RECLAIM pollutants over the facility's starting Allocation plus the nontradeable Allocations;

(E) requests for a permit shield when such requests are made outside applications for initial permit or permit renewal issuance;

(F) any revision that requires or changes a case-by-case evaluation of: reasonably available control technology (RACT) pursuant to Title I of the federal Clean Air Act; or maximum achievable control technology (MACT) pursuant to 40 CFR Part 63, Subpart B;

(G) any revision that results in a violation of regulatory requirements;

(H) any revision that establishes or changes a permit condition that the facility assumes to avoid an applicable requirement;

(I) installation of new equipment subject to a New Source Performance Standard (NSPS) pursuant to 40 CFR Part 60, or a National Emission Standard for Hazardous Air Pollutants (NESHAP) pursuant to 40 CFR Part 61 or 40 CFR Part 63; or,

(J) modification or reconstruction of existing equipment, resulting in an emission increase subject to new or additional NSPS requirements pursuant to 40 CFR Part 60, or to new or additional NESHAP requirements pursuant to 40 CFR Part 61 or 40 CFR Part 63.

Analysis: The proposed permit revision does not meet the requirements of subparagraphs (b)(31)(A) – (J). However, these are only examples of significant revisions. As analyzed above, the proposed revision is not eligible for "de minimis permit revision." Therefore, the revision is a "significant permit revision."

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- ***Rule 3003—Applications***

(j) EPA Review

(1) The Executive Officer shall submit to the EPA Administrator:

(A) each application for initial permit, permit renewal, minor permit revision, de minimis significant permit revision and significant permit revision;

(B) each proposed permit for initial permit, renewal permit, or permit revision, excluding administrative permit revisions;

(C) any revisions to the proposed permit in response to public or affected State comments;

(D) a copy of any notices required by Rules 3003, 3005, or 3006; and,

(E) each final Title V permit, within 5 working days of permit issuance.

(k) EPA Objection
(1) No permit or permit revision for which an application must be transmitted to EPA pursuant to subdivision (j) of this rule may be issued if the EPA objects to its issuance in writing within 45 days of receipt of the proposed permit and all necessary supporting information, or within 90 days if the EPA provides a written request to delay the permit issuance on the basis that an additional 45 days is necessary to review the public and affected State comments made to the proposed permit. The objection shall include a statement of the reasons for the objection and a description of the terms and conditions that the permit must include to respond to the objections.

(m) Review by Affected States
(1) Except for administrative permit revisions, the Executive Officer shall give notice of each proposed permit to any affected State on or before the notice is provided to the EPA.
(2) Any affected State may provide recommendations in writing, based upon applicable requirements or requirements of 40 CFR Part 70, with respect to the proposed permit, within 30 days of receipt of the notice.

- ***Rule 3006—Public Participation***

(a) Public Participation Requirements for Permit Actions
(1) All permit actions for initial permit issuance, significant permit revisions, establishment of general permits and permit renewals shall include the following public participation procedures:
(A) The District shall give notice by publication in a newspaper of general circulation in the county where the source is located, by mail to those who request in writing to be on a list to receive all such notices, and by any other means determined by the Executive Officer to be necessary to assure adequate notice to the affected public.

(B) The notice shall include:
(i) The identity and location of the affected facility;
(ii) The name and mailing address of the facility's contact person;
(iii) The identity and address of the SCAQMD as the permitting authority processing the permit;
(iv) The activity or activities involved in the permit action;
(v) The emissions change involved in any permit revision;
(vi) The name, address, and telephone number of a person whom interested persons may contact to review additional information including copies of the proposed permit, the application, all relevant supporting materials, including

compliance documents as defined in paragraph (b)(5) of Rule 3000, and all other materials available to the Executive Officer that are relevant to the permit decision;

(vii) A brief description of the public comment procedures provided; and

(viii) The time and place of any proposed permit hearing that may be held or a statement of the procedures to request a proposed permit hearing if one has not already been requested.

(D) The notice shall provide at least 30 days for public comment, and shall give at least 30 days of notice if any proposed permit hearing is scheduled.

(F) Any person may request a proposed permit hearing on an application for initial permit, permit renewal, or significant permit revision, or for establishment of a general permit, by filing with the Executive Officer a complete request for a proposed permit hearing within 15 days of the date of publication of notice. On or before the date the request is filed, the person requesting a proposed permit hearing must also mail by first class mail a copy of the request to the contact person of the Title V facility at the address listed in the notice. A complete request for a proposed permit hearing shall include all of the following information: ….

Analysis: Pursuant to Rule 3003(j), the proposed permit package for the significant revision will be submitted to EPA for a 45-day review period. 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. In addition, the SCAQMD will mail the notice to the California Air Resource Board, local air pollution control districts, environmental groups, and interested parties. Following the conclusion of the required review and comment periods for the EPA, other agencies, and the public, subject to any comments received during these periods, the revised Permits to Construct will be issued for the aqueous ammonia tank for the combined-cycle turbines (D163), two combined-cycle turbines (D165, D173), two SCR/CO oxidation catalysts for the combined-cycle turbines (C170/C169, C178/C177), and four simple-cycle turbines (D185, D191, D197, D203).

FEDERAL REGULATIONS

40 CFR 60 Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

The final rule entitled "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Generating Units (*New Source Rule*)," 80 FR 64510 (October 23, 2015), was codified as 40 CFR Part 60, Subpart TTTT, and became effective on 10/23/15. The New Source Rule established national emission standards to limit emissions of carbon dioxide (CO2) from newly constructed, modified, and reconstructed affected fossil fuel-fired electric utility generating units (EGUs).

In order to comply with the Presidential Executive Order on Promoting Energy Independence and Economic Growth, signed by President Trump on 3/28/17, then-EPA Administrator Scott Pruitt issued the following Federal Register notice for the New Source Rule. The Review of the Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Generating Units, 82 FR 16330 (April 4, 2017) announced that the EPA is reviewing The New Source Rule and, if appropriate, will as soon as practicable and consistent with law, initiate reconsideration proceedings to suspend, revise or rescind this rule.

On December 6, 2018, EPA proposed amendments to Subpart TTTT in Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 83 FR 65424 (12/20/2018), for which comments are due by 2/19/19. After further analysis and review, EPA proposed to determine that the best system of emission reduction (BSER) for newly constructed coal-fired units is the most efficient demonstrated steam cycle in combination with the best operating practices. This proposed BSER would replace the determination from the 2015 rule, which identified the BSER as partial carbon capture and storage. The EPA is not proposing to amend and is not reopening the standards of performance for newly constructed or reconstructed stationary combustion turbines. The public comment period ended on March 18, 2019. EPA final action is pending.

The FDOC analysis below is updated for the ***Application*** *below. Although the amendments to Subpart TTTT proposed in the Federal Register on 12/6/18 are pending, the pending language changes affecting the sections below are included in italics within brackets.*

The following sets forth the applicability requirements, emissions standards, applicability analysis, and thermal efficiency calculations for the combined- and single-cycle turbines.

- ***Applicability Requirements***
  Under the applicability requirements, the analysis below shows the final NSPS is applicable to the proposed combined- and simple-cycle turbines.

  §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 AEC commenced after January 8, 2014. **Actual construction of Phase I (combined-cycle turbines and associated equipment) was commenced on 8/7/17.**

§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.

Combined-Cycle Turbine:

(1) From *Table 15*, the turbine base load rating is 2032 MMBtu/hr (LHV) at 100% load, 59 °F and 60% relative humidity (case 12). The 2032 MMBtu/hr rating is higher than the 250 MMBtu/hr threshold.

(2) The turbine generator rating is 230.459 MW-net plus one-half of the steam turbine generator rated at 215.402 MW-net (divided equally between the two turbines) is equal to 338.16 MW-net (case 12), which is higher than the 25 MW-net threshold.

Simple-Cycle Turbine:

(1) From *Table 31*, the turbine rating is 795 MMBtu/hr (LHV) at 100% load, 59 °F and 60% relative humidity (case 12). The 795 MMBtu/hr base load rating is higher than the 250 MMBtu/hr threshold.

(2) The turbine generator rating of 99.087 MW-net 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.

[*12/20/18 Fed Reg –Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.]*

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than the product of the unit's net design efficiency and the unit's potential electric output or 219,000 MWh, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to
CO2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (e.g., not connected to a natural gas pipeline).

(9) The proposed Washington County EGU project….

(10) The proposed Holcomb EGU project….

Analysis: The NSPS is applicable to the proposed combined- and 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 two gas-fired subcategories and associated standards are 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 [*12/20/18 Fed Reg – Table 1, 2, or 3* (but Table 3 is not applicable to turbines)] of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

Table 2 of Subpart TTTT of Part 60 – CO_2 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 more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and 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.	450 kg of CO_2 per MWh of gross energy output (1,000 lb CO_2/MWh); or 470 kilograms (kg) of CO_2 per megawatt-hour (MWh) of net energy output (1,030 lb/MWh)
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 CO_2 per gigajoule (GJ) of heat input (120 lb CO_2/MMBtu)

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

Compliance with the applicable CO_2 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)….

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 10^6 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 above the product of the "design efficiency" or 50%, whichever is less, and "potential electric output" on a 12-operating-month and 3-year-rolling average basis, the standard is 1000 lb CO_2/MWh-gross, which is the standard for base load natural gas-fired units. If the turbines operate 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 CO_2/MMBtu, which is the standard for non-base load natural gas-fired units with a small allowance for distillate oil. This latter standard is readily achievable because the CO_2 emission rate of natural gas is 117 lb CO_2/MMBtu.

Combined-Cycle Power Block:
All turbines will operate on natural gas 100% of the time.

Page 2-6 of the original Application, dated 10/23/15, indicates the design efficiency is 56 percent on a LHV basis. Thus, 50 percent will be used because it is less than the provided 56% design efficiency. The potential electric output will be calculated using the net MW ratings (case 12), instead of the formula in the definition.

Design efficiency or 50%, whichever is less * potential electric output =

(0.50) * [230.459 MW-net /turbine + (1/2) * 215.402 MW-net/steam generator] * (8760 hours/yr) = 1,481,140.8 MWh-net → 1,481,141 MWh-net

If a combined-cycle turbine generates more electricity than 1,481,141 MWh-net, it will need to comply with the 1000 lb CO_2/MWh-gross emission limit. If it generates less, it will need to comply with the 120 lb CO_2/MMBtu standard.

As shown in the **revised** thermal efficiency calculations below, the combined-cycle GHG efficiency is estimated as ~~937.88~~ **916.01** lb CO_2/MWh-gross, assuming an 8 percent performance degradation, which is less than the 1000 lb CO_2/MWh-gross emission limit.

Simple-Cycle Turbines:
Each turbine will operate on natural gas 100% of the time.

Page 2-7 of the original Application, dated 10/23/15, indicates the design efficiency is 41 percent on a LHV basis, which is less than 50%.

Design efficiency x potential electric output = (0.41) * (99.087 MW-net/turbine) * (8760 hr/year) = 355,880.9 MWh-net

If any simple-cycle turbine generates more electricity than 355,880.9 MWh-net/yr, it will need to comply with the 1000 lb CO_2/MWh-gross emission limit. For each turbine, the permitted annual net electric sales is ~~233,647~~ **104,834** MWh-net/turbine (calculated as 99.087 MW-net/turbine x ~~2358~~ **1058** permitted hours, including startups and shutdowns). Since the permitted annual net electric sales is significantly less than the potential electric output threshold, the applicable standard is 120 lb CO_2/MMBtu. As the AEC is natural-gas fired only, the turbines are expected to emit CO_2 at a rate at 117 lb CO_2/MMBtu, thereby complying with the 120 lb CO_2/MMBtu standard.

As shown in the **revised** thermal efficiency calculations below, the simple-cycle GHG efficiency is estimated as ~~1356.03~~ **1506.98** lb CO_2/MWh-gross, assuming an 8 percent performance degradation. The inability to meet the 1000 lb CO_2/MWh-gross emission limit is expected for these non-base load turbines.

- ***Thermal Efficiency Calculations***
  The second step is to perform thermal efficiency calculations to determine whether the proposed combined- and simple-cycle turbines will be able to comply with the emission standard of 1000 lb CO_2/MWh-gross**,** in the event that the combined-cycle power block or any simple-cycle turbines meet the above applicability criteria, including the sales criteria.

  - **Combined-Cycle Power Block**
    - **FDOC Summary**
      For the **FDOC**, for the combined-cycle power block, the annual operating schedule proposed by AES for the thermal efficiency calculations was 4100 hours normal operations, 80 cold starts, 420 combined hot and warm starts, and 500 shutdowns, as set forth in the revised Application, dated 3/30/16, submitted for the FDOC. The expected operating profile for the combined-cycle block, consisting of the two combined-cycle turbines, provided by AES for the purpose of thermal efficiency calculations was the same as the permitted annual operating schedule for each turbine of 4100 hours normal operations, 80 cold starts, 420 combined hot and warm starts, and 500 shutdowns. The permitted annual operating schedule represents the maximum operating schedule for each turbine and allows the facility the flexibility to operate as necessary to meet the emission standard. To comply with the 1000 lb CO_2/MWh-gross, it will be necessary for AES to adjust the actual number of operating hours, starts, and shutdowns.

    - **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**
      For the **Application**, the proposed permitted annual operating schedule is (1) ~~4100~~ **6005** hours of normal operation, (2) 80 cold starts (80 hr), (3) 420 non-cold starts (210 hr), and (4) 500 shutdowns (250 hr) for a total ~~4640~~ **6545** hours for maximum annual emissions per turbine.

Revised *Table 89* below provides the annual hours for each configuration (1-on-1, 2-on-1), net plant power electrical output, net plant heat rate, gross heat rate, net heat rate, gross power output, average net electrical output, and average net heat rate for the four load scenarios for the two configurations. As discussed above, the expected operating profile for the combined-cycle block, consisting of the two combined-cycle turbines, provided by AES for the purpose of thermal efficiency calculations was the same as the permitted annual operating schedule for each turbine. The only updates to FDOC *Table 89* are the incorporation of the revised normal operating hours. One, the "Expected Annual Hours" will be revised from the current 4100 hr to 6005 hr. Two, for the "1-on-1 Configuration," the "Hours per Configuration per Year," will be revised from 900 hr/yr to 1318 hr/yr [calculated as 900 hr/4100 hr x 6005 hr/yr = 1318 hr/yr]. Three, for the "2-on-1 Configuration," the annual hours will be increased from the current 3200 hr/yr to 4687 hr/yr [calculated as 3200 hr/4100 hr x 6005 hr = 4687 hr/yr]. The other "Plant Output" values in the table remain the same.

- **Simple-Cycle Turbine**
  - **FDOC Summary**

    For the **FDOC**, for each turbine, the annual operating schedule proposed by AES for the thermal efficiency calculations is 2000 hours normal operations, 500 startups, and 500 shutdowns for each turbine. This schedule is the same as the permitted schedule.

  - **Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360)**

    For the **Application**, the proposed permitted annual operating schedule is (1) ~~2000~~ **700** hours of normal operation, (2) 500 startups (250 hr), and (3) 500 shutdowns (108 hr), for a total of ~~2358~~ **1058** hours for maximum annual emissions per turbine. (Note: As the Yorke *Applications for Modification* were based on a total of 1060 hours, Yorke's CO_2 emissions calculations and thermal efficiency calculations yielded slightly higher values.)

    Revised *Table 90* below provides the annual normal operating hours for each turbine, net electrical output, net heat rate, gross heat rate, gross power output, and average net heat rate for the three load scenarios. The only update to FDOC *Table 90* is the incorporation of the revised normal operating hours. The "Expected Annual Hours" will be revised from the current 2000 hr to 700 hr. The other "Plant Output" values in the table remain the same.

Table 89 - Heat Rates and Electrical Production – Expected Operating Profile for Combined-Cycle Power Block

Plant Output	**Percent**	**44 (Minimum Turndown)**	**63**	**81**	**100 (Baseload)**	**44 (Minimum Turndown)**	**63**	**81**	**100 (Baseload)**	**Expected Annual Hours**
		1-on-1 Configuration				2-on-1 Configuration				
Hours per Configuration per Year	Hrs/Yr	~~900~~ **1318**				~~3200~~ **4687**				~~4100~~ **6005**
Net Plant Electrical Output	kW	169,219	218,066	268,635	328,051	349,244	446,187	547,390	665,162	
Net Plant Heat Rate	Btu/kWh-LHV	7,061	6,327	6,275	6,155	6,842	6,184	6,159	6,071	
Gross Heat Rate, LHV	Btu/kWh-LHV	6,664	6,034	6,003	5,911	6,485	5,912	5,925	5,869	
Net Heat Rate	Btu/kWh-HHV	7,834	7,020	6,962	6,829	7,592	6,862	6,834	6,736	
Gross Power Output	kW	179,299	228,654	280,802	341,561	368,492	466,722	568,975	688,095	
Average Net Electrical Output	kW	245,993				501,996				
Average Net Heat Rate	Btu/kWh-HHV	7162				7006				

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Table 90 - Heat Rates and Electrical Production – Permitted Operating Profile for Simple-Cycle Turbine

Plant Output	**Percent**	**100**	**75**	**50**
Operating Hours per Year	Hrs/Yr	~~2000~~ **700**		
Net Electrical Output	kW	97,864	72,527	47,565
Net Heat Rate	Btu/kWh-LHV	8,060	8,778	10,359
Gross Heat Rate, LHV	Btu/kWh-LHV	7,950	8,618	10,073
Net Heat Rate, HHV	Btu/kWh-HHV	8,946	9,744	11,498
Gross Power Output	kW	99,215	73,878	48,916
Average Net Heat Rate	Btu/kWh-HHV	10,063		

- **<u>Combined-Cycle Power Block</u>**
For the **FDOC**, the expected operating profile for the combined-cycle block, consisting of the two combined-cycle turbines, provided by AES for the purpose of thermal efficiency calculations was the <u>same</u> as the permitted annual operating schedule for each turbine of 4100 hours normal operations, 80 cold starts, 420 combined hot and warm starts, and 500 shutdowns, as reproduced below.

For the **Application**, the expected operating profile for the combined-cycle block for the purpose of thermal efficiency calculations will continue to be the same as the permitted annual operating schedule for each turbine. The thermal efficiency calculations for the FDOC are updated below to incorporate the proposed change in annual operating hours.

Schedule: ~~900~~ **<u>1318</u>** hr for 1-on-1, ~~3200~~ **<u>4687</u>** hr 2-on-1, for total of ~~4100~~ **<u>6005</u>** hr normal operations
80 cold starts, total for both turbines
420 ~~hot/warm~~ **<u>non-cold</u>** starts (332 hot starts + 88 warm starts), total for both turbines
500 shutdowns, total for both turbines

<u>Startup and Shutdown Durations and Net Heat Rates</u>
In the revised Application submitted on 3/30/16 for the FDOC, AES provided the required heat rates for the cold, hot/warm startups for the baseload to completion period.

Cold Startup Duration, 60 min—20 min (0.33 hr) for first fire to baseload.
40 min (0.67 hr) from baseload to completion.

Hot/Warm Startup Duration, 30 min--15 min (0.25 hr) for first fire to baseload.
15 min (0.25 hr) from baseload to completion.

Cold, Hot/Warm Startup Heat Rates—
First fire to baseload—19,585 Btu/kWh-HHV-net
AES assumed rate to be 2.5 times the 44% load heat rate of 7834 Btu/kWh-HHV-net for the 1-on-1 configuration.

AES clarified the 2.5 multiplier was based on inspection of the startup heat rate for other combustion turbines. These other combustion turbines had a minimum load heat input of 11,189 btu/kWh-LHV and start up heat rate of 18,267 btu/kWh-LHV. The ratio of the startup heat rate to the minimum load heat rate is approximately 1.6, which was increased to 2.5 to be conservative for AEC.

Baseload to completion—7,162 Btu/kWh-HHV-net
AES assumed rate to be the same as the average net heat rate for the 1-on-1 configuration for simplicity.

Shutdown, 30 min—Full 30 min (0.5 hr) for baseload to no fuel combustion

Shutdown Heat Rates—11,751 Btu/kWh-HHV-net

AES assumed rate to be 1.5 times the 44% load rate of 7834 Btu/kWh-HHV-net for the 1-on-1 configuration.

AES clarified the 1.5 multiplier was based on inspection of the shutdown heat rate for other combustion turbines. These other combustion turbines had a minimum load heat input of 11,189 btu/kWh-LHV and a shutdown heat rate 16,520 btu/kWh-LHV. The ratio of the shutdown heat rate to the minimum load heat rate is approximately 1.5.

Annual Hours for Startups and Shutdowns

- Startup Hours (first fire to baseload)
  (80 cold starts/yr)(0.33 hr) + (420 ~~warm or hot~~ **non-cold** starts/yr)(0.25 hr) = 131.4 hr/yr

- Startup Hours (baseload to completion)
  (80 cold starts/yr)(0.67 hr) + (420 ~~warm or hot~~ **non-cold** starts/yr)(0.25 hr) = 158.6 hr/yr

- Shutdown Hours (baseload to no fuel)
  (500 shutdown/yr)(0.5 hr) = 250 hr/yr

Overall Net Heat Rate (without degradation)

Overall Net Heat Rate (without degradation) =

[(Avg net heat rate * annual hrs *for 1-on-1*) + (Avg net heat rate * annual hrs *for 2-on-1*) + (Startup heat rate FIRST FIRE TO BASELOAD * Annual hours FIRST FIRE TO BASELOAD) + (Startup heat rate BASELOAD TO COMPLETION * Annual hours BASELOAD TO COMPLETION) + (Shutdown heat rate BASELOAD TO NO FUEL * Annual hours BASELOAD TO NO FUEL)] /Total annual hrs

[(7162 Btu/kWh-HHV * ~~900~~ **1318** hrs *for 1-on-1*) + (7006 Btu/kWh-HHV * ~~3200~~ **4687** hrs *for 2-on-1*) + (19,585 Btu/kWh-HHV * 131.4 hr) + (7162 Btu/kWh-HHV * 158.6 hr) + (11,751 Btu/kWh-HHV * 250 hr)] / [(~~900~~ **1318** + ~~3200~~ **4687** + 131.4 + 158.6 + 250 hr)] = ~~7653.47~~ **7474.98** Btu/kWh-HHV-net

GHG Efficiency (without degradation)

GHG Efficiency, net (without degradation) =

[(~~7653.47~~ **7474.98** Btu/kWh-HHV-net) (1000 kWh/MWh)(MMBtu/1,000,000 Btu)]
[(53.06 kg CO_2/MMBtu-HHV)(2.2046 lb/kg)] = ~~895.27~~ **874.39** lb CO_2 /MWh-HHV-net

GHG Efficiency, gross (without degradation) =

(~~895.27~~ **874.39** lb CO_2 /MWh-HHV-net) (0.97 MWh-net / MWh-gross)
= ~~868.41~~ **848.16** lb CO_2 /MWh-HHV-gross

GHG Efficiency (with degradation)
AES assumes a maximum of 8% degradation can occur.

GHG Efficiency, net (with degradation) = (~~895.27~~ **874.39** lb CO_2 /MWh-HHV-net) (1 + 0.08)
= ~~966.89~~ **944.34** lb CO_2 /MWh-HHV-net

GHG Efficiency, gross (with degradation) = (~~868.41~~ **848.16** lb CO_2 /MWh-HHV-gross)
(1 + 0.08) = ~~937.88~~ **916.01** lb CO_2 /MWh-HHV-gross

Annual Capacity Factor
Annual Capacity Factor = [(245,993 kW average net electrical output (*for 1-on-1*) x ~~900~~ **1318** hours/year) + (501,996 kW average net electrical output (*for 2-on-1*) x ~~3,200~~ **4687** hours per year)]/[665,162 kW (*for 2-on-1 at 100% CTG Load*) x 8,760 hrs] x 100% = ~~31.37%~~ **45.94%**

***__Compliance Demonstration__**

If the combined-cycle block operates above the "design efficiency" of 56% (or 50%, whichever is less), the 1000 lb CO_2/MWh-gross standard is applicable. The applicant has provided thermal emissions calculations for ~~31.37%~~ **45.94%** capacity factor. Since GHG efficiency increases with an increased capacity factor, the ~~937.88~~ **916.01** lb CO_2/MWh-HHV-gross (with degradation) demonstrates that the combined-cycle block can meet the 1000 lb CO_2/MWh-gross standard.

Conditions E193.11, E193.12, E193.14
Condition E193.11 provides the 1000 lbs per gross megawatt-hours CO_2 emission limit (inclusive of degradation) shall only apply if a turbine supplies greater than 1,481,141 MWh-net electrical output to a utility distribution system on both a 12-operating-month and a 3-year rolling average basis. Compliance with the 1000 lbs per gross megawatt-hours CO_2 emission limit (inclusive of degradation) is determined on a 12-operating month rolling average basis.

Condition E193.12 provides the 120 lbs/MMBtu CO_2 emission limit shall only apply if a turbine supplies no more than 1,481,141 MWh-net electrical output to a utility distribution system on either a 12-operating-month or a 3-year rolling average basis. Compliance with the 120 lbs/MMBtu CO2 emission limit is determined on a 12-operating month rolling average basis.

Condition E193.14 limits the CO2 emissions to ~~610,480~~ **861,119** tpy per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO2 emissions is limited to ~~937.88~~ **916.01** pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations above.

The condition includes a formula for the calculation of greenhouse gases (tons CO_2). Based on fuel consumption, where FF is the monthly fuel usage in millions standard cubic feet:

GHG (CO_2) (tons/month) = {(53.06 kg CO_2/MMBtu) * {(2.2046 lb/kg)(ton/2000 lb)
(1050 MMBtu/MMcf) * FF } = 61.41 * FF

- **Simple-Cycle Turbine**

For the **Application**, the thermal efficiency calculations for the FDOC are updated below to incorporate the proposed change in annual operating hours.

Schedule: ~~2000~~ **700** hr per turbine
500 startups per turbine
500 shutdowns per turbine

Startup and Shutdown Durations and Net Heat Rates
In the revised Application submitted on 3/30/16 for the FDOC, AES provided the required heat rates for the startups for the baseload to completion period.

Startup Duration, 30 min—10 min (0.17 hr) for first fire to baseload.
20 min (0.33 hr) from baseload to completion.

Startup Heat Rate—
First fire to baseload net heat rate—28,746 Btu/kWh-HHV-net
AES assumed rate to be 2.5 times the 50% load heat rate of 11,498 Btu/kWh-HHV-net.

Baseload to completion net heat rate—10,063 Btu/kWh-HHV-net
AES assumed rate to be the same as the average net heat.

Shutdown Duration, 13 min – Full 13 min (~~0.22~~ **0.2167** hr) for baseload to no fuel combustion

Shutdown Net Heat Rate—17,248 Btu/kWh-HHV-net
AES assumed rate to be 1.5 times the 50% load rate of 11,498 Btu/kWh-HHV-net.

Annual Hours for Startups and Shutdowns
- Startup Hours (first fire to baseload)
(500 cold starts/yr)(0.17 hr) = 85 hr/yr

- Startup Hours (baseload to completion)
(500 cold starts/yr)(0.33 hr) = 165 hr/yr

- Shutdown Hours = (500 shutdowns, per turbine)(13 min/shutdown)(hr/60 min) = 108 hr

Overall Net Heat Rate (without degradation)

Overall Net Heat Rate (without degradation) =
[(Avg net heat rate * annual hrs) +
(Startup heat rate FIRST FIRE TO BASELOAD * Annual hours FIRST FIRE TO BASELOAD) +
(Startup heat rate BASELOAD TO COMPLETION * Annual hours BASELOAD TO COMPLETION) +
(Shutdown heat rate BASELOAD TO NO FUEL * Annual hours BASELOAD TO NO FUEL)] /Total annual hrs

[(10,063 Btu/kWh-HHV-net * ~~2000~~ **700** hrs) + (28,746 Btu/kWh-HHV * 85 hr) + (10,063 Btu/kWh-HHV * 165 hr) + (17,248 Btu/kWh-HHV * 108 hr)] / [(~~2000~~ **700** + 85 + 165 + 108 hr)] = ~~11,065.56~~ **12,297.44** Btu/kWh-HHV-net

GHG Efficiency (without degradation)

GHG Efficiency, net (without degradation) =
[(~~11,065.56~~ **12,297.44** Btu/kWh-HHV-net) (1000 kWh/MWh)(MMBtu/1,000,000 Btu)]
[(53.06 kg CO_2/MMBtu-HHV)(2.2046 lb/kg)] = ~~1294.41~~ **1438.51** lb CO_2 /MWh-HHV-net

GHG Efficiency, gross (without degradation) =
(~~1294.41~~ **1438.51** lb CO_2 /MWh-HHV-net) (0.97 MWh-net / MWh-gross)
= ~~1255.58~~ **1395.35** lb CO_2 /MWh-HHV-gross

GHG Efficiency (with degradation)

AES assumes a maximum of 8% degradation can occur.

GHG Efficiency, net (with degradation) = (~~1294.41~~ **1438.51** lb CO_2 /MWh-HHV- net) (1 + 0.08) = ~~1397.96~~ **1553.59** lb CO_2 /MWh-HHV-net

GHG Efficiency, gross (with degradation) = (~~1255.58~~ **1395.35** lb CO_2 /MWh-HHV-gross) (1 + 0.08) = ~~1356.03~~ **1506.98** lb CO_2 /MWh-HHV-gross

*****Compliance Demonstration**

The ~~1356.03~~ **1506.98** lb CO_2 /MWh-HHV-gross demonstrates that each simple-cycle turbine is unable to meet the 1000 lb CO_2/MWh-gross standard. This is expected because the standard is for baseload turbines. Since simple-cycle turbines are permitted to operate as non-baseload units, the relevant performance standard is the fuel-based heat input standard of 120 lb CO_2/MMBtu of heat input. Compliance with this standard can be demonstrated by combusting natural gas as the exclusive fuel.

- Condition E193.13 and E193.15
  Condition E193.13 provides the 120 lbs/MMBtu CO_2 emission limit for non-base load turbines shall apply. Compliance with the 120 lbs/MMBtu CO2 emission limit is determined on a 12-operating month rolling average basis.

  Condition E193.15 limits the CO2 emissions to ~~120,765~~ **54,185** tpy per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO_2 emissions is limited to ~~1356.03~~ **1506.98** pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations above.

40 CFR 60 Subpart Da—Standards of Performance for Electric Utility Steam Generating Units
The analysis for the ***Application*** *is the same as for the FDOC.*

§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 combined-cycle turbines, because the heat recovery steam generators are unfired and not equipped with duct burners.

40 CFR 60 Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
The analysis for the ***Application*** *is the same as for the FDOC.*

§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 to the combined-cycle turbines because the heat recovery steam generators are unfired and not equipped with duct burners.

40 CFR Part 60 Subpart GG--NSPS for Stationary Gas Turbines
The analysis for the ***Application*** *is the same as for the FDOC.*

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 combined- and simple-cycle turbines are subject to the requirements of 40 CFR Subpart KKKK (see below) and thus are exempt from the requirements of this subpart per §60.4305(b).

<u>40 CFR Part 60 Subpart KKKK-- NSPS for Stationary Gas Turbines</u>
*The analysis for the **Application** is the same as for the FDOC.*

Subpart KKKK 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

(a)—This subpart is applicable to stationary combustion turbines with a heat input greater than 10 MMBtu/hr (10.7 gigajoules per hour), based on the higher heating value of the fuel, which commenced construction, modification or reconstruction after February 18, 2005. 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. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc.

<u>Analysis</u>*:* This subpart is applicable to the combined-cycle turbines, rated at 2275 MMBtu/hr at 28 ºF each, and the simple-cycle turbines, rated at 882 MMBtu/hr at 59 ºF each.

§60.4320(a)—Gas turbines are required to meet the NOx emission limits specified in Table 1 of this subpart. Table 1 provides NOx 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 850 MMBtu/hr, the NOx emission limit is 15 ppmv @ 15% O_2.

<u>Analysis</u>*:* Since the combined- and simple-cycle turbines are rated at greater than 850 MMBtu/hr each, an emissions limit of 15 ppmv NOx will be included for these turbines. The combined-cycle turbines will meet the BACT limit of 2.0 ppmv @ 15% O_2, and the simple-cycle turbines will meet the BACT limit of 2.5 ppmv @ 15% O_2. Compliance with this section is expected.

§60.4330(a)(2)—Gas turbines are required to comply with (a)(1), (a)(2), or (a)(3) to meet the sulfur dioxide emission limit. Paragraph (a)(1) specifies the turbine exhaust gas shall not contain SO_2 in excess of 0.90 lbs/MWh gross output. Paragraph (a)(2) specifies the fuel shall not contain total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input for units located in continental areas.

<u>Analysis</u>*:* The 0.90 lbs/MWh is a stack limit that requires annual source testing for verification 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 in the analysis for §60.4365 below, the natural-gas fired turbines are expected to be in compliance with the 0.06 lb/MMBtu limit. Accordingly, an emissions limit of 0.06 lb/MMBtu SO_2 will be included for the combined- and simple-cycle turbines, pursuant to this subpart.

§60.4340—To demonstrate compliance for NOx if water or steam injection is not used, an alternative to the required annual performance testing is the installation and operation of a continuous monitoring system consisting of a certified NOx and O_2 CEMS.

Analysis: For this project, monitoring of the emissions from each combined- and simple-cycle turbine will be achieved with a CEMS certified in accordance with Rule 2012.

§60.4360—The total sulfur content of the fuel being fired in the turbine must be monitored using total sulfur methods described in §60.4415, except as provided in §60.4365, discussed below.

§60.4365—An election may be made not to monitor the total sulfur content of the fuel combusted in the turbine pursuant to the monitoring requirements in §60.4370, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input for units located in continental areas. Two sources of information may be used to make the required demonstration: (1) 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 natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and has potential sulfur emissions of less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas, or (2) Representative fuel sampling data which show the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu).

Analysis:
Rule 431.1 limits pipeline natural gas to 16 ppmv sulfur limit (calculated as H_2S) specified in this rule. The 16 ppmv sulfur is equivalent to 1.0 grain/100 SCF (0.0626285 grain/100 SCF per 1 ppm), which is significantly less than 20 grains/100 SCF.

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

To convert 0.75 gr S/100 scf to units of lb SO_2/MMBtu--
(0.75 gr S/100 ft^3) (1 lb/7000 gr) (ft^3/913 Btu [LHV])(1E+06 Btu/MMBtu)
(64 lb SO_x/32 lb S) = 0.0023 lb SO_2/MMBtu < 0.06 lb SO_2/MMBtu limit

<u>40 CFR Part 63 Subpart YYYY--NESHAPS for Stationary Combustion Turbines</u>
*The FDOC analysis is updated for the **Application** below.*

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."

Combined-Cycle 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 revised *Table 26* above, the formaldehyde emissions from the combined-cycle turbines is ~~3.64~~ **5.30** tpy (calculated as 2 turbines * ~~1.82~~ **2.65** tpy/turbine). The total combined HAPs is ~~8.10~~ **11.80** tpy (calculated as 2 turbines * ~~4.05~~ **5.90** tpy/turbine).

Simple-Cycle Turbines
From revised *Table 42* above, the formaldehyde emissions from the simple-cycle turbines is ~~1.44~~ **0.68** tpy (calculated as 4 turbines * ~~0.36~~ **0.17** tpy/turbine). The total combined HAPs is ~~3.2~~ **1.49** tpy (calculated as 4 turbines * ~~0.80~~ **0.372** tpy/turbine).

Auxiliary Boiler
From *Table 30* above, the formaldehyde emissions from the auxiliary boiler remains 0.00111 tpy. The total combined HAPs is 0.0074 tpy.

Facility
The total combined formaldehyde emissions from all sources is ~~5.08~~ **5.98** tpy, which is less than 10 tpy. The total combined HAPs from all sources is ~~11.31~~ **13.30** tpy, which is less than 25 tpy. Therefore, the AEC 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. The 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 of at least 100% of the major source amount; and
- the unit is not otherwise exempt from CAM.

The combined- and simple-cycle turbines are located at a major source for which a Title V permit is required.

For the **Application**, the CAM applicability is the same as for the FDOC, except that the CO major source threshold is corrected from 50 tpy to 100 tpy. The applicability is summarized in the new table below.

Table 91 – CAM Applicability

Equipment (device no.)	Subject to Emission Limitation or Standard	Use of External Control Device to Achieve Compliance with Limitation	Potential Pre-Control Emissions of at Least 100% of the Major Source Amount	Exemption	Applicability
Combined-Cycle Gas Turbines Nos. CCGT-1 & CCGT-2 (D165, D173)	CO: 1.5 ppmv	YES	YES > 100 TPY	CEMS[1]	NO
	NOx: 2.0 ppmv	YES	YES > 10 TPY	CEMS[1]	NO
	PM10: 8.5 lb/hr	NO			NO
	SOx: 0.06 lbs/MMBtu	NO			NO
	VOC: 2.0 ppmv	YES	YES > 10 TPY		YES
Simple-Cycle Gas Turbines Nos. SCGT-1, SCGT-2, SCGT-3, SCGT-4 (D185, D191, D197, D203)	CO: 2 ppmv	YES	YES > 100 TPY	CEMS[1]	NO
	NOx: 2.5 ppmv	YES	YES > 10 TPY	CEMS[1]	NO
	PM10: 6.23 lb/hr	NO			NO
	SOx: 0.06 lbs/MMBtu	NO			NO
	VOC: 2 ppmv	YES	NO < 10 TPY		NO

[1] Each turbine is equipped with Continuous Emission Monitoring System (CEMS) for NOx pursuant to Rule 2012 and a CEMS for CO pursuant to Rule 218 and 218.1. Under 40 CFR §64.2(b)(1)(vi), emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method are exempt from CAM. Therefore, the CAM requirements do not apply to the turbines.

<u>Combined-Cycle Turbines</u>

For the combined-cycle turbines, the NOx, CO, and VOC emissions are subject to BACT limits. Each turbine is controlled with an SCR to meet the NOx BACT limit and a CO catalyst to meet the CO and VOC BACT limits. For normal operations, the pre-control NOx, CO, and VOC are higher than the major source thresholds of 10 tpy, 100 tpy, and 10 tpy, respectively. Thus the CAM requirements are applicable to NOx, CO, and VOC, unless otherwise exempted.

For each turbine, a continuous emission monitoring system (CEMS) will be installed for NOx and for CO. The NOx CEMS will be certified in accordance with Rule 2012 requirements, and the CO CEMS will be certified in accordance with Rule 218 requirements. 40 CFR Part 64.2(b)(1)(vi) provides that the requirements of this part shall not apply to an emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in §64.1. §64.1 defines "continuous compliance determination method" to mean "a method, specified by the applicable standard or an applicable permit condition, which: (1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and (2) Provides data either in units of the standard or correlated directly with the compliance limit." Since the NOx and CO CEMS qualify as continuous compliance determination methods, the CEMS provide an exemption from this subpart for NOx and CO.

This subpart also applies to the VOC emissions because the VOC BACT limit is achieved with the assistance of the oxidation catalyst. The oxidation catalyst is primarily installed to control CO emissions, but also controls VOC emissions to a very minor degree. The pre-control and post-control VOC levels have been provided by the manufacturer as 2.0 ppmvd in *Table 15 – Combined-Cycle Turbine Operating Scenarios.* The CO catalyst is located at the outlet of the turbine and designed to provide the required control efficiency at the expected turbine exhaust temperature range. There are no operational requirements for the CO catalyst. Since both CO and VOC are controlled by the oxidation catalyst, CO monitoring is a surrogate for VOC monitoring.

Simple-Cycle Turbines
For the simple-cycle turbines, the NOx, CO, and VOC emissions are subject to BACT limits. Each turbine is controlled with an SCR to meet the NOx BACT limit and a CO catalyst to meet the CO and VOC BACT limits. For normal operations, the pre-control NOx and CO are higher than the major source thresholds of 10 tpy and 100 tpy, respectively. The pre-control VOC, however, is less than the 10 tpy threshold. Thus the CAM requirements are applicable to NOx and VOC, unless otherwise exempted.

The analysis for the combined-cycle turbines are also applicable to the simple-cycle turbines. Since the NOx and CO CEMS qualify as a continuous compliance determination method~~s~~, the CEMS provide an exemption from this subpart for NOx and CO.

40 CFR Part 68—Chemical Accident Prevention Programs
The analysis for the ***Application*** *is the same as for the FDOC.*

§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 and Threshold Quantities for Accidental Release Prevention [Alphabetical Order—77 Substances] listed "ammonia (anhydrous)" with a threshold quantity of 10,000 lbs, and "ammonia (conc 20% or greater)" with a threshold quantity of 20,000 lbs.

Because the two new ammonia tanks (Devices D163, D164) installed with the AEC project will contain 19% ammonia, not anhydrous ammonia or ammonia with a 20% or greater concentration, Part 68 is not applicable. Therefore, facility condition F24.1, which requires compliance with the accidental release prevention requirements pursuant to 40 CFR Part 68, is not applicable to the new tanks.

Facility condition F24.1 is applicable to the four existing ammonia tanks (Devices D19, D151, D152, and D153) in Section D, because they are permitted to use 29% aqueous ammonia. Condition F24.1 will be removed from the facility permit after the four existing tanks are removed from the facility.

Regulation XXXI—Acid Rain Permit Program (40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 - Acid Rain Provisions)

Acid Rain provisions are designed to control SO_2 and NOx emissions that could form acid rain from fossil fuel fired combustion devices in the electricity generating industry. Facilities are required to cover SO_2 emissions with "SO_2 allowances" or purchase of SO_2 offsets on the open market. The facility is also required to monitor SO_2 emissions through use of fuel gas meters and gas constituent analysis (use of emission factors is also acceptable in certain cases), or with the use of exhaust gas CEMS. The AEC facility will comply with the monitoring requirements of the acid rain provisions with the use of gas meters in conjunction with natural gas default sulfur data as allowed by the Acid Rain regulations (Appendix D to 40 CFR Part 75). If additional SO_2 credits are needed, AEC will obtain the credits from the SO_2 trading market. Based on the above, compliance with this rule is expected.

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 several discretionary approvals by government agencies. A project is exempt from CEQA if by statute, if considered ministerial or categorical, 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 AEC 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 4/4/19, AES submitted a *Petition for Post-Certification Amendment, Modification of Gas Turbine Operating Hours and Combined Cycle Gas Turbine (CCGT) Stack Height* to amend the CEC License. AES and the CEC are in the process of incorporating the other pending application changes that had been submitted to the South Coast AQMD into the CEC license for the AEC.

California Code of Regulations (CCR), Title 20, Chapter 11—Greenhouse Gases Emission Performance Standard, Article 1—Provisions Applicable to Powerplants 10 MW and Larger (SB 1368)

The California Emissions Performance Standard (EPS) of 1100 lbs CO_2/MW-hour-net of electricity applies to local publicly owned electric utilities. California regulations stipulate that no local publicly owned electric utility shall enter into a covered procurement if greenhouse gases emissions from the power plant(s) subject to the covered procurement exceed the EPS. A "covered procurement" is defined in §2901(d) as "(1) A new ownership investment in a base load generation power plant, or (2) A new or renewed contract commitment, including a lease, for the procurement of electricity with a term of five years or greater by a local publicly owned electric utility with: (A) a base load generation power plant, unless the power plant is deemed compliant, or (B) any generating units added to a deemed-compliant base load generation power plant that combined result in an increase of 50 MW or more to the power plant's rated capacity."

The local publicly owned electric utility from which AES 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.

The applicable sections of the regulation are reproduced below, with the rule analysis following.

§ 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.

§ 2901. Definitions.

(a) "Annualized plant capacity factor" means the ratio of the annual amount of electricity produced, measured in kilowatt hours, divided by the annual amount of electricity the powerplant could have produced if it had been operated at its maximum permitted capacity during all hours of the year, expressed in kilowatt hours.

(b) "Baseload generation" means electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent.

(c) "Combined-cycle natural gas" means a powerplant that employs a combination of one or more natural gas turbines and one or more steam turbines in which electricity is produced in the steam turbine from otherwise lost waste heat exiting from one or more of the gas turbines.

(k) “Permitted capacity" means the rated capacity of the powerplant unless the maximum output allowed under the operating permit is the effective constraint on the maximum output of the powerplant.

(l) "Powerplant" means a facility for the generation of electricity, and is:
(1) a single generating unit; or
(2) multiple generating units that meet the following conditions:
(A) the generating units are co-located;
(B) each generating unit utilizes the same fuel and generation technology; and
(C) one or more of the generating units are operationally dependent on another.

(m) "Rated capacity" means the powerplant's maximum rated output. For combustion or steam generating units, rated capacity means generating capacity and shall be calculated pursuant to Section 2003.

(Pursuant to § 2003(a), **t**he "generating capacity" of an electric generating facility means the maximum gross rating of the plant's turbine generator(s), in megawatts ("MW"), minus the minimum auxiliary load.)

§ 2902. Greenhouse Gases Emission Performance Standard.

(a) The greenhouse gases emission performance standard (EPS) applicable to this chapter is 1100 pounds (0.5 metric tons) of carbon dioxide (CO_2) per megawatt hour (MWh) of electricity.

(b) Unless otherwise specified in this Article, no local publicly owned electric utility shall enter into a covered procurement if greenhouse gases emissions from the powerplant(s) subject to the covered procurement exceed the EPS.

§ 2903. Compliance with the Emission Performance Standard.

(a) Except as provided in Subsection (b), a powerplant's compliance with the EPS shall be determined by dividing the powerplant's annual average carbon dioxide emissions in pounds by the powerplant's annual average net electricity production in MWh. This determination shall be based on capacity factors, heat rates, and corresponding emissions rates that reflect the expected operations of the powerplant and not on full load heat rates.

§ 2905. Annual Average Electricity Production.

(a) Except as provided in Subsection (b), a powerplant's annual average electricity production in MWh shall be the sum of the net electricity available for all of the following: use onsite or at a host site in a commercial or industrial process or for sale or transmission from the powerplant.

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, South Coast AQMD need not make a determination.

Thermal efficiency calculations are provided above to demonstrate compliance with *40 CFR 60 Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*. For the purpose of showing compliance with the requirements of Subpart TTTT only, the thermal efficiency calculations indicate the greenhouse gas efficiency, with 8% degradation, for the combined-cycle block is ~~966.89~~ **944.34** lb CO_2/MWh-HHV-net.

RECOMMENDATION

Based on the above analysis, it is recommended that the revised Permits to Construct be issued 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.

APPENDIX – PLANNING, RULE DEVELOPMENT & AREA SOURCES (PRDAS) MODELING REVIEW MEMO, DATED JULY 30, 2019