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~~PRELIMINARY~~ FINAL DETERMINATION OF COMPLIANCE for PERMITS TO CONSTRUCT FOR ALAMITOS ENERGY CENTER (AEC)

EQUIPMENT DESCRIPTION

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

Note: *In Section H, all equipment are for the AEC project.*

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 GALS; DIAMETER: 13 FT; LENGTH: 45 FT A/N: 579167	D163				C157.1, E73.2, 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	D164				C157.1, E73.2, 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	D165	C169	NOX: MAJOR SOURCE**	**CO**: ~~2~~ 1.5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996;	A63.2, A99.1, A99.2, A195.8, A195.9,

DRY LOW-NOX COMBUSTOR, GE DLN 2.6, WITH A/N: 579142 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	 [B166] [B167] [B168]			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 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006]; 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)	A195.10, A327.1, B61.1, C1.3, C1.4, D29.2, D29.3, D82.1, D82.2, <u>E73.2,</u> E193.4, E193.5, ~~E193.6,~~ ~~E193.7,~~ E193.8, E193.11, E193.12, E193.14, E448.1, I297.1, K40.4

				[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]; **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, BASF, 265.8 CU. FT.; WIDTH: 26 FT 2 IN; HEIGHT: 71 FT 9.6 IN; LENGTH: 2.1 IN A/N: 579160	C169	D165, C170			E73.2, E193.5
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 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, E73.2, E193.4, E193.5
STACK, TURBINE NO. CCGT-1, HEIGHT: 140 FT; DIAMETER: 20 FT A/N: 579142	S172	C170			
GAS TURBINE, NO. CCGT-2**,** COMBINED-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL 7FA.05, 2275 MMBTU/HR HHV AT 28	D173	C177	NOX: MAJOR SOURCE**	**CO**: ~~2~~ 1.5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-	A63.2, A99.1, A99.2, A195.8, A195.9,

F, WITH DRY LOW-NOX COMBUSTOR, GE DLN 2.6, WITH A/N: 579143 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	 [B174] [B175] [B176]			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 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006]; 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	A195.10, A327.1, B61.1, C1.3, C1.4, D29.2, D29.3, D82.1, D82.2, E73.2, E193.4, E193.5, ~~E193.6,~~ ~~E193.7,~~ E193.8, E193.11, E193.12, E193.14, E448.1, I297.2, K40.4

				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]; **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, BASF, 265.8 CU. FT.; WIDTH: 26 FT 2 IN; HEIGHT: 71 FT 9.6 IN; LENGTH: 2.1 IN A/N: 579161	C177	D173, C178			E73.2, E193.5
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 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, E73.2, E193.4, E193.5
STACK, TURBINE NO. CCGT-2**,** HEIGHT: 140 FT; DIAMETER: 20 FT A/N: 579143	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	D181	C183		**CO**: 50 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-	A63.4, A99.5, A195.13, A195.14, C1.7, D29.5, D29.6, D82.3, E73.2, E193.4, E193.5, E193.10,

BURNER, NATURAL GAS, JZHC/COEN, MODEL RMB, WITH LOW NOX BURNER, 70.8 MMBTU/HR	[B182]			1988]; CO: 400 PPMV NATURAL GAS (5) [RULE 1146, 11-1-2013]; CO: 2000 PPMV NATURAL GAS (5A) [RULE 407, 4-2-1982]; **NOx:** 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: 38.46 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005] **PM10**: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; 0.0072 LB/MMBTU NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002] **VOC**: 0.0052 LB/MMBTU NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]	H23.7, I297.7, K40.5
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 AMMONIA INJECTION, AQUEOUS AMMONIA	C183 [B184]	D181 S211		**NH3**: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.16, D12.15, D12.16, D12.17, D29.4, E73.2, E193.4, E193.5
STACK, AUXILIARY BOILER, HEIGHT: 80 FT; DIAMETER: 3 FT	S211	C183			

A/N: 579158					
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 GENERATOR, 100.438 MW GROSS AT 59 F	D185 [B186]	C187	NOX: MAJOR SOURCE**	**CO**: ~~4.0~~ 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]; 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	A63.3, A99.3, A99.4, A195.10, A195.11, ~~A195.12~~, A195.17, A327.1, B61.1, C1.5, C1.6, D29.2, D29.3, D82.1, D82.2, E73.2, E193.4, E193.5, ~~E193.6,~~ ~~E193.7,~~ E193.9, E193.13, E193.15, E448.1, I297.3, K40.4

				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]; **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: 2 FT; LENGTH: 2 FT 1.5 IN A/N: 579162	C187	D185 C188			<u>E73.2, E193.5</u>
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 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]	A195.15, D12.12, D12.13, D12.14, D29.4, <u>E73.2,</u> E193.4, <u>E193.5</u>
STACK, TURBINE NO. SCGT-1, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN A/N: 579145	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	D191	C193	NOX: MAJOR SOURCE**	**CO**: ~~4.0~~ <u>2.0</u> PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002;	A63.3, A99.3, A99.4, A195.10, A195.11, ~~A195.12~~, <u>A195.17,</u>

A/N: 579147 GENERATOR, 100.438 MW GROSS AT 59 F	[B192]			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]; 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];	A327.1, B61.1, C1.5, C1.6, D29.2, D29.3, D82.1, D82.2, E73.2, E193.4, E193.5, ~~E193.6,~~ ~~E193.7,~~ E193.9, E193.13, E193.15, E448.1, I297.4, K40.4

				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]; **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: 2 FT; LENGTH: 2 FT 1.5 IN A/N: 579163	C193	D191 C194			E73.2, E193.5
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 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]	A195.15, D12.12, D12.13, D12.14, D29.4, E73.2, E193.4, E193.5
STACK, TURBINE NO. SCGT-2, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN A/N: 579147	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 GENERATOR, 100.438 MW GROSS AT 59 F	D197 [B198]	C199	NOX: MAJOR SOURCE**	**CO**: ~~4.0~~ 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)	A63.3, A99.3, A99.4, A195.10, A195.11, ~~A195.12~~, A195.17, A327.1, B61.1, C1.5, C1.6, D29.2, D29.3, D82.1, D82.2, E73.2, E193.4, E193.5, ~~E193.6,~~ ~~E193.7,~~

				[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]; 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];	E193.9, E193.13, E193.15, E448.1, I297.5, K40.4

				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: 2 FT; LENGTH: 2 FT 1.5 IN A/N: 579164	C199	D197 C200			E73.2, E193.5
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 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]	A195.15, D12.12, D12.13, D12.14, D29.4, E73.2, E193.4, E193.5
STACK, TURBINE NO. SCGT-3, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN A/N: 579150	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 GENERATOR, 100.438 MW GROSS AT 59 F	D203 [B204]	C205	NOX: MAJOR SOURCE**	**CO**: ~~4.0~~ 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,	A63.3, A99.3, A99.4, A195.10, A195.11, ~~A195.12~~, A195.17, A327.1, B61.1, C1.5, C1.6, D29.2, D29.3, D82.1, D82.2, E73.2, E193.4, E193.5, ~~E193.6,~~ ~~E193.7,~~ E193.9, E193.13, E193.15, E448.1, I297.6, K40.4

				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]; 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]; **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,	C205	D203 C206			E73.2, E193.5

165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 2 FT; LENGTH: 2 FT 1.5 IN A/N: 579165					
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 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]	A195.15, D12.12, D12.13, D12.14, D29.4, <u>E73.2,</u> E193.4, <u>E193.5</u>
STACK, TURBINE NO. SCGT-4, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN A/N: 579152	S208	C206			
PROCESS 13: OIL/WATER SEPARATION					
OIL WATER SEPARATOR, NO. OWS-1 (COMBINED-CYCLE TURBINES), WASTE WATER, ABOVE GROUND, 5000 GALS; DIAMETER: 5 FT 6 IN; LENGTH: 30 FT A/N: 579169	D209				<u>E73.2,</u> E193.4, <u>E193.5,</u> E193.16
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	D210				<u>E73.2,</u> E193.4, <u>E193.5,</u> E193.16

(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 new 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 SCAQMD in writing and be based on unit specific source tests performed using SCAQMD-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 SCAQMD 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, 12-5-2014]

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, ~~9-11-1998~~ 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, 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, ~~5~~ 6 and 3 (Devices D39, D42, ~~D51~~ D3, and D45, respectively), describing in detail the steps and schedule that will be taken to render Boilers Nos. 1, 2, ~~5~~ 6, and 3 permanently inoperable.

The retirement plan shall be submitted to SCAQMD 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 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. If SCAQMD notifies AES that the plan is not approvable, AES shall submit a revised plan addressing SCAQMD's concerns within 30 days.

Within 30 calendar days of actual shutdown but no later than December 29, 2019, AES shall provide SCAQMD with a notarized statement that Boilers Nos. 1, 2, and ~~5~~ 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 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boilers Nos. 1, 2, and ~~5~~ 6, or advise SCAQMD as soon as practicable should AES undertake permanent shutdown prior to December 29, 2019.

AES shall cease operation of Boilers Nos. 1, 2 , and ~~5~~ 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, AES shall provide SCAQMD 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 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boiler No. 3, or advise SCAQMD 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):

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.

[RULE 1714, 12-10-2012]

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
SOx	Less than or equal to 3616 LBS IN ANY CALENDAR MONTH
CO	Less than or equal to ~~190,753~~ 180,544 LBS IN ANY ONE YEAR
VOC	Less than or equal to 52,668 LBS IN ANY ONE YEAR
PM10	Less than or equal to 39,440 LBS IN ANY ONE YEAR
SOx	Less than or equal to 7435 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 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, 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, 5.11 lb/mmcf; and SOx, 2.92 lb/mmcf.

For normal operation, the emission factors shall be as follows: CO, ~~16.32~~ 15.28 lb/mmcf; VOC, 4.70 lb/mmcf; PM10, 3.92 lb/mmcf; and SOx, 2.24 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. 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 ~~2.0~~ <u>1.5</u> 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 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 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)]

Note: This is regarding the changes to condition C1.3 below. In a meeting on 3/8/16, AES Manager Steven O'Kane was asked by SCAQMD staff why AES differentiates between warm and hot starts in their Applications because the emissions and durations for both are identical. His response was that the CEC requires differentiation and, therefore, AES does as well. On 6/15/16, CEC clarified that differentiation is required only when there is a difference. Because differentiation is not required by the SCAQMD or the CEC when there is no difference in emissions or duration, the proposed revised language presented in AES's comment letter on the PDOC, dated 7/19/16, to combine the warm and hot starts in condition C1.3 is acceptable and reflected below. The remainder of this DOC will not be revised to combine the warm and hot starts.

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, ~~the number of warm startups shall not exceed 12 in any calendar month, and the number of hot startups shall not exceed 35 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, ~~the number of warm startups shall not exceed 88 in any calendar year~~, and the total number of ~~hot~~ startups shall not exceed ~~332~~ 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 ~~warm~~ non-cold startup is defined as a startup which occurs after the combustion turbine has been shut down less than ~~10 hours or more but less than~~ 48 hours. A ~~warm~~ non-cold startup shall not exceed 30 minutes. The NOx emissions from a ~~warm~~ non-cold startup shall not exceed 17 lbs. The CO emissions from a ~~warm~~ non-cold startup shall not exceed 137 lbs. The VOC emissions from a ~~warm~~ non-cold startup shall not exceed 25 lbs.

~~For the purposes of this condition, a hot startup is defined as a startup which occurs after the steam turbine has been shut down for less than 10 hours. A hot startup shall not exceed 30 minutes. The NOx emissions from a hot startup shall not exceed 17 lbs. The CO emissions from a hot startup shall not exceed 137 lbs. The VOC emissions from a hot 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.

[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.

[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 Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOx emissions	AQMD Laboratory Method 307-91	~~Not Applicable~~ District-Approved Averaging Time	Fuel Sample
VOC emissions	District Method 25.3 Modified	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A/ District Method 5.1	District-Approved Averaging Time	Outlet of the SCR serving this equipment
PM2.5	EPA Method 201A and 202	District-Approved Averaging Time	Outlet of the SCR serving this equipment
NH3 emissions	District Method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

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

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, 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 approved source test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 90 days before the proposed test date and shall be approved by the District before the test commences.

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

The sampling time for 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, ~~an alternative to AQMD Method 25.3~~ for the purpose of demonstrating compliance with VOC BACT limits as determined by ~~CARB and~~ SCAQMD, the operator shall use SCAQMD Method 25.3 modified as follows: ~~may be the following:~~

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

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

c) Analysis of Summa canisters per ~~unmodified EPA Method TO-12 (with pre-concentration) or~~ the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F.

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

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 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	AQMD Laboratory Method 307-91	~~Not Applicable~~ <u>District-Approved Averaging Time</u>	Fuel Sample
VOC emissions	District method 25.3 <u>Modified</u>	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A/ District Method 5.1	District-Approved Averaging Time	Outlet of the SCR serving this equipment

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

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

The test shall be conducted when this equipment is operating at 100 percent of maximum load.

For natural gas fired turbines only, ~~an alternative to AQMD Method 25.3~~ for the purpose of demonstrating compliance with <u>VOC</u> BACT <u>limits</u> as determined by ~~CARB and~~ SCAQMD<u>, the operator shall use Method 25.3 modified as follows:</u> ~~may be the following:~~

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

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

c) Analysis of Summa canisters per ~~unmodified EPA Method TO-12 (with pre-concentration) or~~ the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F.

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

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

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002, RULE 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 Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD.

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 REG XX CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD.

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the 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)]

E73.2 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:

The BACT/LAER determination for the Phase II of this project shall be reviewed and modified (by SCAQMD) 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), C170, C178 (combined-cycle control), C188, C194, C200, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

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]

[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 ~~construct~~ install this equipment according to the following requirements:

~~The 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 condition duplicates the Rule 205 requirements in condition 1.b. in Section E: Administrative Conditions.)~~

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 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), C170, C178 (combined-cycle control), C188, C194, C200, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

~~E193.6 The operator shall construct this equipment according to the following requirements:~~

~~The Permit to Construct shall become invalid if construction is not commenced within 18 months after the issuance date, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The EPA Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified.~~

~~[40 CFR 52.21 – PSD, 6-19-1978]~~

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

~~E193.7 The operator shall construct this equipment according to the following requirements:~~

~~The Permit to Construct shall become invalid if construction is not commenced within 24 months after the issuance date, 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.~~

~~[RULE 1713(c), 10-7-1988]~~

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

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. 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 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 610,480 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO_2 emissions shall not exceed 937.88 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.

[RULE 1714, 12-10-2012]

[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.

[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 a source test report in accordance with the following specifications:

Source test results shall be submitted to the District 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
SOx	Less than or equal to 1207 LBS IN ANY CALENDAR MONTH
CO	Less than or equal to ~~37,710~~ 29,730 LBS IN ANY ONE YEAR
VOC	Less than or equal to 7510 LBS IN ANY ONE YEAR
PM10	Less than or equal to 14,695 LBS IN ANY ONE YEAR
SOx	Less than or equal to 1275 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 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, 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, 2.00 lb/mmcf; and SOx, 7.69 lb/mmcf.

For normal operation, the emission factors shall be as follows: CO, ~~13.33~~ 8.84 lb/mmcf; VOC, 3.17 lb/mmcf; PM10, 7.44 lb/mmcf; and SOx, 1.94 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. 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]

~~A195.12~~ A195.17 The ~~4.0~~ 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 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 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.
[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 in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; 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 Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	1 hour	Outlet of the SCR

			serving this equipment
SOx emissions	AQMD Laboratory Method 307-91	~~Not Applicable~~ District-Approved Averaging Time	Fuel Sample
VOC emissions	District Method 25.3 Modified	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A/ District Method 5.1	District-approved averaging time	Outlet of the SCR serving this equipment
PM 2.5	EPA Method 201A and 202	District-approved averaging time	Outlet of the SCR serving this equipment
NH3 emissions	District Method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

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

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, 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 approved source test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 90 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The sampling time for the 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, ~~an alternative to AQMD Method 25.3~~ for the purpose of demonstrating compliance with VOC BACT limits as determined by ~~CARB and~~ SCAQMD, the operator shall use SCAQMD Method 25.3 modified as follows: ~~may be the following:~~

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

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

c) Analysis of Summa canisters ~~per unmodified EPA Method TO-12 (with pre-concentration) or~~ the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F.

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

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 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	AQMD Laboratory Method 307-91	~~Not Applicable~~ District-Approved Averaging Time	Fuel Sample
VOC emissions	District method 25.3 Modified	1 hour	Outlet of the SCR serving this equipment

PM10 emissions	EPA Method 201A/ District Method 5.1	District-Approved Averaging Time	Outlet of the SCR serving this equipment

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

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

The test shall be conducted when this equipment is operating at 100 percent of maximum load.

For natural gas fired turbines only, ~~an alternative to AQMD Method 25.3~~ for the purpose of demonstrating compliance with VOC BACT limits as determined by ~~CARB and~~ SCAQMD, the operator shall use Method 25.3 modified as follows: ~~may be the following:~~

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

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

c) Analysis of Summa canisters per ~~unmodified EPA Method TO-12 (with pre-concentration) or~~ the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F.

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

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

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002, RULE 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 Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD.

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 REG XX CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD.

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the 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)]

E73.2 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:

The BACT/LAER determination for the Phase II of this project shall be reviewed and modified (by SCAQMD) 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), C170, C178 (combined-cycle control), C188, C194, C200, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

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]

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

E193.5 The operator shall ~~construct~~ <u>install</u> this equipment according to the following requirements:

~~The 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 condition duplicates the Rule 205 requirements in condition 1.b. in Section E: Administrative Conditions.)~~

<u>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.</u>

<u>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.</u>

<u>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 unless an extension is granted by the Permitting Authority.</u>

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

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

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

~~E193.6 The operator shall construct this equipment according to the following requirements:~~

~~The Permit to Construct shall become invalid if construction is not commenced within 18 months after the issuance date, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The EPA Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified.~~

~~[40 CFR 52.21 – PSD, 6-19-1978]~~

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

~~E193.7 The operator shall construct this equipment according to the following requirements:~~

~~The Permit to Construct shall become invalid if construction is not commenced within 24 months after the issuance date, 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.~~

~~[RULE 1713(c), 10-7-1988]~~

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

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 with written notification of the initial startup date. The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request. The records shall include, but not be limited to, the total number of commissioning hours, number of commissioning hours without control, 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 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 120,765 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO2 emissions shall not exceed 1356.03 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.

[RULE 1714, 12-10-2012]

[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.

[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 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 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 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 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 a source test report in accordance with the following requirements:

Source test results shall be submitted to the District no later than 90 days after the source tests required by conditions D29.2, 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)]

AUXILIARY BOILER

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

CONTAMINANT	EMISSIONS LIMIT
CO	Less than or equal to 605 LBS IN ANY CALENDAR MONTH
VOC	Less than or equal to 102 LBS IN ANY CALENDAR MONTH
PM10	Less than or equal to 113.5 LBS IN ANY CALENDAR MONTH
SOx	Less than or equal to 32 LBS IN ANY CALENDAR MONTH

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

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

For commissioning and normal operation, the emission factors shall be as follows: CO, 39.55 lb/mmcf; VOC, 6.67 lb/mmcf; PM10, 7.42 lb/mmcf; and SOx, 2.08 lb/mmcf.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request. The records shall include, but not be limited to, natural gas usage in a calendar month.

[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]

[Devices subject to this condition: D181]

A99.5 The 38.46 lbs/mmscf NOx emission limit(s) shall only apply during the interim period prior to CEMS certification to report RECLAIM emissions, not to exceed one year after start of unit operation.

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

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D181]

A195.13 The 5 PPMV NOx emission limit(s) is averaged over 1 hour, dry basis at 3 percent oxygen. This limit shall not apply to boiler commissioning and startup 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: D181]

A195.14 The 50 PPMV CO emission limit(s) is averaged over 1 hour, dry basis at 3 percent oxygen. This limit shall not apply to boiler commissioning and startup 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: D181]

C1.7 The operator shall limit the number of start-ups to no more than 10 in any one calendar month.

The number of cold startups shall not exceed 2 in any calendar month, the number of warm startups shall not exceed 4 in any calendar month, and the number of hot starts shall not exceed 4 in any calendar month, with no more than 1 startup in any one day.

The number of cold startups shall not exceed 24 in any calendar year, the number of warm startups shall not exceed 48 in any calendar year, and the number of hot startups shall not exceed 48 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 170 minutes. The NOx emissions from a cold startup shall not exceed 4.22 lbs.

For the purposes of this condition, a warm startup is defined as a startup which occurs after the combustion turbine has been shut down 10 hours or more but less than 48 hours. A warm startup shall not exceed 85 minutes. The NOx emissions from a warm startup shall not exceed 2.11 lbs.

For the purposes of this condition, a hot startup is defined as a startup which occurs after the steam turbine has been shut down for less than 10 hours. A hot startup shall not exceed 25 minutes. The NOx emissions from a hot startup shall not exceed 0.62 lbs.

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

[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: D181]

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

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOx emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOx emissions	AQMD Laboratory Method 307-91	~~Not Applicable~~ District-Approved Averaging Time	Fuel Sample
VOC emissions	District method 25.3	1 hour	Outlet of the SCR

			serving this equipment
PM10 emissions	EPA Method 201A/ District Method 5.1	District-approved averaging time	Outlet of the SCR serving this equipment
PM 2.5	EPA Method 201A and 202	District-approved averaging time	Outlet of the SCR serving this equipment
NH3 emissions	District Method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

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

For each firing rate, the following operating data shall be included: (1) the exhaust flow rates, in actual cubic feet per minute (acfm), (2) the firing rates in Btu/hour, (3) the exhaust temperature, in degrees F, (4) the oxygen content of the exhaust gases, in percent, and (5) the fuel flow rate.

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

The test protocol shall include the identity of the testing lab, confirmation that the test lab is approved under the District Laboratory Approval Program for the required test method for the CO pollutant, a statement from the testing lab certifying that it meets the criteria of Rule 304 (no conflict of interest), and a description of all sampling and analytical procedures.

The sampling facilities shall comply with the District Guidelines for Construction of Sampling and Testing Facilities, pursuant to Rule 217.

The sampling time for the PM and PM2.5 tests shall be 1 hour or longer as necessary to obtain a measureable amount of sample.

The test shall be conducted when this equipment is operating at maximum, minimum, and normal operating rates.

[RULE 1146, 11-1-2013; 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: D181]

D29.6 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
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment

The test(s) shall be conducted in accordance with the testing frequency requirements specified in Rule 1146.

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

The test shall be conducted when this equipment is operating at 100 percent of maximum load.

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

[Rule 1146, 11-1-2013; 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]

[Devices subject to this condition: D181]

D82.3 The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 3 percent oxygen on a dry basis.

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

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the boiler 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: D181]

E73.2 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:

The BACT/LAER determination for the Phase II of this project shall be reviewed and modified (by SCAQMD) 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), C170, C178 (combined-cycle control), C188, C194, C200, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

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]

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

E193.10 The operator shall operate and maintain this equipment according to the following requirements:

The commissioning period shall not exceed 30 hours of fired operation for the auxiliary boiler from the date of initial boiler start-up.

The operator shall vent this equipment to the SCR control system whenever the auxiliary boiler is in operation after commissioning is completed.

The operator shall provide the SCAQMD with written notification of the initial startup date. The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request. The records shall include, but not be limited to, the number of commissioning hours 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: D181]

H23.7 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
CO	District Rule	1146

These requirement shall include applicable portable analyzer testing and source testing requirements.

[RULE 1146, 11-1-2013]

[Devices subject to this condition: D181]

I297.7 This equipment shall not be operated unless the facility holds 1351 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: D181]

K40.5 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 90 days after the source tests required by conditions D29.5, D29.6, and D29.4 are conducted.

Emission data shall be expressed in terms of concentration (ppmv), corrected to 3 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 moisture concentration shall be expressed in terms of percent corrected to 3 percent oxygen.

Source test results shall also include, for each firing rate, the following operating data: (1) the exhaust flow rates, in actual cubic feet per minute (acfm), (2) the firing rates in Btu/hour, (3) the exhaust temperature, in degrees F, (4) the oxygen content of the exhaust gases, in percent, and (5) the fuel flow rate.

[RULE 1146, 11-1-2013; 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: D181]

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 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 degrees F and 692 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 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 within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

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

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

[Devices subject to this condition: C170, C178 (combined-cycle), C188, C194, C200, C206 (simple-cycle), C183 (auxiliary boiler)]

E73.2 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:

The BACT/LAER determination for the Phase II of this project shall be reviewed and modified (by SCAQMD) 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), C170, C178 (combined-cycle control), C188, C194, C200, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

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]

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

SCR/CO CATALYSTS FOR SIMPLE-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)]

D12.12 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 110 and 180 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: C188, C194, C200, C206]

D12.13 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 500 degrees F and 870 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: C188, C194, C200, C206]

D12.14 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 3.0 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: C188, C194, C200, C206]

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

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

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

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

[Devices subject to this condition: C170, C178 (combined-cycle), C188, C194, C200, C206 (simple-cycle), C183 (auxiliary boiler)]

E73.2 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:

The BACT/LAER determination for the Phase II of this project shall be reviewed and modified (by SCAQMD) 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), C170, C178 (combined-cycle control), C188, C194, C200, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

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]

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

SCR FOR AUXILIARY BOILER

A195.16 The 5.0 PPMV NH3 emission limit is averaged over 1 hour, dry basis at 3 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 3% 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: C183]

D12.15 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 0.3 and 1.1 pounds per hour.

[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: C183]

D12.16 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 415 degrees F and 628 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: C183]

D12.17 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 2.0 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: C183]

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

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

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

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

[Devices subject to this condition: C170, C178 (combined-cycle), C188, C194, C200, C206 (simple-cycle), C183 (auxiliary boiler)]

E73.2 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:

The BACT/LAER determination for the Phase II of this project shall be reviewed and modified (by SCAQMD) 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), C170, C178 (combined-cycle control), C188, C194, C200, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

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]

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

AMMONIA TANKS

Note: Conditions C157.1 and E144.1 are existing conditions from Section D. The rule tags are updated.

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

[~~RULE 402, 5-7-1976~~ 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]

E73.2 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>The BACT/LAER determination for the Phase II of this project shall be reviewed and modified (by SCAQMD) 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.</u>

<u>[40 CFR 52.21 – PSD, 6-19-1978]</u>

<u>[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle), D181 (auxiliary boiler), C170, C178 (combined-cycle control), C188, C194, C200, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, 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]

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

<u>E193.5 The operator shall install this equipment according to the following requirements:</u>

<u>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.</u>

<u>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.</u>

<u>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 unless an extension is granted by the Permitting Authority.</u>

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

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

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

OIL/WATER SEPARATORS

E73.2 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:

The BACT/LAER determination for the Phase II of this project shall be reviewed and modified (by SCAQMD) 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), C170, C178 (combined-cycle control), C188, C194, C200, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

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]

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

E193.16 The operator shall construct, operate, and main this equipment according to the following requirements:

The equipment shall be equipped with a fixed cover to minimize VOC emissions.

[Devices subject to this condition: D209, D210]

BACKGROUND AND FACILITY DESCRIPTION

Existing Facility

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. The AES Corporation purchased the power plant from SCE 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 six utility boilers (Units 1 - 6), six Selective Reduction Systems (SCRs), four aqueous ammonia tanks (29 wt. %), and Rule 219 exempt equipment.

A summary of the utility boilers are 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 facility is a Title V, Acid Rain, and RECLAIM facility (Cycle 1). The facility is currently in compliance with all federal, state, and local rules and regulations.

Proposed Facility

- *Project Description*

  On December 20, 2013, 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). 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 SCAQMD to cancel the permit applications.

  On October 23, 2015, AES Southland Energy, LLC (AES), a different wholly-owned subsidiary of The AES Corporation, submitted new applications for Permits to Construct an amended AEC (AEC) in the configuration selected by SCE. 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 AEC will consist of two gas turbine power blocks.

  - Power Block 1 will consist of one 2-on-1 combined-cycle gas turbine power block with two natural-gas-fired combustion turbine generators (CTGs), two unfired heat recovery steam generators (HRSGs), an steam turbine generator (STG), an air-cooled condenser, and auxiliary boiler.

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 and CO oxidation catalysts will be utilized for control of NOx and CO/VOC emissions, respectively. One 40,000-gallon ammonia (NH_3) storage tank will store 19% aqueous ammonia which is the reducing agent in the SCRs. An oil/water separator 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 CTGs with intercoolers. 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, a second 40,000-gallon ammonia tank, and a second oil/water separator 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 will 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 will be 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 ~~5~~ 6 will be retired once the AEC CCGT reaches the commissioning stage and become operational. Unit 3 will be retired once the AEC SCGT reaches the commissioning stage and become operational. Units 4 and ~~6~~ 5 may operate through December 31, 2020, the current facility compliance date imposed by the OTC Policy. AES is no longer including the demolition as part of the proposed AEC project, but now plans to accomplish the demolition under a separate CEQA proceeding thought a Memorandum of Understanding with the City of Long Beach.

The facility will continue as a federal Title V, Acid Rain, and RECLAIM facility (Cycle 1).

- *Modeling and Offset Exemption*
  SCAQMD 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 SCAQMD 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 replaces. 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.

AES proposes to replace existing Utility Boiler No. 1 (175 MW-gross), No. 2 (175 MW-gross), Unit ~~5~~ 6 (480 MW-gross), and No. 3 (320 MW-gross) at AGS, with the two combined-cycle turbines (692.951 MW-gross total) and four simple-cycle turbines (401.751 MW-gross total). For the PDOC, AES had proposed that Units 1, 2, 5, and 3 be retired. 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. 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. ~~6~~ 5 (480 MW).

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 the table 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 proposed offset plan is subject to change with respect to the RBEP and RBGS. On 11/6/15, AES and the City of Redondo Beach, an intervenor in the RBEP proceeding, filed a "Petition for Suspension of the Application for Certification of the Redondo Beach Energy Project" with the CEC. On 11/25/15, the CEC Committee ordered all proceedings to be suspended until further order of the Committee, and the cessation of all work on the Application for Certification. Also, on 11/6/15, AES submitted a letter to the SCAQMD requesting the suspension of all permitting activities for RBEP.

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	693.822
	HBGS Unit 1 Retired	11/1/2019	215
	RBGS Unit 7 Retired	10/1/2019	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)	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	692.951
	AGS Unit 1 Retired	12/29/2019	175
	AGS Unit 2 Retired	12/29/2019	175
	AGS Unit ~~5~~ 6 Retired	12/29/2019	480
	AGS Unit 3 Retired	12/31/2020	320
	Simple-Cycle Block[d]	6/1/2021	401.751
	MW Installed		1,094.702
	MW Retired		1150
Total MWs Installed and Retired	Total MW Installed		2,536.552
	Total MW Retired		2,715.00

[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.

- *Proposed Schedule*
  Construction activities are anticipated to last 56 months, from first quarter 2017 until third quarter 2021. 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 in January 2017 and construction on the AEC CCGT is expected to be complete by the first quarter of 2020. The AEC SCGT power block is scheduled to commence in the second quarter of 2020 and be completed by the third quarter of 2021. Construction overlap is not expected between the AEC CCGT and AEC SCGT power blocks.

Major project milestones are listed in the following table.

Table 3 - AEC Schedule Major Milestones

Activity	Dates[1]	Commercial Operation
Demolition of Unit 7	January 2017 – May 2017	Not Applicable
Auxiliary Boiler Commissioning	January 2020	Not Applicable
Construction of AEC CCGT.	June 2017 – March 2020	Second Quarter 2020 (April 1, 2020)
Construction of AEC SCGT.	May 2020 – August 2021	Third Quarter 2021

[1] From Response to Data Request 118 of Data Response Set 6, submitted by AES to CEC, dated 12/14/15.

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.

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 to the CEC.

Original SCAQMD Applications Submitted

AES submitted the following applications to the SCAQMD for Permits to Construct for the amended AEC project (original Application). The environmental consultant is CH_2M Hill.

Table 4 - Applications for Permits to Construct Submitted to SCAQMD

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
579140	10/23/15	1/14/16	RECLAIM/Title V Revision	$1,994.55
579142	10/23/15	1/14/16	Combined-Cycle Turbine	$27,075.57
579143	10/23/15	1/14/16	Combined-Cycle Turbine	$13,537.79 (50%--identical)
579145	10/23/15	1/14/16	Simple-Cycle Turbine	$27,075.57
579147	10/23/15	1/14/16	Simple-Cycle Turbine	$13,537.79 (50%--identical)
579150	10/23/15	1/14/16	Simple-Cycle Turbine	$13,537.79 (50%--identical)
579152	10/23/15	1/14/16	Simple-Cycle Turbine	$13,537.79 (50%--identical)
579158	10/23/15	1/14/16	Auxiliary Boiler	$9,128.07
579160	10/23/15	1/14/16	SCR/CO Catalyst for Combined-Cycle Turbine	$5,752.59
579161	10/23/15	1/14/16	SCR/CO Catalyst for Combined-Cycle Turbine	$2,876.30 (50%--identical)
579162	10/23/15	1/14/16	SCR/CO Catalyst for Simple-Cycle Turbine	$5,752.59
579163	10/23/15	1/14/16	SCR/CO Catalyst for Simple-Cycle Turbine	$2,876.30 (50%--identical)
579164	10/23/15	1/14/16	SCR/CO Catalyst for Simple-Cycle Turbine	$2,876.30 (50%--identical)
579165	10/23/15	1/14/16	SCR/CO Catalyst for Simple-Cycle Turbine	$2,876.30 (50%--identical)
579166	10/23/15	1/14/16	SCR for Auxiliary Boiler	$5,752.59
579167	10/23/15	1/14/16	Ammonia Tank for Combined-Cycle Turbines	$2,281.98
579168	10/23/15	1/14/16	Ammonia Tank for Simple-Cycle Turbines	$1,140.99 (50%--identical)
579169	10/23/15	1/14/16	Oil/Water Separator Combined-Cycle Turbines (>= 10,000 GPD)	$5,752.59
579170	10/23/15	1/14/16	Oil/Water Separator Simple-Cycle Turbines (< 10,000 GPD)	$3,636.95
			Total Fee Required	$161,000.40
			Total Fee Submitted	$161,380.74
			Refund	$380.34

The oil/water wastewater separators are not exempt under Rule 219(p)(16), because this exemption does not include treatment processes where VOC and/or toxic materials are emitted. The applicant inadvertently paid for three identical ammonia tanks and erroneously assumed the oil/water separators are identical, thereby resulting in an overall overpayment.

Note: A/N 579142 is the master file.

Original Applications Deem Completion Chronology
On 10/23/15, AES submitted the original Application. On 11/20/15, SCAQMD issued an additional information letter. On 12/11/15, AES provided a response letter. On 12/18/15, SCAQMD sent an e-mail requesting additional information. On 1/7/16, AES provided a response letter. On 1/14/16, SCAQMD deemed the original Application complete.

Revised Application
In February 2016, AES became aware 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 (revised Application), primarily to increase the number of cold startups for the combined-cycle turbines on a monthly and annual basis. The revised Application includes revised emissions calculations and modeling, and incorporates revisions resulting from recent discussions with the SCAQMD over the course of permitting for the Huntington Beach Energy Project (HBEP) and AEC. The new revisions will be discussed below under the relevant sections.

PROCESS DESCRIPTION

1. A/N 579142, 579143—Combined-Cycle Combustion Turbine Generators Nos. CCGT-1, CCGT-2
   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.

The following table lists the technical specifications for the combined-cycle turbines. The case numbers are from *Table 15*, below.

Table 4A – Combined-Cycle Turbine Specifications

Turbine Parameters	**Specifications**
Manufacturer	General Electric
Model	7FA.05

Fuel Type	Pipeline natural gas
Maximum Turbine Power Output	236.645 MW-gross at 28 ºF (Case 1)
Steam Turbine Generator Output	219.615 MW-gross at 28 ºF (Case 1)
Maximum Turbine Heat Input	2275 MMBtu/hr (HHV) at 28 ºF (Case 1)
Turbine Heat Input at Average Ambient Temperature	2250 MMBtu/hr (HHV) at 65.3 ºF (Case 4)
Gross 2x1 Combined-Cycle	692,905 kW at 28 ºF (Case 1)
Net 2x1 Combined-Cycle	680,779 kW at 28 ºF (Case 1)
NOx Combustion Control	Dry Low NOx Combustors, 9 ppmvd at 15% O_2

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

- *<u>CO Oxidation Catalyst</u>*
The CO oxidation catalyst, located between the HRSG and the SCR, will be used to control CO and VOC emissions. <u>For the PDOC, t</u>he catalyst ~~will~~ <u>was required to</u> reduce CO emissions from 7 - 8 ppm to 2 ppmv, all 1-hr averages, dry basis at 15% O_2. <u>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.</u> The catalyst will reduce the VOC from approximately ~~2.2~~ <u>2.6</u> ppm to 2 ppmv, all 1-hour averages, dry basis at 15% O_2.

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

Table 5 – Combined-Cycle Turbine CO Oxidation Catalyst Specifications

Catalyst Parameters	**Specifications**
Manufacturer	BASF Corp.
Model	TBD
Catalyst Type	Platinum Group Metals, Corrugated SS Foil w/ Catalytic Washcoat
Catalyst Guaranteed Life	NE Nooter/Erickson—Earlier of 36 months from first gas in or 39 months from contracted delivery.
Space Velocity	467,260.55/hr
Catalyst Volume	265.8 ft^3
CO removal efficiency	70% or greater
CO at stack outlet	<u>PDOC--</u>2.0 ppmvd at 15% O_2 <u>FDOC—1.5 ppmvd at 15% O_2</u>
VOC at stack outlet	2.0 ppmvd at 15% O_2
Operating Temperature	570 - 692 ºF

- *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.

  The following table lists the technical specifications for the SCR.

Table 6 – Combined-Cycle Turbine Selective Catalytic Reduction Specifications

Catalyst Parameters	Specifications
Manufacturer	Cormetech
Catalyst Description	Titanium/Vanadium/Tungsten, Corrugated Fiberglass/Ceramic
Catalyst Model No.	TBD
Catalyst Volume	1289 ft^3
Reactor Dimensions	1.5 ft long x 25.7 ft wide x 71.6 ft high
Catalyst Guaranteed Life	NE Nooter/Erickson—Earlier of 36 months from first gas in or 39 months from contracted delivery.
Space Velocity	96,352.10 per hr
Area Velocity	67462.17 ft/hr
Ammonia Injection Rate	44 - 242 lb/hr
Ammonia Slip	5 ppm at 15% O_2
NOx removal efficiency	77% or greater
NOx at stack outlet	2.0 ppmv at 15% O_2
Operating Temperature	570 - 692 ºF
Pressure Drop	1.6 inches water column

- *Performance and Catalyst Life Warranties*
  - *Performance Warranty*

    In a letter dated 6/5/15, Julie Lux, Nooter/Eriksen, provided emissions guarantees for NOx, CO, VOC, PM_{10}, $PM_{2.5}$, and NH_3 for the PDOC. The warranted emissions levels, including 2.0 ppmvd CO at 15% O_2, are summarized in the table below.

    The performance guarantee for 1.5 ppmvd CO at 15% O_2 is pending and expected to be provided in the near future. The FDOC is based on this lower CO concentration.

Table 7 - Combined-Cycle Turbine Warranted Emission Levels for Control Systems

Pollutants	Warranted Emission Levels
NOx	2.0 ppmvd at 15% O_2
CO	PDOC--2.0 ppmvd at 15% O_2 per 6/5/15 guarantee. FDOC--1.5 ppmvd at 15% O_2 (guarantee pending).
VOC	1.0 ppmvd at 15% O_2 (based on source test methods not accepted by SCAQMD).
PM_{10}/$PM_{2.5}$	6.7 lb/hr (not including ammonium sulfate particulates formed in the ~~CO catalyst and~~ SCR catalyst)
NH_3	5 ppmvd at 15% O_2

For a detailed discussion of the BACT/LAER versus warranty levels, see the BACT/LAER analysis under *Regulation XIII—New Source Review (NSR)* below.

  - *Catalyst Life Warranties*

    The Nooter/Eriksen letter indicated the CO and SCR catalysts guarantee life is the earlier of 36 months from first gas in or 39 months from contracted delivery.

3. A/N 579158—Auxiliary Boiler (Combined-Cycle Turbines)

   In a letter dated 12/11/15, the applicant provided a process description and an updated boiler selection. The auxiliary boiler, Babcock & Wilcox (B & W), Model FM 103-88, watertube type, rated at 70.8 MMBtu/hr, assists with the fast start of the combined-cycle turbines. The auxiliary boiler provides enhanced startup times by maintaining the steam cycle in a ready state through the provision of steam for heat recovery steam generator (HRSG) sparging, turbine steam seals, steam pipe warming, condenser deaerating steam, and steam to the fuel gas heater. Prior to a CCGT startup, the auxiliary boiler will increase load from the minimum turndown rate to the maximum load and the produced steam will be directed to the system for HRSG sparging, turbine seals, pipe warming, condenser deaerating and to the fuel gas heater. Once the CCGT completes a startup and the steam turbine reaches maximum output, the auxiliary boiler will reduce load to the minimum turndown firing rate. If extended periods of CCGT outage are expected, the auxiliary boiler could be shut down until a start of the CCGT is expected.

Under the worst-case maximum month emissions scenario, the boiler will be assumed to continuously operate at 30% load per the revised Application, reduced from 50% load per the original Application, to maintain the CCGT in a ready state condition. Under actual operating conditions, the auxiliary boiler would be used only to maintain steam system readiness and could be shut down and taken offline after a startup of the CCGT and the steam systems have reached maximum output.

The following table lists the technical specifications for the auxiliary boiler.

Table 7A – Auxiliary Boiler Specifications

Boiler Parameters	**Specifications**
Boiler Manufacturer/Model	Babcock & Wilcox/Model FM 103-88
Boiler Type	Watertube
Burner Manufacturer/Model	JZHC/Coen RMB
Maximum Heat Input	70.8 MMBtu/hr
Boiler NOx Control	Flue gas recirculation & low NOx burner
NOx at Boiler Outlet	10 ppmv at 3% O_2, 1-hr average
NOx at SCR Outlet	5 ppmv at 3% O_2, 1-hr average
CO at Boiler Outlet	50 ppmv at 3% O_2, 1-hr average

4. <u>A/N 579166—Selective Catalytic Reduction for Auxiliary Boiler</u>
The auxiliary boiler will be equipped with a selective catalytic reduction system.

- *<u>Selective Catalytic Reduction</u>*
  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 10 ppmv to 5.0 ppmv, all 1-hour averages, dry basis at 3% O_2. The ammonia slip will be limited to 5 ppmvd at 3% O_2. Each SCR will be vented through a dedicated stack, which is 3 feet diameter and 80 feet high.

  The exhaust temperature is required to be between 415 and 628 ºF, as specified in condition no. D12.16. 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 2 inches water column, as required by condition no. D12.17. The ammonia flow rate shall be between 0.3 and 1.1 pounds per hour, as required by condition no. D12.15.

The following table lists the technical specifications for the SCR.

Table 8 – Auxiliary Boiler Selective Catalytic Reduction Specifications

Catalyst Properties	Specifications
Manufacturer	Babcock & Wilcox (B & W)
Catalyst Description	Vanadium, Homogeneous Honeycomb
Catalyst Model No.	FM Series
Catalyst Volume	46 ft^3
Reactor Dimensions	7.25 ft long x 5.4 ft wide x 3.7 ft high
Catalyst Guaranteed Life	Cormetech, Inc.--24,000 hours or three years
Space Velocity	485/hr
Area Velocity	47,800 ft/hr
Ammonia Injection Rate	0.3 – 1.1 lb/hr
Ammonia Slip	5 ppm at 3% O_2
NOx removal efficiency	50% or greater
NOx at stack outlet	5.0 ppmv at 3% O_2
Operating Temperature	415 – 628 ºF
Pressure Drop	2.0 inches water column

- *Performance and Catalyst Life Warranties*
  - *Performance Warranty*

    In a letter dated 6/10/15, David Obrecht, Cleaver Brooks, provided guaranteed stack emissions for NOx (post-SCR), CO, VOC, PM_{10}, and NH_3.

    The warranted emissions levels are summarized in the table below.

Table 9 - Auxiliary Boiler Warranted Emission Levels for Control Systems

Pollutants	Warranted Emission Levels
NOx	5 ppmvd at 3% O_2
CO	50 ppmvd at 3% O_2
VOC	0.003 lbs/MMBtu
PM_{10}	0.0043 lbs/MMBtu
NH_3	5 ppmvd at 3% O_2

For a detailed discussion of the BACT/LAER versus warranty levels, see the BACT/LAER analysis under *Regulation XIII—New Source Review (NSR)* below.

- *Catalyst Life Warranties*
  In an e-mail dated 12/7/15, John Nivens, Cormetech, stated that Cormetech's standard SCR catalyst life expectancy guarantee for AES's turbines and auxiliary boiler is 3 years or 24,000 hours.

5. A/N 579145, 579147, 579150, 579152—Simple-Cycle Combustion Turbine Generators Nos. SCGT-1, SCGT-2, SCGT-3, SCGT-4

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.

The following table lists the technical specifications for the simple-cycle turbines. The case numbers are from *Table 31*, below.

Table 9A – Simple-Cycle Turbine Specifications

Turbine Parameters	Specifications
Manufacturer	General Electric
Model	LMS-100 PB
Fuel Type	Pipeline natural gas
Maximum Turbine Power Output	100.438 MW-gross at 59 ºF (Case 12)
Maximum Turbine Heat Input	882 MMBtu/hr (HHV) at 59 ºF (Case 12)
Turbine Heat Input at Average Ambient Temperature	876 MMBtu/hr (HHV) at 65.3 ºF (Case 4)
Gross 4 LMS-100 PB	401.751 kW at 59 ºF (Case 12)
Net 4 LMS-100 PB	386.712 kW at 59 ºF (Case 12)
NOx Combustion Control	Dry Low NOx Combustors, 25 ppmvd at 15% O_2

6. A/N 579162, 579163, 579164, 579165—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. SCGT-1, SCGT-2, SCGT-3, SCGT-4 (Simple-Cycle Turbines)
Each simple-cycle turbine will be equipped with an oxidation catalyst and a selective catalytic reduction system.

- *CO Oxidation Catalyst*
  The CO oxidation catalyst, located between the HRSG and the SCR, will be used to control CO and VOC emissions.

  For the PDOC, the catalyst ~~will~~ was required to reduce CO emissions from 100 ppm to 4 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 2 ppmv, 1-hr average, dry basis at 15% O_2, in accordance with the reduction in the BACT limit from 4 ppmv to 2 ppmv. The catalyst will reduce the VOC from 4 ppm to 2 ppmv, all 1-hour averages, dry basis at 15% O_2.

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

Table 10 – Simple-Cycle Turbine CO Oxidation Catalyst Specifications

Catalyst Parameters	**Specifications**
Manufacturer	BASF Corp.
Model	Camet
Catalyst Type	Platinum Group Metals, Corrugated SS Foil w/ Catalytic Washcoat
Catalyst Guaranteed Life	BASF Corp 7-12 years
Space Velocity	139,539/hr
Catalyst Volume	165.57 ft^3
CO removal efficiency	99% or greater
CO at stack outlet	PDOC--4.0 ppmvd at 15% O_2 FDOC--2.0 ppmvd at 15% O_2
VOC at stack outlet	2.0 ppmvd at 15% O_2
Operating Temperature	500-1250 ºF

- *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 25 ppm to 2.5 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 13.5 feet diameter and 80 feet high.

  The exhaust temperature is required to be between 500 and 870 ºF, as specified in condition no. D12.13. 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 3 inches water column, as required by condition no. D12.14. The ammonia flow rate shall be between 110 and 180 pounds per hour, as required by condition no. D12.12.

  The following table lists the technical specifications for the SCR.

Table 11 – Simple-Cycle Turbine Selective Catalytic Reduction Specifications

Catalyst Parameters	Specifications
Manufacturer	Cormetech
Catalyst Description	Titanium/Vanadium/Tungsten, Ceramic Honeycomb
Catalyst Model No.	CMHT
Catalyst Volume	621.96 ft^3
Reactor Dimensions	11.5 ft long x 4.9 ft wide x 11 ft high
Catalyst Guaranteed Life	Cormetech, Inc.—three years or 24,000 hours
Space Velocity	37,147/hr
Area Velocity	182,639 ft/hr
Ammonia Injection Rate	110 - 180 lb/hr
Ammonia Slip	5 ppm at 15% O_2
NOx removal efficiency	90% or greater
NOx at stack outlet	2.5 ppmv at 15% O_2
Operating Temperature	500 – 870 ºF
Pressure Drop	3.0 inches water column

- *Performance and Catalyst Life Warranties*
  - *Performance Warranty*

    In a document dated 6/16/15, Christopher Vu, General Electric, provided guarantees for NOx, CO, VOC, PM_{10}, and NH_3, based on a GE supplied SCR/CO Catalyst. The warranted emissions levels, including 4.0 ppmvd CO at 15% O_2, are summarized in the table below.

    In a proposal, dated 9/16/16, Bob Zeiss, BASF Corp., provided a performance guarantee for 2.0 ppmvd CO at 15% O_2. A slight increase in the precious metal content will be required. The FDOC is based on this lower CO concentration.

Table 12 - Simple-Cycle Turbine Warranted Emissions for Control Systems

Pollutants	Warranted Emissions
NOx	2.5 ppmvd at 15% O_2
CO	PDOC--4.0 ppmvd at 15% O_2 per 6/16/15 guarantee. FDOC--2.0 ppmvd at 15% O_2 per 9/16/16 guarantee.
VOC	2 ppmvd at 15% O_2
PM_{10}	5 lb/hr (not including ammonium sulfate particulates formed in the SCR catalyst)
NH_3	5 ppmvd at 15% O_2

For a detailed discussion of the BACT/LAER versus warranty levels, see the BACT/LAER analysis under *Regulation XIII—New Source Review (NSR)* below.

- <u>*Catalyst Life Warranties*</u>
  In an e-mail dated 12/7/15, John Nivens, Cormetech, stated that Cormetech's standard SCR catalyst life expectancy guarantee for AES's turbines and auxiliary boiler is 3 years or 24,000 hours.

  In an e-mail dated 12/7/15, Robert Zeiss, BASF Corp, stated that they typically state 7 – 12 years expected life, but they have many installations that have been in service 15 – 20 years.

7. <u>A/N 579167--Ammonia Storage Tank, No. Tank-1 (Combined-Cycle Turbines)</u>
   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.

8. <u>A/N 579168--Ammonia Storage Tank, No. Tank-2 (Simple-Cycle Turbines)</u>
   This 40,000-gallon ammonia tank will provide ammonia to the four SCRs for the simple-cycle turbines. This tank is identical to the tank for the combined-cycle turbines, except the maximum number of tanker truck deliveries is estimated to be three per month.

9. <u>A/N 579169—Oil/Water Separator, No. OWS-1 (Combined-Cycle Turbines)</u>
   The oil/water separator for the combined-cycle turbine power block will treat stormwater from process areas that could potentially include oil or other lubricants for removal of accumulated oil that may result from equipment leakage or small spills and large particulate matter that may be present from equipment washdowns. The secondary containment area for the oil/grease-containing equipment is pumped out to the oil/water separator after each rain event to ensure

sufficient capacity is available for additional stormwater. The oil/water separator throughput is 400 gallons/minute.

From the separator, the stormwater is directed to an existing retention basin and then ultimately discharged to the existing stormwater outfalls which discharge into the AGS cooling water canals and ultimately to the Los Cerritos Channel. The residual oil-containing sludge in the separator will be collected via vacuum truck and disposed of as hazardous waste.

The oil/water separator will be an above ground tank with a capacity of 5000 gallons, measuring 5 feet 6 inches diameter and 30 feet long. The maximum monthly wastewater throughput is 808,737.6 gal/month.

10. A/N 579170—Oil/Water Separator, No. OWS-2 (Simple-Cycle Turbines)
The oil/water separator for the simple-cycle turbine power block is identical to the separator for the combined-cycle turbine power block, except the maximum monthly wastewater throughput is 123,424.04 gal/month.

EMISSIONS CALCULATIONS

Alamitos Generating Station—Existing Equipment

- **Potential to Emit Calculations**
  Potential to emit emissions for AGS are required to evaluate compliance with certain 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 SCAQMD 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. Boiler No. 3, 3350 MMBtu/hr
4. Boiler No. 4, 3350 MMBtu/hr

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 SCAQMD 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 SCAQMD 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

- **<u>Actual Emissions</u>**
  Recent actual AGS emissions are required to evaluate compliance with certain regulations, as discussed in the *<u>Rule Evaluation</u>* section below.

  In a Response Letter dated 12/11/15, the applicant provided actual emissions for 2013 and 2014, reflected in the table 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

		NOx	CO	ROG	PM_{10}/ $PM_{2.5}$	SOx	CO_2e
Year	**Unit**	lb/year (tpy)					tpy
	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

Alamitos Energy Center--New Equipment

1. A/N 579142, 579143—Combined-Cycle Combustion Turbine Generators Nos. CCGT-1, CCGT-2
   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, ~~63.3~~ 65.3 ºF, and 107 ºF), and with or without evaporative cooling of the inlet air to the turbines. The operating scenarios are presented in *Table 5.1B.3R—Combined-Cycle: GE 7FA.05 Performance Data* in Attachment 6 of AES Response Letter, 12/11/15. This table includes the scenarios for 59 ºF missing from the original Application, and revised VOC hourly emission rates based on the BACT limit of 2 ppmvd at 15% O_2, a correction from the emission rates based on 1 ppmvd at 15% O_2 (based on source test methods not accepted by SCAQMD) provided in the original Application.

     For the FDOC, the revised BACT determination reduced BACT for CO from 2 ppmvd to 1.5 ppmvd, both at 15% O_2. In AES Response letter, dated 11/4/16, AES confirmed the CO emission rates for normal operations would be reduced to 0.75 times the original emission rates but the startup/shutdown rates would not be affected. The letter also provided the reduced emission rates.

The operating scenarios data, including the change to a CO BACT of 1.5 ppmvd, are summarized in the following table.

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, ~~2.0~~ 1.5 ppmvd (dry, 15% O_2) BACT, lb/hr	~~10.0~~ 7.53	~~7.92~~ 5.94	~~6.09~~ 4.57	~~9.93~~ 7.44	~~9.88~~ 7.41	~~7.67~~ 5.76	~~5.77~~ 4.33	~~9.50~~ 7.13	~~8.58~~ 6.44	~~6.87~~ 5.15	~~5.51~~ 4.13	~~9.94~~ 7.46	~~7.74~~ 5.81	~~5.78~~ 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) will be used to calculate the normal operation emissions component for the maximum daily emissions and maximum monthly emissions. 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 proposed in the original Application. 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) will be 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.

- Four Operational Modes

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

The following provides an explanation of the four operating modes, and the proposed parameters and emissions associated with each mode. In AES Response Letter, dated 12/11/15, the applicant has clarified that the combustors are not expected to require tuning after commissioning.

Commissioning

Commissioning is a one-time event that is performed after the installation of the turbines and associated equipment, and prior to commercial operation. The facility follows a systematic approach to optimize the performance of the CTGs, 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 original Application provided the duration and corresponding pollutant emission rates for each commissioning activity for a single CTG in *Table 5.1B.1—Summary of Commissioning Emission Estimates: Combined-Cycle Turbines* in *Appendix 5.1B—Commissioning and Operational Emission Estimates*. The $PM_{10}/PM_{2.5}$ and SOx emission rates are based on the maximum hourly emission rates, including the short-term rate for SO_2, from *Table 15* (case 1).

In AES Response e-Mail dated 1/28/16, the applicant provided the fuel usage for each commissioning activity.

The following table provides a summary of the commissioning activity parameters and emissions.

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.

The dispersion modeling analysis, discussed below, shows that the maximum impact would occur if both turbines, with both the SCR and CO oxidation catalyst at 0% control, were simultaneously undergoing commissioning activities with the highest unabated emissions (i.e., CTG Testing (Full Speed No Load)). The modeling results demonstrated that both turbines may undergo simultaneous commissioning without causing the NO_2 or CO ambient standards to be exceeded.

Startup of Combined-Cycle Turbines

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

Three 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 would typically occur if 48 hours or more elapse 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 **warm start event** would typically be 10 hours or more but 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.

3) A **hot start event** would typically be less than 10 hours of a shutdown event. As with a warm start, the time from fuel initiation until reaching the baseload operating rate is expected to take up to 30 minutes.

For daily emissions (for modeling), the applicant requested a maximum of one cold start and one warm start per turbine in the original Application. In the revised Application, the applicant requested a maximum of two cold starts per turbine.

For monthly emissions, the applicant requested a maximum of 2 cold starts, 15 warm starts, 45 hot starts per turbine in the original Application. In the revised Application, the applicant requested a maximum of 15 cold starts, 12 warm starts, 35 hot starts per turbine.

For annual emissions, the applicant requested a maximum of 24 cold starts, 100 warm starts, and 376 hot starts per turbine in the original Application. In the revised Application, the applicant requested a maximum of 80 cold starts, 88 warm starts, 332 hot starts per turbine.

Shutdown of Combined-Cycle Turbines

A shutdown event occurs each time a CTG is shut down. A shutdown starts at the initiation of the turbine shutdown sequence and ends with the cessation of turbine firing. Typically, during the shutdown process, the emission rates will be less than during the start-up process but may be slightly 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), the applicant has requested a maximum of two shutdowns per turbine. For monthly emissions, the applicant has requested a maximum of 62 shutdowns per turbine. For annual emissions, the applicant has requested a maximum of 500 shutdowns per turbine.

- *Startup/Shutdown Emissions*

  The applicant provided maximum startup and shutdown emissions per event for NOx, CO, and VOC, and startup and shutdown hourly emission rates for NOx, CO, VOC, SO_2 (short-term) and $PM_{10/2.5}$ in *Table 5.1-14R—GE 7FA.05 Startup/Shutdown Emission Rates* in AES Response Letter, dated 12/11/15. This table includes revised hourly startup and shutdown emission for VOC based on the BACT limit of 2 ppmvd at 15% O_2, a correction from the emission rates based on 1 ppmvd at 15% O_2 (based on source test methods not accepted by the SCAQMD) provided in the original Application.

  In AES Response letter, dated 11/4/16, AES confirmed the startup/shutdown rates for CO would not be affected by the reduction in the BACT level for CO from 2 ppmvd to 1.5 ppmvd, both at 15% O_2.

  The following table summarizes the emissions for the three types of startup events and the shutdown event.

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 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*
  The startup/shutdown conditions limit and minimize emissions during startups and shutdowns when steady state BACT is not achievable. 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 warm starts per calendar month and year; (3) number of hot starts per calendar month and year; (4) number of startups per day; and (5) duration of cold start, warm start, and hot start; and (6) NOx, CO, and VOC emissions per cold start, warm start, and hot start. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdown; and (3) NOx, CO, and VOC emissions per shutdown.

Normal Operation
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 ~~2.0~~ 1.5 ppmvd, and VOC to 2.0 ppmvd, all 1-hr averages, at 15% O2.

- *Maximum Daily, Monthly, Annual, NSR Emissions Calculations*
  The following sections will discuss maximum daily emissions, maximum monthly emissions, maximum annual emissions, and associated emission factors and permit condition limits. Finally, offset requirements and the calculation of NSR entries will be discussed.

  - *Maximum Daily Emissions per Turbine*
    Maximum daily emissions during normal operations are calculated to determine whether BACT/LAER is 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. 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>
In the original Application, *Table 5.1B.5—Combined-Cycle: Summary of Operation Emissions—Criteria Pollutants*, footnote b indicates the maximum daily emissions are based on 1 cold start, 1 warm start, and 2 shutdowns. The revised Application requested two cold starts and 2 shutdowns. The normal operation emission rates are from *Table 15* (case 1), and the startup and shutdown emissions per event are from *Table 17*. The SOx emission rates are based on the short-term rate (0.75 grains/100 scf).

For strict BACT/LAER applicability, 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.

Table 18 - Combined-Cycle Turbine Maximum Daily Emissions

Pollutants	No. of Normal Operating Hr	Normal Operation Emission Rate, lb/hr	No. of Cold Startups	Lb/cold Startup	No. of Warm Startups	Lb/Warm 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	~~10.0~~ <u>7.53</u>	2	325	0	137	2	133	**~~1126.00~~** **<u>1074.13</u>**
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 startup/day)(1.0 hr/cold start) - (0 warm startup/day) (0.5 hr/warm 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. startups, cold) (lb/startup, cold) + (no. startups, warm) (lb/startup, warm) + (no. shutdowns) (lb/shutdown)

- <u>*Maximum Monthly Emissions and Emission Factors per Turbine*</u>
  Condition A63.2 specifies the monthly emissions limits for CO, VOC, PM_{10}, 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}, and SOx. The number of RECLAIM RTCs required are determined on an annual basis, which are calculated below 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. As explained below, AES has indicated there will be no combination commissioning/normal operating month. Therefore commissioning month(s) emissions and normal operating month emissions will be evaluated below. In addition, the commissioning emission factors and normal operating emission factors will be included in condition A63.2 for CO, VOC, PM_{10}, and SOx. The commissioning emission factor and the post-commissioning/pre-CEMS certification emission factor will be including in conditions A99.1 and A99.2, respectively, for NOx.

- <u>Commissioning Months</u>
  - <u>Maximum Monthly Emissions, Commissioning</u>
    In the AES Response Letter dated 12/11/15, the applicant indicated that the commissioning period will extend over a period of 6 full months, and will not overlap with steady-state operation of the CTGs. The number of commissioning hours per month per turbine is 166 hours.

    In AES response e-mail dated 4/6/16, AES reaffirmed that AEC project engineers has determined the combined-cycle power block commissioning will require six months to complete.

Month 1: CTG Testing and a portion of Steam Blows

		Total Controlled Emissions, lb				
Activity	**Duration (hr)**	**NOx**	**CO**	**VOC**	**SOx**	**$PM_{10}/PM_{2.5}$**
CTG Testing (Full Speed No Load, FSNL)	48	6,240	91,200	12,960	233	408
Steam Blows	118 of 120	8053.5	3823.2	354	573.3	1003
Total	166	14293.5	95,023.2	13,314	806.3	1411

Month 2: Remainder of Steam Blows, Set Unit HRSG & Steam Safety Valves, DLN Emissions Tuning, Emissions Tuning, Emissions Tuning, and a portion of Verify STG on Turning Gear

		Total Controlled Emissions, lb				
Activity	**Duration (hr)**	**NOx**	**CO**	**VOC**	**SOx**	**$PM_{10}/PM_{2.5}$**
Steam Blows	2 of 120	136.5	64.8	6.0	9.7	17.0
Set Unit HRSG & Steam Safety Valves	12	819	389	36.0	58.3	102
Steam Blows – Restoration						
DLN Emissions Tuning	12	567	285	24.0	58.3	102
Emissions Tuning	12	630	298	24.0	58.3	102
Emissions Tuning	12	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.	116 of 168	1607.4	744.3	188.5	563.4	986.0
Total	166	4515.9	2131.1	308.5	806.3	1411

Month 3: Remainder of Verify STG on Turning Gear, CT Base Load Testing/Tuning, Load Test STG / Combined-Cycle (2 x 1) Tuning, and a portion of STG Load Test/ Combined-Cycle Tuning

		Total Controlled Emissions, lb				
Activity	**Duration (hr)**	**NOx**	**CO**	**VOC**	**SOx**	**$PM_{10}/PM_{2.5}$**
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.	52 of 168	720.6	333.7	84.5	252.6	442
CT Base Load Testing/Tuning	24	388	182	46.8	117	204
Load Test STG / Combined-Cycle (2 x 1) Tuning	48	499	251	62.4	233	408
STG Load Test/ Combined-Cycle Tuning	42 of 96	582.3	269.5	68.3	204.3	357
Total	166	2189.9	1036.2	262	806.9	1411.0

Month 4: Remainder of STG Load Test/ Combined-Cycle Tuning, RATA/ Pre-Performance Testing/Source Testing, Source Testing & Drift Test Day 1, and a portion of Source Testing & Drift Test Day 2

		Total Controlled Emissions, lb				
Activity	**Duration (hr)**	**NOx**	**CO**	**VOC**	**SOx**	**$PM_{10}/PM_{2.5}$**
STG Load Test/ Combined-Cycle Tuning	54 of 96	748.7	346.5	87.8	262.7	459
RATA/ Pre-Performance Testing/Source Testing	84	1,164	539	137	408	714
Source Testing & Drift Test Day 1	24	249	125	31.2	117	204
Source Testing & Drift Test Day 2	4 of 24	41.5	20.8	5.2	19.5	34.0
Total	166	2203.2	1031.3	261.2	807.2	1411.0

Month 5: Remainder of Source Testing & Drift Test Day 2, Source Testing & Drift Test Day 3, Source Testing & Drift Test Day 4, Source Testing & Drift Test Day 5, Source Testing & Drift Test Day 6, Source Testing & Drift Test Day 7, and a portion of Performance Testing

		Total Controlled Emissions, lb				
Activity	**Duration (hr)**	**NOx**	**CO**	**VOC**	**SOx**	**$PM_{10}/PM_{2.5}$**
Source Testing & Drift Test Day 2	20 of 24	207.5	104.2	26.0	97.5	170
Source Testing & Drift Test Day 3	24	249	125	31.2	117	204
Source Testing & Drift Test Day 4	24	249	125	31.2	117	204
Source Testing & Drift Test Day 5	24	249	125	31.2	117	204
Source Testing & Drift Test Day 6	24	249	125	31.2	117	204
Source Testing & Drift Test Day 7	24	249	125	31.2	117	204
Performance Testing	26 of 132	420.3	197.8	50.6	126.5	221.0
Total	166	1872.8	927	232.6	809.0	1411.0

Month 6: Remainder of Performance Testing and CALISO Certification & Testing/PPA Testing

		Total Controlled Emissions, lb				
Activity	**Duration (hr)**	**NOx**	**CO**	**VOC**	**SOx**	**$PM_{10}/PM_{2.5}$**
Performance Testing[1]	106 of 132	1713.7	806.2	206.4	515.5	901.0
CALISO Certification & Testing/PPA Testing	60	804	371	97.5	292	510
Total	166	2517.7	1177.2	303.9	807.5	1411

The maximum monthly emissions from any one of the six months for each pollutant are summarized in the table below.

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

- <u>Commissioning Emission Factors</u>
  The commissioning period emission factors are derived for inclusion in condition no. A63.2 for CO, VOC, PM_{10}, and SOx, and in condition no. A99.1 for NOx. 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 from *Table 16*, above.

  Commissioning emissions and normal operating emissions are limited by the monthly emissions limits in condition no. A63.2. Condition no. E193.8 limits the commissioning period to 996 hours of fired operation per turbine, including a maximum of 216 hours without control, to limit and minimize emissions during the commissioning period when steady state BACT is not achievable.

  The table below shows the calculation of the emissions factors.

Table 20 - Combined-Cycle Turbine Commissioning Emission Factors

Pollutant	Total Commissioning Emissions, lb	Total Commissioning Fuel Usage, mmcf	Emission Factor, lb/mmcf
NOx	27,597	1656.24	**16.66**
CO	101,328	1656.24	**61.18**
VOC	14,682	1656.24	**8.86**
$PM_{10}/PM_{2.5}$	8,466	1656.24	**5.11**
SOx	4,841	1656.24	**2.92**

- <u>Normal Operating Month</u>
  - <u>Maximum Normal Operating Month Emissions</u>
    In the AES Response Letter dated 12/11/15, the applicant indicated that the normal operating month will begin in the first month following completion of commissioning activities, with no commissioning carry-over. The maximum controlled normal operating month emissions are shown in the table below.

For maximum monthly emissions per combined-cycle turbine, the applicant requested: (1) 681 normal operating hours, (2) 2 cold starts (2 hr total), (3) 15 warm starts (7.5 hr total), (5) 45 hot starts (22.5 hr total), and (7) 62 shutdowns (31 hr total), for a total of 744 hours per month, in the original Application. The revised Application requested: (1) 674.5 normal operating hours, (2) 15 cold starts (15 hr total), (3) 12 warm starts (6 hr total), (5) 35 hot starts (17.5 hr total), and (7) 62 shutdowns (31 hr total), for a total of 744 hours per month. The normal operation emission rates is from *Table 15* (case 1), and the startup and shutdown emissions per event are from *Table 17*. The SO_x emission rates are based on the short-term rate (0.75 grains/100 scf).

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

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	No. of Cold Startups	lb/cold startup	No. of Warm Startups	lb/warm startup	No. of Hot Startups	lb/hot startup	No. of Shut downs	lb/shutdown	Maximum Monthly Emissions lb/month (tons/month)
NOx	674.5	16.5	15	61	12	17	35	17	62	10	**13,463.25 (6.73)**
CO	674.5	~~10.0~~ 7.53	15	325	12	137	35	137	62	133	**~~26,305.00 (13.15)~~** **24,638.99 (12.32)**
VOC	674.5	5.75	15	36	12	25	35	25	62	32	**7577.38 (3.79)**
$PM_{10}/PM_{2.5}$	674.5	8.50	15	8.50	12	4.25	35	4.25	62	4.25	**6324.00 (3.16)**
SOx	674.5	4.86	15	4.86	12	2.43	35	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, warm) (lb/startup, warm) + (no. startups, hot) (lb/startup, hot) + (no. shutdowns) (lb/shutdown)

- Normal Operating Emission Factors

  The normal operating emission factors are derived for inclusion in condition no. A63.2 for CO, VOC, PM_{10}, and SOx, and in condition no. A99.2 for NOx. As explained in the Rule 2012 analysis below, condition no. A99.2 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.

  The normal operating emission factors are 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	~~26,305.00~~ 24,638.99	~~16.32~~ 15.28
VOC	7577.38	4.70
PM_{10}	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

- Permit Conditions—Monthly Emissions Limits
Condition no. A63.2 specifies the maximum monthly emissions limits per turbine for CO, VOC, PM_{10}, and SOx. The maximum monthly emissions and 30-day averages for each pollutant are based on the highest emissions from any commissioning month (*Table 19*) or normal operating month (*Table 21*). 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. AES has indicated commissioning and normal operations will not occur in the same month.

(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)**	~~26,305~~ 24,638.99 lb/month (~~876.83~~ 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}	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

Condition A63.2 will limit CO emissions to 95,023 lb/month, VOC to 13,314 lb/month, PM_{10} to 6324 lb/month, SOx to 3616 lb/month. The commissioning emission factors are 61.18 lb/mmcf for CO, 8.86 lb/mmcf for VOC, 5.11 lb/mmcf for PM_{10}, and 2.92 lb/mmcf for SOx from *Table 20*. The normal operating emission factors are ~~16.32~~ 15.28 lb/mmcf for CO, 4.70 lb/mmcf for VOC, 3.92 lb/mmcf for PM_{10}, and 2.24 lb/mmcf for SOx from *Table 22*.

- *Maximum Annual Emissions per Turbine*
The annual emissions for the commissioning year and a normal operating year are calculated below. The number of RECLAIM NOx RTCs required are determined on an annual basis

which will be reflected in conditions I297.1 - I297.2, as discussed under the Rule 2005(c)(2) analysis below.

- Commissioning Year

  Condition no. I297.1 – I297.2 specify the pounds of NOx RTCs that are required to be held in the facility's allocation account to offset the annual emissions increase for the first year of operation. The first year of operation is the commissioning year.

  In the AES Response Letter dated 12/11/15, the applicant indicated that the commissioning period will extend over a period of 6 full months, and will not overlap with steady-state operation of the CTGs. In AES response e-mail dated 4/6/16, AES reaffirmed that AEC project engineers has determined the combined-cycle power block commissioning will require six months to complete.

  The maximum commissioning year emissions are calculated by adding the total emissions for commissioning from *Table 16* to six months of maximum monthly normal operating emissions from *Table 21*.

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) + (~~26,305.0~~ 24,638.99 lb/month)(6 normal operating months) = ~~259,158.0~~ 249,161.94 lb/yr (~~129.58~~ 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}	(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)

  Conditions I297.1 and I297.2 will 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 maximum annual emissions per turbine, the applicant requested: (1) 4100 hours of normal operation, (2) 24 cold starts, (3) 100 warm starts, (4) 376 hot starts, and (5) 500 shutdowns for a total of 4612 hours, in the original Application. The revised Application 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. The normal operation emission rates are from *Table 15* (case 4), and the startup and shutdown emissions per event from *Table 17*. The SOx emission rates are based on the long-term rate (0.25 grains/100 scf).

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

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	No. of Cold Startups	lb/cold startup	No. of Warm Startups	lb/warm startup	No. of Hot Startups	lb/hot startup	No. of Shut downs	lb/shutdown	Maximum Annual Emissions lb/yr (tpy)
NOx	4100	16.3	80	61	88	17	332	17	500	10	**83,850 (41.93 tpy)**
CO	4100	~~9.93~~ 7.44	80	325	88	137	332	137	500	133	**~~190,753.0 (95.38 tpy)~~** **180,544.00 (90.27 tpy)**
VOC	4100	5.68	80	36	88	25	332	25	500	32	**52,668 (26.33 tpy)**
$PM_{10}/PM_{2.5}$	4100	8.50	80	8.50	88	4.25	332	4.25	500	4.25	**39,440 (19.72 tpy)**
SOx	4100	1.60	80	1.62	88	0.81	332	0.81	500	0.81	**7434.80 (3.72)**

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

- Permit Conditions—Annual Emissions Limits

  From *Table 25*, the annual emission limits for a normal operating year are included in condition A63.2 for CO, VOC, PM_{10}, and SOx to 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*. 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}, 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 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 the annual emissions be based on 0.25 grains/100 scf. The annual SOx emission factor is calculated below.

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

Pollutants	Maximum Annual Emissions, lb/year	Emission Factors, lb/mmcf
SOx	7434.8	0.75

Emission factor, lb/mmcf = (lb/yr) (yr / 9942.86 mmscf)

Where max annual fuel usage = (4640 hours, incl. startups/shutdowns)

(2250 MMBtu/hr, Case 4) (mmscf/1050 MMBtu) = 9942.86 mmscf/yr

- *New Source Review (NSR) Database Entries*
  This section develops the internal NSR Data Summary Sheet entries.

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

  The 30-day averages per turbine are from *Table 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/~~2~~ 1.5 ppm controlled per case 1)
  = ~~467.21~~ 622.95 lb/hr

  30-DA = 3167.44 lb/day

  Note: The maximum monthly emissions are based on the maximum commissioning month, because these emissions are higher than for the maximum normal operating month. Thus the change from 2 ppmvd to 1.5 ppmvd CO for the BACT level for normal operations does not affect the 30 day-average.

  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. Toxic Pollutants

The applicant provided revised toxic air pollutant (TAC) and hazardous air pollutant (HAP) emissions for each combined-cycle turbine in AES Response Letter, dated 12/11/15. The emission rates in *Table 5.9-1—Air Toxic Emission Rates Modeled for AEC Operation: Combustion Turbines* in the original Application were required by SCAQMD to be revised to be based on US EPA AP-42 emission factors. The emissions rates are for use in the Rule 1401 health risk assessment (HRA) below.

In the revised Application, *Table 5.9-1* has been revised to reflect previously provided changes due to the correction to AP-42 emission factors and new changes due to a higher annual fuel usage resulting from the increase in cold starts. The new changes due to the higher fuel usage are added to the table 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	70,004	35.0
Acetaldehyde[2]	75070	TAC & HAP	1.76E-04	0.39	1789	0.89
Acrolein[2]	107028	HAP & TAC	3.62E-06	0.008	36.7	0.018
Benzene[2]	71432	HAP & TAC	3.26E-06	0.0072	33.1	0.017
1,3-Butadiene	106990	HAP & TAC	4.3E-07	0.0010	4.36	0.0022
Ethylbenzene	100414	HAP & TAC	3.2E-05	0.071	324	0.16
Formaldehyde[2]	50000	HAP & TAC	3.6E-04	0.80	3648	1.82
Hexane	110543	HAP & TAC	Not available	--		--
Naphthalene	91203	HAP & TAC	1.3E-06	0.0029	13.2	0.0066
PAHS (excluding naphthalene)[3, 4]	1151	HAP & TAC	(2.2E-06 – 1.3E-06) * 0.5 = 0.45E-06	0.0010	4.56	0.0023
Propylene (propene)[5]	115071	TAC	Not available			--
Propylene Oxide	75569	HAP & TAC	2.9E-05	0.063	290	0.15
Toluene	108883	HAP & TAC	1.3E-04	0.29	1322	0.66
Xylene	1330207	HAP & TAC	6.4E-05	0.14	649	0.32
Total Annual HAPS Emissions per Turbine, TPY						**4.05**
Total Annual Toxic Air Contaminants Emissions per Turbine, TPY						**39.05**

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 2275 MMBtu/hr (Case 1))

Annual emissions, lb/yr = (Emission Factor) (average annual heat input rate of 10,437,686 MMBtu/yr)

Where average annual heat input = (4640 hr/yr)(2249.5013 MMBtu/hr (Case 4)
= 10,437,686 MMBtu/yr

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

Ammonia
Maximum hourly emissions, lb/hr = (2275 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) = 15.7 lb /hr

AES used the 15.3 lb/hr from *Table 15* (case 1), which is acceptable as the difference is due to rounding differences.

Maximum annual emissions, lb/yr = (4640 hr/yr)(15.1 lb/hr (case 4)) = 70,004 lb/yr = 35.0 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 is 10,437,686 MMBtu/yr.

  Emission factors for CO_2, CH_4, and N_2O are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised April 4, 2014.

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 MMBtu/yr)(53.06 kg/MMBtu)(2.2046 lb/kg)
= 1,220,959,551 lb/yr = 610,479.78 tpy → 610,480 tpy

CH_4 = (10,437,686 MMBtu/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 23,015.10 lb/yr = 11.51 tpy

N_2O = (10,437,686 MMBtu/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 2301.51 lb/yr = 1.15 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 lb/yr CO_2)(1 lb CO_2e/lb CO2) + (23,015.10 lb/yr CH_4)
(25 lb CO2e/lb CH_4) + 2301.51 lb/yr N_2O)(298 lb CO_2e/lb N_2O)
= 1,222,220,778 lb/yr = 611,110.39 tpy = 50,925.87 tons/month

- <u>*Rule Circuit Breakers: SF6*</u>
  Condition F52.2 will 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.

  Each combined- and simple-cycle generator includes an 18-kilovolt (kV) circuit breaker, for a total of 7. The CCGT power block includes a single, 230-kV circuit breaker and each simple-cycle turbine includes a 230-kV circuit breaker, for a total of 5.

  For the CCGT:

CCGT-1, CCGT-2, and Steam Turbine: 3000A 230 kV	230 lb SF_6
CCGT-1: 10000A 18 kV	25 lb SF_6
CCGT-2: 10000A 18 kV	25 lb SF_6
Steam Turbine: 10000A 18 kV	<u>25 lb SF_6</u>
	305 lb SF_6

Annual leakage = (305 lb SF_6) (0.5/100 annual leak rate) = 1.53 lb/yr SF_6 = 0.00076 tpy

Pursuant to the *Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear* (17 CCR 95350-95359), §95352 specifies the maximum annual SF_6 emission rate shall not exceed 1.0% in 2020, and each calendar year thereafter. PSD BACT, however, imposes a more stringent limit of 0.5%.

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, SF_6 is equivalent to 22,800 times the global warming potential of CO_2.

(1.53 lb/yr SF_6)(22,800 lb CO_2e/lb SF_6) = 34,884 lb/yr = 17.44 tpy CO_2e
= 1.45 tons/month CO_2e

- *New Source Review (NSR) Database Entries*
  This section develops the internal NSR Data Summary Sheet entries.

  Operating Schedule: 52 wks/yr, 7 days/wk, 24 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 lb/yr) (yr /8736 hr) = 139,761.85 lb/hr

  CH_4 = (23,015.10 lb/yr) (yr /8736 hr) = 2.63 lb/hr

  N_2O = (2301.51 lb/yr) (yr /8736 hr) = 0.26 lb/hr

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

2. A/N 579160, 579161—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. CCGT-1, CCGT-2 (Combined-Cycle Turbines)
   Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

   A. Criteria Pollutants
      NOx = CO = VOC = PM_{10} = SOx = 0 lb/hr = 0 lb/day

   B. Toxic Pollutants
      From *Table 26* above, the 5 ppmvd BACT level for ammonia results in an annual emission rate of 70,004 lb/yr = 35 tons/yr = 2.92 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 lb/yr) (yr/52 wk) (wk/7 days) = 192.32 lb/day
lb/hr = (192.32 lb/day) (day/24 hr) = 8.01 lb/hr

Note: Ammonia is not a federal HAP.

3. A/N 579158—Auxiliary Boiler (Combined-Cycle Turbines), 70.8 MMBtu/hr
The auxiliary boiler will have a commissioning period and extended startup periods.

A. Criteria Pollutants

Commissioning

From the AES Response Letter dated 12/11/15, the auxiliary boiler will be commissioned at the AEC site. The commissioning process includes first burner light-off, conditioning, establish the air/fuel ratio curve, and establishing the SCR ammonia injection cure.

The commissioning will occur over five days and will require up to 6 fired hours per day. Condition E193.10 will limit the commissioning to 30 hours of fired operation. The daily commissioning emissions will be about the same as two cold starts, as shown in the table below:

Table 27 - Auxiliary Boiler Commissioning Emissions

	NOx	CO	VOC
Daily Emissions	8.44	8.68	9.36
Total Commissioning Emissions	42.2	43.4	46.8
Total Fuel Use	414 MMBtu or 0.39 MMCF		

From the AES Response Letter dated 1/7/16, the applicant has indicated that the commissioning month emissions will not exceed normal operating month emissions. Condition A63.4 specifies the maximum monthly emissions limits for CO, VOC, PM_{10}, and SOx. The maximum monthly emissions for a normal operating month are calculated below.

Separate commissioning period emission factors for CO, VOC, PM_{10}, and SOx will not be included in condition no. A63.4 because these pollutants are uncontrolled and the commissioning period is short. As explained in the Rule 2002 analysis below, condition A99.5 specifies the interim emission factor for NOx prior to CEMS certification is 38.46 lb/mmscf.

Startups/Shutdowns

A startup event occurs each time the auxiliary boiler is started up. A startup begins with the initiation of combustion, and concludes when BACT emissions levels are achieved. During start-up operations, the boiler operates at elevated average concentration rates for NOx, CO, and VOC due to the phased-in effectiveness of the low NOx burner, flue gas recirculation (FGR), and SCR.

Three startup scenarios have been developed for the auxiliary boiler.

1) For a **cold start event**, the auxiliary boiler is at ambient temperature at the time of the startup, which would typically occur if 48 hours or more elapse 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 170 minutes.

2) A **warm start event** would typically be 10 hours or more but 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 85 minutes.

3) A **hot start event** would typically be less than 10 hours of a shutdown event. The time from fuel initiation until reaching the baseload operating rate is expected to take up to 25 minutes.

For daily emissions (for modeling), the applicant has requested a maximum of one cold start.

For monthly emissions, the applicant has requested a maximum of 2 cold starts, 4 warm starts, 4 hot starts for the boiler.

For annual emissions, the applicant has requested a maximum of 24 cold starts, 48 warm starts, and 48 hot starts per turbine, equal to 12 times the monthly amounts.

A shutdown scenario need not be developed because, unlike the CTGs, the boiler shuts down almost instantaneously.

The applicant provided maximum startup emissions per event for NOx, CO, and VOC, and startup/shutdown hourly emission rates for NOx, CO, VOC, SO_2 (0.25 gr/100 scf) and $PM_{10/2.5}$ in *Table 5.1-18—Auxiliary Boiler Startup Emission Rates* in the original Application. The revised Application provided maximum startup emissions per event for SO_2 (corrected to be based on 0.75 gr/100 scf) and PM_{10}. The event emission rates were provided by the manufacturer.

The following table summarizes the emissions for the three types of startup events.

Table 28 – Auxiliary Boiler Start-up 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	170 (2.83)	4.22	4.34	4.69	< 0.3 (0.84)	< 0.3 (0.84)	< 0.048 (0.24)
Warm Start	85 (1.42)	2.11	2.17	2.34	< 0.3 (0.42)	< 0.3 (0.42)	< 0.048 (0.12)
Hot Start	25 (0.42)	0.62	0.64	0.69	< 0.3	< 0.3	< 0.048

					(0.12)	(0.12)	(0.035)

- *Startup Condition*
  The startup condition limits and minimizes emissions when steady state BACT is not achievable. Condition no. C1.7 provides limits for startups. The limits are necessary because condition nos. A195.13 and A195.14 state that BACT for NO and CO, respectively, shall not apply during startups. The startup limits include: (1) number of cold starts per calendar month and year; (2) number of warm starts per calendar month and year; (3) number of hot starts per calendar month and year; (4) number of startups per day; and (5) duration of cold start, warm start, and hot start; and (6) NOx emissions per cold start, warm start, and hot start.

Emissions Calculations
Operating Schedule per year: 52 wk/yr, 7 days/wk, 24 hr/day
Operating schedule per month: 31 days, two cold starts, four warm starts, four hot starts
Cold start: 170 minutes (2.83 hr)
Warm start: 85 minutes (1.42 hr)
Hot start: 25 minutes (0.42 hr)

Normal operating hrs = (31 days)(24 hr) – (2 cold starts)(2.83 hr/cold start) – (4 warm starts) (1.42 hr/warm start) - (4 hot starts)(0.42 hr/hot start) = 730.98 hr

CO: 50 ppm CO
NOx: 5 ppmv NOx per Rule 1146(c)(1)(F)
ROG: Original Application: Cleaver Brooks Guarantee, 6/10/15 = 0.003 lb/MMBtu,
AES requested 0.004 lb/MMBtu including safety margin.

Revised Application & AES Response e-mail, 4/6/16:
5.5 lb/mmscf = 0.0052 lb/mmbtu (based on 1050 btu/cf)
Default Annual Emissions Reporting (AER) emission factor for natural-gas fired boilers

PM: Original Application: Cleaver Brooks Guarantee, 6/10/15 = 0.0043 lb/MMBtu,
Revised Application & AES Response e-mail, 4/6/16:
7.6 lb/mmscf = 0.0072 lb/MMBtu (based on 1050 btu/cf)
Default AER emission factor for natural-gas fired boilers

SOx: Original Application: 0.00068 lb/MMBtu (0.25 gr/100 scf) for monthly emissions.
Revised Application: 0.0020 lb/MMBtu (0.75 gr/100 scf) for monthly emissions.
(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.)

Normal Operating Rate:

Original Application: In AES Response Letter, dated 1/7/16, AES requested the normal operating emission rate be based on 35.3 MMBtu/hr corresponding to operation at 50% load, because the auxiliary boiler will not be operated at 100% load at all times.

Revised Application & AES Response e-mail, 4/6/16: AES requested a monthly heat input limit of 16,055 MMBtu/hr, which is based on a normal operating emission rate of 21.23 MMBtu/hr corresponding to operation at 30% load. Since higher emission factors are to be used for VOC and PM_{10}, the operational profile was reduced to reflect the quantity of VOC and PM_{10} offsets previously secured.

NOx, lbs/hr = (21,230,000 Btu/hr) (8710 dscf/10^6 Btu) (5 ppm per Rule 1146/10^6) (20.9/(20.9-3.0)) (46 lbs NOx/385 scf) = 0.13 lb/hr, normal operating rate (see below for NSR Database Entry hourly rate)

lbs/month = (730.98 hr)(0.13 lb/hr) + (2 cold starts)(4.22 lb/cold start) + (4 warm starts) (2.11 lb/warm start) + (4 hot starts)(0.62 lb/hot start) = 114.39 lb/month = 0.057 tons/month [.68 tpy]

lbs/day = (114.39 lb/month)/(30 days) = 3.81 lb/day
30 DA = 3.81 lb/day

NSR Database Entry: (3.81 lb/day)(day/24 hr) = 0.16 lb/hr

CO, lbs/hr = (21,230,000 Btu/hr) (8710 dscf/10^6 Btu) (50 ppm CO per guarantee /10^6) (20.9/(20.9-3.0)) (28 lbs CO/379 scf) = 0.80 lb/hr, normal operating rate (see below for NSR Database Entry hourly rate)

lbs/month = (730.98 hr)(0.80 lb/hr) + (2 cold starts)(4.34 lb/cold start) + (4 warm starts) (2.17 lb/warm start) + (4 hot starts)(0.64 lb/hot start) = 604.70 lb/month = 0.30 tons/month [3.6 tpy]

lbs/day = (604.70 lb/month)/(30 days) = 20.16 lb/day
30 DA = 20.16 lb/day

NSR Database Entry: (20.16 lb/day)(day/24 hr) = 0.84 lb/hr

ROG, lbs/hr = (21,230,000 Btu/hr) (0.0052 lb/MMBtu /10^6) = 0.11 lb/hr, normal operating rate (see below for NSR Database Entry hourly rate)

lbs/month = (730.98 hr)(0.11 lb/hr) + (2 cold starts)(4.69 lb/cold start) + (4 warm starts)

(2.34 lb/warm start) + (4 hot starts)(0.69 lb/hot start) = 101.91 lb/month
0.051 tons/month [0.61 tpy]

lbs/day = (101.91 lb/month)/(30 days) = 3.40 lb/day
30 DA = 3.40 lb/day

NSR Database Entry: (3.40 lb/day)(day/24 hr) = 0.14 lb/hr

For combustion emissions, the standard assumption is PM_{10} = PM.
PM_{10}, lbs/hr = (21,230,000 Btu/hr) (0.0072 lb/MMBtu/10^6) = 0.15 lb/hr, normal operating rate
(see below for NSR Database Entry hourly rate)

lbs/month = (730.98 hr) (0.15 lb/hr) + (2 cold starts) (0.84 lb/cold start) + (4 warm starts)
(0.42 lb/warm start) + (4 hot starts)(0.12 lb/hot start) = 113.49 lb/month =
0.057 tons/month [0.68 tpy]

lbs/day = (113.49 lb/month)/(30 days) = 3.78 lb/day
30 DA = 3.78 lb/day

NSR Database Entry: (3.78 lb/day)(day/24 hr) = 0.16 lb/hr

SOx, lbs/hr = (21,230,000 Btu/hr) (0.002 lb/MMBtu/10^6) = 0.042 lb/hr, normal operating rate
(see below for NSR Database Entry hourly rate)

lbs/month = (730.98 hr) (0.042 lb/hr) + (2 cold starts) (0.24 lb/cold start) + (4 warm starts)
(0.12 lb/warm start) + (4 hot starts)(0.035 lb/hot start) = 31.80 lb/month =
0.016 tons/month [0.19 tpy]

lbs/day = (31.80 lb/month)/(30 days) = 1.06 lb/day
30 DA = 1.06 lb/day

NSR Database Entry: (1.06 lb/day)(day/24 hr) = 0.04 lb/hr

- *Monthly Emissions Limit*
  Condition A63.4 limits the maximum monthly emissions limits for CO, VOC, PM_{10}, and SOx. From the calculations above, CO will be limited to 605 lbs, VOC to 102 lbs, PM_{10} to 113.5 lbs, and SOx to 32 lbs.

  As the first step to deriving emission factors, the monthly gas usage is derived below. The revised Application is based on a normal operating rate of 21.23 MMBtu/hr (30% load). Cold, warm, and hot startups are based on 41.36 MMBtu/hr, which was stated to be provided by the auxiliary boiler vendor.

Maximum monthly fuel consumption (MMBtu/month) = [(no. normal operating hours) * (21.23 MMBtu/hr)] + {[(no. startups, cold) (hr/startup, cold) + (no. startups, warm) (hr/startup, warm) + (no. startups, hot) (hr/startup, hot)] * [(41.36 MMBtu/hr)]} =

[(730.98 hr) * (21.23 MMBtu/hr)] + {[((2 cold starts)(2.83 hr/cold start) + (4 warm starts) (1.42 hr/warm start) + (4 hot starts)(0.42 hr/hot start)) * (41.36 MMBtu/hr)]} = 16,057 MMBtu/month

(16,057 MMBtu/month) (MMscf/1050 MMBtu) = 15.29 mmscf/month

The normal operating emission factors are derived below for inclusion in condition no. A63.4 for CO, VOC, PM_{10}, and SOx. As explained in the Rule 2002 analysis below, condition A99.5 specifies the interim emission factor for NOx prior to CEMS certification is 38.46 lb/mmscf.

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

Table 29 - Auxiliary Boiler Emission Factors

Pollutants	Maximum Monthly Emissions, lb/month	Emission Factors, lb/mmcf
CO	604.70	39.55
VOC	101.91	6.67
PM_{10}	113.49	7.42
SOx	31.80	2.08

Emission factor, lb/mmcf = (lb/month) (month/15.29 mmscf)

- *Annual Emissions Limit*
  The monthly emissions limits in condition A63.4 are applicable each and every month. Therefore, the annual emissions limits are the monthly emissions limits multiplied by twelve months, unless the annual emissions are limited by permit condition.

  The applicant has not requested that annual emissions be limited to less than the monthly emissions limit multiplied by 12 months. In actuality, the annual emissions will be less than 12 times the monthly emissions, because the annual emissions are based on 365 days but the monthly emissions are based on 31 days.

  The number of RECLAIM NOx RTCs required are determined on an annual basis which will be reflected in condition I297.7, as discussed under the Rule 2005(c)(2) analysis. The use of the interim emission factor of 38.46 lbs/mmscf for the entire year would result in unrealistically high annual emissions. The expected annual NOx emissions are calculated below.

Operating schedule per month: 365 days, 24 cold starts, 48 warm starts, 48 hot starts

Normal operating hrs = (365 days)(24 hr) – (24 cold starts)(2.83 hr/cold start) – (48 warm starts)(1.42 hr/warm start) - (48 hot starts)(0.42 hr/hot start) = 8603.76 hr

NOx, lbs/yr = (8603.76 hr)(0.13 lb/hr) + (24 cold starts)(4.22 lb/cold start) + (48 warm starts)(2.11 lb/warm start) + (48 hot starts)(0.62 lb/hot start) = 1350.8 lb/yr (0.68 tpy)

The annual gas usage is calculated below for use in the toxic emissions and greenhouse gas emissions calculations below.

Maximum annual fuel consumption (MMBtu/month) = [(no. normal operating hours) * (21.23 MMBtu/hr)] + [((no. startups, cold) (hr/startup, cold) + (no. startups, warm) (hr/startup, warm) + (no. startups, hot) (hr/startup, hot)) * (41.36 MMBtu/hr)] =

[(8603.76 hr) * (21.23 MMBtu/hr)] + [((24 cold starts)(2.83 hr/cold start) + (48 warm starts)(1.42 hr/warm start) + (48 hot starts)(0.42 hr/hot start)) * (41.36 MMBtu/hr)] = 189,119.91 MMBtu/yr

B. <u>Toxic Pollutants</u>

The applicant provided revised toxic air pollutant (TAC) and hazardous air pollutant (HAP) emissions for the auxiliary boiler in AES Response Letters, 12/1/15 and 1/7/16. The emission rates in *Table 5.9-2—Air Toxic Emission Rates Modeled for AEC Operation: Auxiliary Boiler* in the original Application were required by the SCAQMD to be revised to be based on the Ventura County Air Pollution Control District (VCAPCD) emission factors for natural gas fired external combustion equipment rated 10 – 100 MMBtu/hr. The emissions rates are for use in the Rule 1401 health risk assessment below.

In the revised Application, *Table 5.9-2* has been revised to reflect previously provided changes due to the correction to VCAPCD emission factors, and new changes due to a lower annual fuel usage. The new changes due to the lower fuel usage are added to the table below.

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**

1 Ventura County APCD emissions factors are provided in lb/MMcf. The natural gas heat content of 1050 MMBtu/MMscf was used for conversion to lb/MMBtu.

2 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) (70.8 MMBtu/hr max rating of boiler)

Annual emissions, lb/yr = (Emission Factor) (average annual heat input rate of 189,119.91 MMBtu/yr)

<u>Ammonia</u>
Maximum hourly emissions, lb/hr = (70.8 MMBtu/hr) (8710 dscf/10^6 Btu) (5 ppm NH_3 /10^6) (20.9/(20.9-3.0)) (17 lbs NH_3/379 scf) = 0.16 lb /hr

Maximum annual emissions, lb/yr = (365 day/yr)(24 hr/day)(0.05 lb/hr at 30% load) = 423 lb/yr = 0.22 tpy

C. Greenhouse Gases (GHG)

Combustion of natural gas in the boiler 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 is 189,119.91 MMBtu/yr.

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 = (189,119.91 MMBtu/yr)(53.06 kg/MMBtu)(2.2046 lb/kg)
= 22,122,504.97 lb/yr = 11,061.25 tpy

CH_4 = (189,119.91 MMBtu/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 417.01 lb/yr = 0.21 tpy

N_2O = (189,119.91 MMBtu/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 41.70 lb/yr = 0.02 tpy

CO_2e = (22,122,504.97 lb/yr CO_2)(1 lb CO_2e/lb CO2) + (417.01 lb/yr CH_4)
(25 lb CO2e/lb CH_4) + (41.70 lb/yr N_2O)(298 lb CO_2e/lb N_2O)
= 22,145,356.82 lb/yr = 11,072.68 tpy = = 922.72 tons/month

New Source Review (NSR) Database Entries
This section develops the internal NSR Data Summary Sheet entries.

Operating Schedule: 52 wks/yr, 7 days/wk, 24 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 = (22,122,504.97 lb/yr) (yr /8736 hr) = 2532.34 lb/hr

CH_4 = (417.01 lb/yr) (yr /8736 hr) = 0.048 lb/hr

N_2O = (41.70 lb/yr) (yr /8736 hr) = 0.005 lb/hr

4. A/N 579166—Selective Catalytic Reduction for Auxiliary Boiler
Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

A. Criteria Pollutants
NOx = CO = VOC = PM_{10} = SOx = 0 lb/hr = 0 lb/day

B. Toxic Pollutants
From *Table 30* above, the 5 ppmvd BACT level for ammonia results in an annual emission rate of 423 lb/yr = 0.21 ton/yr = 0.018 ton/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 = (423 lb/yr) (yr/52 wk) (wk/7 days) = 1.16 lb/day
lb/hr = (1.16 lb/day) (day/24 hr) = 0.05 lb/hr

Note: Ammonia is not a federal HAP.

5. A/N 579145, 579147, 579150, 579152—Simple-Cycle Combustion Turbine Generators Nos. SCGT-1, SCGT-2, SCGT-3, SCGT-4
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. Criteria Pollutants

As with the combined-cycle turbines, emissions from the 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. 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 operating scenarios are presented in *Table 5.1B.7R—Simple-Cycle: GE LMS-100PB Performance Data* in Attachment 6 of AES Response Letter, 12/11/15.

  For the FDOC, the revised BACT determination reduced BACT for CO from 4 ppmvd to 2 ppmvd, both at 15% O_2. In AES Response letter, dated 9/2/16, AES confirmed the CO emission rates for normal operations would be reduced to 0.5 times the original emission rates but the startup/shutdown rates would not be affected.

  The operating scenarios data, including the change to a CO BACT of 2 ppmvd, are summarized in the following table.

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, ~~4.0~~ 2.0 ppmvd (dry, 15% O_2) BACT, lb/hr	~~8.01~~ 4.01	~~6.52~~ 3.26	~~5.04~~ 2.52	~~7.98~~ 3.99	~~7.96~~ 3.98	~~6.44~~ 3.22	~~4.99~~ 2.50	~~6.97~~ 3.49	~~6.27~~ 3.14	~~5.20~~ 2.60	~~4.09~~ 2.05	~~8.05~~ 4.03	~~6.52~~ 3.26	~~5.04~~ 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) will be 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) will be 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
  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 original Application provided the duration and corresponding pollutant emission rates for each commissioning activity for a single CTG in *Table 5.1B.2—Summary of Commissioning Emission Estimates: Simple-Cycle Turbines* in *Appendix 5.1B*. The PM_{10}/$PM_{2.5}$ and SOx emission rates are based on the maximum hourly emission rates, including the short-term rate for SO_2, from *Table 31* (case 1). In AES Response E-Mail dated 1/28/16, the applicant provided the fuel usage for each commissioning activity.

The following table provides a summary of the commissioning activity parameters and emissions.

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.

The dispersion modeling analysis, discussed below, showed that the maximum impact would occur if the four turbines, with both the SCR and CO oxidation catalyst at 0% control, were simultaneously undergoing commissioning activities with the highest unabated emissions (i.e., Testing (Full Speed No Load)). The modeling results demonstrated that all four turbines may undergo simultaneous commissioning without causing the NO_2 or CO ambient standards to be exceeded.

Startup of CTGs
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), the applicant has requested a maximum of two starts per turbine.

For monthly emissions, the applicant has requested a maximum of 62 starts per turbine.

For annual emissions, the applicant has requested a maximum of 500 starts per turbine.

Shutdown of CTGs
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), the applicant has requested a maximum of two shutdowns per turbine.

For monthly emissions, the applicant has requested a maximum of 62 shutdowns per turbine.

For annual emissions, the applicant has requested a maximum of 500 shutdowns per turbine.

- *Startup/Shutdown Emissions*
  The applicant provided maximum startup and shutdown emissions per event for NOx, CO, and VOC, and startup and shutdown hourly emission rates for NOx, CO, VOC, SO_2 and $PM_{10/2.5}$ in *Table 5.1-16—GE LMS-100 Startup/Shutdown Emission Rates* in the original Application. The revised Application provided startup and shutdown emissions per event for PM_{10} and SO_2 (short-term rate). In AES Response letter, dated 9/2/16, AES

confirmed the startup/shutdown rates for CO would not be affected by the reduction in the BACT level for CO from 4 ppmvd to 2 ppmvd, both at 15% O_2.

The following table summarizes the emissions for the startup event and shutdown events.

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)	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*
  The startup/shutdown conditions limit and minimize emissions during startups and shutdowns when steady state BACT is not achievable. 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, ~~A195.12~~ 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 startups per day; and (3) duration of start; and (4) NOx, CO, and VOC emissions per start. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdown; and (3) NOx, CO, and VOC emissions per shutdown.

  Normal Operation
  Normal operation occurs after the CTGs and SCR/CO catalysts are working optimally. The emissions during normal operations are assumed to be fully controlled to BACT levels, 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 ~~4.0~~ 2.0 ppmvd, and VOC to 2.0 ppmvd, all 1-hr averages, at 15% O2.

- *Maximum Daily, Monthly, Annual, NSR Emissions Calculations*
  The following sections will discuss maximum daily emissions, maximum monthly emissions, maximum annual emissions, and associated emission factors and permit condition limits. Finally, offset requirements and the calculation of NSR entries will be discussed.

  - *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

Table 5.1B.9—Simple-Cycle: Summary of Operation Emissions—Criteria Pollutants, footnote b indicates the maximum daily emissions are based on 2 starts and 2 shutdowns. The normal operation emission rates are from *Table 31* (case 1), and the startup and shutdown emissions per event are from *Table 33*. The SOx emission rates are based on the short-term rate (0.75 grains/100 scf).

The maximum controlled daily emissions for normal operations are shown in the table below.

Table 34 - Simple-Cycle Turbine Maximum Daily Emissions

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	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	~~8.01~~ 4.01	2	15.4	2	28.1	~~**267.71**~~ **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}, and SOx. Such 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}, and SOx. The number of RECLAIM RTCs required are determined on an annual basis which will be reflected in conditions I297.3 - I297.6 for the turbines.

  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. As explained below, AES has indicated there will be no combination commissioning/normal operating month. Therefore, commissioning month(s) emissions and normal operating month emissions will be evaluated below. In addition, the commissioning emission factors and normal operating emission factors will be included in condition A63.3 for CO, VOC, PM_{10}, and SOx. The commissioning emission factor and the post-commissioning/pre-CEMS certification emission factor will be included in conditions A99.3 and A99.4, respectively, for NOx.

- Commissioning Months
  - Maximum Monthly Emissions, Commissioning
    In the AES Response Letter dated 12/11/15, the applicant indicated that the commissioning period will extend over a period of 3 full months, and will not overlap with steady-state operation of the CTGs. The number of commissioning hours per month per turbine is 93.33 hours.

    In AES response e-mail dated 4/6/16, AES reaffirmed that AEC project engineers has determined the simple-cycle power block commissioning will require three months to complete.

Month 1: Unit Testing (Full Speed No Load, FSNL), Unit 1 DLN Emissions Tuning, Unit Emissions Tuning, Unit Base Load Testing, Refire Unit, and a portion of Unit Source Testing & Drift Test Day 1-5/RATA/Pre-performance Testing/Part 60/75 Certification and Source Testing

		Total Controlled Emissions, lb				
Activity	**Duration (hr)**	**NOx**	**CO**	**VOC**	**SOx**	**$PM_{10}/PM_{2.5}$**
Unit Testing (Full Speed No Load, FSNL)	4	160	976	20.3	6.48	24.9
Unit DLN Emissions Tuning	12	246	1,080	36.7	19.4	74.8
Unit Emissions Tuning	12	198	869	32.2	19.4	74.8
Unit Base Load Testing	12	198	869	13.7	19.4	74.8
No Operation						
Install Temporary Emissions Test Equipment						
Refire Unit	12	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	41.33 of 168	847.27	3719.70	126.2	66.92	257.57
Total	93.33	1895.27	8593.7	265.8	151.0	581.67

Month 2: A portion of Unit Source Testing & Drift Test Day 1-5/RATA/Pre-performance Testing/Part 60/75 Certification and Source Testing

Activity	**Duration (hr)**	**NOx**	**CO**	**VOC**	**SOx**	**$PM_{10}/PM_{2.5}$**
Unit Source Testing & Drift Test Day 1-5; RATA/Pre-performance Testing/Part 60/75 Certification and Source Testing	93.33 of 168	1913	8399.7	285.0	151.11	581.65

Month 3: The remainder of Unit Source Testing & Drift Test Day 1-5/RATA/Pre-performance Testing/Part 60/75 Certification and Source Testing, Unit Water Wash & Performance Preparation, Unit Performance Testing, and Unit CALISO Certification

		Total Controlled Emissions, lb				
Activity	**Duration (hr)**	**NOx**	**CO**	**VOC**	**SOx**	**$PM_{10}/PM_{2.5}$**
Unit Source Testing & Drift Test Day 1-5; RATA/Pre-performance Testing/Part 60/75 Certification and Source Testing	33.33 of 168	683.27	2999.70	101.78	53.96	207.71
Unit Water Wash & Performance Preparation	24	492	2,160	73.3	38.9	150
Unit Performance Testing	24	492	2,160	73.3	38.9	150
Install Temporary Emissions Test Equipment						
Unit CALISO Certification	12	246	1,080	36.7	19.4	74.8
Total	93.33	1913.27	8399.7	285.08	151.16	582.5

The maximum emissions from any one of the 3 months are summarized in the table below.

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

- Commissioning Emission Factors

  The commissioning period emission factors are derived for inclusion in condition no. A63.3 for CO, VOC, PM_{10}, and SOx, and in condition no. A99.3 for NOx. As explained in the Rule 2012 analysis below, condition 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 from *Table 32*, above. The table below shows the calculation of the emissions factors.

  Commissioning emissions and normal operating emissions are limited by the monthly emissions limits in condition A63.3. Condition no. E193.9 limits the commissioning period to 280 hours of fired operation per turbine, including a maximum of 4 hours without control, to limit and minimize emissions during the commissioning period when steady state BACT is not achievable.

Table 36 - Simple-Cycle Turbine Commissioning Emission Factors

Pollutant	Total Commissioning Emissions, lb	Total Commissioning Fuel Usage, mmcf	Emission Factor, lb/mmcf
NOx	5722	226.68	**25.24**
CO	25,395	226.68	**112.03**
VOC	836	226.68	**3.69**
$PM_{10}/PM_{2.5}$	454	226.68	**2.00**
SOx	1744	226.68	**7.69**

- Normal Operating Month
  - Maximum Normal Operating Month Emissions

    In the AES Response Letter dated 12/11/15, the applicant indicated that the normal operating month will begin in the first month following completion of commissioning activities, with no commissioning carry-over. The maximum controlled normal operating month emissions are shown in the table below.

For maximum monthly emissions per turbine, the applicant has 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 operation emission rates is from *Table 32* (case 1), and the startup and shutdown emissions per event are from *Table 33*. The SO_x emission rates are based on the short-term rate (0.75 grains/100 scf).

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

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	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	~~8.01~~ <u>4.01</u>	62	15.4	62	28.1	**~~8304.0 (4.15)~~ <u>5504.00 (2.75)</u>**
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)

- <u>Normal Operating Month Emission Factors</u>
  The normal operating emission factors are derived for inclusion in condition no. A63.3 for CO, VOC, PM_{10}, and SOx, and in A99.4 for NOx. As explained in the Rule 2012 analysis below, condition A99.3 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.

  The normal operating month emission factors are 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	~~8304~~ <u>5504.00</u>	~~13.33~~ <u>8.84</u>
VOC	1973.32	3.17
PM_{10}	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

- Permit Conditions—Monthly Emissions Limits
  Condition A63.3 specifies the maximum monthly emissions limits per turbine for CO, VOC, PM_{10}, and SOx. The maximum monthly emissions and 30-day averages for each pollutant are based on the highest emissions from any commissioning month (*Table 35)* or normal operating month (*Table 37).* 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. AES has indicated commissioning and normal operations will not occur in the same month.

  (Although condition 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)**	~~8304~~ 5504 lb/month (~~276.80~~ 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}	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

Condition A63.3 will limit CO emissions to 8594 lb/month, VOC to 1973 lb/month, PM_{10} to 4638 lb/month, and SOx to 1207 lb/month. The commissioning emission factors are 112.03 for CO, 3.69 lb/mmcf for VOC, 2.0 lb/mmcf for PM_{10}, and 7.69 lb/mmcf for SOx from *Table 36*. The normal operating emission factors are ~~13.33~~ 8.84 lb/mmcf for CO, 3.17 lb/mmcf for VOC, 7.44 lb/mmcf for PM_{10}, and 1.94 lb/mmcf for SOx from *Table 38*.

- *Maximum Annual Emissions per Turbine*
  The annual emissions for the commissioning year and a normal operating year are calculated below. The number of RECLAIM NOx RTCs required are determined on an annual basis which

will be reflected in conditions I297.3 - I297.6, as discussed under the Rule 2005(c)(2) analysis below.

- Commissioning Year
  Condition I297.3 – I297.6 specify the pounds of NOx RTCs that are required to be held in the facility's allocation account to offset the annual emissions increase for the first year of operation. The first year of operation is the commissioning year.

  In the AES Response Letter dated 12/11/15, the applicant indicated that the commissioning period will extend over a period of 3 full months, and will not overlap with steady-state operation of the CTGs. The maximum commissioning year emissions are calculated by adding the total emissions for commissioning from *Table 32* to nine months of maximum monthly normal operating emissions from *Table 37*.

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) = 68,574.76 lb/yr (34.29 tpy)
CO	(25,395 lb/commissioning) + (~~8304.0~~ 5504 lb/month)(9 normal operating months) = ~~100,131~~ 74,931 lb/yr (~~50.7~~ 37.47 tpy)
VOC	(836 lb/commissioning) + (1973.32 lb/month)(9 normal operating months) = 18,595.88 lb/yr (9.30 tpy)
PM_{10}	(1,744 lb/commissioning) + (4638.14 lb/month)(9 normal operating months) = 43,487.26 lb/yr (21.74 tpy)
SOx	(454 lb/commissioning) + (1206.54 lb/month)(9 normal operating months) = 11,312.86 lb/yr (5.66 tpy)

Conditions I297.3, I297.4, I297.5, and I297.6 will require each turbine to hold 68,575 pounds of RTCs the first year.

- Normal Operating Year
  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 maximum annual emissions per turbine, the applicant has requested: (1) 2000 hours of normal operation (Case 4), (2) 500 startups (250 hr), and (3) 500 shutdowns (108 hr), for a total of 2358 hours. The normal operation emission rates from *Table 31* (case 4), and the startup and shutdown emissions per event are from *Table 33*. The SOx emission rates are based on the long-term rate (0.25 grains/100 scf).

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

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/ startup	No. of Shut downs	lb/shutdown	Maximum Annual Emissions lb/yr (tpy)
NOx	2000	8.20	500	16.6	500	3.12	**26,260.0 (13.13)**
CO	2000	~~7.98~~ <u>3.99</u>	500	15.4	500	28.1	**~~37,710.0 (18.86)~~ <u>29,730.0 (14.87)</u>**
VOC	2000	2.29	500	2.80	500	3.06	**7510.0 (3.76)**
$PM_{10}/PM_{2.5}$	2000	6.23	500	3.12	500	1.35	**14,695 (7.35)**
SOx	2000	0.54	500	0.27	500	0.12	**1275.0 (0.64)**

- <u>Permit Conditions—Annual Emissions Limits</u>
  From *Table 41*, the annual emission limits for a normal operating year are included in condition A63.3 for CO, VOC, PM_{10}, and SOx to 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 rate for the annual averaging period provided in *Table 53*. 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}, 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 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 the annual emissions be based on 0.25 grains/100 scf. The annual SOx emission factor is calculated below.

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

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

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

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

- <u>*New Source Review (NSR) Database Entries*</u>
  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/~~4~~ <u>2</u> ppm controlled per case 1) = ~~298.50~~ <u>597.0</u> lb/hr

30-DA = 286.46 lb/day

Note: <u>The maximum monthly emissions are based on the maximum commissioning month, because these emissions are higher than for the maximum normal operating month. Thus the change from 4 ppmvd to 2 ppmvd CO for the BACT level for normal operations does not affect the 30 day-average.</u>

<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 = ~~154.65~~ <u>154.60</u> 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 applicant provided revised toxic air pollutant (TAC) and hazardous air pollutant (HAP) emissions for each simple-cycle turbine in AES Response Letter No. 2, dated 12/11/15. The emission rates in *Table 5.9-1—Air Toxic Emission Rates Modeled for AEC Operation: Combustion Turbines* in the original Application were required by SCAQMD to be revised to be based on US EPA AP-42 emission factors. The emissions rates are for use in the Rule 1401 health risk assessment below.

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	7.15
Acetaldehyde[2]	75070	TAC & HAP	1.76E-04	0.15	354	0.18
Acrolein[2]	107028	HAP & TAC	3.62E-06	0.0031	7.26	0.0036
Benzene[2]	71432	HAP & TAC	3.26E-06	0.0028	6.55	0.0033
1,3-Butadiene	106990	HAP & TAC	4.3E-07	0.00037	0.86	0.00043
Ethylbenzene	100414	HAP & TAC	3.2E-05	0.027	64.1	0.032
Formaldehyde[2]	50000	HAP & TAC	3.6E-04	0.31	722	0.36
Hexane	110543	HAP & TAC	Not available	--	--	--
Naphthalene	91203	HAP & TAC	1.3E-06	0.0011	2.62	0.0013
PAHS (excluding naphthalene)[3, 4]	1151	HAP & TAC	(2.2E-06 – 1.3E-06) * 0.5 = 0.45E-06	0.00038	0.90	0.00045
Propylene (propene)[5]	115071	TAC	Not available	--	--	--
Propylene Oxide	75569	HAP & TAC	2.9E-05	0.025	58.2	0.029
Toluene	108883	HAP & TAC	1.3E-04	0.11	262	0.13
Xylene	1330207	HAP & TAC	6.4E-05	0.055	128	0.064
Total Annual HAPS Emissions per Turbine, TPY						**0.80**
Total Annual Toxic Air Contaminant Emissions per Turbine, TPY						**7.95**

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 879 MMBtu/hr (Case 1))

Annual emissions, lb/yr = (Emission Factor) (average annual heat input rate of 2,065,608 MMBtu/yr)

Where average annual heat input = (2358 hr/yr)(875.64673 MMBtu/hr)
= 2,064,775 MMBtu/yr

Note: Case 4 in Table 31 shows 876 MMBtu/hr, but AES used the more precise value of 875.64673 MMBtu/hr.

<u>Ammonia</u>
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 hr/yr)(6.07 lb/hr (case 4)) = 14,313 lb/yr = 7.16 tpy

C. Greenhouse Gases (GHG)

- *<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, the average annual heat input rate is 2,064,775 MMBtu/yr.

Emission factors for CO_2, CH_4, and N_2O are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised April 4, 2014.

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 MMBtu/yr)(53.06 kg/MMBtu)(2.2046 lb/kg)
= 241,529,277.3 lb/yr = 120,764.64 tpy → 120,765 tpy

CH_4 = (2,064,775 MMBtu/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 4552.83 lb/yr = 2.28 tpy

N_2O = (2,064,775 MMBtu/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 455.28 lb/yr = 0.23 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 lb/yr CO_2)(1 lb CO_2e/lb CO2) + (4552.83 lb/yr CH_4)
(25 lb CO2e/lb CH_4) + (455.28 lb/yr N_2O)(298 lb CO_2e/lb N_2O)
= 241,778,771.5 lb/yr = 120,889.39 tpy per turbine = 10,074.12 tons/month

- *Circuit Breakers: SF6*
  Condition F52.2 will 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.

  Each combined-cycle and simple-cycle generator includes an 18-kilovolt (kV) circuit breaker, for a total of 7. The CCGT power block includes a single, 230-kV circuit breaker and each simple-cycle turbine includes a 230-kV circuit breaker, for a total of 5.

  For the SCGT:

SCGT-1: 1200A 230 kV	230 lb SF_6
SCGT-2: 1200A 230 kV	230 lb SF_6
SCGT-3: 1200A 230 kV	230 lb SF_6
SCGT-4: 2000A 230 kV	216 lb SF_6
SCGT-1: GCB 18 kV	24 lb SF_6
SCGT-2: GCB 18 kV	24 lb SF_6
SCGT-3: GCB 18 kV	24 lb SF_6
SCGT-4: GCB 18 kV	24 lb SF_6
	1002 lb SF_6

  Annual leakage = (1002 lb SF_6) (0.5/100 annual leak rate) = 5.01 lb/yr SF_6 = 0.0025 tpy

  Pursuant to the *Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear* (17 CCR 95350-95359), §95352 specifies the maximum annual SF_6 emission rate for each gas-insulated switchgear (GIS) owner's active GIS equipment shall not exceed 1.0% in 2020, and each calendar year thereafter. PSD BACT, however, imposes a more stringent limit of 0.5%.

  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, SF_6 is equivalent to 22,800 times the global warming potential of CO_2.

  (5.01 lb/yr SF_6)(22,800 lb CO_2e/lb SF_6) = 114,228.0 lb/yr = 57.11 tpy CO_2e

= 4.76 ton/month

- *New Source Review (NSR) Database Entries*
  This section develops the NSR database entries.

  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 lb/yr) (yr /8736 hr) = 27,647.58 lb/hr

  CH_4 = (4552.83 lb/yr) (yr /8736 hr) = 0.52 lb/hr

  N_2O = (455.28 lb/yr) (yr /8736 hr) = 0.05 lb/hr

  SF_6 = (114,228 lb/yr) (yr /8736 hr) = 13.08 lb/hr

6. A/N 579162, 579163, 579164, 579165—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos.
   SCGT-1, SCGT-2, SCGT-3, SCGT-4 (Simple-Cycle Turbines)
   Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

   A. Criteria Pollutants
   NOx = CO = VOC = PM_{10} = SOx = 0 lb/hr = 0 lb/day

   B. Toxic Pollutants
   From *Table 42* above, the 5 ppmvd BACT level for ammonia results in an annual emission rate of 14,309 lb/yr = 7.16 ton/yr = 0.60 ton/month.

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

   NH_3, lb/day = (14,309 lb/yr) (yr/52 wk) (wk/7 days) = 39.31 lb/day
   lb/hr = (39.31 lb/day) (day/24 hr) = 1.64 lb/hr

   Note: Ammonia is not a federal HAP.

7. A/N 579167--Ammonia Storage Tank, No. Tank-1 (Combined-Cycle Turbines), 40,000 gallons
8. A/N 579168--Ammonia Storage Tank, No. Tank-2 (Simple-Cycle Turbines), 40,000 gallons
   Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

No emissions are expected because the filling losses will be controlled by a vapor return line and the breathing losses by the 50 psig pressure valve.

NH_3 = 0 lb/hr = 0 lb/day

9. A/N 579169—Oil/Water Separator, No. OWS-1 (Combined-Cycle Turbines), 5000 gallons
Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

Total Containment Area = 106,000 ft^2
Components will have their own containment dikes with normally shut drains. The dike contents will be pumped to the separator.

Long Beach Yearly Average Precipitation, 30 year average = 12.26 inches (1.02 ft)

For worst case, assume maximum monthly volume is the same as average annual volume.

Max monthly volume = (106,000 ft containment area)(1.02 ft average precipitation)(7.48 gal/ft^3)
= 808,737.6 gal/month

Pursuant to AP-42, Section 5.1, Final Section, Table 5.1-3—Fugitive Emission Factors for Petroleum Refineries, April 2015:

Controlled emission factor, refinery = 0.2 lb VOC/1000 gal waste water for covered separators.

The above emission factor is based on oil/water separators for petroleum refining operations, where the water is contaminated with petroleum products. At the AEC, the water is contaminated with lubricating oils and grease from the equipment. Since lubricating oil has a significantly lower vapor pressure than lubricating oils and grease, the above emission factor will be adjusted based on the relative vapor pressure of the materials expected to be in the storm water.

Vapor pressure of turbine lubricant:
http://qclubricants.com/msds/CHEVRON%20_turbine_2190_TEP_msds.pdf -- Chevron Safety Data Sheet for Chevron Turbine Oil Symbol 2190 TEP shows the vapor pressure is < 0.01 mm Hg at 37 ºC (100 ºF).

Vapor pressure of crude oil:
http://oilspill.fsu.edu/images/pdfs/msds-crude-oil.pdf -- BP West Coast Products, LLC, Material Safety Data Sheet for Crude Oil shows the vapor pressure is AP 1 to 2 at 100 ºF (REID-PSIA). The conversion from Reid vapor pressure units to millimeters of mercury (mm Hg) requires the use of the nomograph shown in EPA AP-42, Chapter 7.1, Figure 7.1-13a. The

nomograph shows 2 psi Reid vapor pressure is equal to 2.2 psi stock true vapor pressure, both at 100 ºF. To convert 2 psia Reid vp to mm Hg--

(2 psia Reid vp)(2.2 psia true vp/2 psi Reid vp)(51.7149 mm Hg/psia) = 113.77 mm Hg

The adjusted controlled emission factor for AEC is calculated as follows:

Controlled emission factor, AEC = (0.2 lb VOC/1000 gal waste water, refinery)
(vp of lubricating oil, 0.01 mm Hg)/(vp of crude oil, 113.77 mm Hg at 100 ºF)
= 0.000018 lb VOC/1000 gal wastewater

To calculate maximum monthly emissions:

VOC, lb/month = (808,737.6 gal/month) (0.000018 lb VOC/1000 gal)
= 0.015 lb/month = 0.0000075 tons/month = 0.00009 tpy

lb/hr = (0.015 lb/month) (month/30 days)(day/24 hr)= 0.000021 lb/hr
(For NSR Data Summary Sheet)

30-day average = 0.015 lb / 30 days = 0.0005 lb/day

10. A/N 579170—Oil/Water Separator, No. OWS-2 (Simple-Cycle Turbines), 5000 gallons
Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

Total Containment Area = ~~16,177~~ 16,117 ft^2
(including lube oil skids, GSU transformers, aux transformers, fin fan cooler pump skid, gas conditioning, GT fuel gas skid, LMS-100 PB miscellaneous skids, ammonia containment and unloading)

Max monthly volume = (~~16,177~~ 16,117 ft containment area)(1.02 ft average precipitation)
(7.48 gal/ft^3) = ~~123,424.04~~ 122,966.26 gal/month

To calculate maximum monthly emissions:

VOC, lb/month = (~~123,424.04~~ 122,966.26 gal/month) (0.000018 lb VOC/1000 gal)
= 0.0022 lb/month = 0.0000011 tons/month = 0.000013 tpy

lb/hr = (0.0022 lb/month) (month/30 days)(day/24 hr)= 0.0000031 lb/hr
(For NSR Data Summary Sheet)

30-day average = 0.0022 lb / 30 days = 0.000073 lb/day

11. Facility Maximum Monthly and Annual Emissions, Normal Operation
    a. Maximum Monthly Emissions, Normal Operations
    The facility maximum monthly emissions are calculated for the public notice.

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	~~13.15~~ 12.32	3.79	3.16	1.81		50,925.87
Combined-Cycle Turbine	6.73	~~13.15~~ 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	~~4.15~~ 2.75	0.99	2.32	0.60		10,074.12
Simple-Cycle Turbine	3.49	~~4.15~~ 2.75	0.99	2.32	0.60		10,074.12
Simple-Cycle Turbine	3.49	~~4.15~~ 2.75	0.99	2.32	0.60		10,074.12
Simple-Cycle Turbine	3.49	~~4.15~~ 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**	**~~43.20~~ 35.94**	**11.59**	**15.66**	**6.04**	**8.26**	**143,077.15**

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

Table 44 - Facility Maximum Daily Emissions, Normal Operations

	Tons/Day						
	NOx	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**	**SOx**	**NH_3**	**CO_2e**
Facility Total	0.92	~~1.44~~ 1.20	0.39	0.52	0.20	0.28	4769.24

c. Maximum Annual Emissions, Normal Operations
The facility maximum annual emissions are calculated for the public notice and for the purpose of rule applicability, as discussed under the rule analysis section below.

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	~~95.38~~ 90.27	26.33	19.72	3.72		611,110.39
Combined-Cycle Turbine	41.93	~~95.38~~ 90.27	26.33	19.72	3.72		611,110.39
Circuit Breakers for Combined-Cycle Turbine Power Block							17.44
Simple-Cycle Turbine	13.13	~~18.86~~ 14.87	3.76	7.35	0.64		120,889.39
Simple-Cycle Turbine	13.13	~~18.86~~ 14.87	3.76	7.35	0.64		120,889.39
Simple-Cycle Turbine	13.13	~~18.86~~ 14.87	3.76	7.35	0.64		120,889.39
Simple-Cycle Turbine	13.13	~~18.86~~ 14.87	3.76	7.35	0.64		120,889.39
Circuit Breakers for Simple-Cycle Turbine Power Block							57.11
Auxiliary Boiler	0.68	3.60	0.61	0.68	0.19		11,072.68
SCR/CO Catalyst for Combined-Cycle Turbine						35.0	
SCR/CO Catalyst for Combined-Cycle Turbine						35.0	
SCR/CO Catalyst for Simple-Cycle Turbine						7.16	
SCR/CO Catalyst for Simple-Cycle Turbine						7.16	
SCR/CO Catalyst for Simple-Cycle Turbine						7.16	
SCR/CO Catalyst for Simple-Cycle Turbine						7.16	
SCR for Auxiliary Boiler						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**	**~~269.80~~ 243.62**	**68.31**	**69.52**	**10.19**	**98.85**	**1,716,925.57**

RULE EVALUATION

The AEC project is expected to comply with all applicable SCAQMD 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 SCAQMD 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. ~~Condition E193.5 implements Rule 205.~~

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." ~~Condition E193.6 implements 40 CFR 52.21 – PSD.~~

§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." ~~Condition E193.7 implements Rule 1713(c).~~

~~All three conditions, E193.5, E193.6, and E193.7, are applicable to the facility.~~ The requirements for Rule 205, 40 Part 52.21, and Rule 1713 are consolidated in conditions E73.2 and E193.5.

Rule 212—Standards for Approving Permits
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 equipment under Regulation XXX (Title V) that may emit air contaminants located within 1000 feet from the outer boundary of a school, unless 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 subsection will require public notice because the proposed equipment will be located within 1000 feet of the outer boundary of a school. The nearest K-12 school—Rosie the Riveter Charter High School, 690 N. Studebaker Road, Long Beach, CA 90803-- is located 971 feet away from the closest combined-cycle turbine. The school is located outside the entrance to the facility. All students participate in both high school and vocational training. The current enrollment is 64 students in grades 9^{th} – 12^{th}.

  Subdivision (d) provides that in the case of notifications performed under paragraph (c)(1) of this rule, distribution of the public notice shall be to the parents or legal guardians of children in any school within 1/4 mile (1320 feet) of the facility and the applicant shall provide distribution of the public notice to each address within a radius of 1000 feet from the outer property line of the proposed new or modified facility. As the initial step, the Greatschools website (www.greatschools.org) was consulted to identify nearby schools and their approximate distances from the facility. Planning, Rule Development & Area Sources (PRDAS) staff was then requested to provide accurate distances from the boundary of the AGS facility to any schools that may be within ¼ mile, using Google Earth and a map of the AGS facility.

  The next closest schools and their distances to the boundary of the AGS facility are as follows: (1) Kettering Elementary School, 550 Silvera Avenue, Long Beach, CA 90803, with a distance of 310 meters (0.19 miles), and (2) Hill Classical Middle School, 1100 Iroquois Avenue, Long Beach, CA 90805, with a distance of 880 meters (0.55 miles). Since Kettering Elementary School is located within ¼ mile of the facility, the public notice is also required to be distributed to the parents or legal guardians of the students at that school.

- ***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.

  This subsection will require public notice because the on-site emission increases from the AEC will exceed the daily maximum thresholds set forth in subdivision (g) for VOC, NOx, PM_{10}, SOx, and CO, as shown below.

Table 47 - Rule 212(c)(2) Applicability

	VOC	NOx	PM_{10}	SOx	CO	Lead
AEC 30-day averages, lb/day	1154.12	1887.87	1043.78	403.0	7500.88	0
Rule 212(c)(2) Daily Maximum, lbs/day	30	40	30	60	220	3
Increase Exceed Daily Maximum?	Yes	Yes	Yes	Yes	Yes	No

CC = combined-cycle turbine, SC = simple-cycle turbine

VOC (30-day), lb/day = [(443.8 lb/day-CC)(2 CC)] + [(65.78 lb/day-SC)(4 SC)] + (3.40 lb/day-boiler) = 1154.12 lb/day
NOx (30-day), lb/day = [(476.45 lb/day-CC)(2 CC)] + [(232.79 lb/day-SC)(4 SC)] + (3.81 lb/day-boiler) = 1887.87 lb/day
PM_{10} (30-day), lb/day = [(210.8 lb/day-CC)(2 CC)] + [(154.60 lb/day-SC)(4 SC)] + (3.78 lb/day-boiler) = 1043.78 lb/day
SOx (30-day), lb/day = [(120.53 lb/day-CC)(2 CC)] + [(40.22 lb/day-SC)(4 SC)] + (1.06 lb/day-boiler) = 403.0 lb/day
CO (30-day), lb/day = [(3167.44 lb/day-CC)(2 CC)] + [(286.46 lb/day-SC)(4 SC)] + (20.16 lb/day-boiler) = 7500.88 lb/day

The public notice requirements for subdivision (c)(2) are found in subdivisions (d) and (g). The District will prepare the public notice which will contain sufficient information to fully describe the project. In accordance with subdivision (d), the applicant will be required to distribute the public notice to each address within ¼ mile radius of the project.

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

Pursuant to (g)(1), the District will make the following information available for public inspection at Bay Shore Neighborhood Library, located at 195 Bay Shore Avenue, Long Beach, CA 90803, during the 30-day comment period: (1) public notice, (2) project information submitted by the applicant, and (3) District's permit to construct evaluation.

Pursuant to (g)(2), the public notice will be published in a newspaper which serves the area that will be impacted by the project (Press Telegram).

Pursuant to (g)(3), the public notice will be mailed to the following persons: the applicant, Region IX EPA administrator, CARB, chief executives of the city and county where the project will be located, regional land use planning agency, and state and federal land managers whose lands may be affected by the emissions from the proposed project.

The Rule 212(c)(2) public notice will be combined with the Rule 3006 Title V public notice for a single public notice, with the public notice periods running concurrently for a single 30-day public comment period. (The Title V public notice requirements <u>and completion</u> are discussed below under *<u>Regulation XXX – Title V</u>*.)

Rule 212 Public Notice Requirements Completion—Original Noticing

The PDOC (engineering evaluation) and proposed revised Title V permit were issued on 6/30/16.

- *Publication of Public Notice*
  On 7/8/16, the Notice of Intent to Issue Permits Pursuant to SCAQMD Rules 212, 1710, 1714, and 3006 was published in the Press Telegram. The public comment period ended on 8/9/16. Also see *Regulation XXX – Title V*, below.

- *EPA Significant Permit Revision Review for Title V*
  On 6/30/16, SCAQMD electronically submitted the public notice, PDOC analysis, and proposed Title V facility permit to the EPA for the 45-day review. The EPA was forwarded the comment letters received (AES and Helping Hand Tools (Rob Simpson)) on 8/17/16 and will be forwarded the SCAQMD's responses for review. Also see *Regulation XXX – Title V*, below.

- *SCAQMD Distribution of Public Notice*
  On 6/30/16, SCAQMD mailed (or e-mailed, if requested) the public notice (also PDOC analysis and proposed Title V facility permit, as appropriate) to AES, other persons listed in Rule 212(g)(3), environmental groups, and other interested parties.

- *SCAQMD Submittal to CEC*
  On 6/30/16, SCAQMD electronically submitted the public notice, PDOC analysis, and proposed Title V facility permit to the CEC.

- *SCAQMD Website Availability of Public Notice*
  On 6/30/16, the public notice, PDOC analysis and proposed Title V facility permit were available for review on the SCAQMD website.

- *Library Availability of Public Notice*
  The public notice, PDOC analysis and proposed Title V facility permit were available for public review at the SCAQMD's headquarters in Diamond Bar, and at the Bay Shore Neighborhood Library, 195 Bay Shore Avenue, Long Beach, CA 90803.

- *AES Distribution of Public Notice to Each Address Within ¼ mile Radius of the Project*
  In a letter dated 7/28/16, AES provided the following verification that the public notice was distributed to all addresses within one-quarter mile of the facility: (1) copy of the public notice with a distribution date of 7/11/16; (2) map showing ¼-mile public notice radius; (3) list of addresses; and (4) e-mail, dated 7/20/16, from Christopher Roeser, Graphics 360, stating that they delivered to the Irvine Post Office the mailing containing 189 envelopes on 7/12/16. The list of addresses included 26 addresses in Leisure World Seal Beach. The public comment period ended on 8/11/16.

- *AES Distribution of Public Notice to Parents/Guardians of Students at Required Nearby Schools*

In the same letter dated 7/28/16, AES provided the following verification that the public notice was distributed to the parents and guardians of the required nearby schools

Rosie the Riveter Charter High School—The school provided the addresses for the students attending the school directly to AES and AES mailed dated public notices directly to the parents/guardians of the students. AES provided the following verification: (1) copy of the public notice with a distribution date of 7/12/16, and (2) list of ten addresses with a copy of ten USPS postmarks for Costa Mesa, dated 7/12/16. The public comment period ended on 8/11/16.

Kettering Elementary School—The Long Beach Unified School District (LBUSD) requested AES use a mailing vendor the LBUSD uses for distributing public notices. The LBUSD provided the students' addresses to the mailing vendor and AES provided sealed envelopes with the dated public notice to the vendor. The mailing vendor then applied the address and postage to the envelopes and posted the envelopes. AES provided the following verification: (1) copy of the public notice with a distribution date of 7/25/16; (2) declaration of mailing by Norah Jaffan, project manager of NotificationMaps.com, stating that on 7/25/16 she caused a copy of the notice to be mailed to the attached mailing list; and (3) attached mailing list with a sample copy of an addressed envelope. The public comment period ended on 8/24/16.

- *Comment Letters*
  Written comments were submitted by (1) AES Alamitos on July 19, 2016 and (2) Helping Hand Tools (Rob Simpson) on August 9, 2016.

- *Response to Comments*
  An addendum has been added to this FDOC to address the comments received during this comment period.

Rule 212 Public Notice Requirements Completion to Date—Re-noticing

The PDOC (engineering evaluation) and proposed revised Title V permit are being re-noticed. The re-noticing is 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 (http://docketpublic.energy.ca.gov/PublicDocuments/13-AFC-01/TN212284_20160713T160604_Preliminary_Staff_Assessment.pdf). There is no change in the documents that are being released as part of this re-noticing. The re-notice public notice describes how any new comments can be submitted.

- *Publication of Re-Notice Public Notice*
  On 11/17/16, the re-notice Notice of Intent to Issue Permits Pursuant to SCAQMD Rules 212, 1710, 1714, and 3006 was published in the Press Telegram. Also see *Regulation XXX – Title V*, below.

- *EPA Significant Permit Revision Review for Title V*

On 11/10/16, SCAQMD electronically submitted the re-notice public notice, PDOC analysis, and proposed Title V facility permit to the EPA for the 45-day review. Also see *Regulation XXX – Title V*, below.

- *SCAQMD Distribution of Re-Notice Public Notice*
  On 11/10/16, SCAQMD mailed and e-mailed the re-notice public notice, PDOC analysis and proposed Title V facility permit to AES. On 11/15/16, SCAQMD mailed (or e-mailed, if requested) the re-notice public notice (also PDOC analysis and proposed Title V facility permit, as appropriate) to the other persons listed in Rule 212(g)(3), environmental groups, and other interested parties. The re-notice distribution included those who had received the original public notice mailed on 6/30/16, and additional states and public agencies.

- *SCAQMD Submittal to CEC*
  On 11/10/16, SCAQMD posted the re-notice public notice on the CEC website.

- *SCAQMD Website Availability of Public Notice*
  On 11/15/16, the re-notice public notice, PDOC analysis and proposed Title V facility permit were available for review on the SCAQMD website.

- *Library Availability of Public Notice*
  The re-notice public notice, PDOC analysis and proposed Title V facility permit are available for public review at the SCAQMD's headquarters in Diamond Bar, and at the Bay Shore Neighborhood Library, 195 Bay Shore Avenue, Long Beach, CA 90803.

- *AES Distribution of Re-Notice Public Notice to Each Address Within ¼ mile Radius of the Project*
- *AES Distribution of Re-Notice Public Notice to Parents/Guardians of Students at Required Nearby Schools*
  AES is in the process of distributing the re-notice public notice to all addresses within one-quarter mile of the facility and to the parents and guardians of Rosie the Riveter Charter High School and the Kettering Elementary School.

- *Comments Received*
  If any comments are received, they will be addressed before the Permits to Construct are issued.

- ***Rule 212(c)(3)***
  Public notice is required for any new or modified equipment under Regulation XX or XXX with increases in emissions of toxic contaminants for which a person may be exposed to a maximum individual cancer risk greater than, or equal to one in a million during a lifetime (70 years) for facilities with more than one permitted unit, 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 using the risk assessment procedures and toxic air contaminants specified under Rule 1402.

This subsection will **not** require public notice. The increases in toxic emissions from any combined-cycle turbine, any simple-cycle turbine, or the auxiliary boiler will not expose a person to a maximum individual cancer risk that is greater than or equal to one in a million. See the Rule 1401 rule analysis below.

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. Compliance with this rule is expected.

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 and auxiliary boiler because they will be firing exclusively on pipeline quality natural gas.

Rule 402 – Nuisance

This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. Nuisance problems are not expected from the turbines, auxiliary boiler, and other equipment during normal operation.

Rule 403 – Fugitive Emissions

The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule includes the prohibition of fugitive dust emissions that remains visible in the atmosphere beyond the property line of the emission source.

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

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

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

During normal operations, fugitive emissions are not expected from the operation of the turbines, auxiliary boiler, SCR/oxidation catalysts, ammonia tanks, and oil/water separators. 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~~/LAER~~ limit of ~~2~~ 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~~/LAER~~ limit of ~~4~~ 2 ppmvd at 15% O_2. The auxiliary boiler is expected to comply with the BACT~~/LAER~~ limit of 50 ppmv CO.

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.

- Combined-Cycle Turbines

  Each gas turbine is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the grain loading is expected to be 0.007 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

- <u>Simple-Cycle Turbines</u>
  Each gas turbine is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the grain loading is expected to be 0.01 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

- <u>Auxiliary Boiler</u>
  The maximum PM emission rate during normal operation is 0.15 lb/hr, which is significantly less than the PM emission rates from the turbines above. Compliance with the 0.1 gr/scf limit is expected.

Rule 431.1 – Sulfur Content of Gaseous Fuels

The natural gas supplied to the gas turbines and auxiliary boiler 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

This rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.

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.

- 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

This rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.

<u>Rule 1135 – Emissions of NOx from Electric Power Generating Systems</u>

This rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.

<u>Rule 1146—Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, as amended 11/1/13</u>

NOx emissions from the auxiliary boiler are not subject to this rule, because this rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions. However, the CO emissions are subject to this rule.

Paragraph (a)—This rule is applicable to boilers of equal to or greater than 5 MMBtu/hr rated heat input capacity, including the auxiliary boiler.

Paragraph (b)(8)—"Group I Unit" means any unit burning natural gas with a rated heat input greater than or equal to 75 MMBtu/hr, excluding thermal fluid heaters. The auxiliary boiler is a Group I unit.

Subparagraph (c)(1)--Subparagraph (c)(1)(F) is applicable to Group I units.

The requirements listed in subparagraphs (c)(1)(F) are shown below:

Rule Reference	Category	Limit	Unit Shall be in Full Compliance on or before
(c)(1)(F)	Group I Units	5 ppm or 0.0062 lbs/10^6 Btu	January 1, 2013

Since AEC will be a RECLAIM facility, the 5 ppm NOx is not applicable to the auxiliary boiler pursuant to Rule 1146. The 5 ppm NOx is applicable pursuant to the top-down PSD BACT analysis below. Condition A195.13 specifies the NOx limit is 5 ppm, and condition D29.5 requires an initial source test.

Paragraph (c)(4)—The CO limit is 400 ppmv, corrected to 3% O_2, for natural gas.

The top-down PSD BACT analysis below indicates BACT~~/LAER~~ requires the more stringent limit of 50 ppm. The Cleaver Brooks warranty letter, dated 6/10/15, guarantees 50 ppm CO. Condition A195.14 specifies the limit is 50 ppm, and condition D29.5 requires an initial source test.

Paragraph (c)(6)—Any unit(s) with a rated heat input capacity greater than or equal to 40 million Btu per hour and an annual heat input greater than 200 x 10^9 Btu per year shall have a continuous in-stack nitrogen oxides monitor or equivalent verification system in compliance with 40 CFR part 60 Appendix B Specification 2. Maintenance and emission records shall be maintained and made accessible for a period of two years to the Executive Officer.

This NOx requirement is not applicable to the auxiliary boiler, because the RECLAIM requirements supersede the Rule 1146 requirements. Pursuant to Rule 2012--RECLAIM Monitoring Recording and Recordkeeping Requirements, the auxiliary boiler is classified as a "major NOx source." As such, the boiler will be required to be equipped with a certified CEMS to meet RECLAIM requirements.

Paragraph (d)(3)—All parts per million emission limits specified in subdivision (c) are referenced at 3 percent volume stack gas oxygen on a dry basis averaged over a period of 15 consecutive minutes. Subdivision (c) sets forth emission limits for NOx and CO.

The 5 ppm NOx and 50 ppm CO limits are imposed pursuant to BACT~~/LAER~~, not Rule 1146. BACT requires a 1-hour averaging time. Accordingly, condition D29.5 require 1-hour averaging times for NOx, CO, VOC, and NH_3. The sampling times for PM_{10} and $PM_{2.5}$ are 1 hour or longer as necessary to obtain a measurable sample.

Paragraph (d)(4)—Compliance with the NOx and CO emission requirements of paragraph (c)(1) shall be determined using a District approved contractor under the Laboratory Approval Program according to the following procedures:

(A) District Source Test Method 100.1—Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling (March 1989), or …..

Condition D29.5 requires the use of Method 100.1 and a LAP-approved contractor.

Paragraph (d)(6)—Compliance with the NOx emission requirements in paragraph (d)(4) shall be conducted once:

(A) every three years for units with a rated heat input greater than or equal to 10 million Btu per hour, except for units subject to paragraph (c)(6) (CEMS).

As a major NOx source, the boiler will be required to be equipped with a certified CEMS to meet RECLAIM requirements, which supersede the above requirement.

Paragraph (d)(8)— Any owner or operator of units subject to this rule shall perform diagnostic emission checks of NOx emissions with a portable NOx, CO and oxygen analyzer according to the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Units Subject to South Coast Air Quality Management District Rules 1146 and 1146.1 according to the following schedule:

(A) On or after July 1, 2009, the owner or operator of units subject to paragraphs (c)(1), (c)(2), (c)(3), and (c)(4) shall check NOx emissions at least monthly or every 750 unit operating hours, whichever occurs later. If a unit is in compliance for three consecutive diagnostic emission checks, without any adjustments to the oxygen sensor set points, then the unit may be checked quarterly or every 2,000 unit operating hours, whichever occurs later, until the resulting diagnostic emission check exceeds the applicable limit specified in paragraphs (c)(1), (c)(2), or (c)(3).

(B) On or after January 1, 2015 or during burner replacement, whichever occurs later, the owner or operator of units subject to paragraph (c)(5) shall check NOx emissions according to the tune-up schedule specified in subparagraph (c)(5)(B).

(C) Records of all monitoring data required under subparagraphs (d)(8)(A) and (d)(8)(B) shall be maintained for a rolling twelve month period of two years (5 years for Title V facilities) and shall be made available to District personnel upon request.

(D) The portable analyzer diagnostic emission checks required under subparagraph (d)(8)(A) and (d)(8)(B) shall only be conducted by a person who has completed an appropriate District-approved training program in the operation of portable analyzers and has received a certification issued by the District.

For NO_X: RECLAIM supersedes the above requirements. As a major NOx source, the boiler will be required to be equipped with a certified CEMS to meet RECLAIM requirements.

For CO: Rule 1146(d)(9) specifies that an owner or operator shall comply with the above requirements as applied to CO.

Paragraph (d)(9)—An owner or operator shall as applied to CO emissions specified in paragraph (d)(8) **and** subparagraph:

(A) (d)(6)(A) for units greater than or equal to 10 mmbtu/hr.

Condition (d)(6)(A) requires source testing every three years. Condition D29.6 requires testing to be conducted in accordance with the testing frequency requirements specified in Rule 1146. In addition, condition H23.7 requires compliance with the applicable requirements of Rule 1146.

REGULATION XIII—NEW SOURCE REVIEW (NSR)

The SCAQMD 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 SCAQMD interpreting the emission increase to be 1 lb/day or greater of uncontrolled emissions.

The SCAQMD 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. Specifically, NOx and VOC are precursors to ozone, PM_{10}, and $PM_{2.5,}$ and SOx is a precursor to PM_{10} and $PM_{2.5}$. Thus, this rule requires BACT for NOx (non-RECLAIM), PM_{10}, SOx, VOC, and ammonia. <u>As discussed below, Rules 1701(b)(1) and 1703(a)(2) require BACT for CO.</u> ~~Moreover, the SCAQMD has determined that BACT is required 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). <u>Rule 1302(s) (as amended 11/4/16) defines a "major polluting facility"</u> ~~A facility is a major polluting facility~~ (same as major stationary source) <u>located in the South Coast Air Basin</u> ~~if it~~ <u>as any facility which</u> 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, ~~100~~ <u>70</u> tpy; (4) CO, 50 tpy; and (5) PM_{10}, 70 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 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.

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 SCAQMD 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 following sets forth the 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 are performed under Rule 1703(a)(2) below for NOx, PM_{10}, and CO. ~~for the two pollutants subject to PSD review, NOx and PM10. Although not subject to PSD review, a top-down BACT analysis is also included for CO to provide a more complete review~~. This section also compares the BACT/LAER levels established pursuant to NSR and PSD analyses to the warranted levels.

1. A/N 579142, 579143—Combined-Cycle Combustion Turbine Generators Nos. CCGT-1, CCGT-2
2. A/N 579160, 570161—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. CCGT-1, CCGT-2 (Combined-Cycle Turbines)
   - *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.

     Combustor design--The formation of VOCs is limited by designing the combustion system to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures with an excess of combustion air. Good combustor design (such as dry low NOx combustors) and best operating practices will minimize the formation of VOC while reducing the combustion temperature and NOx emissions. (Dry low NOx combustors and NOx control are discussed below in greater detail under the top-down BACT analysis for NOx.)

     Oxidation catalyst—As discussed in the top-down BACT analysis for CO, an oxidation catalyst is typically a precious metal catalyst bed located in the HRSG. In addition to controlling CO by enhancing the oxidation of CO to CO_2, the catalyst enhances the oxidation of VOC to CO_2 without the addition of any reactant. Oxidation catalysts have been successfully installed on numerous combined- and simple-cycle combustion turbines.

     Based on combined-cycle facilities recently permitted by the SCAQMD, including (1) LA City, DWP Scattergood Generating Station (2013), (2) Pasadena City, Dept. of Water & Power (2013), and (3) El Segundo Power (2011), the BACT/LAER limit for VOC is 2 ppm at 15% O_2 (1-hr averaging), without or with duct burner. This limit is consistent with the most stringent level found among recent BACT determination for combined-cycle natural gas fired combustion turbines.

The proposed/guaranteed levels is 1 ppm in the original Application, based on a top-down BACT analysis that included non-SCAQMD and SCAQMD combined-cycle turbine projects. The 1 ppmvd at 15% O_2 BACT levels is based on non-SCAQMD projects for which the VOC test methods ~~is~~ are **not** recognized by the SCAQMD. The proposed CTGs will be unable to meet a 1 ppmvd limit using the SCAQMD-approved test method, entitled SCAQMD Method 25.3—Determination of Low Concentration Non-Methane Non-Ethane Organic Compound Emissions for Clean Fueled Combustion Sources. The BACT/LAER limit for VOC remains 2 ppm at 15% O_2 (1-hr averaging). AES has accepted the SCAQMD's determination in the revised Application.

Conditions 29.2 and 29.3 require modified SCAQMD Method 25.3 for VOC source testing. The conditions include a three-step procedure that describes modified Method 25.3, which lists requirements to provide improved accuracy at the lower end of the range that were developed by the SCAQMD Source Test Engineering Department for turbines.

The SCAQMD has reviewed source test methods used by some non-SCAQMD projects. Following are a summary of findings by the Source Test Engineering Dept.

- For some non-SCAQMD projects, the sampling and analysis were performed using Method TO-12—Method for the Determination of Non-Methane Organic Compounds (NMOC) in Ambient Air Using Cryogenic Preconcentration and Direct Flame Ionization Detection (PDFID). The SCAQMD had learned that because Method TO-12 is an ambient concentration method, laboratories were variously modifying the method to one for stack sampling to compensate for the methane and ethane interferences and the higher concentrations in the stack samples. Methane and ethane, defined as non-VOC compounds, are required to be separated from the VOC compounds in the sample. The test results from TO-12 were inconsistent and it became unclear as to what the methods, modified in various ways by each laboratory, were actually measuring. In response, SCAQMD developed modified Method 25.3--Determination of Low Concentration Non-Methane Non-Ethane Organic Compound Emissions from Clean Fueled Combustion Sources to accurately sample and analyze stack exhaust from turbines. For example, TO-12 uses cryogenic preconcentration to try to physically freeze out methane and ethane from the stack sample by adjusting the temperature of the gaseous sample. Since the separation is not precise, if some of the methane and ethane is left in the sample, then the analyzed VOC concentration of the sample is erroneously high. If some of the VOC is removed along with the methane and ethane, then the analyzed VOC concentration is erroneously low. Modified Method 25.3 uses gas chromatography to precisely analyze a gas sample for VOC because gas chromatography provides separate peaks for methane, ethane, and VOC compounds.

- For some non-SCAQMD projects, stack samples were collected in specially-prepared stainless steel (SUMMA) canisters with the internal vacuum kept above 5 inches of mercury (same as 127 mm of mercury) during sampling. This procedure was from a prior iteration of modified Method 25.3. In the current version of modified Method 25.3, conditions D29.2 and D29.3 now require the stack samples to be extracted directly into Summa canisters, while maintaining a final canister pressure between 400-500 mm of mercury absolute to minimize condensation issues. The partial vacuum in the canister serves to minimize the amount of water-soluble VOC that is condensed out with the water in the canister and lost from the gaseous portion of the sample. If part of the VOC is condensed out, the gaseous portion that remains and is analyzed will result in erroneously low VOC concentration results (low-bias test results).

- For some non-SCAQMD projects, stack samples were collected into nitrogen purged Tedlar sample bags instead of Summa canisters. The Tedlar sample bags are from EPA Method 18, which differs from the SCAQMD sampling methods in that a partial vacuum is not created in the sample bag. Without a partial vacuum, the water-soluble VOC condenses out and the analysis of the remaining gaseous portion results in erroneously low VOC concentration results.

- For some non-SCAQMD projects, the VOC testing and analyses were performed according to EPA Method 25A. EPA Method 25A cannot detect oxygenated hydrocarbons such as formaldehyde, and VOC concentrations less than 2 ppm are in the statistical noise of EPA Method 25A. Previous parallel testing on similar gas-fired sourced in the SCAQMD using SCAQMD Method 25.3 have shown results higher than those given by EPA Method 25A. The higher results given by SCAQMD Method 25.3 are most likely due to the ability of Method 25.3 to detect oxygenated hydrocarbons (an ability that EPA Method 25A does not have) and the actual presence of such hydrocarbons in low concentrations from natural gas-fired turbines. Oxygenated hydrocarbons cause destructive interference with flame ionization detector (FID) methods, i.e., the oxygenated hydrocarbons subtract from the VOC readings. EPA Method 25A is an FID method.

Due to the potential erroneously low readings from methods used by other agencies, the SCAQMD uses modified District Method 25.3. The 2 ppmvd VOC is the lowest achievable as measured by any method.

The applicant has proposed to install dry low NOx combustors and an oxidation catalyst to meet a VOC BACT of 2 ppm at 15% O_2 (1-hr averaging), on which the PDOC/FDOC will be based.

- *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.

Natural-gas-fired turbines in California are typically required to combust only California Public Utilities Commission (CPUC) pipeline-quality natural gas with a sulfur content of less than 1 grain of sulfur per 100 scf. 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. Therefore, the use of pipeline-quality natural gas with low sulfur content is BACT 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 applicant is proposing a BACT limit of 5 ppm at 15% O_2 (1-hr averaging).

  The CARB "Guidance for Power Plant Siting and Best Available Control Technology," dated September 1999, recommends that BACT levels for ammonia for gas turbines be set at not more than 5 ppmvd at 15% O_2. The SCAQMD BACT for non-major sources for gas turbines rated at 50 MW or higher is 5.0 ppmvd at 15% O_2, and the BACT/LAER for major sources is the same limit with the additional requirement of 1-hr averaging. Therefore, the proposed limit of 5 ppm at 15% O_2 (1-hr averaging) meets BACT/LAER.

  The SCAQMD's search of the EPA RACT/BACT/LAER Clearinghouse, Statewide Best Available Control Technology (BACT) Clearinghouse, and other databases found the EPA RACT/BACT/LAER Clearinghouse lists three facilities with an ammonia slip limit of less than 5 ppmvd at 15% O_2. The following three facilities were shown having an ammonia slip limit of 2 ppmvd at 15% O_2, and a NOx limit of 2.0 ppmvd at 15% O_2.

  1) Kleen Energy Systems, LLC—Commercial operation started in July 2011. The 2.0 ppmvd at 15% O2 has been verified on the EPA RACT/BACT/LAER Clearinghouse database. The permit, dated 7/2/13, indicates a 2.0 ppmvd ammonia slip limit is applicable during steady state operation, and a 5.0 ppmvd ammonia slip limit is applicable during transient operation. Transient operations include cold, warm and hot startups, shut-downs, shifts between loads, fuel switch and equipment cleaning, as well as operation below 60% load. In contrast, the SCAQMD does require BACT during periods of shifts between loads and operation at below 60% load. As AEC turbines are equipped with fast start and ramp-up/ramp-down capabilities, load changes are expected to be a regular occurrence. As the minimum turndown for the turbines is 44% load, operation at below 60% load is expected to be a regular occurrence. The Kleen Energy System limits do not meet the definition of BACT as implemented by the SCAQMD for a facility with these operating characteristics.

     The permit limits for Kleen Energy are not achieved in practice for facilities where BACT must be met during shifts between loads and at below 60% load. Condition D29.2

requires the initial source testing for combined-cycle turbines to be performed at 45, 75, and 100 percent of maximum load, and for the simple-cycle turbines at 50, 75, and 100 percent of maximum load, because emission rates may vary with load.

2) Salem Harbor Station Redevelopment—Scheduled to start operation in June 2017. The permit, dated 1/30/14, does not include an ammonia slip limit.

3) CPV Towantic, LLC—Scheduled to be on line in 2018. The 2.0 limit has not been demonstrated as achieved in practice.

Therefore, the BACT/LAER ammonia slip limit for combined-cycle turbines remains 5.0 ppmvd at 15% O2.

- *BACT/LAER vs. Guaranteed Levels*
  Based on the above BACT/LAER analysis for VOC, SO_2, and NH_3, and the PSD top-down BACT analysis for NOx, PM_{10}, and CO performed under Rule 1703(a)(2), the SCAQMD has determined that BACT/LAER emission limits for combined-cycle facilities are as set forth in the table below. The table below presents the SCAQMD BACT/LAER determinations, the limits proposed by AES, and the guarantees for NOx, CO, VOC, and ammonia provided by Julie Lux, Nooter/Eriksen, in a letter dated 6/5/15.

Table 48 - Combined-Cycle Gas Turbine BACT/LAER Requirements, Proposed and Guaranteed Emissions Levels

	NOx	CO	VOC	PM_{10}/SOx	NH_3
SCAQMD Combined-Cycle Gas Turbine BACT/LAER Limits	2.0 ppmvd at 15% O_2, 1-hr average	PDOC--2.0 ppmvd at 15% O_2, 1-hr average FDOC--1.5 ppmvd at 15% O_2, 1-hr average	2.0 ppmvd at 15% O_2, 1-hr average	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5.0 ppmvd at 15% O_2, 1-hr average
AES Proposed BACT/LAER	2.0 ppmvd at 15% O_2, 1-hr average	PDOC--2.0 ppmvd at 15% O_2, 1-hr average FDOC--1.5 ppmvd at 15% O_2, 1-hr average	Original--1.0 ppmvd at 15% O_2, 1-hr average Revised--2.0 ppmvd at 15% O_2, 1-hr average based on SCAQMD Method 25.3	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5 ppmvd at 15% O_2
Nooter/Eriksen Guarantees Guarantee Pending	2 ppmvd at 15% O_2	PDOC--2 ppmvd at 15% O_2 FDOC--1.5 ppmvd at 15% O_2	1 ppmvd at 15% O_2	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5 ppmvd at 15% O_2
Compliance?	Yes	Yes	Yes	Yes	Yes

- *Commissioning, Startups and Shutdowns*
  Condition nos. A195.8, A195.9, and A195.10 provide that the BACT limits of 2.0 ppmvd NOx, ~~2.0~~ 1.5 ppmvd CO, and 2.0 ppmvd ROG, respectively, shall not apply during commissioning, startup, and shutdown periods.

  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, warm, and hot startups. The startup limits include: (1) number of cold starts per calendar month and year; (2) number of warm starts per calendar month and year; (3) number of hot starts per calendar month and year; (4) number of starts per day; (5) duration of cold starts, warm starts, and hot starts; and (6) NOx, CO, and VOC emissions per cold start, warm start, and hot start.

  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. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdowns; and (3) NOx, CO, and VOC emissions per shutdown.

3. A/N 579145, 579147, 579150, 579152—Simple-Cycle Combustion Turbine Generators Nos. SCGT-1, SCGT-2, SCGT-3, SCGT-4
4. A/N 579162, 579163, 579164, 579165—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. SCGT-1, SCGT-2, SCGT-3, SCGT-4 (Simple-Cycle Turbines)
   - *BACT/LAER for VOC Emissions*
     The discussion on VOC formation and technologies for VOC control are the same as for the combined-cycle turbines.

     Based on simple-cycle facilities recently permitted by the SCAQMD, including (1) Canyon Power Plant (2011) and (2) CPV Sentinel (2012 & 2013), the BACT/LAER limit for VOC is 2.0 ppm at 15% O_2 (1-hr averaging). This limit is consistent with the most stringent level found among recent BACT determination for simple-cycle natural gas fired combustion turbines based on modified SCAQMD Method 25.3. See discussion on combined-cycle turbines regarding non-SCAQMD approved source test methods and their effects on measured VOC emission levels.

The applicant has proposed to install dry low NOx combustors and an oxidation catalyst to meet a VOC BACT of 2.0 ppm at 15% O_2 (1-hr averaging).

- *BACT/LAER for SO_2 Emissions*
  As with the combined-cycle turbines, the use of pipeline-quality natural gas with low sulfur content is BACT for SO_2.

- *BACT/LAER for Ammonia Emissions*
  As with the combined-cycle turbines, the proposed limit of 5 ppm at 15% O_2 (1-hr averaging) meets BACT/LAER. The SCAQMD's search of the EPA RACT/BACT/LAER Clearinghouse, Statewide Best Available Control Technology (BACT) Clearinghouse, and other databases found no simple-cycle facilities with an ammonia slip limit of less than 5 ppmvd.

- *BACT/LAER vs. Guaranteed Levels*
  Based on the above BACT/LAER analysis for VOC, SO_2, and NH_3, and the PSD top-down BACT analysis for NOx, PM_{10}, and CO performed under Rule 1703(a)(2), the SCAQMD has determined that BACT/LAER emission limits for simple-cycle facilities are as set forth in the table below. The table below presents the SCAQMD BACT/LAER determinations, the limits proposed by AES, and the guarantees for NOx, CO (4 ppmv), VOC, and ammonia provided by Christopher Vu, GE Power & Electric, in a guarantee document dated 6/16/15. In a revised proposal, dated 9/16/16, Bob Zeiss, BASF Corp., provided a performance guarantee for 2.0 ppmvd CO at 15% O_2. A slight increase in the precious metal content will be required.

Table 49 - Simple-Cycle Gas Turbine BACT/LAER Requirements, Proposed and Guaranteed Emissions Levels

	NOx	CO	VOC	PM_{10}/SOx	NH_3
SCAQMD Simple-Cycle Gas Turbine BACT/LAER	2.5 ppmvd at 15% O_2, 1-hr average	PDOC--4.0 ppmvd at 15% O_2, 1-hr average FDOC--2.0 ppmvd at 15% O_2, 1-hr average	2.0 ppmvd at 15% O_2, 1-hr average	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5.0 ppmvd at 15% O_2, 1-hr average
AES Proposed BACT/LAER	2.5 ppmvd at 15% O_2, 1-hr average	PDOC--4.0 ppmvd at 15% O_2, 1-hr average	2.0 ppmvd at 15% O_2, 1-hr average	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5.0 ppmvd at 15% O_2

	NOx	CO	VOC	PM_{10}/SOx	NH_3
		FDOC--2.0 ppmvd at 15% O_2, 1-hr average			
GE Power & Water Guarantees BASF Co. Guarantee	2.5 ppmvd at 15% O_2	PDOC--4 ppmvd at 15% O_2 FDOC--2 ppmvd at 15% O_2	2.0 ppmvd at 15% O_2	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5.0 ppmvd at 15% O_2
Compliance?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

- *Commissioning, Startups and Shutdowns*
  Condition nos. A195.11, ~~A195.12~~ A195.17, and A195.10 provide that the BACT limits of 2.5 ppmvd NOx, ~~4.0~~ 2.0 ppmvd CO, and 2.0 ppmvd ROG, respectively, shall not apply during commissioning, startup, and shutdown periods.

  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. 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 emissions per start.

  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. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdowns; and (3) NOx, CO, and VOC emissions per shutdown.

5. A/N 579158—Auxiliary Boiler (Combined-Cycle Turbines), 70.8 MMBtu/hr
6. A/N 579166—Selective Catalytic Reduction for Auxiliary Boiler
   - *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. The commercially available control measures that are identified in

the most-stringent BACT determinations are use of low-sulfur, pipeline quality natural gas and good combustion practice to ensure complete combustion. This is BACT for the auxiliary boiler.

- *BACT/LAER for SO_2 Emissions*
  As with the combined- and simple-cycle turbines, the use of pipeline-quality natural gas with low sulfur content is BACT for SO_2.

- *BACT/LAER for Ammonia Emissions*
  As with the combined- and simple-cycle turbines, the proposed limit of 5 ppm at 15% O_2 (1-hr averaging) meets BACT/LAER.

- *BACT/LAER vs. Guaranteed Levels*
  Based on the above BACT/LAER analysis for VOC, SO_2, and NH_3, and the PSD top-down BACT analysis for NOx, PM_{10}, and CO performed under Rule 1703(a)(2), the SCAQMD has determined that BACT/LAER emission limits for auxiliary boilers are as set forth in the table below. The table below presents the SCAQMD BACT/LAER determinations, the limits proposed by AES, and the guarantees for NOx, CO, VOC, and ammonia provided by David Obrecht, Cleaver Brooks, in a letter dated 6/10/15.

Table 50 - Auxiliary Boiler BACT/LAER Requirements, Proposed and Guaranteed Emissions Levels

	NOx	CO	VOC	PM_{10}/SOx	NH_3
SCAQMD Boiler, ≥ 75 MMBtu/hr, BACT/LAER Limits	5.0 ppmvd at 3% O_2, 1-hr average	50 ppmvd at 3% O_2, 1-hr average	None	Natural gas	5.0 ppmvd at 3% O_2, 1-hr average
AES Proposed BACT/LAER	5.0 ppmvd at 3% O_2, 1-hr average	50 ppmvd at 3% O_2, 1-hr average	Natural gas	Natural gas	5.0 ppmvd at 3% O_2
Cleaver Brooks Guarantees	5 ppmvd at 3% O_2	50 ppmvd at 3% O_2	Natural gas	Natural gas	5.0 ppmvd at 3% O_2
Compliance?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

- *Commissioning, Startups and Shutdowns*
  Condition nos. A195.13 and A195.14 provide that the BACT limits of 5.0 ppmvd NOx and 50.0 ppmvd CO, respectively, shall not apply during commissioning and startup periods.

  During commissioning, it is not technically feasible for the auxiliary boiler to meet the BACT limits for NOx and CO during the entire period. The emissions are only partially abated as the operation of the low NOx burner, FGR and SCR catalyst are optimized. To limit the duration of the commissioning period during which BACT is not achievable, condition no. E193.10 limits the commissioning period to 30 hours of fired operation.

During startups, it is not technically feasible for the auxiliary boiler to meet the BACT limits for NOx and CO during the entire startup. The SCR that is used to achieve the required emissions reduction for NOx is not fully effective when the surface of the catalyst is below the manufacturers' recommended operating range. Further, the low NOx burner, FGR and other combustion components require the startup period to become fully functional. Condition C1.7 specifies limits for cold, warm, and hot startups. The startup limits include: (1) number of cold starts per calendar month and year; (2) number of warm starts per calendar month and year; (3) number of hot starts per calendar month and year; (4) number of starts per day; (5) duration of cold starts, warm starts, and hot starts; and (6) NOx emissions per cold start, warm start, and hot start.

7. A/N 579167--Ammonia Storage Tank, No. Tank-1 (Combined-Cycle Turbines), 40,000 gallons
8. A/N 579168--Ammonia Storage Tank, No. Tank-2 (Simple-Cycle Turbines), 40,000 gallons

   For an ammonia storage tank, BACT 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.

9. A/N 579169—Oil/Water Separator, No. OWS-1 (Combined-Cycle Turbines), 5000 gallons
10. A/N 579170—Oil/Water Separator, No. OWS-2 (Simple-Cycle Turbines), 5000 gallons

    The Bay Area Air Quality Management District BACT Guideline indicates that for Water Treating – Oil/Water Separator, the achieved-in-practice BACT for VOC is a vapor-tight fixed cover totally enclosing the separator tank liquid contents.

    Since turbine lubricant has a significantly lower vapor pressure (0.01 mm Hg) than crude oil (113.77 mm Hg), condition E193.16 will require a fixed cover to minimize VOC emissions. A "vapor-tight" cover would imply that the inspector is required to check for fugitive emissions with a portable analyzer. Both tanks will be equipped with gasketed covers.

- ***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 District. As discussed for the BACT/LAER requirements above, the SCAQMD 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 SCAQMD 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 ~~5~~ 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.

The combined- and simple-cycle turbines, but not the auxiliary boiler, are exempt from the modeling requirements of Rule 1303 (CO, PM_{10}, SO_2). However, the applicant has provided a modeling analysis of impacts for the entire project to evaluate the project's air quality impacts for the CEC's CEQA document. This modeling analysis includes 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. The applicant has provided the modeling for the project required to demonstrate compliance with these rules.

Pursuant to SCAQMD 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 this project. PRDAS staff reviewed the applicant's dispersion modeling analysis, by independently reproducing the modeling analysis, to verify compliance with SCAQMD rules and in support of the CEC's CEQA document. Their 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 and independent modeling results. **(See Appendix of this document for copy of memo.) 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.**

<u>AERMOD, METEOROLOGICAL DATA, BACKGROUND DATA</u>

The applicant utilized AERMOD (version 15181) for the air dispersion modeling which is the current EPA approved model and requires hourly meteorological data. The meteorological data from the SCAQMD's North Long Beach meteorological station was used, which is appropriate for the project. The MET data is for the periods of January 1, 2006 through December 31, 2009, and January 1, 2011 through December 31, 2011. At the direction of the SCAQMD, 2010 meteorological data were not recommended for use because the data do not meet the 90 percent completeness requirements. Similarly, 2012 met data were not recommended for use because the collected wind speeds are suspicious. The final preprocessed AERMET data files for 2006 through 2009 and 2011 were provided via e-mail by the SCAQMD. This surface data has been coupled with the upper air data from the National Climatic Data Center twice-daily soundings from the San Diego Miramar National Weather Service station (Station #03190).

The original Application indicated that the three most recent years of background hourly NO_2 data from the Hudson Long Beach monitoring station (South Coastal Los Angeles County 3), the three most recent years of background CO, SO_2, ozone, 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} and $PM_{2.5}$ data from the South Long Beach monitoring station (South Coastal Los Angeles County 2) were used to determine the background concentrations. Further, the SCAQMD has stated that hourly NO_2 data collected at the Hudson Long Beach monitoring station (South Coastal Los Angeles County 3, EPA ID 06-037-4006) are considered representative of the AEC site. This monitoring station is located approximately 7.2 miles to the northwest of the AEC site and is considered representative because it captures the large NOx-emitting sources in the Ports area that are upwind of the AEC. The South Long Beach monitoring station is the nearest to AEC but only measures PM_{10} and $PM_{2.5.}$ The predicted modeling impacts were added to the background concentrations for comparison to the ambient air quality standards.

The maximum modeled 1-hour and annual NO_2 concentrations include NO_2 to NOx conversion ratios of 0.80 and 0.75, respectively, as approved by EPA.

The base modeling receptor grid for the AERMOD modeling 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

- *PRDAS Staff's Comments*

  PRDAS staff's modeling review memo indicated the AERMOD modeling generally conforms to the SCAQMD's dispersion modeling methodology. The applicant utilized AERMOD (version 15181) for the air dispersion modeling, which is the current EPA approved model. The applicant used meteorological data from the SCAQMD's Long Beach station, which is appropriate for the project. The EPA-approved NO_2 to NO_x conversion ratios of 0.80 and 0.75 are assumed for evaluating 1-hour and annual NO_2 impacts from the project, respectively. The receptor grid area covered is adequate to determine the maximum impacts from the facility.

  In an e-mail dated 5/3/16, PRDAS staff informed the applicant's consultant that their proposed background concentrations reflected the 2009-2013 period and are 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. Their modeling review memo incorporates these background concentrations which are added to their predicted modeling impacts for comparison to the ambient air quality standards.

FUMIGATION IMPACTS

Fumigation (both inversion break-up and shoreline fumigation) is a meteorological condition that can produce high concentrations of ground-level pollutants. Fumigation impacts can be greater than impacts predicted with the AERMOD model. To verify that fumigation impacts do not result in higher ambient air quality impacts, the application conducted fumigation modeling. The effects of fumigation on the maximum modeled impacts were evaluated using the EPA AERSCREEN (Version 15181), as requested by the CEC. The results of the fumigation modeling were based on the respective loads and operating scenarios which were identified in the normal operation dispersion modeling discussed in detail below, as the worst-case impact scenario for each combination of pollutant and averaging time. Regulatory default mixing heights were selected.

The original Application stated the combined- and simple-cycle turbines are located more than 3,000 meters away from the shoreline. However, for modeling purposes, all emission sources were conservatively assumed to be located at the auxiliary boiler distance of 2,960 meters from the shoreline. These model inputs into AERSCREEN resulted in no fumigation occurrences because the plume heights were below the thermal internal boundary layer (TIBL) heights for the distance to shoreline of 2,960 meters. The original Application concluded that as there are no fumigation occurrences, no fumigation impacts are expected from AEC operation.

In an e-mail dated 4/28/16, PRDAS staff informed AES's consultant that the AERSCREEN runs provided for the shoreline fumigation and inversion break-up impacts did not have the inversion break-up option turned on in the model. The consultant was requested to re-run AERSCREEN to include inversion break-up. In addition, the shoreline fumigation runs provided did not include the simple-cycle turbines, but are required to be included for all runs. In an e-mail dated 5/2/16, AES provided the inversion break-up analysis.

PRDAS staff has reviewed the applicant's revised fumigation analysis. The tall stacks that will be constructed along the shoreline may cause fumigation. During these short term events, the maximum impacts could be higher than predicted by AERMOD for normal operation. Only the shorter averaging periods, less than or equal to 8 hours should be considered, because these meteorological phenomena do not persist for long periods. AERSCREEN (version 15181), the model recommended by EPA, was utilized for the analysis. The modeling parameters for the worst-case operating scenarios were used for each of the modeled pollutants and averaging times. The federal NO_2 and SO_2 standards cannot be evaluated with AERSCREEN due to the form of those standards and are not considered in this analysis. Because AERSCREEN can only be run with one emission source, the total project impacts were determined by adding the impacts from the seven combustion equipment.

Shoreline Fumigation--For all of the sources, shoreline fumigation was not calculated by AERSCREEN because the plume height was below the thermal internal boundary layer heights for the distance to the shoreline. The analysis indicated the combustion sources are too far away from the shoreline to result in shoreline fumigation occurrences.

Inversion Break-up—The impacts, combined with background concentrations, are below the applicable ambient air quality standards, as shown in the table below. The table incorporates maximum modeled concentrations and updated background levels provided by PRDAS staff.

Table 50A –Inversion Break-up Impacts during Normal Operations – Total Project

Pollutant	Averaging Period	Maximum Modeled ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Predicted Concentration ($\mu g/m^3$)	State Standard CAAQS ($\mu g/m^3$)	Federal Standard, Primary NAAQS ($\mu g/m^3$)	Compliance?
NO_2	1-hour	69.4	255.5	324.9	339	--	Yes
SO_2	1-hour	4.9	58.2	63.1	655	--	Yes
	3-hour	4.9	58.2	63.1	--	1,300	Yes
CO	1-hour	414	4237	4651	23,000	40,000	Yes
	8-hour	138	2977	3115	10,000	10,000	Yes

The maximum 1-hour NO_2 concentration includes an ambient NO_2 to NOx conversion ratio of 0.80.

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, a dispersion modeling analysis was performed at three different load scenarios at three temperature conditions for each turbine type (combined- and simple-cycle).

For combined-cycle turbines, the loads (45%, 75%, 100%) and temperatures (28 ºF, 65.3 ºF, and 107 ºF) are reflected in *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 reflected in *Table 31 - Simple-Cycle Turbine Operating Scenarios*, above. This load analysis included the operation of the auxiliary boiler. The load analysis results are presented in revised *Table 5.1C.8a—Operational Results—Load Analysis* in the revised Application, and were used to select the worst-case impacts for each criteria pollutant and corresponding averaging period.

1. **Combined-Cycle Gas Turbines Modeled Rates and Stack Parameters**
   The combined-cycle emission rates and operating scenario resulting in the maximum predicted concentrations are presented in revised *Table 5.1-31—AEC CCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts* in the revised Application. The emission rates and operating scenarios have been reviewed.

For the PDOC, the normal operating rate for CO was based on the BACT level of 2 ppmvd at 15% O_2 for combined-cycle turbines. For the FDOC, the BACT level will be decreased from 2 ppmv to 1.5 ppmv. In an e-mail dated 8/24/16, PRDAS Manager Jillian Wong had indicated that, for the simple-cycle turbines, the decrease in the BACT level from 4 ppmv to 2 ppmv would not require the project to be remodeled. "If the actual permitted CO emission levels are going to be lower than what was reviewed in our modeling evaluation, then there is no need to remodel the project since the impacts would be lower than what we had already analyzed. If the project's emissions did not exceed any CAAQS or NAAQS with the higher emission rate, then we would not expect any exceedances with the lower emission rate." This response also applies to the combined-cycle turbines. Accordingly, the project was not remodeled for the decrease in BACT levels for CO for the combined-cycle and simple-cycle turbines for the FDOC.

Table 51 - Modeled Emission Rates - Normal Operation for AEC CCGT [1]

Averaging Time	Worst-case Emission Scenario	Pollutant	Emissions Per Turbine, lbs/hr [2]
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.	NO_2	61
		CO	325
		SO_2	3.84
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.	NO_2	61
		SO_2	3.72
3-hour	SO_2: Both turbines continuous average (75%) load operation, 65.3 °F ambient temperature.	SO_2	3.72
8-hour	CO: Both turbines complete two cold starts, 2 shutdowns, and balance of period at minimum (45%) load, 28 °F ambient temperature.	CO	118
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.	PM_{10}, $PM_{2.5}$	8.5
		SO_2	3.72
Annual	NO_2, PM_{10}, $PM_{2.5}$: Both turbines operate at minimum (44%) load for 4100 normal operating hours, 80 cold starts, 88 warm starts, 332 hot starts, and 500 shutdowns, for total of 4640 hours, 65.3 °F ambient temperature. Condition A63.2 limits annual CO, VOC, PM_{10}, and SOx emissions, which also indirectly limits annual NOx emissions.	NO_2	6.24
		PM_{10}, $PM_{2.5}$	4.50

1 See *Table 5.1-31—AEC CCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts* on pages 5.1-31 and 5.1-32, and discussion on page 5.1-31 of the revised Application.

2 The maximum 1-hour NOx and CO emission rates are based on a 60-minute cold start-up event at 28 ºF. The 1-, 3-, and 24-hour SO_2 emission rates are based on the worst case fuel sulfur content of 0.75 grain per 100 dscf of natural gas.

Table 52 - Modeled Stack Parameters - Normal Operation for AEC CCGT [1]

		Stack Diameter (m)	**Stack Height (m)**	**Exhaust Temp (°F (°K))**	**Exhaust velocity (ft/s (m/s))**	**Scenario**
NO_2	1-hour	6.10	42.7	170 (350)	40 (12.2)	CC03
	1-hour (federal)	6.10	42.7	170 (350)	40 (12.2)	CC03
	Annual	6.10	42.7	170 (350)	38.8 (11.8)	CC07
CO	1-hour	6.10	42.7	170 (350)	40 (12.2)	CC03
	8-hour	6.10	42.7	170 (350)	40 (12.2)	CC03
SO_2	1-hour	6.10	42.7	178 (354)	51.2 (15.6)	CC02
	1-hour (federal)	6.10	42.7	175 (353)	48.9 (14.9)	CC06
	3-hour	6.10	42.7	175 (353)	48.9 (14.9)	CC06
	24-hour	6.10	42.7	175 (353)	48.9 (14.9)	CC06
PM_{10}, $PM_{2.5}$	24-hour	6.10	42.7	170 (350)	38.8 (11.8)	CC07
	Annual	6.10	42.7	170 (350)	38.8 (11.8)	CC07

1 See *Table 5.1C.5—Operational Stack Parameters* in *Appendix 5.1C.1*, and *Table 5.1-31—AEC CCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts*.

2. **Simple Cycle Gas Turbines Modeled Rates and Stack Parameters**

The simple-cycle turbine emission rates and operating scenario resulting in the maximum predicted concentrations are presented in *Table 5.1-32-- AEC SCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts*, a source for the information presented in the two tables below. The emission rates and operating scenarios have been reviewed.

As clarified in AES Response Letter, dated 1/7/16, the maximum 1-hour NOx and CO emission rates are based on a startup event, a shutdown event, and the balance at steady-state operation (Case 3--50% load), not on 60 minutes of a start-up event as indicated in footnote a to *Table 5.1-32* in the original Application.

For the PDOC, the normal operating rate for CO was based on the BACT level of 4 ppmvd at 15% O_2 for simple-cycle turbines. For the FDOC, the BACT level will be decreased from 4 ppmv to 2 ppmv. As explained above for the decrease in BACT levels for the combined-cycle turbines, the project was not remodeled for the decrease in BACT levels for the combined-cycle and simple-cycle turbines for the FDOC.

Table 53 - Modeled Emission Rates - Normal Operation for AEC SCGT [1]

Averaging Time	Worst-case Emission Scenario	Pollutant	Emissions Per Turbine, lbs/hr [2, 3]
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.	NO_2	21.2
		CO	44.9
		SO_2	1.62
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.	NO_2	21.2
		SO_2	1.61
3-hour	SO_2: Four turbines continuous maximum (100%) load operation, 65.3 °F ambient temperature.	SO_2	1.61
8-hour	CO: Four turbines complete 2 starts, 2 shutdowns, and balance of period at minimum (50%) load, 28 °F ambient temperature.	CO	15.0
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.	PM_{10}, $PM_{2.5}$	6.23
		SO_2	1.61
Annual	NO_2, PM_{10}, $PM_{2.5}$: Four turbines operate at minimum (50%) load for 2000 normal operating hours, 500 starts, and 500 shutdowns, for total of 2358 hours, 65.3 °F ambient temperature. Condition A63.3 limits annual CO, VOC, PM_{10}, and SOx emissions, which also indirectly limits annual NOx emissions.	NO_2	2.29
		PM_{10}, $PM_{2.5}$	1.68

[1] See *Table 5.1-32—AEC SCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts* on pages 5.1-32 and 5.1-33, and discussion on page 5.1-32 of the revised Application.

2 The maximum 1-hour NOx and CO emission rates are based on a startup event, a shutdown event, and the balance at steady-state operation (Case 3—50% load at 28 °F) per AES Response Letter, dated 1/7/16.

3 The 1-, 3-, and 24-hour SO_2 emission rates are based on the worst case fuel sulfur content of 0.75 grain per 100 dscf of natural gas.

Table 54 - Modeled Stack Parameters - Normal Operation for AEC SCGT [1]

		Stack Diameter (m)	Stack Height (m)	Exhaust Temp (°F (°K))	Exhaust velocity (ft/s (m/s))	Scenario
NO_2	1-hour	4.11	24.4	888 (749)	78 (23.8)	SC03
	1-hour (federal)	4.11	24.4	888 (749)	78 (23.8)	SC03
	Annual	4.11	24.4	883 (746)	77.4 (23.6)	SC07
CO	1-hour	4.11	24.4	888 (749)	78 (23.8)	SC03
	8-hour	4.11	24.4	888 (749)	78 (23.8)	SC03
SO_2	1-hour	4.11	24.4	789 (693)	109 (33.3)	SC01
	1-hour (federal)	4.11	24.4	798 (699)	108 (33.0)	SC05
	3-hour	4.11	24.4	798 (699)	108 (33.0)	SC05
	24-hour	4.11	24.4	798 (699)	108 (33.0)	SC05
PM_{10}, $PM_{2.5}$	24-hour	4.11	24.4	883 (746)	77.4 (23.6)	SC07
	Annual	4.11	24.4	883 (746)	77.4 (23.6)	SC07

1 See *Table 5.1C.5—Operational Stack Parameters* in *Appendix 5.1C.1—Dispersion Modeling and Climate Information*, and *Table 5.1-32—AEC SCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts*.

3. Auxiliary Boiler Modeled Rates and Stack Parameters

The auxiliary boiler emission rates and stack parameters included in each combined- and simple-cycle modeled scenario are presented in revised *Table 5.1-33-- Auxiliary Boiler Emission Rates and Stack Parameters* in the revised Application. The emission rates and operating scenarios have been reviewed.

As explained in AES Response Letter, dated 12/11/15, the auxiliary boiler was not modeled in startup mode as part of the worst-case operational modeling scenarios for 1-hour NO_2 and 1-hour CO because startup of the auxiliary boiler does not occur concurrently with the worst-case emission scenario and only occurs prior to startup of one of the combined-cycle turbines. A process description for the auxiliary boiler was provided in the same letter.

As clarified in AES Response Letter, dated 1/7/16, the normal operating emission rates are based on 100% load for 1-hour and 3-hour averaging periods, but on 50% load for 24-hour and annual averaging periods. A review of the 8-hour averaging period indicates that the normal operating rate is correctly based on 100% load. The revised Application changed the load from 50% to 30% and corrected the SO_2 emission factor basis from 0.25 grains/100 scf to 0.75 grains/100 scf.

Table 55 - Modeled Emission Rates - Normal Operation for Auxiliary Boiler [1]

Averaging Time	Worst-case Emission Scenario	Pollutant	Emissions Per Turbine, lbs/hr [2]
1-hour	NO_2: Boiler maximum firing rate operation (excluded startups and shutdowns). CO: Boiler maximum firing rate operation (excluded startups and shutdowns). SO_2: Boiler maximum firing rate operation (excluded startups and shutdowns).	NO_2	0.42
		CO	2.83
		SO_2	0.14
1-hour (federal)	NO_2: Boiler maximum firing rate operation (excluded startups and shutdowns). SO_2: Boiler maximum firing rate operation (excluded startups and shutdowns).	NO_2	0.42
		SO_2	0.14
3-hour	SO_2: Boiler maximum firing rate operation (excluded startups and shutdowns).	SO_2	0.14
8-hour	CO: Boiler complete 1 cold start and balance of period at maximum firing rate operation.	CO	2.37
24-hour	PM_{10}, $PM_{2.5}$: Boiler operate at 30% of maximum firing rate for 31 days, including 2 cold starts, 4 warm starts, 4 hot starts, averaged over 30 days. SO_2: Boiler operate at 30% of maximum firing rate for 31 days, including 2 cold starts, 4 warm starts, 4 hot starts, averaged over 30 days.	PM_{10}, $PM_{2.5}$	0.16
		SO_2	0.046
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_2	0.15
		PM_{10}, $PM_{2.5}$	0.15

1 See *Table 5.1-33—Auxiliary Boiler Emission Rates and Stack Parameters* on page 5.1-34, and discussion on page 5.1-33 of the revised Application.

2 The maximum 1-hour NOx and CO and 1-hour and 3-hour SO_2 emission rates are based on normal operation at the maximum hourly firing rate.

3 The 1-, 3-, and 24-hour SO_2 emission rates are based on the short-term fuel sulfur content of 0.75 grain per 100 dscf of natural gas.

Table 56 - Modeled Stack Parameters - Normal Operation for Auxiliary Boiler [1]

		Stack Diameter (m)	Stack Height (m)	Exhaust Temp (°F (°K))	Exhaust velocity (ft/s (m/s))	Scenario
NO_2	1-hour	0.91	24.4	318 (432)	69.5 (21.2)	AB
	1-hour (federal)	0.91	24.4	318 (432)	69.5 (21.2)	AB
	Annual	0.91	24.4	318 (432)	69.5 (21.2)	AB
CO	1-hour	0.91	24.4	318 (432)	69.5 (21.2)	AB
	8-hour	0.91	24.4	318 (432)	69.5 (21.2)	AB
SO_2	1-hour	0.91	24.4	318 (432)	69.5 (21.2)	AB
	1-hour (federal)	0.91	24.4	318 (432)	69.5 (21.2)	AB
	3-hour	0.91	24.4	318 (432)	69.5 (21.2)	AB
	24-hour	0.91	24.4	318 (432)	69.5 (21.2)	AB
PM_{10}, $PM_{2.5}$	24-hour	0.91	24.4	318 (432)	69.5 (21.2)	AB
	Annual	0.91	24.4	318 (432)	69.5 (21.2)	AB

1 See *Table 5.1C.5—Operational Stack Parameters* in *Appendix 5.1C.1—Dispersion Modeling and Climate Information*, and *Table 5.1-33—Auxiliary Boiler Emission Rates and Stack Parameters*.

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.

The applicant has provided a modeling analysis of impacts for the entire project in support of the CEC's CEQA document. The dispersion modeling analysis for maximum AEC operational impacts includes the operation of the two combined-cycle turbines, four simple-cycle turbines, and the auxiliary boiler. The applicant correctly included startups and shutdowns for the maximum hourly emissions for the turbines. Given the number of startups and shutdowns, the emissions from these events cannot be considered as intermittent, as described in the US EPA's memo dated 3/1/2011.

The maximum AEC operational impacts are presented in revised *Table 5.1-38-- AEC Operation Impacts Analysis—Maximum Modeled Impacts Compared to the Ambient Air Quality Standards* in the revised Application. PRDAS staff has reviewed the applicant's analysis and provided updated background concentrations, which are incorporated in the table below.

Table 57 - Modeled Results - Normal Operation for Total Project

Pollutant	Averaging Period	Maximum Predicted Impact (µg/m³)	Background Concentration (µg/m³)[1]	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]	1-hour	31.3	255.5	286.8	339	--		No
	1-hour (98th percentile)[2]	22.6	146.3	168.9	--	188		No
	Annual	0.2	47.6	47.8	57	100		No
SO_2	1-hour	2.1	58.2	60.3	655	--		No
	1-hour (99th percentile)[3]	2.1	~~58.2~~ 30.1	~~60.3~~ 32.2	--	196		
	3-hour	1.7	58.2	59.9	--	1,300		No
	24-hour	0.5	7.9	8.4	105	--		No
CO	1-hour	186	4,237	4,423	23,000	40,000		No
	8-hour	44	2,977	3021	10,000	10,000		No
PM_{10}	24-hour	1.7	59.0	60.7	-	150		No
	24-hour	1.7			50	150	2.5	No
	Annual	0.2			20		1	No
$PM_{2.5}$	24-hour	1.3			-	35	2.5	No
	Annual	0.2			12	12	1	No

[1] The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 to NOx conversion ratios of 0.80 and 0.75, respectively.

[2] On 4/12/10, the U.S. EPA established a new 1-hour NO_2 standard of 100 ppb (188 µg/m³). The form of the federal 1-hour NO_2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations.

[3] On 6/2/10, the U.S. EPA established a new 1-hour SO_2 standard of 75 ppb (196 µg/m³). The form of the federal 1-hour SO_2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.

5. Modeled Results – Normal Operation for Auxiliary Boiler

The auxiliary boiler are subject to the modeling requirements of Rule 1303(b)(1). The maximum auxiliary boiler impacts were not provided in any table in the original or revised Applications. PRDAS staff has provided the maximum modeled concentrations and updated background concentrations for the following table.

Table 57A - Modeled Results - Normal Operation for Auxiliary Boiler

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)[1]	Total Predicted Concentration ($\mu g/m^3$)	State Standard CAAQS ($\mu g/m^3$)	Federal Standard, Primary NAAQS ($\mu g/m^3$)	Rule 1303 Thresholds ($\mu g/m^3$)	Exceeds Any Threshold?
NO_2	1-hour	1.2	255.5	256.7	339	--		No
	1-hour (98th percentile)	1.1	146.3	147.4	--	188		No
	Annual	0.03	47.6	47.63	57	100		No
SO_2	1-hour	0.5	58.2	58.7	655	--		No
	1-hour (99th percentile)	0.5	30.1	30.6	--	196		
	3-hour	0.5	58.2	58.7	--	1,300		No
	24-hour	0.1	7.9	8.0	105	--		No
CO	1-hour	10	4,237	4,247	23,000	40,000		No
	8-hour	6	2,977	2,983	10,000	10,000		No
PM_{10}	24-hour	0.3	59.0	59.3	-	150		No
	24-hour	0.3			50	150	2.5	No
	Annual	0.04			20		1	No
$PM_{2.5}$	24-hour	0.1			-	35	2.5	No
	Annual	0.04			12	12	1	No

The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 to NOx conversion ratios of 0.80 and 0.75, respectively.

6. <u>Modeled Results - Rule 2005</u>

See Rule 2005 analysis below.

<u>COMMISSIONING IMPACTS</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.

As discussed above, 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 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.

1. **Combined-Cycle Gas Turbines**
The total duration of the AEC CCGT commissioning period is expected to be up to 1,992 hours (996 hours per turbine). During the commissioning period, each GE 7FA.05 will be operated for up to 216 hours without emission control systems in operation. Although SCAQMD PRDAS staff has indicated that the annual averaging period is to be based on routine operation and not include a once-in-a-lifetime event, such as commissioning, the applicant provided modeling for annual impacts for the commissioning year, consisting of commissioning emissions and normal operating emissions the balance of the year.

A total of three scenarios were modeled. The three scenarios consist of two GE 7FA.05s modeled at 10% load, 40% load, and 80% load, with all scenarios including the operation of the auxiliary boiler. The conservative assumption is that both turbines would be commissioned simultaneously. The modeling for the short-term averaging periods include NOx and CO only.

Separate scenarios for commissioning impacts were not run for SO_2 and $PM_{10}/PM_{2.5}$ since emissions of these pollutants are higher during normal operation than during commissioning. The sum of the maximum operational impacts from the combined-cycle turbines and the auxiliary boiler were conservatively used to represent commissioning impacts.

The AERMOD dispersion analysis was conducted using the parameters and emission rates for commissioning of the AEC CCGT, as presented in revised *Table 5.1-29--AEC CCGT Commissioning Dispersion Modeling Scenarios* in the revised Application. The highest unabated emission rates per turbine occur during CTG testing at full speed with no load, with this event lasting up to 48 hours.

Table 58 - Modeled Emission Rates and Stack Parameters – Commissioning for AEC CCGT (Two Turbines) [1]

						Emission Rates Per Turbine (lb/hr)[a]				
Scenarios	**No. of Turbines/ Modeling Load**	**Stack Diameter (m)**	**Stack Height (m)**	**Exit Velocity (m/sec)**	**Exhaust Temperature (°K)**	**1-hr NOx**	**1-hr CO**	**8-hr CO**	**Annual NOx**	**Annual $PM_{10}/PM_{2.5}$**
CTG Testing (Full Speed No Load)	Two/10%	6.10	42.7	9.33	361	130	1900	1900	N/A	N/A
Steam Blows	Two/40%	6.10	42.7	11.9	359	68.3	N/A	N/A	N/A	N/A
Emissions Tuning	Two/80%	6.10	42.7	16.1	366	63.0	N/A	N/A	N/A	N/A
Commissioning Year[2]	Two/Worst Case	6.10	42.7	11.8	350	N/A	N/A	N/A	9.39	5.47

1 See *Table 5.1C.1—Commissioning Stack Parameters* in *Appendix 5.1C.1*, and *Table 5.1-29—AEC CCGT Commissioning Dispersion Modeling Scenarios* on page 5.1-30 in the revised Application.

2 Emission rates, stack exit velocity, and stack temperature for the commissioning year, consisting of commissioning emissions and normal operating emissions the balance of the year, are based on the operational load resulting in the highest modeled impact of NOx, PM_{10}, and $PM_{2.5}$.

The modeling shows that the maximum impact occurs when the two turbines are simultaneously undergoing commissioning activities with the highest unabated emissions, and the auxiliary boiler is in operation. The results of the modeling analysis are presented in revised *Table 5.1-36--AEC CCGT Commissioning Impacts Analysis—Maximum Modeled Impacts Compared to the Ambient Air Quality Standards* in the revised Application.

PRDAS staff has reviewed the applicant's analysis and provided updated background concentrations, which are incorporated in the table below.

Table 59 - Modeled Results – Commissioning for AEC CCGT (Auxiliary Boiler in Normal Operation)

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Predicted Concentration ($\mu g/m^3$)	State Standard CAAQS ($\mu g/m^3$)	Federal Standard, Primary NAAQS ($\mu g/m^3$)	Rule 1303 Thresholds ($\mu g/m^3$)	Exceeds Any Threshold?
NO_2	1-hour	67.6	255.5	323.1	339	--		No
	Federal 1-hour	Analysis excluded because turbine testing at full speed with no load will occur once in the lifetime of AEC and last less than 48 hours.			--	188		
	Annual	0.3	47.6	47.9	57	100		No
SO_2	1-hour	2.2	58.2	60.4	655	--		No
	Federal 1-hour	Analysis excluded because turbine testing at full speed with no load will occur once in the lifetime of AEC and last 48 hours.			--	196		
	3-hour	1.9	58.2	60.1	--	1,300		No
	24-hour	0.6	7.9	8.5	105	365		No
CO	1-hour	1,231	4,237	5,468	23,000	40,000		No
	8-hour	835	2,977	3,812	10,000	10,000		No
PM_{10}	24-hour	1.6	59.0	60.6	-	150		No
	24-hour	1.6			50	150	2.5	No
	Annual	0.2			20		1	No
$PM_{2.5}$	24-hour	1.1			-	35	2.5	No
	Annual	0.2			12	12	1	No

The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 to NOx conversion ratios of 0.80 and 0.75, respectively.

2. **<u>Simple-Cycle Gas Turbines</u>**

The total duration of the AEC SCGT commissioning period is expected to be up to 1,120 hours (280 hours per turbine). During the commissioning period, each GE LMS-100 PB will be operated for up to 4 hours without emission control systems in operation. Although SCAQMD PRDAS staff has indicated that the annual averaging period is to be based on routine operation and not include a once-in-a-lifetime event, such as commissioning, the applicant provided modeling for annual impacts for the commissioning year, consisting of commissioning emissions and normal operating emissions the balance of the year.

A total of three scenarios were modeled. The three scenarios consist of four GE LMS-100 PB modeled at 5% load, 75% load, and 100% load, with all scenarios including the operation of two GE 7FA.05 turbines and the auxiliary boiler. The conservative assumption is that four turbines would be commissioned simultaneously. The modeling for the short-term averaging periods include NOx and CO only. For SOx and PM_{10}, the highest short-term emission rates (Case 1) and resulting maximum air quality impact result from normal operating conditions were used to represent commissioning impacts.

The AERMOD dispersion analysis was conducted using the parameters and emission rates for commissioning of the AEC SCGT, as presented in *Table 5.1-30--AEC SCGT Commissioning Dispersion Modeling Scenarios*, which is a source for the table below. The highest unabated emission rates per turbine occur during CTG testing at full speed with no load, with this event lasting up to 4 hours.

Table 60 - Modeled Emission Rates and Stack Parameters – Commissioning for AEC SCGT (Four Turbines) [1]

						Emission Rates Per Turbine (lb/hr)				
Scenarios	**No. of Turbines/ Modeling Load**	**Stack Diameter (m)**	**Stack Height (m)**	**Exit Velocity (m/sec)**	**Exhaust Temperature (°K)**	**1-hr NOx**	**1-hr CO**	**8-hr CO**	**Annual NOx**	**Annual PM_{10}/$PM_{2.5}$**
Testing (Full Speed No Load)	Four/5%	4.11	24.4	10.0	728	40.1	244	244	N/A	N/A
Commissioning and Normal Operating Year [2]	Four/Worst Case	4.11	24.4	23.6	746	N/A	N/A	N/A	2.95	1.88

1 See *Table 5.1C.1—Commissioning Stack Parameters* in *Appendix 5.1C.1—Dispersion Modeling and Climate Information*, and *Table 5.1-30—AEC SCGT Commissioning Dispersion Modeling Scenarios* on page 5.1-30 in the revised Application.

2 Emission rates, stack exit velocity, and stack temperature for the combined annual commissioning and operation are based on the operational load resulting in the highest modeled impact of NOx, PM_{10}, and $PM_{2.5}$.

The simple-cycle turbines will be commissioned after the combined-cycle turbines are already in operation. The modeling shows the maximum impact occurs while the four simple-cycle turbines are simultaneously undergoing commissioning activities with the highest unabated emissions presented in the table above, the two combined-cycle turbines are simultaneously operating with the steady-state emissions presented in *Table 51 - Modeled Emission Rates - Normal Operation for AEC CCGT* above, and the auxiliary boiler is in operation. The results of the modeling analysis are presented in revised *Table 5.1-37-- AEC SCGT Commissioning Impacts Analysis—Maximum Modeled Impacts Compared to the Ambient Air Quality Standards* in the revised Application.

PRDAS staff has reviewed the applicant's analysis and provided updated background concentrations, which are incorporated in the table below.

Table 61 - Modeled Results – Commissioning for AEC SCGT (CCGT & Auxiliary Boiler in Normal Operation)

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Predicted Concentration ($\mu g/m^3$)	State Standard CAAQS ($\mu g/m^3$)	Federal Standard, Primary NAAQS ($\mu g/m^3$)	Rule 1303 Thresholds ($\mu g/m^3$)	Exceeds Any Threshold?
NO_2	1-hour	61.9	255.5	317.4	339	--		No
	Federal 1-hour	Analysis excluded because turbine testing at full speed with no load will occur once in the lifetime of AEC and last 4 hours.			--	188		N/A
	Annual	0.20	47.6	47.8	57	100		No
SO_2	1-hour	2.1	58.2	60.3	655	--		No
	Federal 1-hour	Analysis excluded because turbine testing at full speed with no load will occur once in the lifetime of AEC and last 4 hours.			--	196		N/A
	3-hour	1.7	58.2	59.9	--	1,300		No
	24-hour	0.5	7.9	8.4	105	365		No
CO	1-hour	470	4,237	4,707	23,000	40,000		No
	8-hour	240	2,977	3,217	10,000	10,000		No
PM_{10}	24-hour	1.7	59.0	60.7	-	150		No
	24-hour	1.7			50	150	2.5	No
	Annual	0.2			20		1	No
$PM_{2.5}$	24-hour	1.3			-	35	2.5	No
	Annual	0.2			12	12	1	No

The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 to NOx conversion ratios of 0.80 and 0.75, respectively.

3. <u>Auxiliary Boiler</u>

As explained in AES Response Letter, dated 12/11/15, the auxiliary boiler will be commissioned and ready for operation before the commissioning of the combined-cycle turbines. Because the commissioning will be completed in five days and the daily emissions are equivalent to two cold startups, the commissioning does not need to be modeled separately.

- ***<u>Rule 1303(b)(2)—Offsets</u>***

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.

- **<u>Combined-Cycle Turbines, A/N 579142, 579143</u>**
- **<u>Simple-Cycle Turbines, A/N 579145, 579147, 1549150, 579152</u>**
    - <u>VOC, SOx, and PM_{10}</u>
      SCAQMD 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.

    - <u>NOx</u>
      For NOx RTC requirements, see *Rule 2005(c)(2)* analysis below.

- **<u>Auxiliary Boiler, A/N 579158</u>**
- **<u>Oil-Water Separator, Combined-Cycle Turbines, A/N 579169</u>**
- **<u>Oil-Water Separator, Simple-Cycle Turbines, A/N 579170</u>**
    - <u>VOC, SOx, and PM_{10}</u>
      Rule 1304(d)(2)(B) specifies that any modified facility that has a post-modification potential equal to or more than 4 tpy VOC, 4 tpy SOx, and 4 tpy PM_{10} is required to provide offsets for the emissions increases. This requirement is applicable to the auxiliary boiler and two oil-water separators.

Table 62 - Post-Modification Project 30-Day Averages

A/N	**Equipment**	**VOC 30-Day Average, lbs/day**	**SOx 30-Day Average, lbs/day**	**PM_{10} 30-Day Average, lbs/day**
579158	Auxiliary Boiler	3.40	1.06	3.78
579169	Oil/Water Separator, Combined-Cycle Turbines	0.0005		
579170	Oil/Water Separator, Simple-Cycle Turbines,	0.000073		
	Total Project, lbs/day	**3.40 lb/day**	**1.06 lb/day**	3.78 **lb/day**

VOC
ERCs required = 3.40 x 1.2 offset factor = 4.08 lb/day → 4 lb/day

SO_X
ERCs required = 1.06 x 1.2 offset factor = 1.27 lb/day → 1 lb/day

PM_{10}
ERCs required = 3.78 x 1.2 offset factor = 4.54 lb/day → 5 lb/day

- NOx
  For NOx RTC requirements for the auxiliary boiler, see *Rule 2005(c)(2)* analysis below.

The following table summarizes the number of ERCs and RTCs required for each permit unit.

Table 63 - Post-Modification ERCs and RTCs Required

A/N	Equipment	VOC ERCs, lbs/day	SOx ERCs, lbs/day	PM_{10} ERCs, lbs/day	NOx RTCs, lb/yr (first year)
579142	Combined-Cycle Turbine				108,377
579143	Combined-Cycle Turbine				108,377
579145	Simple-Cycle Turbine				68,575
579147	Simple-Cycle Turbines				68,575
579150	Simple-Cycle Turbines				68,575
579152	Simple-Cycle Turbines				68,575
579158	Auxiliary Boiler	4	1	5	1351
579169	Oil-Water Separator, Combined-Cycle Turbines				
579170	Oil-Water Separator, Simple-Cycle Turbines				
	Total Project, lbs/day	**4**	**1**	**5**	First year: 218,105 lb for combined-cycle turbines & boiler. First year: 274,300 lb for simple-cycle turbines.

Regarding the NOx RTCs, 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.

A summary of the Certificates of Proof for Registered Emission Reduction Credit, with the ERC seller/originator history, for the VOC ERCs and the PM_{10} ERCs provided for the AEC are shown in the table below. Since Rule 1309--Emission Reduction Credits and Short Term Credits is not SIP-approved, the Short-Term ERCs (STERCs) provided have been converted to ERCs for use as offsets.

ROG ERCs-- Based on the original application, AES provided 5 lbs/day of ROG in the form of a stream of Short Term ERCs. Since the revised application increased the ROG emission factor but reduced the normal operating rate from 50% to 30% load, 4 lbs/day of ROG ERCs are now required. As shown in Table 63A, AES is providing ERC Certificate No. AQ014405 for 5 lb/day from which 4 lb/day will be used for this project.

PM_{10} ERCs— Based on the original application, AES provided 5 lbs/day of PM_{10} ERCs. Although the revised application increased the PM_{10} emission factor and reduced the normal operating rate from 50% to 30% load, 5 lbs/day of PM_{10} ERCs are still required. As shown in Table 63A, AES is providing ERC Certificate No. AQ014168 for 4 lb/day and ERC Certificate No. AQ014169 for 1 lb/day.

SOx ERCs—Based on the original application, AES did not provide any SOx ERCs. Since the methodology for determining the number of ERCs is to multiply the offset factor of 1.2 times the 30-day average, then round to a whole number, 1 lb/day of SOx ERC was required. Since the revised application corrected the normal operating rate from a basis of 0.25 grains/100 cf (original application) to 0.75 grains/100 cf, it became clearer that 1 lb/day of SOx ERC is required. AES has agreed to and did provide 1 lb/day of SOx ERC. As shown in Table 63A, AES is providing ERC Certificate No. AQ014451 for 1 lb/day.

Table 63A - ERC Certificate Nos. and History

		AES Alamitos, LLC					Seller of ERCs		Originator of ERCs		
Emittent	**STERC Cert. No**	**ERC Cert. No.**	**Title Change Appl. No.**	**Date of Issue**	**ERC Type**	**Amount (lb/day)**	**Name**	**Cert. No.**	**Address**[1]	**Cert. No.**	**Zone**
PM_{10}		AQ014168	578696	10/9/2015	ERC	4	CE2 Carbon Capital, LLC ID 178346	AQ014162	750 Eldridge St, Terminal Island, CA 90731	AQ006307	01-Coastal
PM_{10}		AQ014169	578697	10/9/2015	ERC	1	CE2 Carbon Capital, LLC ID 178346	AQ014160	1001 N Tustin, Santa Ana, CA 92705	AQ000491	01-Coastal
					PM_{10} Total	**5**					
ROG	AQ014175	AQ014405	578453	10/13/2015	STERC	5 (STERC Stream)	Element Markets LLC (ID 155272)	AQ014124	500 Crenshaw Blvd, Torrance, CA 90503	AQ013346	01-Coastal
ROG	AQ014176		578454		STERC			AQ014125		AQ013347	
ROG	AQ014177		578455		STERC			AQ014126		AQ013348	
ROG	AQ014178		578457		STERC			AQ014127		AQ013349	
ROG	AQ014179		578458		STERC			AQ014128		AQ013350	
ROG	AQ014180		578459		STERC			AQ014129		AQ013351	
ROG	AQ014181		578460		STERC			AQ014130		AQ013352	
					ROG Total	**5**					
SOx		AQ014451	588028	8/16/2016	ERC	1	Olduvai Gorge, LLC (ID 151262)	AQ014449	7800 Beverly Blvd, Los Angeles, CA 90036	AQ000006	01-Coastal
				~~*AES has agreed to provide 1 lb/day SOx ERC.*~~							
					SOx Total	**1**					

1 The Certificates of Proof include the address where the reduction was created, but not the company name.

- ***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 will comply with all applicable rules and regulations of the District, as required by this rule.

- ***Rule 1303(b)(5)-Major Polluting Facilities***
- ***Rule 2005(g)—Additional Federal Requirements for Major Stationary Sources***

  Any major modification at an existing major polluting facility shall comply with the following provisions. AGS is an existing major polluting facility as defined by Rule 1302(s), and its replacement by AEC is a major modification under Rule 1302(r).

  - ***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.

    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 done by CEC for a project subject to CEC jurisdiction.

    The CEC prepared a 927-page Preliminary Staff Assessment (PSA) which was made available by CEC on July 13, 2016 (http://docketpublic.energy.ca.gov/PublicDocuments/13-AFC-01/TN212284_20160713T160604_Preliminary_Staff_Assessment.pdf). The PSA includes an environmental assessment of air quality, alternatives, biological resources, cultural resources, hazardous materials management, land use, noise and vibration, public health, socioeconomics, soil & water resources, traffic & transportation, transmission line safety & nuisance, and visual resources, and an engineering assessment of facility design, geology & paleontology, power plant efficiency, power plant reliability, transmission system engineering, waste management, and worker safety & fire protection. The CEC concluded that with implementation of staff's recommended mitigation measures described in the conditions of certification, the AEC would comply with all applicable laws, ordinances, regulations, and standards (LORS). In this PDOC, the SCAQMD determined that the proposed AEC, with the required mitigation, will not result in significant air quality impacts and will comply with all applicable federal, state and local air quality rules and regulations. This analysis was considered by CEC staff and incorporated, as appropriate, into the CEC PSA.

AES and the CEC provided an alternatives study in the Supplemental Application for Certification and the PSA, respectively.

AES

~~Section 6 of the Supplemental AFC presents a review~~ On pages 6-1 to 6-12 of the Supplemental AFC, AES presents a project objectives list and an evaluation of alternatives, including the "no project" alternative, power plant site alternatives, alternative project design features (alternative natural gas supply pipeline routes, electrical transmission system alternatives, water supply alternatives), technology alternatives (generation technology alternatives, conventional boiler and steam turbine, nuclear, Kalina combined-cycle, internal combustion engines), fuel technology alternatives, NOx control alternatives, energy storage options, and waste discharge alternatives. The applicant found that the alternatives considered were either infeasible, unable to reduce or avoid any adverse environmental impacts, or would not attain most of the basic objectives of the project. On page 6-1, the AFC concluded: "This section evaluates reasonable alternatives to the AEC that could feasibly attain most of the project objectives and reduce or eliminate any significant effects of the project. As demonstrated by the analyses contained in this AFC, the project will not result in any significant environmental impacts. Therefore, as detailed in the following sections, there are no alternatives that would be preferred over the proposed project."

CEC

On pages 4.2-1 to 4.2-17 of the PSA, the CEC provides an analysis of alternatives. On pg. 4.2-1, the CEC concludes: "As required by the California Environmental Quality Act (CEQA), this section evaluates a reasonable range of alternatives to the proposed Alamitos Energy Center (AEC or proposed project) that would feasibly attain most of the basic objectives of the project and would avoid or substantially lessen any of the significant effects of the project."

Instead of merely using the applicant's project objectives as a yardstick as asserted by the commenter, the CEC provided a broad interpretation of the applicant's project objectives, then reviewed the objectives for consistency with the State Water Resources Control Board's *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*

(OTC Policy), California Independent System Operator (CAISO) planning, state's Renewable Portfolio Standard (RPS), state energy policies and procurement planning, CPUC decisions, and North American Electric Reliability Council and the Western Electricity Coordinating Council reliability standards. The alternatives evaluation included "preferred resources" (energy efficiency, demand response, utility scale and distributed renewable generation, and energy storage), alternative sites, and no-project alternative.

On page 4.2-7, the CEC explains that natural gas-fired generation is necessary because preferred resources, including energy storage, cannot ensure reliability: "The state's loading order established by the energy agencies in 2003 calls for meeting new electricity needs first with efficiency and demand response (jointly, demand-side management), followed by renewable energy and distributed generation, and only then with efficient, utility-scale natural gas-fired generation…. In recent years, energy storage has achieved preferred resource status due to its ability to a) absorb over-generation that may occur at high levels of solar penetration, and b) obviate the need for natural gas-fired generation and associated capacity to meet ramping needs during evening hours when solar resource output declines to zero. Preferred resources can provide many of the services provided by dispatchable, natural gas-fired generation. However, where preferred resources cannot ensure reliability, because they lack necessary operating characteristics or are not available in sufficient quantities, the CPUC has found that the procurement of clean, efficient natural gas-fired generation is necessary and is consistent with the state's loading order."

On page 1-5, the CEC concluded: "As required by CEQA staff evaluated a reasonable range of alternatives to the proposed project that would feasibly attain most of the basic objectives of the project and would avoid or substantially lessen any of the significant effects of the project. As a starting point, staff reviewed the alternatives analysis provided by the applicant in the SAFC. The applicant found that the alternatives considered in the SAFC were either infeasible, unable to reduce or avoid any adverse environmental impacts, or would not attain most of the basic objectives of the project; staff concurs with the applicant's assessment of their alternatives…. Staff has not identified a feasible alternative that would be environmentally superior to the proposed AEC."

- ***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 10/23/15, Stephen O'Kane, Manager, AES Alamitos, LLC, certified that all major stationary sources that are owned or operated by AES in California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emissions limitations and standards under the Clean Air Act.

The SCAQMD 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 SCAQMD 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. The facility IDs for AES Alamitos, AES Huntington Beach, and AES Redondo Beach are 115394, 115389, and 115536, respectively. For AES Huntington Beach, the disposition is missing for NOV P28630, but clicking on P28630 opens a new screen that indicates the Follow Up Status is “In Compliance.” For AES Redondo Beach, the disposition is missing for NOV P60572, but the P60572 link indicates the Follow Up Status is “In Compliance.” The reason the dispositions are missing is that the NOVs are awaiting disposition by a SCAQMD prosecutor. Prior to issuance of the Permits to Construct, the SCAQMD 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).

As shown in *Table 71 – Prevention of Significant Deterioration Applicability*, the net emissions increases (AEC PTE – AGS actual) exceed 15 tpy PM_{10} and 40 tpy NOx. The applicant has identified the San Gabriel Wilderness, approximately 53 km from the AEC site, as the nearest Class I area. Tables C-1 and 4-1 requires 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 is not required.

Rule 1304.1—Electrical Generating Facility Fee for Use of Offset Exemption

The relevant sections are presented below, followed by the rule analysis.

(a) 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.

(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}).

*Note: Tables A1 and A2 indicate the annual offset fee rates (Ri) and single payment offset fee rates (Li) for PM, NOx (non-RECLAIM sources only), SOx, and VOC are adjusted **annually by the CPI**.*

Rule 1304.1 was adopted on 9/6/13. Therefore, 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 Governing Board-approved annual percent fee increase, effective each July 1.

(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.

(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.

Analysis:
In an e-mail, dated 2/25/16, 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.

The SCAQMD has provided a Rule 1304.1 Excel calculator that is available on the SCAQMD website to calculate total annual fee and total single fee for a set of turbines. Estimates of the annual offset fees that are required to be remitted prior to the issuance of the permits to construct are shown below in *Table 65* for the combined-cycle turbines and in *Table 66* for the simple-cycle turbines. Estimates of the single offset fees are shown below in *Table 65A* for the combined-cycle turbines and in *Table 66A* for the simple-cycle turbines. The annual offset fees paid will be credited towards the single offset fees that AES has indicated it will switch to subsequent to the initial payment.

- Combined-Cycle Turbines
  The inputs for the calculator are discussed below.

  a-Gross Rating of New Replacement Units (MW): 692.951 MW

  Basis:
  [(231.197 MW-gross/ CTG) * (2 CTGs) + 230.557 MW-gross/steam turbine]
  = 692.951 MW (Case 12)

  b-Maximum Fraction of Time Allowed to Operate (%): 53%

  Basis:
  c-Max Allowable Operating Hours Annually (hr/yr) = 4612 hr/yr

  Hours in a Year (hr/yr) = 8760 hr/yr

Fraction of Time Allowed to Operate = 4640 hr/yr ÷ 8760 hr/yr = 53%

Note: For the purpose of this rule, startup and shutdown hours are included.

e-Average Last 2 years of Existing Unit(s) Actual Generation (MWh/yr): ~~311,104~~ <u>250,750</u> MW-net

<u>Basis</u>:
Rule 1304.1(c) defines $C_{2YRAvgExisting}$ to mean "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." 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.

Once the timing of the issuance of the permits to construct is determined, the "e-Average Last 2 years of Existing Unit(s) Actual Generation (MWh/yr)" for the appropriate 24-month period will be finalized and used to calculate the initial annual fee for PM_{10}, SOx, and VOC.

For a preliminary estimate, the applicant provided the 2013 and 2014 generation for Boilers Nos. 1, 2, ~~5~~ <u>6</u>, and 3.

Table 64 - AGS 2-Year Average Electrical Production (2013 & 2014)

			2013		**2014**		**2-Year Average**	
Unit	**Rating MW-gross**	**Shutdown Date**	**MWh-gross**	**MWh-net**	**MWh-gross**	**MWh-net**	**MWh-gross**	**MWh-net**
1	175	12/29/2019	17,923	15,645	22,414	22,103	20,168	18,874
2	175	12/29/2019	30,766	26,094	85,834	82,964	58,300	54,529
~~5~~ <u>6</u>	480	12/29/2019	~~510,029~~ <u>260,275</u>	~~489,433~~ <u>250,662</u>	~~74,250~~ <u>196,690</u>	~~71,345~~ <u>189,409</u>	~~292,139~~ <u>228,482</u>	~~280,389~~ <u>220,035</u>
3	320	12/31/2020	369,385	350,913	499,518	473,800	434,452	412,357

Source: http://energyalmanac.ca.gov/electricity/web_qfer/

To offset the 692.951 MW for the installation of the combined-cycle turbines, assume 175 MW are provided by the retirement of Unit 1, 38 MW from the retirement of Unit 2, and 480 MW from the retirement of Unit ~~5~~ <u>6</u>. For Unit 2, the remaining 137 MW will be used to offset the simple-cycle turbines.

$C_{2YRAvgExisting}$ = (18,874 MW-net, Unit 1) + (54,529 MW-net, Unit 2) (38 MW/175 MW) + (~~280,389~~ <u>220,035</u> MW-net, Unit ~~5~~ <u>6</u>)
= ~~311,104~~ <u>250,750</u> MW-net

$PTEr_{PM10}$: 421.6 lb/day

<u>*Basis*:</u>
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)." *Table 23* provides the 30-day averages per turbine.

210.8 lb/day-turbine * 2 turbines = 421.6 lb/day

$PTEr_{SOx}$: 241.06 lb/day

<u>*Basis*:</u>
120.53 lb/day-turbine * 2 turbines = 241.06 lb/day

$PTEr_{VOC}$: 887.60 lb/day

<u>*Basis*:</u>
443.8 lb/day-turbine * 2 turbines = 887.60 lb/day

$PTEr_{NOx}$: Not applicable to RECLAIM facility.

<u>Total Annual Fee</u>
Table 65 shows the preliminary estimate for the Total Annual Fee ($/yr) is ~~$2,127,993~~ <u>$2,172,216</u> for the fiscal year ending on 6/30/14. This amount is required to be adjusted by the annual fee for each subsequent fiscal year.

The fee increases to date are: (1) 1.6% effective 7/1/14, (2) 1.4% effective 7/1/15, and (3) 2.4% effective 7/1/16. The fee for the fiscal year starting 7/1/16 is ~~$2,244,924.89~~ <u>$2,291,577.91</u>. [~~$2,127,993~~ <u>$2,172,216</u> * 1.016 * 1.014 * 1.024 = ~~$2,244,924.89~~ <u>$2,291,577.91</u>]

<u>Total Single Fee</u>
Table 65A shows the preliminary estimate for the Total Single Fee ($/yr) is ~~$53,204,741.00~~ <u>$54,310,426</u> for the fiscal year ending on 6/30/14.

The fee for the fiscal year starting 7/1/16 is ~~$56,128,308.32~~ <u>$57,294,750.02</u>. [~~$53,204,741.00~~ <u>$54,310,426</u> * 1.016 * 1.014 * 1.024 = ~~$56,128,308.32~~ <u>$57,294,750.02</u>]

<u>Annual Payment Prior to Issuance of Permits to Construct, Switching to Single Payment by End of First Year</u>

The preliminary estimated annual payment that will be required to be remitted prior to the issuance of the permits to construct for the combined-cycle turbines is ~~$2,244,924.89~~ $2,291,577.91 (7/1/16 fiscal year).

The preliminary estimated subsequent single payment is ~~$53,883,383.43~~ $55,003,172.11 (7/1/16 fiscal year). [~~$56,128,308.32~~ $57,294,750.02 - ~~$2,244,924.89~~ $2,291,577.91 = ~~$53,883,383.43~~ $55,003,172.11]

Table 65 - Rule 1304.1 Emissions Offset Fee Calculator for Combined-Cycle Turbines—Annual Fee Payment

Input Cumulative Project Profile Values:									
a-Gross Rating of New Replacement Unit(s) (MW)					**692.951**				
b-Maximum Fraction of Time Allowed to Operate (%)					**53**				
Hours in a Year (hr/yr)					8,760				
c-Max Allowable Operating Hours Annually (hr/yr)					4640				
d-Max Allowed Generation New Replacement Unit(s) Annually (MWhr/yr)					3,215,293	= C_{rep}*			
e- Average Last 2 Years of Existing Unit(s) Actual Generation (MWh/yr)					~~311,104~~ 250,750	= $C_{2YRAvgExisting}$			
ANNUAL FEE PAYMENT (> 100 MW Cumulatively):									
i	$PTEr_{PM10}$	$R_{PM10\ A1}$	$R_{PM10\ A2}$	$R_{PM10\ blended}$	OF_{PM10}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{PM10}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
PM10	**421.60**	997	3,986	3,555	1.00	3,215,293	~~311,104~~ 250,750	~~0.903~~ 0.922	~~**1,353,638**~~ **1,381,769**
	$PTEr_{SOx}$	$R_{SOx\ A1}$	$R_{SOx\ A2}$	$R_{SOx\ blended}$	OF_{SOx}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{SOx}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
SOx	**241.06**	793	3,170	2,827	1.00	3,215,293	~~311,104~~ 250,750	~~0.903~~ 0.922	~~**615,533**~~ **628,325**
	$PTEr_{VOC}$	$R_{VOC\ A1}$	$R_{VOC\ A2}$	$R_{VOC\ blended}$	OF_{VOC}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{VOC}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
VOC	**887.60**	47	185	165	1.20	3,215,293	~~311,104~~ 250,750	~~0.903~~ 0.922	~~**158,822**~~ **162,123**
	$PTEr_{NOx}$	$R_{NOx\ A1}$	$R_{NOx\ A2}$	$R_{NOx\ blended}$	OF_{NOx}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{NOx}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
NOx**	**Not Applicable**	666	2,663	2,375	1.20	3,215,293	~~311,104~~ 250,750	~~0.903~~ 0.922	**Not Applicable**
** Only applicable if project source is not in RECLAIM						**TOTAL ANNUAL FEE ($/yr)**			~~**2,127,993**~~ **2,172,216**
* If C_{rep} is known it can be entered directly (in MWh)									

Table 65A - Rule 1304.1 Emissions Offset Fee Calculator for Combined-Cycle Turbines—Single Fee Payment

Input Cumulative Project Profile Values:									
a-Gross Rating of New Replacement Unit(s) (MW)					**692.951**				
b-Maximum Fraction of Time Allowed to Operate (%)					**53**				
Hours in a Year (hr/yr)					8,760				
c-Max Allowable Operating Hours Annually (hr/yr)					4640				
d-Max Allowed Generation New Replacement Unit(s) Annually (MWhr/yr)					3,215,293	= C_{rep}*			
e- Average Last 2 Years of Existing Unit(s) Actual Generation (MWh/yr)					~~311,104~~ 250,750	= $C_{2YRAvgExisting}$			
SINGLE FEE PAYMENT (> 100 MW Cumulatively):									
i	$PTEr_{PM10}$	$L_{PM10\ A1}$	$L_{PM10\ A2}$	$L_{PM10\ blended}$	OF_{PM10}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{PM10}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
PM10	**421.60**	24,911	99,643	88,858	1.00	3,215,293	~~311,104~~ 250,750	~~0.903~~ 0.922	~~33,837,900~~ 34,541,109
	$PTEr_{SOx}$	$L_{SOx\ A1}$	$L_{SOx\ A2}$	$L_{SOx\ blended}$	OF_{SOx}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{SOx}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
SOx	**241.06**	19,816	79,262	70,683	1.00	3,215,293	~~311,104~~ 250,750	~~0.903~~ 0.922	~~15,390,278~~ 15,710,114
	$PTEr_{VOC}$	$L_{VOC\ A1}$	$L_{VOC\ A2}$	$L_{VOC\ blended}$	OF_{VOC}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{VOC}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
VOC	**887.60**	1,159	4,635	4,133	1.20	3,215,293	~~311,104~~ 250,750	~~0.903~~ 0.922	~~3,976,573~~ 4,059,203
	$PTEr_{NOx}$	$L_{NOx\ A1}$	$L_{NOx\ A2}$	$R_{NOx\ blended}$	OF_{NOx}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{NOx}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
NOx**	**Not Applicable**	16,643	66,571	59,366	1.20	3,215,293	~~311,104~~ 250,750	~~0.903~~ 0.922	**Not Applicable**
** Only applicable if project source is not in RECLAIM						**TOTAL SINGLE FEE ($/yr)**			~~53,204,741~~ 54,310,426
* If C_{rep} is known it can be entered directly (in MWh)									

- Simple-Cycle Turbines with Intercoolers
  The inputs for the calculator are discussed below.

  a-Gross Rating of New Replacement Units (MW): 401.75 MW

  Basis:
  (100.438 MW-gross/ CTG) * (4 CTGs) = 401.75 MW (Case 12)

  b-Maximum Fraction of Time Allowed to Operate (%): 27%

  Basis:
  c-Max Allowable Operating Hours Annually (hr/yr) = 2358 hr/yr

  Hours in a Year (hr/yr) = 8760 hr/yr

  Fraction of Time Allowed to Operate = 2358 hr/yr ÷ 8760 hr/yr = 27%

  Note: For the purpose of this rule, startup and shutdown hours are included.

  e-Average Last 2 years of Existing Unit(s) Actual Generation (MWh/yr): 384,172 MW-net

  Basis:
  To offset the 401.75 MW for the installation of the simple-cycle turbines, assume 137 MW are provided by the retirement of Unit 2 and 265 MW from the retirement of Unit 3. At this time, AES has not finalized plans for the surplus 55 megawatts from the retirements.

  $C_{2YRAvgExisting}$ = (54,529 MW-net, Unit 2) (137 MW/175 MW) +
  (412,357 MW-net, Unit 3)(265 MW/320 MW) = 384,172 MW-net

  $PTEr_{PM10}$: ~~619~~ 618 lb/day

  Basis:
  Table 39 provides the 30-day averages per turbine.

  154.60 lb/day-turbine * 4 turbines = 618 lb/day

  $PTEr_{SOx}$: 161 lb/day

  Basis:
  40.22 lb/day-turbine * 4 turbines = 161 lb/day

$PTEr_{VOC}$: 263 lb/day

Basis:
65.78 lb/day-turbine * 4 turbines = 263 lb/day

$PTEr_{NOx}$: Rule 1304.1 is not applicable to NOx for a RECLAIM facility.

Total Annual Fee

Table 66 shows the preliminary estimate for the Total Annual Fee ($/yr) is $1,466,085 for the fiscal year ending on 6/30/14. This amount is required to be adjusted by the annual fee for each subsequent fiscal year.

The fee increases to date are: (1) 1.6% effective 7/1/14, (2) 1.4% effective 7/1/15, and (3) 2.4% effective 7/1/16. The fee for the fiscal year starting 7/1/16 is $1,546,645.46. [$1,466,085 * 1.016 * 1.014 * 1.024 = $1,546,645.46]

Total Single Fee

Table 66A shows the preliminary estimate for the Total Single Fee ($/yr) is $36,650,221.00 for the fiscal year ending on 6/30/14.

The fee for the fiscal year starting 7/1/16 is $38,664,127.77. [$36,650,221.00 * 1.016 * 1.014 * 1.024 = $38,664,127.77]

Annual Payment Prior to Issuance of Permits to Construct, Switching to Single Payment by End of First Year

The preliminary estimated annual payment that will be required to be remitted prior to the issuance of the permits to construct for the combined-cycle turbines is $1,546,645.46 (7/1/16 fiscal year).

The preliminary estimated subsequent single payment is $37,117,482.31 (7/1/16 fiscal year). [$38,664,127.77 - $1,546,645.46 = $37,117,482.31]

Table 66 - Rule 1304.1 Emissions Offset Fee Calculator for Simple-Cycle Turbines—Annual Fee Payment

Input Cumulative Project Profile Values:									
a-Gross Rating of New Replacement Unit(s) (MW)					**401.75**				
b-Maximum Fraction of Time Allowed to Operate (%)					**27**				
Hours in a Year (hr/yr)					8,760				
c-Max Allowable Operating Hours Annually (hr/yr)					2,358				
d-Max Allowed Generation New Replacement Unit(s) Annually (MWhr/yr)					947,326.5	= C_{rep}*			
e- Average Last 2 Years of Existing Unit(s) Actual Generation (MWh/yr)					**384,172**	= $C_{2YRAvgExisting}$			
ANNUAL FEE PAYMENT (> 100 MW Cumulatively):									
i	$PTEr_{PM10}$	$R_{PM10\ A1}$	$R_{PM10\ A2}$	$R_{PM10\ blended}$	OF_{PM10}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{PM10}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
PM10	**618.00**	997	3,986	3,242	1.00	947,326.5	**384,172**	0.594	**1,191,050**
	$PTEr_{SOx}$	$R_{SOx\ A1}$	$R_{SOx\ A2}$	$R_{SOx\ blended}$	OF_{SOx}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{SOx}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
SOx	**161.00**	793	3,170	2,578	1.00	947,326.5	**384,172**	0.594	**246,771**
	$PTEr_{VOC}$	$R_{VOC\ A1}$	$R_{VOC\ A2}$	$R_{VOC\ blended}$	OF_{VOC}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{VOC}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
VOC	**263.00**	47	185	151	1.20	947,326.5	**384,172**	0.594	**28,264**
	$PTEr_{NOx}$	$R_{NOx\ A1}$	$R_{NOx\ A2}$	$R_{NOx\ blended}$	OF_{NOx}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{NOx}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
NOx**	**Not Applicable**	666	2,663	2,166	1.20	947,326.5	**384,172**	0.594	**Not Applicable**
** Only applicable if project source is not in RECLAIM							**TOTAL ANNUAL FEE ($/yr)**		**1,466,085**
* If C_{rep} is known it can be entered directly (in MWh)									

Table 66 - Rule 1304.1 Emissions Offset Fee Calculator for Simple-Cycle Turbines—Single Fee Payment

Input Cumulative Project Profile Values:									
a-Gross Rating of New Replacement Unit(s) (MW)					**401.75**				
b-Maximum Fraction of Time Allowed to Operate (%)					**27**				
Hours in a Year (hr/yr)					8,760				
c-Max Allowable Operating Hours Annually (hr/yr)					2,358				
d-Max Allowed Generation New Replacement Unit(s) Annually (MWhr/yr)					947,326.5	= C_{rep}*			
e- Average Last 2 Years of Existing Unit(s) Actual Generation (MWh/yr)					**384,172**	= $C_{2YRAvgExisting}$			
SINGLE FEE PAYMENT (> 100 MW Cumulatively):									
i	$PTEr_{PM10}$	$L_{PM10\ A1}$	$L_{PM10\ A2}$	$L_{PM10\ blended}$	OF_{PM10}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{PM10}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
PM10	**618.00**	24,911	99,643	81,041	1.00	947,326.5	**384,172**	0.594	**29,773,040**
	$PTEr_{SOx}$	$L_{SOx\ A1}$	$L_{SOx\ A2}$	$L_{SOx\ blended}$	OF_{SOx}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{SOx}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
SOx	**161.00**	19,816	79,262	64,465	1.00	947,326.5	**384,172**	0.594	**6,169,917**
	$PTEr_{VOC}$	$L_{VOC\ A1}$	$L_{VOC\ A2}$	$L_{VOC\ blended}$	OF_{VOC}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{VOC}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
VOC	**263.00**	1,159	4,635	3,770	1.20	947,326.5	**384,172**	0.594	**707,264**
	$PTEr_{NOx}$	$L_{NOx\ A1}$	$L_{NOx\ A2}$	$L_{NOx\ blended}$	OF_{NOx}	C_{rep}	$C_{2YRAvgExisting}$	Ratio	F_{NOx}
	(lbs/day)	($ per lb/day)	($ per lb/day)	($ per lb/day)	-	(MWhr/yr)	(MWhr/yr)	-	($)
NOx**	**Not Applicable**	16,643	66,571	54,143	1.20	947,326.5	**384,172**	0.594	**Not Applicable**
** Only applicable if project source is not in RECLAIM								**TOTAL SINGLE FEE ($/yr)**	**36,650,221**
* If C_{rep} is known it can be entered directly (in MWh)									

- Combined-Cycle Turbines and Simple-Cycle Turbines with Intercoolers
  Total Annual Fee
  The preliminary estimate for the total annual fee for the combined- and simple-cycle turbines is ~~$3,791,570.35~~ $3,838,223.37 for the fiscal year starting 7/1/16. [~~$2,244,924.89~~ $2,291,577.91 (combined-cycle) + $1,546,645.46 (simple-cycle) = ~~$3,791,570.35~~ $3,838,223.37]

  Total Single Fee
  The preliminary estimate for the total single fee for the combined- and simple-cycle turbines is ~~$94,792,436.09~~ $95,958.877.79 for the fiscal year starting 7/1/16. ~~[$56,128,308.32~~ $57,294,750.02 (combined-cycle) + $38,664,127.77 (simple-cycle) = ~~$94,792,436.09~~ $95,958.877.79]

- Annual Payment Prior to Issuance of Permits to Construct, Switching to Single Payment by End of First Year
  The preliminary estimated annual payment that will be required to be remitted prior to the issuance of the permits to construct for the combined-cycle turbines is ~~$3,791,570.35~~ $3,838,223.37 (7/1/16 fiscal year).

  The preliminary estimated subsequent single payment is ~~$91,000,865.74~~ $92,120,654.42 (7/1/16 fiscal year). ~~[$94,792,436.09~~ $95,958.877.79 - ~~$3,791,570.35~~ $3,838,223.37 = ~~$91,000,865.74~~ $92,120,654.42]

  Prior to actual remittal, the fees will be finalized using the most recent twenty-four months average of the MWh generation of the Utility Boilers to be replaced (C2YRAvgExisting) and the offset fee rates applicable at that time.

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 *Table* 2 above, the schedule for AGS Boilers Nos. 1, 2, and ~~5~~ 6 shutdown is 12/29/2019. The combined-cycle block startup is scheduled for 11/1/2019. The schedule for AGS Boiler No. 3 shutdown is 12/31/2020. The simple-cycle block startup is scheduled for 6/1/2021.

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.

(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, ~~A195.12~~ 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.

Auxiliary Boiler

BACT-- Condition nos. A195.13 and A195.14 set forth the BACT limits for NOx and CO, respectively.

Monthly Emissions--Condition no. A63.4 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 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.

Oil/Water Separators

BACT—Condition E193.16 requires fixed covers for the tanks.

Monthly Emissions—Throughput limits are not necessary because the 30-day averages for both tanks are no more than 0.0005 lb/day.

Rule 1325—Federal PM2.5 New Source Review Program

Rule 1325 was amended on 12/5/14 to incorporate administrative changes to definitions, provisions and exclusions, based on comments received from the U.S. EPA regarding SIP approvability of Rule 1325. The amended rule was approved into the California State Implementation Plan on 5/1/15. The applicable requirements of 40 CFR Part 51, Appendix S, were necessary for permitting actions until Rule 1325 became SIP-approved.

The relevant sections 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; located in areas federally designated pursuant to Title 40 of the Code of Federal Regulations (40 CFR) 81.305 as non-attainment for $PM_{2.5}$. With respect to major modifications, this rule applies on a pollutant-specific basis to emissions of $PM_{2.5}$ and its precursors, for which (1) the source is major, (2) the modification results in a significant increase, and (3) the modification results in a significant net emissions increase.

(b) Definitions

For the purposes of this rule, the definitions in Title 40 CFR 51.165(a)(1), as it exists on June 3, 2011 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, 100 tons or more per year of $PM_{2.5}$, or its precursors. A facility is considered to be a major polluting facility only for the specific pollutant(s) with a potential to emit of 100 tons or more per year.

(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
$PM_{2.5}$: 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.

(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:
The applicability analysis is summarized in the table below.

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	10.19	69.52
Net Emissions Increase (AEC PTE – AGS actual)	89.59	5.51	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.		
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.
Rule 1325 Applicable?	Yes	No	No

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 was 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.

Condition F2.1 will limit the $PM_{2.5}$ emissions for the facility to 100 tpy.

For Boiler Nos. 1 – 6, the $PM_{2.5}$ emission factor is 0.00113 lb/MMBtu, which was approved by SCAQMD Source Testing Dept., 9/2/15, as discussed for the emissions calculations above. [(0.00113 lb/MMBtu) (1050 MMBtu/MMcf) = 1.19 lb/mmscf

For the Combined-Cycle Turbines, the $PM_{2.5}$ emission factor is assumed to be equal to the PM_{10} emission factor for normal operation from condition A63.2, 3.92 lb/mmcf.

For the Auxiliary Boiler, the $PM_{2.5}$ emission factor is assumed to be equal to the PM_{10} emission factor from condition A63.4, 7.42 lb/mmcf.

For the Simple-Cycle Turbines, the $PM_{2.5}$ emission factor is assumed to be equal to the PM_{10} emission factor for normal operation from condition A63.3, 7.44 lb/mmcf.

Source test conditions D29.2 and D29.5 require EPA Method 201A and 202 for $PM_{2.5}$ testing. These methods do not specify an averaging time. Consultation with the SCAQMD source testing department indicates the sampling time is required to be long enough to obtain a measureable amount of sample, with past tests requiring at least 4 hours of sampling for the turbines. The sampling time required for the auxiliary boiler is possibly more than 1 hour but additional experience is required to determine a minimum sampling time.

Pending $PM_{2.5}$ Threshold Revision

The applicable regulations for lowering the $PM_{2.5}$ threshold for major source from 100 tpy to 70 tpy follows.

40 CFR 52.245 New Source Review rules

(d) By August 14, 2017, the New Source Review rules for $PM_{2.5}$ for the South Coast Air Quality Management District must be revised and submitted as a SIP revision. The rules must satisfy the requirements of sections 189(b)(3) and 189(e) and all other applicable requirements of the Clean Air Act for implementation of the 2006 $PM_{2.5}$ NAAQS.

The CAA Section 189 referenced above has been codified as 42 U.S.C. 7513a. Plan provisions and schedules for plan submissions, reproduced below.

§7513a. Plan provisions and schedules for plan submissions

(B) SERIOUS AREAS

(3) MAJOR SOURCES

For any Serious Area, the terms "major source" and "major stationary source" include 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, at least 70 tons per year of PM–10.

In reclassifying SCAQMD as serious nonattainment for $PM_{2.5,}$ the necessary New Source Review (NSR) rules are not due to EPA until August 14, 2017. Section 189(b)(3) is the requirement for major sources to be considered those with a potential to emit of 70 tons per year. As such, this threshold will not apply until SCAQMD adopts/revises its $PM_{2.5}$ NSR requirements to meet section 189(b)(3) by August 14, 2017.

At the SCAQMD Governing Board Meeting on October 7, 2016, a public hearing was set for November 4, 2016 to consider amendments to Rule 1325. Amendments to Rule 1325 are proposed 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" PM2.5 nonattainment area to a "serious" nonattainment area and with U.S. EPA's Fine Particulate Matter National Ambient Air Quality Standards implementation rule. The proposed amendments are intended to facilitate SIP approval of the regulations.

The amendment proposed to add ammonia and VOC as precursors to $PM_{2.5}$, per Clean Air Act Subpart 4 requirements. The major polluting facility thresholds will be lowered from the current 100 tons per year per pollutant to 70 tons per year per pollutant. These amendments will be effective after August 14, 2017 or upon the effective date of EPA's approval of these amendments to this rule, whichever is later. U.S. 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 58010 (August 24, 2016). The proposed amendments were adopted without change on November 4, 2016.

Rule 1401—New Source Review of Toxic Air Contaminants
Rule 2005(i) – RECLAIM Rule 1401 Compliance

Rule 1401 specifies limits for maximum individual cancer risk (MICR), and acute and chronic hazard index (HI) from new permit units and relocations or modifications to existing permit~~s~~ units that emit toxic air contaminants. Because the limits are for each permit unit, the limits are for each turbine and the auxiliary boiler. Rule 2005(j) requires compliance with Rule 1401 for RECLAIM facilities. 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 (1.0×10^{-5}) 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), unless paragraph (e)(3) applies, 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, unless paragraph (e)(3) applies, will not exceed 1.0 at any receptor location.

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 (Revised OEHHA Guidelines). On June 5, 2015, the SCAQMD approved amendments to Rule 1401 to revise definitions and risk assessment procedures to be consistent with the Revised OEHHA Guidelines. These updated guidelines take into account recent scientific advances which have found greater risk to children when they are exposed to cancer causing compounds.

The applicant provided health risk assessment (HRA) modeling using the California Air Resources Board's (ARB) *Hotspots Analysis Reporting Program Version 2* (HARP 2, version 16088) Air Dispersion Modeling and Risk Assessment Tool (ADMRT), which incorporates methodology presented in the Revised OEHHA Guidelines. The SCAQMD HRA procedures require HARP to be used in Tier 4 risk assessments. The HARP On-Ramp tool was used to import the American Meteorological Society/EPA Regulatory Model (AERMOD) air dispersion modeling output plot files into HARP2. The AERMOD dispersion model (Version 15181) was used to predict ground-level concentrations of air toxic emissions associated with AEC. The AERMOD settings, source parameters, meteorological data, and source definition for the risk assessment were the same as the air quality impact analysis methodology performed for Rules 1303 and 1703.

- <u>Combined-Cycle Turbines</u>
  The toxic air contaminants emissions calculations for determination of the maximum hourly and annual emissions rates are shown in *Table 26 - Combined-Cycle Turbine Toxic Air Contaminants/Hazardous Air Pollutants*, above.

  The maximum hourly turbine impacts for the combined-cycle turbines 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 1-hour ground-level impact in the dispersion modeling (Case 7 in *Table 15*). The annual turbine impacts were also 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*).

  AES Response Letter, dated 12/11/15, provided a revised health risk assessment in *Table 12-2—Health Risk Assessment Summary: Individual Units.* The health risk assessment in *Table 5.9-4—Health Risk Assessment Summary: Individual Units* in the original Application was required to be revised to be based on US EPA AP-42 emission factors.

  In the revised Application, the results of the risk assessment analysis are in revised *Table 5.9-4*. For the combined-cycle turbines, the table has been revised to reflect previously provided changes due to the change to AP-42 emission factors and new changes due to a higher annual fuel usage resulting from the increase in cold starts. The new changes due to the higher fuel usage are included the table below.

  PRDAS staff has reviewed the applicant's health risk assessment by independently performing the health risk assessment. The risk assessment results provided by PRDAS staff show minor differences from the applicant's results and are used to demonstrate compliance with the Rule 1401 standards in the table below. The modeling review memo shows the maximum results for the boiler, CCGT and SCGT. In an e-mail dated 4/29/16, PRDAS staff provided results for each turbine.

  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).

Table 68--Model Results for HRA for Combined-Cycle Turbine

Health Risk Index	Residential/ Sensitive Receptor Risk	Worker Receptor Risk	Rule 1401 Thresholds (T-BACT)	Exceeds Any Threshold?
		CCGT-1		
MICR	0.48×10^{-6}	0.025×10^{-6}	10×10^{-6}	No

HIC	0.0017	0.0012	1	No
HIA	0.00657	0.00662	1	No
CCGT-2				
MICR	0.49 x 10^{-6}	0.025 x 10^{-6}	10 x 10^{-6}	No
HIC	0.00123	0.00171	1	No
HIA	0.00657	0.00672	1	No

- Auxiliary Boiler

  The toxic air contaminants emissions calculations for determination of the maximum hourly and annual emissions rates are shown in *Table 30 - Toxic Air Contaminants/Hazardous Air Pollutants for Auxiliary Boiler*, above.

  The maximum hourly and annual impacts for the auxiliary boiler were predicted, based on the auxiliary boiler operating at 100 percent load for the hourly impacts and 50% load for the annual impacts.

  AES Response Letter, dated 12/11/15, provided a revised health risk assessment in *Table 12-2—Health Risk Assessment Summary: Individual Units*. The health risk assessment in *Table 5.9-4—Health Risk Assessment Summary: Individual Units* in the original Application was required to be revised to be based on VCAPCD emission factors.

  In the revised Application, the results of the risk assessment analysis are in revised *Table 5.9-4*. For the auxiliary boiler, the table has been revised to reflect previously provided changes due to the change to VCAPCD emission factors, and new changes due to a lower annual fuel usage. The new changes due to the lower fuel usage are added to the table below.

  PRDAS staff has reviewed the applicant's health risk assessment. The risk assessment results provided by PRDAS staff show minor differences from the applicant's results and are used to demonstrate compliance with the Rule 1401 standards in the table below.

Table 69--Model Results for HRA for Auxiliary Boiler

Health Risk Index	Residential/ Sensitive Receptor Risk	Worker Receptor Risk	Rule 1401 Thresholds	Exceeds Any Threshold?
MICR	0.0091 x 10^{-6}	0.00091 x 10^{-6}	1 x 10^{-6}	No
HIC	0.0000284	0.0000967	1	No
HIA	0.000318	0.00049	1	No

- <u>Simple-Cycle Turbines</u>

  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 turbine impacts for the simple-cycle turbines 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 1-hour ground-level impact in the dispersion modeling (Case 7 in *Table 31*). The annual turbine impacts were also 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*). (AES clarified that, for hourly impacts, the maximum ground-level for normalized emission rates (i.e., emission rates that do not vary by load or ambient temperature) occur at an ambient temperature of 107 °F at minimum load. However, as this exhaust scenario cannot occur at the same time as the worst-case 1-hour combined-cycle exhaust scenario for the combined-cycle turbines, the scenario resulting in the maximum ground-level impact from the 65.3 °F ambient temperature scenarios was chosen.)

  AES Response Letter, dated 12/11/15, provided the health risk assessment in *Table 12-2—Health Risk Assessment Summary: Individual units*. The health risk assessment in *Table 5.9-4—Health Risk Assessment Summary: Individual Units* in the original Application was required to be revised to be based on US EPA AP-42 emission factors.

  The risk assessment results provided by PRDAS staff show minor differences from the applicant's results and are used to demonstrate compliance with the Rule 1401 standards in the table below.

Table 70--Model Results for HRA for Simple-Cycle Turbine

Health Risk Index	Residential/ Sensitive Receptor Risk	Worker Receptor Risk	Rule 1401 Thresholds (T-BACT)	Exceeds Any Threshold?
SCGT-1				
MICR	0.049×10^{-6}	0.0019×10^{-6}	10×10^{-6}	No
HIC	0.000126	0.000136	1	No
HIA	0.00151	0.00237	1	No
SCGT-2				
MICR	0.049×10^{-6}	0.0019×10^{-6}	10×10^{-6}	No
HIC	0.000124	0.000137	1	No
HIA	0.00153	0.00385	1	No
SCGT-3				
MICR	0.048×10^{-6}	0.0019×10^{-6}	10×10^{-6}	No
HIC	0.000122	0.000137	1	No
HIA	0.00174	0.00242	1	No

SCGT-4				
MICR	0.047×10^{-6}	0.0019×10^{-6}	10×10^{-6}	No
HIC	0.00012	0.0000466	1	No
HIA	0.00175	0.00239	1	No

- Facility-wide

  Because the Rule 1401 limits are for each permit unit, the limits are for each turbine and the auxiliary boiler. The following facility-wide health risk assessment is provided for CEQA and informational purposes only.

  AES Response Letter, dated 12/11/15, provided the health risk assessment in *Table 12-3—Health Risk Assessment Summary: Facility*. The health risk assessment in *Table 5.9-5—Health Risk Assessment Summary: Facility* in the original Application was required to be revised to be based on corrected emission factors for the turbines and auxiliary boiler.

  In the revised Application, the results of the risk assessment analysis are in revised *Table 5.9-5*. The table has been revised to reflect previously provided changes due to the corrected emission factors, and new changes due to the changes in annual fuel usages for the combined-cycle turbines and auxiliary boiler. The facility-wide results represent the combined predicted risk for all seven combustion units operating simultaneously. The maximum impacts reported represent the maximum predicted impacts at one receptor from all sources combined. The maximum impacts reported for the individual equipment shown in the tables above may occur at different receptors. Therefore, the results for the individual equipment are not directly additive to arrive at facility-wide results.

  PRDAS staff has reviewed the applicant's health risk assessment. The results provided by PRDAS staff show minor differences from the applicant's results, except for the cancer burden. The applicant provided a cancer burden of 1.79×10^{-9}, but PRDAS staff provided a cancer burden of 0.0097. The risk assessment results provided by PRDAS staff are used to demonstrate compliance with the Rule 1401 standards in the table below.

Table 70A--Model Results for HRA for Facility

Health Risk Index	Residential/ Sensitive Receptor Risk	Worker Receptor Risk	Rule 1401 Thresholds (T-BACT)	Exceeds Any Threshold?
MICR	1.1×10^{-6}	0.052×10^{-6}	10×10^{-6}	No
HIC	0.0028	0.00364	1	No
HIA	0.0176	0.0188	1	No
Cancer Burden	0.0097		0.5	No

PRDAS staff based the cancer burden of 0.0097 on a radius of 0.63 km and a population density of 7000 persons/km^2.

- 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

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 SCAQMD. On 7/25/07, the EPA and SCAQMD signed a new "Partial PSD Delegation Agreement." The agreement is intended to delegate the authority and responsibility to the District for issuance of initial PSD permits and for PSD permit modifications where the applicant does not seek to use the emissions calculation methodologies promulgated in 40 CFR 52.21 (NSR Reform) but not included in SCAQMD Regulation XVII. The Partial Delegation agreement did not delegate authority and responsibility to SCAQMD to issue new or modified PSD permits based on Plant-wide Applicability Limits (PALS) provisions of 40 CFR 52.21.

Since this is a partial delegation the facilities in the South Coast Air Basin (SCAB) may either apply directly to EPA for the PSD permit in accordance with the current requirements of 40 CFR Part 52 Subpart 21, or apply to the SCAQMD in accordance with the current requirements of Regulation XVII. AES has opted to apply to the SCAQMD.

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.

- ***RULES 1701, 1702, 1706--PSD APPLICABILITY***
  The relevant PSD applicability rule sections are presented below, followed by the applicability analysis.

  Rule 1701(b) Applicability
  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 to 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 District 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. The following table summarizes the Rule 1701(b)(2)(A) and (B) analysis to determine which pollutants are subject to PSD review <u>for requirements other than BACT, such as modeling</u>. <u>Rules 1701(b)(1) and 1703(a)(2) require BACT for all permit units with a net emission increase of a criteria air contaminant.</u> 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.

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

Alamitos Energy Center (AEC) Potential to Emit, TPY = Emissions Increase (*Table 45*)	~~269.80~~ 243.62	137.06	10.19	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)	~~–18.10~~ -44.28	89.59	5.51	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

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 ~~PSD~~ by Rules 1701(b)(1) and 1703(a)(2), top-down BACT analyses are presented below for NOx, PM_{10}, and CO. ~~the two pollutants subject to PSD review, NOx and PM_{10}. Although not subject to PSD review for AEC, a top-down BACT analysis is also presented below for CO for the purpose of completeness.~~

A. Top-Down BACT Analysis for Combined-Cycle Gas Turbines and Simple-Cycle Gas Turbines for Nitrogen Oxide (NOx) Emissions

Step 1: Identify all available control technologies.

NOx is a by-product of the combustion of natural gas-and-air mixture in the turbines, which are high temperature environments. Thermal NO_X is created by the high temperature reaction in the combustion chamber between the nitrogen and oxygen in the combustion air. The heat from combustion causes the nitrogen (N_2) molecules in the combustion air to dissociate into individual N_2 atoms, which then combine with oxygen (O_2) molecules in the air to form nitric oxide (NO) and nitrogen dioxide (NO_2). The principal form of nitrogen oxide produced during turbine combustion is NO, but NO reacts quickly to form NO_2, creating a mixture of NO and NO_2 called NOx.

Combustion controls minimize the amount of NOx created during the combustion process. The control technologies include:

A. Water or Steam Injection
B. Dry-Low NOx (DLN) Combustors

Post- combustion controls remove NOx from the exhaust stream after the combustion has occurred. The control technologies include:

A. SCR
B. SCONOx (now EMx)
C. Selective Non-Catalytic Reduction (SNCR)

Combustion Control Technologies

A. Water or Steam Injection

The injection of water or steam into the combustor of a gas turbine quenches the flame and absorbs heat, reducing the combustion temperature. This temperature reduction reduces the formation of thermal NOx. Typically combined with a post-combustion control technology, water or steam injection alone can achieve a NOx emission of 25 part(s) per million dry volume (ppmvd) at 15 percent O_2, but with the added economic, energy, and environmental expenses of using water.

B. Dry-Low NOx (DLN) Combustors

In conventional combustors, the fuel and air are injected separately and mixed by diffusion before combustion occurs. This method of combustion results in combustion "hot spots," which produce higher levels of NOx.

Lean premix and catalytic combustors are two types of DLN combustors that are available alternatives to the conventional combustors to reduce NOx combustion "hot spots."

Lean premix combustors are the most popular DLN combustors available. These combustors reduce the formation of thermal NOx through the following processes: (1) using excess air to reduce the flame temperature (i.e., lean combustion); (2) reducing combustor residence time to limit exposure in a high-temperature environment; (3) mixing fuel and air in an initial "pre-combustion" stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or (4) achieving two-stage rich/lean combustion using a primary fuel-rich combustion stage to limit the amount of oxygen available to combine with the nitrogen in the combustion air, and then using a secondary lean burn-stage to complete combustion in a cooler environment. Lean premix combustors have only been developed for gas-fired turbines. The more advanced designs are capable of achieving a 70- to 90-percent NOx reduction with a vendor-guaranteed NOx concentration of 9 to 25 ppmvd.

Catalytic combustor technology is available under the trade name XONON^{TM}. The XONON^{TM} combustion system improves the combustion process by lowering the peak combustion temperature through the use of a catalyst to reduce the formation of thermal NOx. The combustion process is comprised of a partial combustion of the fuel in the catalyst module followed by a completion of the combustion downstream of the catalyst. In the catalyst module, a portion of the fuel is combusted without a flame at relatively low temperature to produce a hot gas. A homogenous combustion region is located immediately downstream where the remainder of the fuel is combusted.

<u>Post-Combustion Control Technologies</u>

A. <u>SCR</u>

SCR is a post-combustion control technology designed to control NOx emissions from gas turbines, boilers, and other NOx-emitting equipment. The SCR system consists of a catalyst bed with an ammonia injection grid located upstream of the catalyst. The ammonia reacts with the NOx and oxygen in the presence of a catalyst to form nitrogen and water. The catalyst consists of a support system with a catalyst coating typically of titanium dioxide, vanadium pentoxide, or zeolite. A small amount of ammonia that is not consumed in the reaction is emitted in the exhaust stream and is referred to as "ammonia slip."

B. <u>EMx^{TM} (formerly SCONOx)</u>

The EMx^{TM} system uses a single catalyst to remove NOx emissions in the turbine exhaust gas by oxidizing NO to NO_2 and then absorbing NO_2 onto the catalytic surface using a potassium carbonate absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EMx catalyst is from 300 to 700 degrees Fahrenheit (°F). EMx^{TM} does not use ammonia, so there are no ammonia emissions from this catalyst system. When all of the potassium carbonate absorber coating has been converted to N_2 compounds, NOx can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the gas reacts with the nitrites and nitrates to form water and N_2. Carbon dioxide (CO_2) in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst.

C. Selective Non-Catalytic Reduction (SNCR)
SNCR involves injection of ammonia or urea into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,600 to 2,100 °F. This technology is not available for combustion turbines because gas turbine exhaust temperatures are below the required minimum temperature of 1,600 °F.

Step 2: Eliminate technically infeasible options.

Combustion Control Technologies

A. Water or Steam Injection
The use of water or steam injection is considered a feasible technology for reducing NOx emissions to 25 ppmvd when firing natural gas. When combined with SCR, water or steam injection can achieve 2 ppmvd and 2.5 ppmvd NOx levels for combined- and simple-cycle turbines, respectively, but at a slightly lower thermal efficiency as compared to DLN combustors.

B. Dry-Low NOx (DLN) Combustors
The use of lean premix combustors is a feasible technology for reducing NOx emissions from the AEC. DLN combustors are capable of achieving 9 to 25 ppmvd NOx emission over a relatively large operating range (70 to 100 percent load), and when combined with SCR can achieve controlled NOx emissions of 2 ppmvd and 2.5 ppmvd NOx levels for combined- and simple-cycle turbines, respectively.

The XONON™ catalytic combustor has been demonstrated successfully in a 1.5-MW simple-cycle pilot facility and is commercially available for turbines rated up to 10 MW. The technology has not been demonstrated on commercial gas turbines greater than 10 MW, such as the proposed combined- and simple-cycle turbines. XONON™ is an innovative but not currently demonstrated technology that has received very limited trial operation. Therefore, the technology is not considered feasible for AEC.

Post-Combustion Control Technologies

A. SCR

The use of SCR, with an ammonia slip of less than 5 ppm, is considered a feasible technology for reducing NOx emissions to achieve 2 ppmvd and 2.5 ppmvd NOx levels for combined- and simple-cycle turbines, respectively.

B. EMx™ (formerly SCONOx)

The use of EMx™ system is considered a feasible technology for reducing NOx emissions from AEC.

In the Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Pio Pico Energy Center, PSD Permit No. SD 11-01, dated June 2012, the EPA noted that the EMx™ technology is a relatively newer technology that has yet to be demonstrated in practice on combustion turbines greater than 50 MW. The manufacturer has stated that it is a scalable technology and that NOx guarantees of <1.5 ppm are available.

In the Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Palmdale Hybrid Power Plant, PSD Permit No. SE 09-01, dated August 2011, the EPA noted that it is unclear what NO_X emission levels can actually be achieved by the technology. The EPA found only one BACT analysis that determined that EMx™/SCONOx was BACT for a large combustion turbine. However, the accompanying permit for the facility, Elk Hills Power in California, allowed the use of SCR or SCONOx to meet a permit limit of 2.5 ppm, and the actual technology that was installed in that case was SCR. The EPA noted that the Redding Power Plant in California, a 43 MW gas-fired combustion turbine, was permitted with a 2.0 ppm demonstration limit using SCONOx. In a letter dated June 23, 2005 from the Shasta County Air Quality Management District (Shasta County AQMD) to the Redding Electric Utility, however, it was determined that the unit could not meet the demonstration limit and, as a result, the limit was revised to 2.5 ppm. Based on these two examples, it appears that EMx™ has been demonstrated to achieve 2.5 ppm only.

The technology has not been demonstrated in practice on combustion turbines greater than 50 MW, such as the proposed combined- and simple-cycle turbines. EMx™ is carried forward in this BACT analysis as a potential NOx control technology. However, substantial evidence demonstrates that EMx™ is not yet demonstrated as technically feasible for the AEC project.

C. Selective Non-Catalytic Reduction (SNCR)
SNCR is not considered technically feasible for the proposed combined- and simple-cycle turbines. SNCR requires exhaust gas temperatures in the range of 1,600 to 2,100 °F, which is higher than the exhaust temperatures from natural-gas-fired combustion turbine installations. For the proposed combined-cycle turbines, the turbine exhaust temperature range is expected to be 170 to 223 °F. For the proposed simple-cycle turbines, the turbine exhaust temperature range is expected to be 789 to 981 °F.

Step 3: Rank remaining control technologies.

Combined-Cycle Turbines
A summary of recent BACT limits for similar combined-cycle, natural gas-fired combustion turbines is provided in the table below.

IDC Bellingham was included because it is the only known facility that was permitted with a BACT limit less than the 2.0 ppm, 1-hr average, proposed by AEC. IDC Bellingham was permitted with a limit of 1.5 ppm during normal operations. However, this project was cancelled, so this limit has never been demonstrated as achievable. As shown in the table below, all recently issued permits indicate that a limit of 2.0 ppm based on a 1-hr average represents the highest level of NO_X control.

Table 72 - Summary of Recent NOx BACT Limits for Similar Combined-Cycle, Natural Gas-Fired Combustion Turbines

Facility	Permit Issuance	NOx Limit @ 15% O_2
LA City, DWP Scattergood Generating Station, California	2013	2.0 ppm (1-hr)
Pasadena City, Dept. of Water & Power, California	2013	2.0 ppm (1-hr)
Langley Gulch Power Plant, Idaho	2013	2.0 ppm (3-hr rolling)
El Segundo Power, LLC, California	2011	2.0 ppm (1-hr)
Lower Colorado River Authority, Texas	2011	2.0 ppm (24-hr)
~~Palmdale Hybrid Power Project, California~~ *Note: Project was revised and renamed Palmdale Energy Project. FSA released on 9/12/16.*	~~2011~~ Not issued yet	2.0 ppm (1-hr) 2.0 ppm (1-hr)
Avenal Energy Project, California	2011	2.0 ppm (1-hr)
Warren County Power Station, Virginia	2010	2.0 ppm (1-hr)
Live Oaks Power Plant, Georgia	2010	2.5 ppm (3-hr)
Colousa Generating Station, California	2010	2.0 ppm (1-hr)
Victorville II Hybrid Power Project, California	2010	2.0 ppm (1-hr)
Pondera Capital Management, King Power Station, Texas	2010	2.0 ppm (1-hr)
Russell City Energy Center, California	2010	2.0 ppm (1-hr)
Madison Bell Energy Center, Texas	2009	2.0 ppm (24-hr rolling)

Chouteau Power Plant, Oklahoma	2009	2.0 ppm (1-hr)
Lamar Power Partners, Texas	2009	2.0 ppm (24-hr)
Patillo Branch Power Company, Texas	2009	2.0 ppm (24-hr)
FMPA Cane Island Power Park, Florida	2008	2.0 ppm (24-hr)
FPL West County Energy Center Unit 3, Florida	2008	2.0 ppm (24-hr)
Kleen Energy Systems, Connecticut	2008	2.0 ppm (1-hr)
Blythe Energy LLC (Blythe II), California	2007	2.0 ppm (3-hr)
PSO Southwestern Power Plant, Oklahoma	2007	9.0 ppm (no averaging time)
Carlsbad Energy Center – NRG, California	2007	2.0 ppm (1-hr)
Rocky Mountain Energy Center, Colorado	2006	3.0 ppm (1-hr)
San Joaquin Valley Energy Center, California	2006	2.0 ppm (1-hr)
Elk Hills Power, California	2006	2.5 ppm (1-hr)
Inland Empire Energy Center, California	2005	2.0 ppm (1-hr)
Bicent (California) Malburg (formerly Vernon City, Light and Power Dept.), California	2003	2.0 ppm (1-hr)
Burbank City, Burbank Water & Power, SCPPA (Magnolia Power Plant), California	2003	2 ppm (3-hr)
LA City, DWP Haynes Generating Station, California	2002	2 ppm (1-hr)
IDC Bellingham, Massachusetts	2000	1.5 ppm (1-hr)—Project cancelled

For combined-cycle turbines, the available control technologies are ranked according to control effectiveness in the table below.

Table 73 - NO_X Control Technologies for Combined-Cycle Turbines Ranked by Control Effectiveness

NOx Control Technology	**Controlled Emission Rate (ppmvd @ 15% O_2, 1-hr average)**
Water or Steam Injection	25
Dry Low-NOx Combustors (lean premix)	9 - 25
EMx^{TM} with Dry Low-NOx Combustors (lean premix)	2.5
SCR with Dry Low-NOx Combustors (lean premix)	2.0

Simple-Cycle Turbines

A summary of recent BACT limits for similar simple-cycle, natural gas-fired combustion turbines is provided in the table below.

Table 74 - Summary of Recent NOx BACT Limits for Similar Simple-Cycle, Natural Gas-Fired Combustion Turbines

Facility	Permit Issuance	NOx Limit @ 15% O_2
LA City, DWP Scattergood Generating Station, California	2013	2.5 ppm (1-hr)
CPV Sentinel, California	2012 & 2013	2.5 ppm (1-hr)
Pio Pico Energy Center, California	2012	2.5 ppm (1-hr)
Walnut Creek Energy Park, California	2011	2.5 ppm (1-hr)
TID Almond 2 Power Plant, California	2010	2.5 ppm (1-hr)
Canyon Power Plant, California	2010	2.5 ppm (1-hr)
Starwood Power – Midway, California	2008	2.5 ppm (1-hr)
Panoche Energy, California	2007	2.5 ppm (1-hr)

For simple-cycle turbines, the available control technologies are ranked according to control effectiveness in the table below. The controlled emission rates are from Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Pio Pico Energy Center.

Table 75 - NOx Control Technologies for Simple-Cycle Turbines Ranked by Control Effectiveness

NOx Control Technology	Controlled Emission Rate (ppmvd @ 15% O_2, 1-hr average)
Water or Steam Injection	> 9
Dry Low-NOx Combustors and Inlet Air Coolers	9
SNCR	~ 4.5 (based on demonstrated control efficiency of 40 – 60%)
SCR with water injection	2.5
SCR with Dry Low NOx Combustors	2.5

Step 4: Evaluate most effective controls.

Combined-Cycle Turbines
Based on the information presented in this BACT analysis, NOx emission rates of 2.0 ppm (1-hour) are the lowest NOx emission rates achieved in practice at similar sources.

Simple-Cycle Turbines
Based on the information presented in this BACT analysis, NOx emission rates of 2.5 ppm (1-hour) are the lowest NOx emission rates achieved in practice at similar sources. SCR has not been able to duplicate the emission rate of 2.0 ppm NOx achieved with combined-cycle turbines, because the exhaust gas temperatures are higher for simple-cycle turbines.

Step 5: Select the BACT.

<u>*Combined-Cycle Turbines*</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. This is the same as the BACT proposed by AES.

<u>*Simple-Cycle Turbines*</u>
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. This is the same as the BACT proposed by AES.

B. <u>Top-Down BACT Analysis for Combined-Cycle Gas Turbines and Simple-Cycle Gas Turbines for Particulate Matter (PM_{10}) Emissions</u>

Step 1: Identify all available control technologies.

A. <u>Combustion Control Technologies</u>
The major sources of PM_{10} emissions from a natural-gas-fired gas turbine equipped with SCR for post-combustion control of NOx are: (1) the conversion of fuel sulfur to sulfates and ammonium sulfates; (2) unburned hydrocarbons that can lead to the formation of particulate matter in the exhaust stack; and (3) particulate matter in the ambient air entering the gas turbine through the inlet air filtration system, and the aqueous ammonia dilution air. Therefore, the use of clean-burning, low-sulfur fuels such as natural gas will result in minimal formation of PM_{10} during combustion. Best combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, thereby minimizing emissions of unburned hydrocarbons that can lead to formation of particulate matter at the stack. In addition to good combustion, use of high-efficiency filtration on the inlet air and SCR dilution air system will minimize the entrainment of particulate matter into the exhaust stream.

B. <u>Post-Combustion Control Technologies</u>
Two post-combustion control technologies designed to reduce particulate matter emissions from industrial sources are electrostatic precipitators and baghouses.

Step 2: Eliminate technically infeasible options.

Electrostatic precipitators and baghouses are typically used on solid/liquid-fuel fired or other types of sources with high particulate matter emission concentrations. Neither of these control technologies is appropriate for use on natural-gas-fired turbines because of the very low levels and small aerodynamic diameter of particulate matter from natural gas combustion. Therefore, electrostatic precipitators and baghouses are not considered technically feasible control technologies. However, clean-burning fuels, best combustion practices, and inlet air filtration are considered technically feasible for control of PM_{10} emissions from combined- and simple-cycle turbines.

Step 3: Rank remaining control technologies.

The use of clean-burning fuels, best combustion practices, and inlet air filtration are the technically feasible natural-gas-fired turbine control technologies. No add-on control devices are technically feasible to control PM_{10} emissions from natural-gas-fired turbines.

Step 4: Evaluate most effective controls.

Based on the information presented in this BACT analysis, using good combustion practice, pipeline quality natural gas with low sulfur content, and inlet air filtration to control PM_{10} emissions is consistent with BACT at similar sources.

Step 5: Select the BACT.

Based on the above review, the BACT for PM_{10} emissions is using pipeline-quality natural gas with low sulfur content, good combustion practice, and inlet air filtration. This is the same as the BACT proposed by AES.

C. Top-Down BACT Analysis for Combined-Cycle Gas Turbines and Simple-Cycle Turbines for Carbon Monoxide (CO) Emissions

Step 1: Identify all available control technologies.

Combustion Control Technologies

CO is formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of CO is limited by designing the combustion system to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures (in excess of 1,800 °F) with an excess of combustion air. Higher combustion temperatures tend to reduce the formation of CO but increase the formation of NOx. The application of water or steam injection or dry low-NOx combustors tends to lower combustion temperatures and to reduce NOx formation, but potentially increasing CO formation. However, using good combustor design and following best operating practices will minimize the formation of CO while reducing the combustion temperature and NOx emissions.

Post-Combustion Control Technologies

A. Oxidation Catalyst

An oxidation catalyst is typically a precious metal catalyst bed. The catalyst enhances oxidation of CO to CO_2 without the addition of any reactant. Oxidation catalyst is a well-demonstrated technology for large combustion turbines.

B. EMx^{TM} (formerly SCONOx)

The EMx^{TM} system can reduce both NOx and CO from gas turbines. CO emissions are reduced by the oxidation of CO to CO_2 in the catalyst.

Step 2: Eliminate technically infeasible options.

Combustion Control Technologies

Good combustor design and best operating practices are technically feasible options for controlling CO emissions from combined- and simple-cycle turbines.

Post-Combustion Control Technologies

A. Oxidation Catalyst

The use of oxidation catalyst is considered a feasible technology for reducing CO emissions to ~~2~~ 1.5 ppmvd for combined-cycle turbines and to ~~4~~ 2.0 ppmvd for simple-cycle turbines, when firing natural gas.

B. EMx^{TM} (formerly SCONOx)

The use of EMx^{TM} system is considered a feasible technology for reducing CO emissions from AEC. In the Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Palmdale Hybrid Power Plant, PSD Permit No. SE 09-01, dated August 2011, the EPA noted it is unclear what level of control would be achieved by the technology on a long-term basis with a short (1-hr) averaging period. The manufacturer claims that emission rates below 1 ppm are achievable, but there is a lack of information that demonstrates this on large combustion turbines. EMx^{TM} is carried forward in this BACT analysis as a potential CO control technology. However, substantial evidence demonstrates that EMx^{TM} is not yet demonstrated as technically feasible for the AEC project.

Step 3: Rank remaining control technologies.

Combined-Cycle Turbines
A summary of recent BACT limits for similar combined-cycle, natural gas-fired combustion turbines is provided in the table below.

Table 76 - Summary of Recent CO BACT Limits for Similar Combined-Cycle, Natural Gas-Fired Combustion Turbines

Facility	Permit Issuance	CO Limit @ 15% O_2, without duct firing	CO Limit @ 15% O_2, with duct firing
LA City, DWP Scattergood Generating Station, California	2013	2.0 ppm (1-hr)	
Pasadena City, Dept. of Water & Power, California	2013	2.0 ppm (1-hr)	
Langley Gulch Power Plant, Idaho	2013	2.0 ppm (3-hr rolling)	
El Segundo Power, LLC, California	2011	2.0 ppm (1-hr)	2.0 ppm (1-hr)
Lower Colorado River Authority, Texas	2011	4.0 ppm (3-hr)	
~~Palmdale Hybrid Power Project, California~~ *Note: Project was revised and renamed Palmdale Energy Project. FSA released on 9/12/16.*	~~2011~~ Not issued yet	~~2.0 ppm (1-hr) (3-yr demonstration period)~~ ~~1.5 ppm (1-hr) (Post-demonstration)~~ 2.0 ppm (1-hr)	~~2.0 ppm (1-hr) (3-yr demonstration & post-demonstration)~~ 2.0 ppm (1-hr)
Avenal Energy Project, California	2011	2.0 ppm (1-hr) (3-yr demonstration period) 1.5 ppm (1-hr) (Post-demonstration)	2.0 ppm (1-hr) (3-yr demonstration & post-demonstration)
Warren County Power Station, Virginia	2010	1.5 ppm (1-hr)	2.4 ppm (1-hr)
Live Oaks Power Plant, Georgia	2010	2.0 ppm (3-hr)	3.2 ppm (3-hr)
Colousa Generating Station, California	2010	3.0 ppm (3-hr)	
Victorville II Hybrid Power Project, California	2010	2.0 ppm (1-hr)	3.0 ppm (1-hr)
Pondera Capital Management, King Power Station, Texas	2010	2.0 ppm (3-hr)	
Russell City Energy Center, California	2010	2.0 ppm (1-hr)	2.0 ppm (1-hr)
Madison Bell Energy Center, Texas	2009	17.5 ppm (1-hr rolling)	
Chouteau Power Plant, Oklahoma	2009	8.0 ppm (1-hr)	
Lamar Power Partners, Texas	2009	15 ppm (24-hr rolling)	
Patillo Branch Power Company, Texas	2009	2.0 ppm (3-hr rolling)	

Facility	Permit Issuance	CO Limit @ 15% O_2, without duct firing	CO Limit @ 15% O_2, with duct firing
FMPA Cane Island Power Park, Florida	2008	8.0 ppm (24-hr)	
Kleen Energy Systems, Connecticut	2008	0.9 ppm (1-hr)	1.8 ppm (1-hr)
Carlsbad Energy Center – NRG, California	2007	2.0 ppm (1-hr)	
Elk Hills Power, California	2006	4.0 ppm (1-hr)	
Inland Empire Energy Center, California	2005	3.0 ppm (1-hr)	
Bicent (California) Malburg (formerly Vernon City, Light and Power Dept.), California	2003	2.0 ppm (3-hr)	2.0 ppm (3-hr)
Burbank City, Burbank Water & Power, SCPPA (Magnolia Power Plant), California	2003	2.0 ppm (1-hr)	2.0 ppm (1-hr)
LA City, DWP Haynes Generating Station, California	2002	4.0 ppm (1-hr)	4.0 ppm (1-hr)

As the above table demonstrates, most projects have permitted CO emission rates that are the same as or higher than the CO emission rate proposed for the combined-cycle turbines. Four projects, however, have CO emission rates that are lower, as discussed below.

- Kleen Energy Systems, Connecticut
  This facility currently has the lowest permit limits for CO. The permit includes CO limits of 0.9 ppm and 1.8 ppm, on a 1-hr averaging basis for operating without and with duct burner, respectively. The initial source tests were performed in June 2011. Based on a November 2011 letter from the Connecticut Department of Energy & Environmental Protection, the facility was able to successfully demonstrate compliance with the CO emission limits of 0.9 and 1.7 ppmvd for unfired and fired operation, respectively.

  It should be emphasized that the Kleen Energy Systems permit provides an exemption from these limits during periods of "shifts between loads," as well as operation below 60% load. Further, the permit does not specify limits for those periods of shifts between loads, which realistically can comprise a substantial percentage of normal operations. In contrast, the SCAQMD does require BACT during periods of shifts between loads and operation at below 60% load. As AEC turbines are equipped with fast start and ramp-up/ramp-down capabilities, load changes are expected to be a regular occurrence. As the minimum turndown for the turbines is 44% load, operation at below 60% load is expected to be a regular occurrence. The Kleen Energy System limits do not meet the definition of BACT as implemented by the SCAQMD for a facility with these operating characteristics.

The permit limits for Kleen Energy are not achieved in practice for facilities where BACT must be met during shifts between loads and at below 60% load. Condition D29.2 requires the initial source testing for combined-cycle turbines to be performed at 45, 75, and 100 percent of maximum load, and for the simple-cycle turbines at 50, 75, and 100 percent of maximum load, because emission rates may vary with load.

- Warren County Power Station, Virginia
  The final PSD permit, dated 12/17/10, includes CO emission limits of 1.5 ppm and 2.4 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively. The 1.5 ppm without duct burner is lower than the SCAQMD BACT/LAER limit of 2.0 ppm, but the 2.4 ppm with duct burner is higher than the SCAQMD BACT/LAER limit of 2.0 ppm. Based on publicly available information, commercial operation started in December 2014.

  ~~The SCAQMD Science & Technology Advancement Office will be requested to provide a BACT determination for the CO emissions levels emitted while operating without duct burner achieved by this facility's combined-cycle turbines. Achieved-in-practice LAER is based on a minimum of 183 operating days (6 months). The review will require additional data, including CEMS data and the percentage of normal operating hours without duct burning.~~

  Update: Following the issuance of the AEC PDOC, the SCAQMD contacted the Virginia Department of Environmental Quality (DEQ) regarding Warren County Power Station. The most recent amended PSD permit, dated 10/24/13, had not revised the CO limits for operating without and with duct burner. The engineering evaluation indicated the limits had been proposed by the applicant. For CO, the limits remain 1.5 ppmv without duct burner firing and 2.4 ppmv with duct burner firing.

  The only source test on the three turbines were performed in December 2014. The SCAQMD Source Test Engineering Dept. was requested to provide a formal evaluation of the source test protocol (88 pages) and source test report for Turbine 1A (963 pages) for the source test performed on 12/5 – 12/7/2014. The evaluation was to determine whether the data quality met the standards of the SCAQMD.

  The following comments and conclusions are from the SCAQMD Source Test Engineering evaluation.

  - Some of the reported gaseous emissions fell short of established analytical standards, and the reported emissions have been recalculated upward to default levels for qualitative compliance determination only. This applies to reported CO concentrations. SCAQMD regards the valid reporting range of measurement of a EPA Method 10 analyzer as being 20-95% of the instrument full-scale-range (FSR). Gas measurements (as measured at the stack) falling below this lower limit are adjusted upward to the 20% FSR value for gas concentration Rule/Permit Compliance limit determination only, and adjusted CO values cannot be used quantitatively for mass emission or emission factor calculations because they are probably overstated.

- The adjusted CO values indicate the turbines without duct burner operation meet the 1.5 ppm CO @ 15% limit.

As indicated in the PDOC, achieved-in-practice LAER is based on a minimum of 183 cumulative operating days (6 months). Warren County Generating Station started commercial operation in December 2014. The Virginia DEQ has confirmed that each turbine has operated a minimum of 6 months without the duct burner since December 2014. The SCAQMD has obtained and reviewed validation data, including CO CEMS data for CO for the two years of operation which includes operation without the duct burner and with the duct burner, for the three turbines. The SCAQMD has made a BACT determination that CO BACT for combined-cycle turbines is 1.5 ppmvd at 15% O_2.

Upon SCAQMD's request, AES is in the process of securing a written performance guarantee from the equipment vendor to ensure the proposed simple-cycle turbines with oxidation catalyst will comply with the new BACT standard of 1.5 ppmvd CO at 15% O_2 without duct burner.

- Avenal Energy Project, California
  The final PSD permit includes CO emission limits of 1.5 ppm and 2.0 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively, after a 3-year demonstration period during which the CO emissions limit is 2.0 ppm for operating without and with duct burner. The CEC website indicates the license was withdrawn by Applicant on 9/1/15.

- Palmdale Energy Project (formerly Palmdale Hybrid Power Project), California
  The final PSD permit specifies CO emission limits of 1.5 ppm and 2.0 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively, after a 3-year demonstration period during which the CO emissions limit is 2.0 ppm for operating without and with duct burner. This facility was not constructed.

The CEC website indicates a Petition to Amend was filed on 7/27/15, and the Amendment Preliminary Staff Assessment (PSA) was released on 3/23/16 for the revised project, now renamed the Palmdale Energy Project. Pg. 4.1-26 of the PSA indicates CO emission concentrations would be limited to 2.0 ppmvd, which is ~~the same as proposed~~ higher than the 1.5 ppmvd required for the AEC combined-cycle turbines for the FDOC. The Final Staff Assessment (FSA) for the project was released on 9/12/16. The CO limit remains 2.0 ppmvd.

The available control technologies are ranked according to control effectiveness in the table below. The controlled emission rates are from Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Palmdale Hybrid Power Plant. Based on the lack of information for similar units, EMx™ is conservatively being compared as equivalent to oxidation catalyst.

Table 77 - CO Control Technologies for Combined-Cycle Turbines Ranked by Control Effectiveness

CO Control Technology	Controlled Emission Rate (ppmvd @ 15% O_2, 1-hr average without duct firing)	Controlled Emission Rate (ppmvd @ 15% O_2, 1-hr average with duct firing)
Good combustion practices	8.0 ppm	8.0 ppm
Oxidation catalyst and good combustion practices	0.9 - 2 ppm	2.0 - 2.4 ppm
EMx™ and good combustion practices	0.9 - 2 ppm	2.0 – 2.4 ppm

Simple-Cycle Turbines
A summary of recent BACT limits for similar simple-cycle, natural gas-fired combustion turbines is provided in the table below.

Table 78 - Summary of Recent CO BACT Limits for Similar Simple-Cycle, Natural Gas-Fired Combustion Turbines

Facility	Permit Issuance	CO Limit @ 15% O_2
Marsh Landing Generating Station		2 ppm (1-hr)
Mariposa Energy		2 ppm (3-hr)
LA City, DWP Scattergood Generating Station, California	2013	4 ppm (1-hr)
CPV Sentinel, California	2012 & 2013	4 ppm (1-hr)
Pio Pico Energy Center, California	2012	4 ppm (1-hr)
Walnut Creek Energy Park, California	2011	4 ppm (1-hr)
TID Almond 2 Power Plant, California	2010	4 ppm (3-hr)

Facility	Permit Issuance	CO Limit @ 15% O_2
Canyon Power Plant, California	2010	4 ppm (1-hr)
Starwood Power – Midway, California	2008	6 ppm (none)
Panoche Energy, California	2007	6 ppm (3-hr rolling)

For the PDOC, ~~As~~ the above table demonstrate~~s~~d that most projects have CO emission rates that are the same as or higher than the CO emission rate of 4 ppmvd initially proposed for the AEC. For the FDOC, the addition of Marsh Landing and Mariposa Energy demonstrates BACT will be reduced from 4 ppmvd to 2 ppmvd, both at 15% O_2.

Step 4: Evaluate most effective controls.

Even assuming that EMx™ is equivalent to oxidation catalyst for controlling CO emission, it was determined to be not as effective as SCR for controlling NOx emissions. As EMx™ would not ensure that the BACT limit of 2.0 ppm NOx for combined-cycle turbines and 2.5 ppm NOx for simple-cycle turbines will be achieved, it is eliminated in this step due to environmental impacts.

Combined-Cycle Turbines
Based on the updated information presented in this BACT analysis, CO emission rates of ~~2.0~~ 1.5 ppm (1-hour) are the lowest CO emission rates achieved in practice at similar sources.

Simple-Cycle Turbines
Based on the updated information presented in this BACT analysis, CO emission rates of ~~4.0~~ 2.0 ppm (1-hour) are the lowest CO emission rates achieved in practice at similar sources.

Step 5: Select the BACT.

Combined-Cycle Turbines
Based on a review of the available control technologies for CO emissions from natural gas-fired combined-cycle turbines, the conclusion is that BACT using good combustion practice and oxidation catalyst to control CO emissions to ~~2.0~~ 1.5 ppm (1-hour average) during normal operation. This is ~~the same as~~ lower than the BACT initially proposed by AES. AES will meet the 1.5 ppm.

Simple-Cycle Turbines

Based on a review of the available control technologies for CO emissions from natural gas-fired simple-cycle turbines, the conclusion is that BACT using good combustion practice and oxidation catalyst to control CO emissions to ~~4.0~~ 2.0 ppm (1-hour average) during normal operation. This is ~~the same as~~ lower than the BACT initially proposed by AES. AES will meet the 2.0 ppm.

D. ***Top-Down BACT Analysis for Auxiliary Boiler for Nitrogen Oxide (NOx) Emissions***

Step 1: Identify all available control technologies.
Available combustion and post-combustion control technologies include good combustion practice, staged air/fuel combustion, low NOx burner, flue gas recirculation (FGR), and SCR.

The FGR system is not as common as some of the other control technologies. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products that act as inerts during combustion of the fuel and air mixture which reduces combustion temperatures, thereby suppressing the thermal NOx mechanism. In addition, FGR reduces NOx formation by lowering the oxygen concentration in the primary flame zone.

Step 2: Eliminate technically infeasible options.
The control technologies identified above are considered technically feasible for natural-gas fired boilers.

Step 3: Rank remaining control technologies.

A summary of recent BACT limits for similar natural gas-fired auxiliary boilers is provided in the table below.

Table 79 - Summary of Recent NOx BACT Limits for Similar Auxiliary Boilers

Facility	Permit Issuance	NOx Limit @ 3% O_2
~~El Segundo Power Redevelopment Project, California~~ Project cancelled	~~Pending~~	~~5 ppm NOx (1-hr)~~
Gilroy Cogeneration Project, California (Add SCR to meet new Bay Area AQMD NOx Limit)	2013	5 ppm NOx (1-hr)
Carroll County Energy, Ohio	2013	0.02 lb/MMBtu
Oregon Clean Energy, Oregon	2013	0.02 lb/MMBtu
Green Energy Partners/Stonewall, Virginia	2013	0.011 lb/MMBtu (9 ppm)
~~Palmdale Hybrid Power, California~~	~~2011~~	9 ppmvd (3-hr)

Project was revised and renamed Palmdale Energy Project. FSA released on 9/12/16.	Not issued yet	9 ppmvd (1-hr)

The control technologies are ranked below in order from least effective to most effective.

Good Combustion Practice, Conventional Burner
Staged Air/Fuel
FGR Alone
Low-NOx Burner with Good Combustion Practice
Low-NOx Burner with FGR
Low-NOx Burner with SCR

For all non-RECLAIM facilities, *SCAQMD Rule 1146—Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters* requires natural gas-fired boilers with a rated heat input greater than or equal to 75 MMBtu/hr to meet 5 ppm at 3% O_2 or 0.0062 lbs/10^6 Btu on or before 1/1/13. An SCR is required to meet the 5 ppm limit.

Step 4: Evaluate the most effective controls.
Based on the information presented in this BACT analysis, NOx emission rates of 5.0 ppm (1-hour) are the lowest NOx emission rates achieved in practice at similar sources.

Step 5: Select the BACT.
Based on a review of the available control technologies for NOx emissions from natural gas-fired auxiliary boilers, the conclusion is that BACT is the control of NOx emissions to 5.0 ppmvd (1-hour average) during normal operation. AES proposes control with good combustion design and practice, low NOx burner, flue gas recirculation and SCR to achieve emission rates of 5.0 ppm (1-hour) during normal operation. Without the SCR, the NOx emissions would be 10.0 ppmvd.

E. Top-Down BACT Analysis for Auxiliary Boiler for Particulate Matter (PM_{10}) Emissions

Step 1: Identify all available control technologies.

The combustion control and post-combustion control technologies available to control PM_{10} from an auxiliary boiler are the same as those described above for the combustion turbines.

Step 2: Eliminate technically infeasible options.

The technically infeasible and feasible options are the same as those described above for the combustion turbines.

Step 3: Rank remaining control technologies.

The commercially available control measures that are identified in the most stringent BACT determinations for auxiliary boilers are use of pipeline quality natural gas with low sulfur content and good combustion practice. No add-on control devices are technically feasible to control PM_{10} emissions from natural-gas-fired boilers.

Step 4: Evaluate most effective controls.

Based on the information presented in this BACT analysis, using pipeline quality natural gas with a low sulfur content and good combustion practice to control PM_{10} emissions is consistent with BACT at similar sources.

Step 5: Select the BACT.

Based on the above review, the BACT for PM_{10} emissions from the auxiliary boiler is using pipeline-quality natural gas with low sulfur and good combustion practice. This is the same as the BACT proposed by AES.

F. Top-Down BACT Analysis for Auxiliary Boiler for Carbon Monoxide (CO) Emissions

Step 1: Identify all available control technologies.
The available control technologies are good combustion practice and oxidation catalyst.

Step 2: Eliminate technically infeasible options.
The identified control technologies are considered technically feasible for natural-gas fired boilers.

Step 3: Rank remaining control technologies.
A summary of recent BACT limits for similar natural gas-fired auxiliary boilers is provided in the table below.

Table 80 - Summary of Recent CO BACT Limits for Similar Auxiliary Boilers

Facility	Permit Issuance	NOx Limit @ 3% O_2
El Segundo Power Redevelopment Project, California	Pending	50 ppm NOx (1-hr)
Carroll County Energy, Ohio	2013	0.055 lb/MMBtu
Oregon Clean Energy, Oregon	2013	0.037 lb/MMBtu (= 50 ppm)
Green Energy Partners/Stonewall, Virginia	2013	0.037 lb/MMBtu (= 50 ppm)
~~Palmdale Hybrid Power, California~~ *Note: Project was revised and renamed Palmdale Energy Project. FSA released on 9/12/16.*	~~2011~~ Not issued yet	~~50 ppm (3-hr)~~ 50 ppm (1-hr)
AES Huntington Beach (Steam-generating utility boiler)	2004	5 ppm (1-hr), Oxidation Catalyst

The control technologies are ranked below in order from least effective to most effective.

Good Combustion Practice
Oxidation Catalyst

Step 4: Evaluate the most effective controls.

The use of an oxidation catalyst has not been identified as demonstrated technology for auxiliary boilers. Since an auxiliary boiler is used relatively infrequently during the start-up cycles for the combined-cycle turbines, the installation of oxidation catalyst for CO control is not considered cost effective. In *Table 80*, for the AES Huntington Beach facility, the oxidation catalyst was installed on a large steam-generating utility boiler, which operates relatively continuously.

Since 4/10/1998, SCAQMD Minor Source BACT had required all natural gas – fired, watertube type boilers to meet 100 ppm at 3% O_2, and all firetube type boilers to meet 50 ppm at 3% O_2, with good combustion practice. Although the auxiliary boiler is a watertube boiler, a guarantee of 50 ppm has been provided by Cleaver Brooks, 6/10/15.

Step 5: Select the BACT.

Based on a review of the available control technologies for CO emissions from auxiliary boilers, the conclusion is that BACT using good combustion practice to control CO emissions to 50 ppm (1-hour average) during normal operation. This is the same as the BACT proposed by AES.

2. ***Rule 1703(a)(3)(A) Analysis—Certification of Compliance***

Stephen O'Kane, Manager, AES Alamitos, LLC, provided a letter, dated 10/23/15, stating that, as a corporate officer of AES Alamitos, LLC, he certifies 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 with all applicable emissions limitations and standards under the Clean Air Act.

The SCAQMD 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 SCAQMD 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. The facility IDs for AES Alamitos, AES Huntington Beach, and AES Redondo Beach are 115394, 115389, and 115536, respectively. For AES Huntington Beach, the disposition is missing for NOV P28630, but clicking on P28630 opens a new screen that indicates the Follow Up Status is "In Compliance." For AES Redondo Beach, the disposition is missing for NOV P60572, but the P60572 link indicates the Follow Up Status is "In Compliance." The reason the dispositions are missing is that the NOVs are awaiting disposition by a District prosecutor. Prior to issuance of the Permits to Construct, the SCAQMD will confirm that the compliance status of AES has not changed.

3. ***Rule 1703(a)(3)(F) Analysis—Copy of Application to EPA, Federal Land Manager, Forest Service***

Permit applications for the subject project were submitted to the SCAQMD on 10/23/15 and were deemed complete by SCAQMD on 1/14/16, with the last submittal of additional information received on January 7, 2016. On 1/20/16, SCAQMD mailed a copy of the original Application, including the modeling CDs, to the following contacts for the affected agencies:

Andrea Nick, Air Resource Specialist, Forest Service Region 5
Randy Moore, Regional Forester, U.S. Forest Service, Pacific Southwest Region
Gerardo Rios, U.S. EPA, Region IX
Don Shepherd, National Park Service, Air Resources Division
Tonnie Cummings, Air Resources Specialist, National Park Service, Pacific West Region

On 4/1/16, SCAQMD mailed a copy of the revised Application, including the modeling CDs, to the same agencies. 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.

~~Comments have not yet been received from the Forest Service.~~ 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.

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
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 ($\mu g/m^3$)**	**AEC Maximum Predicted Impact ($\mu g/m^3$) (*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

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 SCAQMD monitoring stations. AES has 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 incorporates these updated background concentrations.

B. <u>Rule 1703(a)(3)(C)—Air Quality Impacts Analysis</u>

(1) <u>National and State Ambient Air Quality Standards</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.

(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).

- *<u>Class II Increment Analysis</u>*
  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.

  In the revised Application, revised *Table 5.1-40-- AEC Predicted Impacts Compared to the PSD Air Quality Impact Standards* shows the maximum predicted 1-hour CO, 8-hour CO, 1-hr NO_2, annual NO_2, 24-hour PM_{10}, and annual PM_{10} impacts from operation of the AEC with a comparison to the respective Significant Impact Levels and the Class II PSD Increment Standards. PRDAS staff has reviewed the applicant's analysis**.**

Table 82 – Maximum Modeled Project Impacts Compared to Class II SILs and PSD Increment Standards

Pollutant	Averaging Time	AEC Maximum Predicted Impact (µg/m^3) *(Table 57)*	Significant Impact Level (µg/m^3)	Significant?	PSD Class II Increment Standard (µg/m^3)	Exceeds Class II SIL?
NO_2	1-hr	31.3	7.52	Yes	N/A	Yes, cumulative impact assessment required.
	Annual	0.2	1.0	No	25	No
CO	1-hr	186	2,000	No	N/A	No
	8-hr	44	500	No	N/A	No
PM_{10}	24-hr	1.7	5.0	No	30	No
	Annual	0.2	1.0	No	17	No

The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 to NOx conversion ratios of 0.80 and 0.75, respectively.

As shown in the table above, the maximum predicted impacts for annual NO_2, 1-hr and 8-hr CO, and 24-hr and annual PM_{10} are below 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.

The maximum predicted 1-hour NO_2 impact of 31.3 µg/m^3 exceeds 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. Therefore, 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.

- *Cumulative Impacts of the AEC and Nearby Sources*

  The SCAQMD identified the following two facilities within 10 km of the AEC for inclusion in the cumulative impact assessment. These facilities were selected to be included based on the facility emissions and distance to the project.

  - Los Angeles Department of Water and Power, Haynes Generating Station (SCAQMD ID 800074), located in Long Beach, CA, with 10 emission sources.

- Beta Offshore (SCAQMD ID 166073), located in Huntington Beach, CA, with 13 emission sources.

SCAQMD provided the stack locations, stack parameters, and 1-hour NO_2 emission rates for the emission sources at these two facilities, and requested that the Beta Offshore emissions sources be modeled as rural sources.

In addition, the SCAQMD also requested that emissions from shipping lane activity off the California coast be included in the cumulative impact assessment. SCAQMD provided the relevant locations, source parameters, and 1-hour NO_2 emission rates for the shipping lane activity, and requested that the shipping lane emission sources be modeled as rural sources.

The cumulative impacts of the AEC and competing sources were assessed for all receptors where the AEC impacts alone exceeded the 1-hour NO_2 SIL of 7.52 $\mu g/m^3$. Based on a comparison of these results to the 1-hour NO_2 NAAQS of 188 $\mu g/m^3$, it was determined that there were receptors where the contributions from the AEC combined with those from competing sources and representative background concentrations exceeded the 1-hour NO_2 NAAQS. Therefore, the AERMOD-generated output files were reviewed to assess the contribution of the AEC's emissions at each of the receptors where an exceedance of the 1-hour NO_2 NAAQS was modeled. The files show that the maximum contribution for the AEC to any modeled exceedance was less than the 1-hour NO_2 Class II SIL of 7.52 $\mu g/m^3$. Therefore, the AEC's contribution to each modeled exceedance is less than significant and would not cause or contribute to any modeled exceedance of the 1-hour NO_2 NAAQS.

In AES Response Letter, dated 12/11/15, the applicant provided additional information to clarify *Table 5.1C.11—Competing Source Results* in the original Application. The response included new *Table 19-1—Competing Source Results*. This table presents: (1) the maximum contribution to a modeled exceedance of the NAAQS from each facility modeled as part of the PSD competing source assessment, and (2) the maximum modeled impact from all competing sources combined with the 3-year average, 98th percentile background concentration.

PRDAS staff has reviewed the applicant's analysis and provided the updated background concentration, which is incorporated in the table below. The 1-hour NO_2 impact from the project plus cumulative projects plus background is 251.3 μg/m^3, which exceeds the 1-hour NO_2 NAAQS of 188 μg/m^3. An examination of each facility's contributions to the modeled exceedances shows that Alamitos' maximum contributions to the modeled exceedances was 6.9 μg/m^3, which is less than the 1-hour NO_2 SIL of 7.52 μg/m^3. Therefore, Alamitos' impacts are less than significant and do not cause or contribute to the modeled exceedance.

Table 83 - Competing Sources Results

	1-hour NO_2 Concentrations (μg/m^3)				
Combustion Sources	**2006**	**2007**	**2008**	**2009**	**2011**
AEC (max contribution)	6.54	6.36	6.76	**6.87**	6.75
Haynes Generating Station (max contribution)	48.0	48.0	48.0	48.0	48.0
Beta Offshore (max contribution)	0.36	0.61	0.33	0.37	0.73
Shipping Lanes (max contribution)	101	104	105	102	97.8
All Sources (max impact)	105	108	108	105	99
Background Concentration	146.3				
All Sources with Background Concentration[5]	**251.3**				

The maximum 1-hour NO2 concentrations include an ambient NO_2 to NOx conversion ratio of 0.80.

(3) ***Class I Area Impact Analysis***

A Class I impact analysis was conducted 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, 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. 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 (~~29.86~~ 23.74 tpy), and sulfuric acid (0 tpy) will be approximately ~~568.33~~ 562.21 tpy. Therefore, the maximum Q/D for the project will be approximately ~~10.72~~ 10.60 ton/km-year, where Q is ~~568.33~~ 562.21 tpy and D is 53 km, the distance to the nearest Class I area, San Gabriel Wilderness.

NOx = (2 combined-cycle turbines)(41.93 tons/yr per turbine)(8760 hr/4640 hr) + (4 simple-cycle turbines)(13.13 tons/yr per turbine)(8760 hr/2358 hr) + (0.68 tons/yr per auxiliary boiler) (8760 hr/8760 hr) = ~~354,11~~ 354.11 tpy

PM = (2 combined-cycle turbines)(19.72 tons/yr per turbine)(8760 hr/4640 hr) + (4 simple-cycle turbines)(7.35 tons/yr per turbine)(8760 hr/2358 hr) + (0.68 tons/yr per auxiliary boiler) (8760 hr/8760 hr) = 184.36 tpy

SO_2 = (2 combined-cycle turbines)(~~4.59~~ 3.72 tons/yr per turbine)(8760 hr/4640 hr) + (4 simple-cycle turbines)(~~0.83~~ 0.64 tons/yr per turbine)(8760 hr/2358 hr) + (0.19 tons/yr per auxiliary boiler) (8760 hr/8760 hr) = ~~29.86~~ 23.74 tpy

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.

In the original Application, the results of the visibility and deposition modeling are found in *Appendix 5.1G—Class I Air Quality Related Values Analysis*. The *Dispersion Modeling Protocol for Air Quality Related Values at Class I Areas Near the Alamitos Energy Center*, October 2015, is found in *Appendix 5.1F—Dispersion Modeling Protocols*. AES indicates the results were prepared as a separate document and submitted to the appropriate FLM for review and approval. The protocol was also indicated to have been submitted to the appropriate FLM for review and approval. In the revised Application, the proposed changes resulted in revisions to Appendix 5.1G, but not to Appendix 5.1F.

On 1/20/16, SCAQMD mailed a copy of the original Application, including the modeling CDs, to the National Park Service, Forest Services, and EPA. On 4/1/16, SCAQMD mailed a copy of the revised Application, including the modeling CDs, to the same agencies.

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.

~~Comments have not yet been received from the Forest Service.~~ 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.

- *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. 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.

  A summary of the predicted annual NO_2, 24-hour PM_{10}, and annual PM_{10} impacts and a comparison to the Class I SIL is presented in revised *Table 5.1-41-- AEC Predicted Impacts Compared to the Class I SIL and PSD Class I Increment Standards* in the revised Application.

  A radial receptor ring was placed 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 are below the SIL, therefore comparison with the increment standard is 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. PRDAS staff has reviewed the applicant's analysis**.**

Table 84 – Maximum Modeled Impacts Compared to Class I SILs

Pollutant	Averaging Period	Maximum Predicted Impact at 50 km (μg/m^3)	Significance Impact Level (μg/m^3)	Exceeds Class I SIL?
NO_2	Annual	0.0047	0.1	No
PM_{10}	24-hour	0.056	0.3	No
	Annual	0.0046	0.2	No

The annual NO_2 concentration includes an ambient NO_2 to NOx conversion ratio of 0.75.

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) <u>Growth</u>

The growth component involves a discussion of general commercial, residential, industrial, and other growth associated with AEC. AEC consists of the replacement of existing electrical generating utility boilers with newer more efficient combustion turbines that will be entirely located within the existing AGS facility boundaries. As such, AEC is not anticipated to result in general commercial, residential, industrial, or other growth. The resulting ancillary growth is not expected to result in material impacts to air quality or impairment to visibility, soils, and vegetation. The City of Los Alamitos and the general project area is already heavily developed and is close to the Los Angeles metropolitan area. Because of the existing stock of housing and industrial and commercial services and the fact that AEC will replace existing electrical generation within the western Los Angeles basin, AEC is not expected to require or cause any material offsite growth that could impair soils or vegetation. During AEC construction, it is not anticipated that the work force will cause any increase to preexisting housing and services. The limited work force and outside services required for the AEC's operation once construction is complete also will not materially affect the area. Lastly, by locating AEC on an existing power plant site and due to the urban nature of the project area, the project is not expected to induce growth or to result in impacts to soils and vegetation.

(2) <u>Soil and Vegetation Impacts</u>

The additional impact analysis includes consideration of potential impacts to soils and vegetation associated with AEC.

- *<u>Nitrogen Deposition Impacts</u>*
  Section 5.2 Biological Resources of the Supplemental AFC, submitted to CEC on 10/26/15, includes an analysis of nitrogen deposition impacts. Nitrogen oxide gases convert to nitrate particulates in a form that is suitable for uptake by most plants and could be used to promote plant growth and primary productivity. Coastal salt marshes are the most common natural habitats in the vicinity of the AEC where nitrogen deposition may occur. Various studies that have nitrogen loading in intertidal salt marsh wetlands have found critical loads to range from between 63 and 400 kilograms-nitrogen per hectare per year (kg N ha^{-1} yr^{-1}). AES evaluated the wet and dry nitrogen deposition result from depositional nitrogen emissions from AEC using AERMOD (version

15181). Conservative assumptions regarding nitrogen formation and deposition included: (1) 100 percent conversion of nitrogen oxides (NOx) and ammonia (NH_3) into atmospherically derived nitrogen within the turbine stacks rather than allowing for the conversion to occur over distance and time within the atmosphere, (2) maximum potential emissions for AEC were assumed to occur each year, and (3) all nitrogen emitted was in the form of nitric acid, the most depositionally aggressive species. Based on the above modeling approach, the maximum modeled annual deposition averaged over five years was 3.62 kg N ha^{-1} yr^{-1}, which occurs on the eastern fence line of the AEC site. Revised Section 5.2, submitted to the CEC on 4/12/16, indicates the maximum modeled annual deposition averaged over five years has been revised to 2.32 kg N ha^{-1} yr^{-1}. This annual deposition is less than the critical loads, which range between 63 and 400 kg N ha^{-1} yr^{-1}.

- <u>*Secondary NAAQS*</u>
  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.

  The dispersion modeling to demonstrate compliance with the primary NAAQS shown in *Table 57* also demonstrates that NO_2, SO_2 and PM_{10} will be in compliance with the secondary NAAQS, as shown in the table below. EPA has not promulgated secondary NAAQS for CO.

Table 85 - Model Results – Normal Operation for AEC - Compliance with Secondary NAAQS

Pollutant	Averaging Period	Maximum Predicted Impact (μg/m^3) *(Table 57)*	Background Concentration (μg/m^3)^2	Total Predicted Concentration (μg/m^3)	Federal Secondary NAAQS (μg/m^3)	Exceeds Any Threshold?
NO_2	Annual	0.20	47.6	47.8	100	No
SO_2	3-hour	1.7	58.2	59.9	1,300	No
PM_{10}	24-hour	1.7	59.0	60.7	150	No

(3) <u>*Visibility Impairment--Class II Area Analysis*</u>

The additional impact analysis also evaluates the potential for visibility impairment (e.g., plume blight) associated with AEC. In a letter dated 1/25/13, U.S. EPA Region 9 provided comments for LA City, DWP Scattergood Generating Station, a repowering project with a similar design configuration. The EPA indicated the PSD additional impacts analysis is required to also consider visibility impacts on Class II areas.

The applicant provided a quantitative visibility analysis for Class II areas within 50 km of AEC. The analysis was performed using the VISCREEN plume modeling program pursuant to the procedures outlined in the "*Workbook for Plume Visual Impact Screening and Analysis (Revised)*" (EPA, 1992), the Park Service's IMPROVE network suggested visual range, and AERMOD meteorological data. The VISCREEN Tier I assessment was conducted using criteria for Class I areas, because there are currently no thresholds for visibility impacts on Class II areas.

The applicant conducted a survey of California State Parks and Wilderness areas designated as Class II areas within 50 km of AEC. The four Class II areas, identified by the applicant and approved by the SCAQMD for inclusion in the analysis, were evaluated.

The *Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report – Revised (2010)* guidance document for addressing Class I areas recommends the use of the U.S. Environmental Protection Agency's (EPA) VISCREEN screening model to assess the plume contrast and color contrast (ΔE) when compared to the sky and terrain backgrounds. The VISCREEN screening model can use a tiered approach to determine if the facility's emissions would impact visibility at a nearby Class I area.

The VISCREEN screening model was developed to present a visual effect evaluation of emissions from a source as observed from a given vantage point on either a sky or terrain background. Emissions input into the model are assumed to travel along an infinitely long, straight line toward the specified area of concern. A Tier I assessment utilizes conservative assumptions for both plume characteristics and dispersion conditions to determine if the plume would have an impact on visibility. If a Tier I assessment exceeds the FLAG guidance levels of concern for Class I areas of 2.0 for ΔE and 0.05 (absolute value) for the perceptibility threshold, then a Tier II assessment would be conducted. A Tier II assessment provides a more realistic representation of the possible worst-case meteorology and plume transport for a specific area to be analyzed.

The VISCREEN Tier I modeled results for each Class II area evaluated are summarized in *Table 5.1-42—AEC Tier I VISCREEN Results* in the original Application. The maximum modeled values for color difference and contrast are presented for inside the area analyzed, regardless of the

VISCREEN modeled lines of sight for the observer. In the revised Application, *Table 5.1-42* has been revised to incorporate the increases in SO_2, NOx, and PM_{10} (no H_2SO_4) annualized emissions and to provide more conservative results.

The VISCREEN Tier I assessment for each Class II area did not exceed the criterion for color contrast or plume contrast, as shown in the table below. As the modeled results are below the conservative Class I area criterion for both color difference and contrast, AEC will not adversely affect visibility at these or other nearby Class II areas.

PRDAS staff has reviewed the applicant's analysis**.** The modeling review memo states the evaluation is presented solely for informational purposes as there are no thresholds for visibility impacts on Class II areas.

Table 86 - PSD Class II Tier I VISCREEN Results

Class II Area	Minimum Distance (km)	Maximum Distance (km)	Variable	Sky	Terrain	Criteria[a]
Crystal Cove State Park	30.3	35.5	Color Contrast	1.009	1.893	2.0
			Plume Contrast	0.012	0.016	|0.05|
Water Canyon/ Chino Hills State Park	29.6	42.2	Color Contrast	1.393	1.951	2.0
			Plume Contrast	0.016	0.016	|0.05|
Kenneth Hahn State Park	34.6	37.3	Color Contrast	0.815	1.594	2.0
			Plume Contrast	0.01	0.014	|0.05|

Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases

Rule 1714 was adopted into the SIP on 12/10/12, and became effective on 1/9/13. Upon the effective date, the SCAQMD became the Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permitting authority for sources located within the SCAQMD.

The relevant rule 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 EPA to mean the air pollutant as an aggregate group of six GHGs: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). All other attainment air contaminants, as defined in Rule 1702 subdivision (a), shall be regulated for the purpose of Prevention of Significant Deterioration (PSD) requirements pursuant to Regulation XVII, excluding Rule 1714.

(c) The provisions of 40 CFR Part 52.21 are incorporated by reference, with the excluded subsections of 40 CFR Part 52.21 listed in (c)(1).

(d)(1) An owner or operator must obtain a PSD permit pursuant to this rule before beginning actual construction, as defined in 40 CFR 52.21(b)(11), of a new major stationary source or major modification to an existing major source as defined in 40 CFR 52.21(b)(1) and (b)(2), respectively.

In May 2010, EPA issued the GHG permitting rule officially known as the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (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.

PSD APPLICABILITY ANALYSIS FOR GHGs:

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 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 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.

<u>PSD REQUIREMENTS ANALYSES</u>:

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.

<u>Top-Down BACT Analysis</u>

1. <u>Top-Down BACT Analysis for Combined-Cycle Gas Turbine Power Block and Simple-Cycle Gas Turbine Block for Carbon Dioxide (CO_2) Emissions</u>

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.

Step 1: Identify all available control technologies.

As determined by EPA and the Department of Energy, the available CO_2 control technologies are:

A. Carbon capture and storage (CCS)
B. Lower Emitting Alternative Technology
C. Thermal efficiency

A. Carbon Capture and Storage/Sequestration (CSS)

CCS technology is composed of three main components: (1) CO_2 capture and compression, (2) transport, and (3) storage/sequestration.

CO_2 Capture and Compression. Three capture technologies are primarily being considered for CCS: pre-combustion, oxy-combustion, and post-combustion. Pre-combustion capture refers to a process in which solid fuel such as coal is converted into gaseous hydrogen and CO by applying heat under pressure in the presence of steam and oxygen. The CO is converted to CO_2, using shift reactors, and captured before combusting the hydrogen-based fuel. Pre-combustion capture is applicable primarily to gasification plants. Oxy-combustion technology uses air separators to remove the nitrogen from combustion air so that the combustion products are almost exclusively CO_2, thereby reducing the volume of exhaust gases needed to be treated by the carbon capture system. Oxyfuel combustion still requires the development of oxy-fuel combustors and other components with higher temperature tolerances to withstand the high gas turbine exhaust temperatures. The post-combustion capture technologies include three methods, namely sorbent adsorption, physical adsorption, and chemical absorption. Of these technologies, the post-combustion technology is most applicable to AEC.

CCS systems involve use of adsorption or absorption processes to separate and capture CO_2 from the flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The concentrated CO_2 is then compressed to "supercritical" temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer, depleted coal seam, or ocean site, or the CO_2 would be used in crude oil production for enhanced oil recovery.

The capture of CO_2 from gas streams can be accomplished using either physical or chemical solvents or solid sorbents. Applicability of different processes to particular applications will depend on temperature, pressure, CO_2 concentration, and contaminants in the gas or exhaust stream. Although CO_2 separation processes have been used for years in the oil and gas industries, the CO_2 concentration of these gas streams are significantly higher than the concentration in power plant exhaust. CO_2 separation from power plant exhaust has been demonstrated in large pilot-scale tests as discussed below, but it has not been commercially implemented in full-scale power plant applications.

After separation, the CO_2 must be compressed to supercritical temperature and pressure for suitable pipeline transport and geologic storage properties. Although compressor systems for such applications are proven commercially available technologies, incorporation of CO_2 compression equipment will require the installation of specialized equipment with high operating energy requirements.

CO_2 Transport. The supercritical CO_2 would then be transported to an appropriate location for injection into a suitable storage reservoir. The transport options may include pipeline or truck transport, or in the case of ocean storage, transport by oceangoing vessels.

Because of the extremely high pressures and the unique thermodynamic and dense-phase fluid properties of supercritical CO_2, specialized designs are required for CO_2 pipelines. Control of potential propagation fractures and corrosion also require careful attention to contaminants such as O_2, N_2, CH_4, water, and hydrogen sulfide.

While transport of CO_2 via pipeline is proven technology, doing so in urban areas will present additional concerns. Development of new rights–of-way in congested areas would require significant resources for planning and execution, and public concern about potential for leakage may present additional barriers. Securing a right-of-way easement on public property for the installation and operation of a high-pressure CO_2 pipeline could result in extensive delays due to resolving concerns raised by the public based on the perceived hazards associated with the pipeline. Securing sufficient private property for siting a CO_2 pipeline would be cost prohibitive within an urban area.

The Technical Advisory Committee for the California Carbon Capture and Storage Review Panel stated in the August 2010 report that there are no existing CO_2 pipelines in California. In addition, there are no CO_2 pipeline projects underway in California.

CO_2 Storage. CO_2 storage methods include geologic sequestration, oceanic storage, and mineral carbonation. Oceanic storage has not been demonstrated in practice. Geologic sequestration is the process of injecting captured CO_2 into deep subsurface rock formations for long-term storage, which includes the use of a deep saline aquifer or depleted coal seams, and the use of compressed CO_2 to enhance oil recovery in crude oil production operations.

With geologic sequestration, a suitable geological formation is identified close to the proposed project, and the CO_2 captured from the process is compressed and transported to the sequestration location. CO_2 is injected into that formation at a high pressure and to depths generally greater than 2,625 feet. Below this depth, the pressurized CO_2 remains "supercritical" and behaves like a liquid. Supercritical CO_2 is denser and takes up less space than gaseous CO_2. Once injected, the CO_2 occupies pore spaces in the surrounding rock, like water in a sponge. Saline water that already resides in the pore space would be displaced by the denser CO_2. Over time, the CO_2 can dissolve in residual water, and chemical reactions between the dissolved CO_2 and rock can create solid carbonate minerals, more permanently trapping the CO_2. No pilot studies of CO_2 injection into onshore or offshore geologic formations in the vicinity of the project site have been conducted to date.

B. <u>Lower Emitting Alternative Technology</u>

Commercially available and low or non-GHG emitting power production technology include geothermal, hydroelectric, biomass fueled, solar power, nuclear powered, and wind facilities. The Supplemental AFC presents a review of project alternatives to the AEC. The review considered alternative technologies that could feasibly attain most of the project objectives and reduce or eliminate any significant effects of the project. Alternative generating technologies including conventional boiler and steam turbine, simple-cycle combustion turbines only, wind energy, photovoltaic and solar thermal technologies, Kalina combined-cycle (a mixture of ammonia and water is used in place of pure water in the steam cycle), internal combustion engines and energy storage were considered but rejected because of the inability of these technologies to provide generating capacity for local reliability needs, meet peak energy demands, and provide flexible generation with minimum environmental effects.

The proposed AEC design and operation consists of a 2-by-1 combined-cycle turbine power block and a four simple-cycle turbine power block. The applicant has determined that this configuration is the only alternative that meets all of the project objectives. A primary objective is to provide fast starting and stopping, flexible, controllable generation with the ability to ramp up and down through a wide range of electrical output to allow the integration of renewable energy into the electrical grid to satisfy California's Renewable Portfolio Standard. The lower GHG emitting technologies would fundamentally redefine the project and alter the business purpose. The EPA does not require a BACT analysis to redefine the applicant's project. As a result, no additional lower emitting alternative technologies are feasible to incorporate into the project without changing the business purpose of the project.

C. <u>Thermal Efficiency</u>

Power generation through fossil fuel combustion is a chemical reaction process. Because CO_2 emissions are directly related to the quantity of fuel burned, the less fuel burned per amount of energy produced (greater energy efficiency), the lower the GHG emissions per unit of energy produced. The thermal efficiency is defined as the dimensionless ratio of the useful work performed by the process and the heat input to the process. The heat rate, measured in Btu/kWh, is generally used as a thermal efficiency indicator. The thermal efficiency is at the highest when the reaction is at stoichiometric conditions.

The following factors affect the thermal efficiency of a power plant:

- Thermal dynamic cycle selection, combined-cycle versus simple-cycle
- Turbine design
- Fuel selection

The proposed AEC includes both combined- and simple-cycle turbines. In many applications, combined-cycle turbines are more thermally efficient than simple-cycle turbines. The reason is that a combined-cycle turbine is equipped with a heat recovery steam generator that recovers waste heat from the gas turbine that allows the production of more electricity in the steam turbine generator without additional fuel consumption. As California's renewable energy portfolio continues to grow, a primary objective of the AEC is to support renewable power generation. As the electrical output from renewable resources such as wind and solar plants drops, the AEC must be able to come online quickly. Unlike combined-cycle turbines, simple-cycle turbines can be started up and shut down quickly. With the inclusion of the simple-cycle turbines, AEC is designed to serve both peak and intermediate loads. Operating in either load-following (adjusting power output as demand fluctuates) or partial shutdown mode will become necessary to maintain electrical grid reliability.

AES indicates the operationally flexible turbine class and steam cycle designs selected for the AEC are the most thermally efficient for the project design objectives. For example, the fast start capability of the combined- and simple-cycle turbines minimizes emissions during startup and increases the efficiency of the power plant. Also, the AEC proposes to combust exclusively natural gas, the lowest GHG-emitting fossil fuel available.

Although new power generating system would emit GHG emissions, the high thermal efficiency of new power generating equipment and the system build-out of renewable resources in California would result in a net health reduction of GHG emissions from new and existing fossil resources.

Step 2: Eliminate technically infeasible options.

The second step for the BACT analysis is to eliminate technically infeasible options from the control technologies identified in Step 1. For each option that was identified, a technology evaluation was conducted to assess its technical feasibility. The technology is feasible only when it is available and applicable. A technology that is not commercially available for the scale of the project was considered infeasible. An available technology is considered applicable only if it can be reasonably installed and operated on the proposed project.

A. <u>Carbon Capture and Storage</u>

The technical feasibility of each step of the CCS is discussed below.

CO_2 Capture and Compression. Three fundamental types of carbon capture systems are employed throughout various process and energy industries: sorbent adsorption, physical absorption, and chemical absorption.

- ***Sorbent Adsorption***. Sorbent-based capture technology can be used for post-combustion capture of CO_2. However, the technology has not been demonstrated on combined-cycle gas turbine power plants. Commercial-scale systems currently in operation contain a significantly higher concentration of CO_2 in the exhaust. A sorbent-based carbon capture process is currently judged to be technologically infeasible for a natural gas-fired commercial power plant application.

- **Physical Absorption**. Physical absorption technology is commercially available for CO_2 removal but has not been demonstrated in practice for power generation applications. Commercial-scale systems currently in operation contain a significantly higher concentration of CO_2 in the exhaust. A physical absorption capture process is currently judged to be technologically infeasible for a commercial power plant application.

- **Chemical Absorption.** A chemical solvent CCS approach would be required to capture the approximate 3 to 5 percent CO_2 emitted from the flue gas generated from the natural-gas-fired systems used at the AEC facility. To date, a chemical solvent technology has not been demonstrated for the operating scale proposed.

  The Bellingham Energy Center in Massachusetts was a combined-cycle plant, rated at 320 MW, that operated continuously from 1991 until 2005. This plant captured 330 tons of CO_2 per day, for a capture efficiency of 85 – 95%, from a 40 MW slipstream. The CO_2 was used to supply the local beverage industry. The Fluor Corp Econamine FG Plus system used was a CO_2 recovery process based on a proprietary formulation of mono-ethylene amine (MEA) solvent. The plant operated under difficult gas specifications and contained 14% oxygen and only 3% CO_2. In addition, a significant backpressure or pressure fluctuation in the flue gas could not be tolerated. The Bellingham plant was decommissioned in 2005 as a result of financial difficulties, including rising gas prices and discontinuation of tax credits.

The Sumitomo Chemical plant in Japan has a base load natural gas combined-cycle unit with CCS operating on an 8 MW slip-stream that captures about 150 tons of CO_2 per day for commercial use in the food and beverage industry. A Fluor Econamine FG carbon capture system has been operating since 1994.

The capture technology has not been scaled up and demonstrated on a large commercial power plant application. Therefore, a solvent-based carbon capture process is currently judged to be technologically infeasible for the AEC.

Carbon Transportation. The basic technologies required for CO_2 transportation (i.e., pipeline, tanker truck, ship) are in commercial use today for a number of applications and can be considered commercially available for liquid CO_2.

Carbon Storage. The following discusses the potential use of deep saline aquifers, compressed CO_2 to enhance oil recovery in crude oil production operations, and ocean sequestration as potential options for the storage of captured CO_2.

- ***Enhanced Oil Recovery (EOR).*** Although the CO_2 could be used for EOR applications in the vicinity of AEC, only pilot-scale projects are known in the region, and only estimates are available on the capacity of these miscible oil fields. Therefore, the exact location, time frame, and needed flow rates for those existing or future EORs are unclear because this information is typically treated as being a trade secret. Furthermore, the feasibility of obtaining the necessary permits to build infrastructure and a pipeline to transport CO_2 to these fields through a densely urbanized area is uncertain.

  The potential to sell CO_2 to industrial or oil and gas operations is infeasible for an operation such as AEC, where daily operation depends on grid dispatch needs, particularly to offset reductions from renewable energy sources. Even if a potential EOR opportunity could be identified, such an operation would typically need a steady supply of CO_2. Intermittent CO_2 supply from potentially short duration with uncertain daily operation would be virtually impossible to sell on the market, making the EOR option unviable.

  At this time, the technical feasibility of using enhanced oil recovery for CO_2 storage for the new power generating system cannot be determined. Therefore CCS using enhanced oil recovery cannot be demonstrated to be technically feasible in practice for the new power generating system.

- ***Deep Saline Aquifer.*** At this time, the technical feasibility of using deep saline aquifer injection for CO_2 storage for the new power generating system cannot be determined. Based on mapping by DOE's National Energy Technology Laboratory's NatCarb viewer, the nearest known saline aquifer sites, located in New Mexico, Utah, and Texas, are undergoing early phases of evaluation. Therefore CCS using enhanced oil recovery cannot be demonstrated to be technically feasible in practice for the new power generating system.

- ***Ocean Sequestration.*** The effectiveness of ocean sequestration as a full-scale method for CO_2 capture and storage is unclear given the limited availability of injection pilot tests and the ecological impacts to shallow and deep ocean ecosystems. Ocean sequestration is conducted by injecting supercritical liquid CO_2 from either a stationary or towed pipeline at targeted depth interval, typically below 3,000 feet. Long-term effects on the marine environment, including pH excursions, are uncertain. Ocean storage and its ecological impacts are still in the research phase, and not commercially available.

It should be noted that the beverage carbonation use for the CO_2 from the Bellingham Energy Center and the Sumitomo Chemical plant does not qualify as permanent sequestration.

CSS Feasibility
According to *EPA's New Source Review Workshop Manual* (EPA, 1990): "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

On January 8, 2014, the EPA proposed an NSPS for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines. The action proposed standards for natural gas-fired combustion turbines (NGCC) that are based on modern, efficient natural gas combined-cycle technology as the best system of emission reduction. The action proposed a separate standard of performance for fossil fuel-fired electric utility steam generating units and integrated gasification combined-cycle units that burn coal, petroleum coke and other fossil fuels that is based on partial implementation of carbon capture and storage as the best system of emission reduction. (79 Fed. Reg. 1430)

At that time, the EPA noted that, CCS has not been implemented for NGCC units, and the EPA believes there is insufficient information to make a determination regarding the technical feasibility of implementing CCS at these types of units. The EPA is aware of only one NGCC unit that has implemented CCS on a portion of its exhaust stream [Bellingham Energy Center]. The cyclical operation of the NGCC, combined with the low concentration of CO_2 in the flue gas stream, means that the EPA cannot assume that the technology for the coal-fired units can be easily transferred to NGCC without larger scale demonstration projects on units operating more like a typical NGCC. (79 Fed. Reg. 1436)

On 8/3/2015, EPA released the final NSPS. On 10/23/15, the NSPS was published in the Federal Register and codified in 40 CFR part 60, Subpart TTTT, a new subpart specifically created for Clean Air Act 111(b) standards of performance for greenhouse gases from fossil fuel-fired electric generating units (EGUs). The effective date is 10/23/15. (80 Fed. Reg. 64510)

After evaluation of comments received, the EPA again rejected partial CCS as the Best System of Emission Reduction (BSER) because EPA concluded that there is not sufficient information to determine whether implementing CCS for combustion turbines is technically feasible. EPA conceded that while commenters made strong arguments that the technical issues raised at proposal could in many instances be overcome, EPA concluded that there is not sufficient information at this time to determine that CCS is adequately demonstrated for all base load natural-gas fired combustion turbines. While commenters make a strong case that the existing and planned NGCC-with-CCS projects demonstrate the feasibility of CCS for NGCC units operating at steady state conditions, many NGCC units do not operate this way. For example, the Bellingham, MA and Sumitomo NGCC units cited by the commenters operated at steady load conditions with a limited number of starts and stops, similar to the operation of coal-fired boilers. The base load natural gas-fired combustion turbine subcategory includes not only true base load units, but also some intermediate units that cycle more frequently, including fast-start NGCC units that sell more than 50 percent of their potential output to the grid. Fast-start NGCC units [and simple-cycle turbines] are designed to be able to start and stop multiple times in a single day and can ramp to full load in less than an hour. EPA is not aware of any pilot-scale CCS projects that have demonstrated how fast and frequent starts, stops, and cycling will impact the efficiency and reliability of CCS. Furthermore, for those periods in which a NGCC unit is operating infrequently, the CCS system might not have sufficient time to start up. During these periods, no CO_2 control would occur. Thus, if the NGCC unit is intended to operate for relatively short intervals for at least a portion of the year, the owner or operator could have to oversize the CCS to increase control during periods of steady state operation to make up for those periods when no control is achieved by the CCS, leading to increased costs and energy penalties. EPA indicated that while it is optimistic that these hurdles are surmountable, it is simply premature at this point to make a finding that CCS is technically feasible for the universe of combustion turbines that are covered by this rule. EPA noted that the Department of Energy has not yet funded a CCS demonstration project for a NGCC unit, and no NGCC-with-CCS demonstration projects are currently operational or being constructed in the U.S. (80 Fed. Reg. 64614)

In summary, post-combustion carbon capture technologies are still in the developmental stage or installed on small commercial scale projects, a conclusion supported by EPA's studies. These technologies are not commercially available for the project size of a full-scale commercial power plant. Consequently, CSS is not yet demonstrated as technically feasible for the AEC project.

B. <u>Lower Emitting Technology</u>

As discussed above, commercially available lower emitting technology was determined to be infeasible for the site as it would fundamentally alter the business purpose of the source.

C. <u>Thermal Efficiency</u>

California has established a Greenhouse Gases Emission Performance Standard for California power plants to quantify feasible energy efficiency levels. Senate Bill (SB) 1368 limits long-term investments in baseload generation by the state's publicly owned utilities to power plants that meet an emissions performance standard jointly established by the CEC and the California Public Utilities Commission (CPUC). The resulting CEC regulations, as codified in California Code of Regulations (CCR), Title 20, Chapter 11, Article 1, establish a standard for baseload generation (defined as with a capacity factor of at least 60 percent) of 1100 pounds CO_2 per megawatt-hour-net. This standard is further discussed below under the rule analysis. Because local publicly owned electric facilities are required to make the determination regarding compliance with the EPS prior into entering into a covered procurement, SCAQMD need not make a determination.

EPA promulgated *40 CFR 60 Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*, with an effective date of 10/23/15. These standards are applicable to any stationary combustion turbine that commences construction after 1/8/14 or commences modification or reconstruction after 6/18/14. The two standards applicable to natural-gas fired turbines are summarized below.

- 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 is subject to a CO_2 emission standard of 450 kg of CO_2 per MWh of gross energy output (1000 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 are subject to a CO_2 emission standard of 50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2/MMBtu).

Thermal efficiency is a technically feasible alternative for reducing GHG emissions from a fossil-fuel fired power plant. In conclusion, thermal efficiency standards are achieved in practice and eligible for consideration under Step 3 of the BACT analysis.

Step 3: Rank remaining control technologies.

Because carbon capture and sequestration (CCS) and lower emitting alternative technology were determined to be infeasible for the AEC project, these options are not carried forward in the BACT analysis to Step 3. The remaining feasible technology is:

Thermal efficiency

Thermal Efficiency

Thermal efficiency is technically feasible as a control technology for BACT consideration.

Step 4: Evaluate the most effective controls.

Step 4 of the BACT analysis is to evaluate the remaining technically and economically feasible controls and consider whether energy, environmental, and/or economic impacts associated with the remaining control technologies would justify selection of a less-effective control technology. The top-down approach specifies that the evaluation begin with the most-effective technology.

The remaining feasible technology is:

Thermal efficiency

Thermal Efficiency
As CCS and lower emitting alternative technologies are not technically feasible, thermal efficiency remains the most effective, technically feasible, and economically feasible GHG control technology for the AEC.

California's Renewable Portfolio Standard (RPS) requirement was increased from 20 percent by 2010 to 33 percent by 2020, with the adoption of Senate Bill 2 on April 12, 2011. Senate Bill 350 will increase the RPS requirement to 50 percent by 2030. To meet the new RPS requirements, the amount of natural gas generation will have to be significantly increased. The AEC will aid in the effort to meet California's RPS standard because a significant attribute of the AEC is that the combined- and simple-cycle facility can operate similarly to a peaking plant but at higher thermal efficiency. Based on design, the combined-cycle turbines are capable of achieving full load operation within 15 minutes of initiating a warm or hot startup. The simple-cycle turbines can achieve full load operation within 10 minutes of initiating a startup. This allows an increased use of wind power and other renewable energy sources, with backup power available from the AEC.

A database review of BACT determinations identified six recently-permitted facilities with natural gas-fired combustion turbines for which a GHG BACT analysis was performed. Each of the projects proposed the use of combined-cycle configurations to produce commercial power, and the BACT analyses for each of the projects concluded that thermal efficiency was the only feasible combustion control technology.

- EPA issued the PSD Permit for the Palmdale Hybrid Power Project in October 2011. This project consists of a hybrid of natural gas fired combined-cycle generating system (two GE 7FA combustion gas turbines and one shared steam turbine) integrated with solar thermal generating system. Based on EPA's analysis CCS was eliminated as a control option because it was deemed economically infeasible.

- EPA issued the PSD Permit for the Lower Colorado River Authority (LCRA) Project in November 2011. This project consists of a natural gas fired combined-cycle generating system with two GE 7FA combustion gas turbines and a shared steam turbine. Based on the review of the available control technologies for GHG emissions, EPA concluded that BACT for LCRA was the use of new thermally efficient combustion turbines with applicable GHG emission limit.

- The Bay Area Air Quality Management District issued the PSD permit for the Calpine Russell City Energy Center in 2010. According to a presentation by Calpine, thermal efficiency was the only feasible combustion control technology considered as CCS was determined to be not commercially available. Thermal efficiency was found to be the top level of control feasible for a combined-cycle power plant, and hence was the technology selected at GHG BACT for Russell City.

- EPA issued the PSD Permit for the Pio Pico Energy Center Project in November 2012. The project consists of three simple-cycle GE LMS100 generators. EPA concluded that BACT was the use of new thermally efficient combustion gas turbines with applicable GHG emission limits.

- SCAQMD issued the PSD Permit for the LA City, DWP Scattergood Generating Station in 2013. The project consisted of one GE 7FA combined-cycle gas turbine and two simple-cycle GE LMS100 generators. SCAQMD concluded that BACT was the use of new thermally efficient combustion gas turbines with applicable GHG emission limits.

- SCAQMD issued the PSD Permit for the Pasadena City, Dept. of Water & Power in 2013. The project consisted of one LM6000 combined-cycle gas turbine. SCAQMD concluded that BACT was the use of new thermally efficient combustion gas turbines with applicable GHG emission limits.

As demonstrated by the EPA and SCAQMD permits, thermal efficiency is the most cost effective control technology for GHG emissions from power plants. The proposed General Electric Model 7FA.05 combined-cycle turbines and the General Electric Model LMS-100 PB simple-cycle turbines are acceptable for GHG PSD permits under the BACT thermal efficiency requirement.

Step 5: Select the BACT.

Based on the above analysis, 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.

<u>Combined-Cycle Turbines</u>
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.

<u>Simple-Cycle Turbines</u>

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.

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.

Step 1: Identify all available control technologies.
The following control technologies are available.

A. Circuit Breakers Not Containing GHGs
Dielectric oil and compressed air circuit breakers do not contain any GHG pollutants. No other alternative materials to SF_6 are currently available.

B. Totally Enclosed SF_6 Circuit Breakers with Leak Detection Systems
These breakers are designed as a totally enclosed hermetically sealed pressure system with a specified maximum leak rate and an alarm warning when a certain percentage of the SF_6 has escaped. The best equipment can be guaranteed to leak at a rate of no more than 0.5 weight percent per year. The use of an alarm identifies potential leak problems to allow the amount leaked to be minimized.

No add-on control options for GHG emissions are currently available due to the nature of the electrical system containing the SF_6.

Step 2: Eliminate technically infeasible options.

Both control options are technically feasible.

Step 3: Rank remaining control technologies.

Dielectric oil or compressed air circuit breakers would have a CO_2e emission rate of 0 tpy.

Enclosed-pressure SF_6 circuit breakers with 0.5% (by weight) annual leakage rate and leak detection systems will have a CO_2e emission rate of 74.55 tons per calendar year, as calculated above.

Step 4: Evaluate the most effective controls.

Despite decades of research to develop a desirable alternative to SF_6, none has been developed. SF_6 remains the preferred gas for electrical insulation and for arc quenching and current interruption equipment used in the transmission and distribution of electricity. The following properties make SF_6-based circuit breakers superior to the alternatives: (1) high thermal conductivity, (2) high dielectric strength, and (3) fast thermal and dielectric recovery. In addition, the National Institute of Standards and Technology (NIST) reported in 1977 that equipment insulated with SF_6 uses significantly less land and has relatively low radio and audible noise emissions, relative to dielectric oil and compressed air circuit breakers. Therefore, dielectric oil and compressed air circuit breakers are eliminated as the top-ranked control option because of adverse environmental and energy impacts.

Step 5: Select the BACT.

Based on the above review, 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 above BACT determination is 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 operator is required to 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. Section 98.303 sets forth equation DD-1 and is reproduced below.

§98.303 CALCULATING GHG EMISSIONS.

(a) Calculate the annual SF_6 and PFC emissions using the mass-balance approach in Equation DD-1 of this section:

$$\text{User Emissions} = (\text{Decrease in } SF_6 \text{ Inventory}) + (\text{Acquisitions of } SF_6) - (\text{Disbursements of } SF_6) - (\text{Net Increase in Total Nameplate Capacity of Equipment Operated}) \quad \text{(Eq. DD-1)}$$

where:

Decrease in SF_6 Inventory = (pounds of SF_6 stored in containers, but not in energized equipment, at the beginning of the year) − (pounds of SF_6 stored in containers, but not in energized equipment, at the end of the year).

Acquisitions of SF_6 = (pounds of SF_6 purchased from chemical producers or distributors in bulk) + (pounds of SF_6 purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear) + (pounds of SF_6 returned to facility after off-site recycling).

Disbursements of SF_6 = (pounds of SF_6 in bulk and contained in equipment that is sold to other entities) + (pounds of SF_6 returned to suppliers) + (pounds of SF_6 sent off site for recycling) + (pounds of SF_6 sent off-site for destruction).

Net Increase in Total Nameplate Capacity of Equipment Operated = (The Nameplate Capacity of new equipment in pounds, including hermetically sealed-pressure switchgear) − (Nameplate Capacity of retiring equipment in pounds, including hermetically sealed-pressure switchgear). (Note that Nameplate Capacity refers to the full and proper charge of equipment rather than to the actual charge, which may reflect leakage).

(b) Use Equation DD-1 of this section to estimate emissions of PFCs from power transformers, substituting the relevant PFC(s) for SF_6 in the equation.

Further, EPA stated in a response to public comment that the BACT requirements to equip the circuit breakers with a leak detection system and appropriately calibrate such system are not redundant to CARB's Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear (California Code of Regulations, Subchapter 10, Article 4, Subarticle 3.1, §95350-§95359).

Accordingly, facility condition F52.2 is included to enforce the BACT requirements for circuit breakers, using the same language as in the Pio Pico PSD permit. Annual CO_2e emissions from circuit breakers will be limited to 74.55 tons per calendar year. The maximum CO_2e from the combined-cycle turbine power block is 17.44 tpy, and from the simple-cycle turbine power block is 57.11 tpy.

3. Top-Down BACT Analysis for Auxiliary Boiler for Carbon Dioxide (CO_2) Emissions

Natural gas combustion in the auxiliary boiler will produce GHG emissions. The GHG will primarily be CO_2.

Step 1: Identify all available control technologies.

The auxiliary boiler operates at maximum load only when assisting the startup of a combined-cycle turbine and operates at minimum turndown firing rate the remainder of the time.

There are no add-on controls for GHG emissions that are technically feasible for boilers. Available control technologies are as follows:

1. **Low Carbon Fuel**
   The carbon content of the fuel, relative to its Btu value, has a significant impact on GHG emissions. The following emission factors for CO_2 are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised April 4, 2014.

   Natural Gas = 53.06 kg CO_2/MMBtu = 117 lb CO_2/MMBtu
   Diesel Fuel Oil No. 2 = 73.96 kg CO_2/MMBtu = 163 lb CO_2/MMBtu

   AES proposes to use exclusively natural gas, which is the lowest GHG emitting fuel available.

2. **Good Combustion Practices**
   Good combustion practices can reduce fuel usage and GHG emissions.

Step 2: Eliminate technically infeasible options.
Both control options are technically feasible.

Step 3: Rank remaining control technologies.
The exclusive use of natural gas is more effective than good combustion practices.

Step 4: Evaluate the most effective controls.
The exclusive use of natural gas is the most effective control.

Step 5: Select the BACT.
Both the exclusive use of natural gas and good combustion practices are BACT. This is the same as the BACT proposed by AES.

Regulation XX—RECLAIM

- ***Rule 2002—Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx)***
  (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.

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.

- Auxiliary Boiler
  From Rule 2002, Table 1:

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor*	2000 (Tier I) Ending Emission Factor
Boilers, Heaters, Steam Gens****	Natural Gas	Mmcf	38.460	38.460

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Accordingly, condition A99.5 specifies the interim RECLAIM emission factor is 38.46 lbs NOx/mmcf during the interim period prior to CEMS certification.

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.

- ***Rule 2005—New Source Review for RECLAIM***
  This rule sets forth pre-construction review requirements for modifications to RECLAIM facilities.

  - ***(c)(1)(A)--BACT***
    See the *Rule 1703(a)(2)—Top-Down BACT* analysis, above.

  - ***(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 NO2 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.)

    The revised Application indicates that although each combustion emission unit was modeled, the results in *Table 5.1-39-- Rule 2005 Air Quality Thresholds and Standards Applicable to the AEC (per emission unit)* are only for the emission unit causing the highest modeled concentrations, which is one combined-cycle turbine.

    As shown in the table below, the peak 1-hour and annual NO_2 impacts plus the highest background values do not exceed the most stringent air quality standards, as demonstrated in the above table.

    PRDAS staff has reviewed the applicant’s analysis and provided a corrected maximum predicted impact for the federal 1-hour standard and updated background concentrations, which are incorporated in the table below.

Table 88 – Rule 2005 Modeled Results – Normal Operation for a Single Combined-Cycle Turbine

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Predicted Concentration ($\mu g/m^3$)	State Standard CAAQS ($\mu g/m^3$)	Federal Standard, Primary NAAQS ($\mu g/m^3$)	Exceeds Threshold?
NO_2	1-hour	13.8	255.5	286.8	339	--	No
	Federal 1-hour	12.4	146.3	159.1	--	188	No
	Annual	0.1	47.6	47.7	57	100	No

The maximum 1-hour and annual NO_2 concentrations include ambient NO_2 to NOx conversion ratios of 0.80 and 0.75, respectively.

- ***(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).

  A determination is required here 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, AES Alamitos received change of operator permits, not Permits to Construct, for the power plant in 1999. The NOx RTCs initially allocated was 704,485 pounds. The RTCs required for the first year of operation of the combined-cycle turbines and auxiliary boiler are 218,105 pounds. The RTCs required for the first year of operation of the simple-cycle turbines are 274,300 pounds. From *Table 45*, the NOx potential to emit for AEC for a normal operating year is 274,120.0 pounds (137.06 tpy). All RTC requirements are less than the initial allocation. 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 for each NOx-emitting equipment.

  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.

- RTCs Required to Be Held the First Year of Operation
  Combined-Cycle Turbines
  Conditions I297.1 and I297.2 will require each turbine to hold 108,377 pounds of RTCs the first year (*Table 24*).

  Simple-Cycle Turbines
  Conditions I297.3, I297.4, I297.5, and I297.6 will require each turbine to hold 68,575 pounds of RTCs the first year (*Table 40*).

  Auxiliary Boiler
  Condition I297.7 will require auxiliary boiler to hold 1351 pounds of RTCs the first year from the annual emissions calculations above.

- 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 third quarter 2021.

  Section B: RECLAIM Annual Emission Allocation, printed 4/29/16, indicates the NOx RTC holding for 1/2020 through 12/2020 is 432,413 lbs NOx, which is more than the 218,105 lbs required for the first year of operation of the two combined-cycle turbines and the auxiliary boiler. The NOx RTC holding for 1/2021 through 12/2021 is 394,195 lbs NOx, which is more than the 274,300 lbs required for the first year of operation of the four simple-cycle turbines.

- Years Subsequent to First Year
  Pursuant to Rule 2005, 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 Dept.

- ***(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 perking units because they are permitted to operate 2358 hours per year. Therefore, under Rule 2012(c)(1)(C), they are major NOx sources.

  - Auxiliary Boiler: Rule 2012(c)(1)(A)(i) classifies any boiler with a maximum rated capacity greater than or equal to 40 but less than 500 million Btu per hour and an annual heat input greater than 90 billion Btu per year as a major NOx source. The auxiliary boiler is rated at 70.8 MMBtu/hr. From the emissions calculations above, the annual heat input is 189.12 billion Btu/yr. Therefore, the auxiliary boiler is a major NOx source.

  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

The proposed project is considered as a "significant permit revision" to the RECLAIM/Title V permit for this facility. Rule 3000(b)(31) specifies that a "significant permit revision" includes "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."

Pursuant to Rule 3003(j), a proposed permit incorporating this permit revision will be submitted to EPA for a 45-day review. Pursuant to Rule 3006(a), all public participation procedures will be followed prior to the issuance of the permit.

Pursuant to Rule 3006(a)(1)(B) , the public notice is required to include the following:

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.

The Title V public notice will be combined with the Rule 212(g) notice. The public notice periods for both are anticipated to run concurrently for a single 30-day public comment period. (The Rule 212 public notice requirements and completion are discussed above under the Rule 212 analysis above.)

Title V Public Notice Requirements Completion—Original Noticing

The "Rule 212 Public Notice Requirements Completion—Original Noticing" discussion, above, is incorporated here. As indicated in that discussion, the PDOC (engineering evaluation) and proposed revised Title V permit were issued on 6/30/16.

- *Publication of Public Notice*
  On 7/8/16, the Notice of Intent to Issue Permits Pursuant to SCAQMD Rules 212, 1710, 1714, and 3006 was published in the Press Telegram. Pursuant to Rule 3006(a)(1)(F), any person may request a proposed permit hearing on these applications for significant revision to a Title V permit by submitting to the SCAQMD a complete Hearing Request Form (Form 500G) for a proposed hearing by 7/26/16. No Title V Public Hearing requests were received. The public comment period ended on 8/9/16.

- *EPA Significant Permit Revision Review*
  On 6/30/16, SCAQMD electronically submitted the public notice, PDOC analysis, and proposed Title V facility permit to the EPA for the 45-day review. The EPA was forwarded the comment letters received (AES and Helping Hand Tools (Rob Simpson)) on 8/17/16 and will be forwarded the SCAQMD's responses for review.

- *Comment Letters*
  Written comments were submitted by (1) AES Alamitos on July 19, 2016 and (2) Helping Hand Tools (Rob Simpson) on August 9, 2016.

- *Response to Comments*
  An addendum has been added to this FDOC to address the comments received during this comment period.

Title V Public Notice Requirements Completion to Date—Re-noticing
The "Rule 212 Public Notice Requirements Completion to Date—Re-noticing" discussion, above, is incorporated here. As indicated in that discussion, the PDOC (engineering evaluation) and proposed revised Title V permit are being re-noticed. The re-noticing is 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 (http://docketpublic.energy.ca.gov/PublicDocuments/13-AFC-01/TN212284_20160713T160604_Preliminary_Staff_Assessment.pdf). There is no change in the documents that are being released as part of this re-noticing. The re-notice public notice describes how any new comments can be submitted.

- *Publication of Re-Notice Public Notice*
  On 11/17/16, the re-notice Notice of Intent to Issue Permits Pursuant to SCAQMD Rules 212, 1710, 1714, and 3006 was published in the Press Telegram. Also see *Regulation XXX – Title V*, below.

- *EPA Significant Permit Revision Review for Title V*
  On 11/10/16, SCAQMD electronically submitted the re-notice public notice, PDOC analysis, and proposed Title V facility permit to the EPA for the 45-day review. The EPA will be forwarded any

comments received during this second comment period and will be forwarded the SCAQMD's responses for review.

- *Comments Received*
  If any comments are received, they will be addressed before the Permits to Construct are issued.

FEDERAL REGULATIONS

40 CFR 60 Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

On January 8, 2014, EPA withdrew the proposal for the new source performance standard (NSPS), Subpart TTTT, for carbon dioxide emissions that had been published on April 13, 2012 for new affected fossil fuel-fired electric utility generating units. In a separate action on the same day, the EPA proposed new standards of performance for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines. (79 Fed. Reg. 1430)

For the new proposed NSPS, the EPA considered two options for codifying the requirements. Under the first option, EPA proposed to codify the standards of performance for the respective sources within existing 40 CFR Part 60 subparts. Applicable GHG standards for electric utility steam generating units would be included in subpart Da and applicable GHG standards for stationary combustion turbines would be included in subpart KKKK. In the second option, the EPA co-proposed to create a new subpart TTTT (as in the original proposal for this rulemaking) and to include all GHG standards of performance for covered sources in that newly created subpart. (79 Fed. Reg. 1436-1437)

On 8/3/2015, EPA promulgated the final NSPS, after receiving more than two million comments. The NSPS was published in the Federal Register and codified in 40 CFR part 60, Subpart TTTT, a new subpart specifically created for Clean Air Act 111(b) standards of performance for greenhouse gases from fossil fuel-fired electric generating units (EGUs). The effective date was 10/23/15. (80 FR 64510)

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 will commence after January 8, 2014, if the permits are approved.

§60.5580 defines "*base load rating"* to mean "the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions…." ISO conditions mean 15 deg C (59 °F) ambient temperature, 60% relative humidity, and 14.70 psia.

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 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.

(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 new 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 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.

<u>Combined-Cycle Power Block</u>:
All turbines will operate on natural gas 100% of the time.

Page 2-6 of the original Application indicates the design efficiency is 56 percent on a LHV basis. Thus, 50 percent will be used because it is less. 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 thermal efficiency calculations below, the combined-cycle GHG efficiency is estimated as 937.88 lb CO_2/MWh-gross, assuming an 8 percent performance degradation.

<u>Simple-Cycle Turbines</u>:
Each turbine will operate on natural gas 100% of the time.

Page 2-7 of the original Application 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 MWh-net/turbine (calculated as 99.087 MW-net/turbine x 2358 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 thermal efficiency calculations below, the simple-cycle GHG efficiency is estimated as 1356.03 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**
    For the combined-cycle power block, the annual operating schedule proposed by AES for the thermal efficiency calculations is 4100 hours normal operations, 80 cold starts, 420 combined hot and warm starts, and 500 shutdowns, in the revised Application. These are the totals for the combined-cycle block, consisting of the two combined-cycle turbines.

    This schedule is 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 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.

    Table 89 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.

  - **Simple-Cycle Turbine**
    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.

Table 90 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.

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				3200				4100
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		
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		

- **Combined-Cycle Power Block**

  Schedule: 900 hr for 1-on-1, 3200 hr 2-on-1, for total of 4100 hr normal operations
  80 cold starts, total for both turbines
  420 hot/warm starts (332 hot starts + 88 warm starts), total for both turbines
  500 shutdowns, total for both turbines

  Startup and Shutdown Durations and Net Heat Rates

  In the revised Application, 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.

<u>Annual Hours for Startups and Shutdowns</u>

- <u>Startup Hours (first fire to baseload)</u>
  (80 cold starts/yr)(0.33 hr) + (420 warm or hot starts/yr)(0.25 hr) = 131.4 hr/yr

- <u>Startup Hours (baseload to completion)</u>
  (80 cold starts/yr)(0.67 hr) + (420 warm or hot starts/yr)(0.25 hr) = 158.6 hr/yr

- <u>Shutdown Hours (baseload to no fuel)</u>
  (500 shutdown/yr)(0.5 hr) = 250 hr/yr

<u>Overall Net Heat Rate (without degradation)</u>

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 $_{\text{FIRST FIRE TO BASELOAD}}$ * Annual hours $_{\text{FIRST FIRE TO BASELOAD}}$) +
(Startup heat rate $_{\text{BASELOAD TO COMPLETION}}$ * Annual hours $_{\text{BASELOAD TO COMPLETION}}$) +
(Shutdown heat rate $_{\text{BASELOAD TO NO FUEL}}$ * Annual hours $_{\text{BASELOAD TO NO FUEL}}$)] /Total annual hrs

[(7162 Btu/kWh-HHV * 900 hrs *for 1-on-1*) + (7006 Btu/kWh-HHV * 3200 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 + 3200 + 131.4 + 158.6 + 250 hr)]
= 7653.47 Btu/kWh-HHV-net

<u>GHG Efficiency (without degradation)</u>

GHG Efficiency, net (without degradation) =
[(7653.47 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 lb CO_2 /MWh-HHV-net

GHG Efficiency, gross (without degradation) =
(895.27 lb CO_2 /MWh-HHV-net) (0.97 MWh-net / MWh-gross)
= 868.41 lb CO_2 /MWh-HHV-gross

<u>GHG Efficiency (with degradation)</u>

AES assumes a maximum of 8% degradation can occur.

GHG Efficiency, net (with degradation) = (895.27 lb CO_2 /MWh-HHV-net) (1 + 0.08)
= 966.89 lb CO_2 /MWh-HHV-net

GHG Efficiency, gross (with degradation) = (868.41 lb CO_2 /MWh-HHV-gross)
(1 + 0.08) = 937.88 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 hours/year) + (501,996 kW average net electrical output (*for 2-on-1*) x 3,200 hours per year)]/[665,162 kW (*for 2-on-1 at 100% CTG Load*) x 8,760 hrs] x 100% = 31.37%

*****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% capacity factor. Since GHG efficiency increases with increased capacity factor, the 937.88 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 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 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:

$$GHG\ (CO_2)\ (\text{tons/month}) = \{(53.06\ \text{kg}\ CO_2/\text{MMBtu}) * \{(2.2046\ \text{lb/kg})(\text{ton}/2000\ \text{lb})(1050\ \text{MMBtu/MMcf}) * FF\} = 61.41 * FF$$

- **Simple-Cycle Turbine**

Schedule: 2000 hr per turbine
500 startups per turbine
500 shutdowns per turbine

Startup and Shutdown Durations and Net Heat Rates

In the revised Application, 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 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 $_{\text{FIRST FIRE TO BASELOAD}}$ * Annual hours $_{\text{FIRST FIRE TO BASELOAD}}$) +
(Startup heat rate $_{\text{BASELOAD TO COMPLETION}}$ * Annual hours $_{\text{BASELOAD TO COMPLETION}}$) +
(Shutdown heat rate $_{\text{BASELOAD TO NO FUEL}}$ * Annual hours $_{\text{BASELOAD TO NO FUEL}}$)] /Total annual hrs

[(10,063 Btu/kWh-HHV-net * 2000 hrs) + (28,746 Btu/kWh-HHV * 85 hr) + (10,063 Btu/kWh-HHV * 165 hr) + (17,248 Btu/kWh-HHV * 108 hr)] / [(2000 + 85 + 165 + 108 hr)] = 11,065.56 Btu/kWh-HHV-net

GHG Efficiency (without degradation)

GHG Efficiency, net (without degradation) =

[(11,065.56 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 lb CO_2 /MWh-HHV-net

GHG Efficiency, gross (without degradation) =

(1294.41 lb CO_2 /MWh-HHV-net) (0.97 MWh-net / MWh-gross)

= 1255.58 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 lb CO_2 /MWh-HHV- net) (1 + 0.08)

= 1397.96 lb CO_2 /MWh-HHV-net

GHG Efficiency, gross (with degradation) = (1255.58 lb CO_2 /MWh-HHV-gross)

(1 + 0.08) = 1356.03 lb CO_2 /MWh-HHV-gross

*****Compliance Demonstration**

The 1356.03 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 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 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

§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.

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

§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.

<u>40 CFR Part 60, Subpart Dc--Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units</u>

§60.40c Applicability and delegation of authority

The affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and has a maximum design input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr.

> <u>Analysis</u>: Subpart Dc is applicable to the auxiliary boiler, rated at 70.8 MMBtu/hr, because the initial construction will be commenced after June 9, 1989.

§60.48c(g)(2) As an alternative to meeting the requirements of paragraph (g)(1) [requires the recording and maintenance of records of the amount of each fuel combusted during each operating day], the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

> <u>Analysis</u>*:* There are no emission standards, compliance, stack testing, or emission monitoring requirements for natural gas fired boilers. This boiler will combust only natural gas.
>
> This paragraph requires the recording of the calendar monthly usage of natural gas and the use of a non-resettable totalizing fuel meter.
>
> Rule 2012 requires this RECLAIM major NOx source to meet stringent requirements regarding the recording of calendar monthly usage and the use of a non-resettable totalizing fuel meter. Moreover, Rule 2012 requires a NOx CEMS which is not required by this subpart. Section F: RECLAIM Monitoring and Source Testing of the facility permit is comprised of a standard list of operating conditions for RECLAIM facilities, including requirements for NOx major sources. Pursuant to permitting procedure, permit conditions enforcing standard RECLAIM requirements are not added to a facility permit. In contrast, RECLAIM conditions regarding the number of RTCs required and interim emission factors are included as permit conditions because they are based on emissions calculations that are specific to a facility.

<u>40 CFR Part 60 Subpart GG--NSPS for Stationary Gas Turbines</u>
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>
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.

> *Analysis:* 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

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

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

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 Table 26 above, the formaldehyde emissions from the combined-cycle turbines is 3.64 tpy (2 * 1.82 tpy/turbine). The total combined HAPs is 8.10 tpy (2 * 4.05 tpy/turbine).

Simple-Cycle Turbines

From Table 42 above, the formaldehyde emissions from the simple-cycle turbines is 1.44 tpy (4 * 0.36 tpy/turbine). The total combined HAPs is 3.2 tpy (4 * 0.80 tpy/turbine).

Auxiliary Boiler

From Table 30 above, the formaldehyde emissions from the auxiliary boiler is 0.00111 tpy. The total combined HAPs is 0.0074 tpy. These emissions are for 365 days per year.

Facility

The total combined formaldehyde emissions from all sources is 5.08 tpy, which is less than 10 tpy. The total combined HAPs from all sources is 11.31 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 63, Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

§63.11193--This subpart is applicable to owner or operator of industrial, commercial, or institutional boiler as defined in §63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in §63.2, except as specified in §63.1195.

§63.11237--"Industrial boiler" means "a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity."

Analysis: As determined for *Subpart YYYY*, the AEC will be an area source. The auxiliary boiler will be an industrial boiler.

§63.11195--The types of boilers listed in paragraphs (a) through (g) of this section are not subject to this subpart and to any requirements in this subpart.

(e) A gas-fired boiler as defined in this subpart.

§63.11237--"Gas-fired boiler" includes any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Analysis: As a gas-fired boiler, the auxiliary boiler is not subject to this subpart.

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 (Title V renewal) or post-control emissions (initial Title V or revision) of at least 100% of the major source amount; and
- the unit is not otherwise exempt from CAM.

The combined- and simple-cycle turbines, and auxiliary boiler are located at a major source for which a Title V permit is required.

Combined-Cycle Turbines

For the combined-cycle turbines, the NOx, CO, and VOC emissions are subject to BACT limits. Each turbine is controlled with an SCR and CO catalyst to meet BACT limits. For each turbine, the highest annual post-control NOx, CO, and VOC emissions are higher than the major source thresholds. Specifically, the NOx emissions are 54.19 tpy (commissioning year), which is higher than the 10 tpy major source threshold. The CO emissions are ~~129.58~~ 124.58 tpy (commissioning year), which is higher than the 50 tpy threshold. The VOC emissions are 30.07 tpy (commissioning year), which is higher than the 10 tpy threshold. Thus, the CAM regulations are applicable to the combined-cycle turbines for NOx, CO, and VOC.

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 minor degree. The CO catalyst is located at the outlet of the turbine and designed to provide the required control efficiency at the expected turbine exhaust temperature range. There are no operational requirements for the CO catalyst. To assure that the catalyst is not exhausted, each turbine is required to be source tested every three years for VOC pursuant to condition D29.3.

<u>Simple-Cycle Turbines</u>
For the simple-cycle turbines, the NOx, CO, and VOC emissions are subject to BACT limits. Each turbine is controlled with an SCR and CO catalyst to meet BACT limits. For each turbine, the highest annual post-control NOx and CO emissions are higher than the major source thresholds. Specifically, the NOx emissions are 34.29 tpy (commissioning year), which is higher than the 10 tpy major source threshold. The CO emissions are ~~50.7~~ <u>37.47</u> tpy (commissioning year), which is ~~higher~~ <u>lower</u> than the 50 tpy threshold. The VOC emissions are 9.3 tpy (commissioning year), which is lower than the 10 tpy threshold. Thus, the CAM regulations are applicable to the simple-cycle turbines for NOx ~~and CO~~.

The analysis for the combined-cycle turbines are also applicable to the simple-cycle turbines. Since the NOx ~~and CO~~ CEMS qualif~~y~~<u>ies</u> as <u>a</u> continuous compliance determination method~~s~~, the CEMS provide<u>s</u> an exemption from this subpart for NOx ~~and CO~~.

<u>Auxiliary Boiler</u>
For the auxiliary boiler, the NOx and CO are subject to BACT limits. The boiler is controlled with an SCR to meet the BACT limit for NOx. The highest annual post-control NOx emissions is lower than the major source threshold. Specifically, the NOx emissions are 0.68 tpy, which is lower than the 10 tpy major source threshold. Thus, the CAM regulations are not applicable to the auxiliary boiler.

40 CFR Part 68—Chemical Accident Prevention Programs
§68.1—This part sets forth the list of regulated substances and thresholds and the requirements for owners or operators of stationary sources concerning the prevention of accidental releases.

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

§68.130(a)—Regulated toxic and flammable substances are listed with the associated threshold quantities in Tables 1, 2, 3, and 4 to §68.130. Table 1 to §68.130—List of Regulated Toxic Substances 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 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 Air Quality, Biological Resources, and Public Health Assessment sections. The CEC's 12-month licensing process is a certified regulatory program under CEQA. The CEC is the lead agency for the project.

The CEC will publish the Preliminary Staff Assessment (PSA) after the SCAQMD issues the Preliminary Determination of Compliance (PDOC). Typically, the PSA will indicate CEC is the CEQA lead agency, and CEC staff conducts its environmental analysis in accordance with the requirements of CEQA, and no additional environmental impact report (EIR) is required because the CEC's site certification program has been certified by the California Resources Agency as meeting all requirements of a certified regulatory program. Further, the CEC's siting regulations require staff to independently review the SAFC and assess whether the list of environmental impacts contained is complete and additional or more effective mitigation measures are necessary, feasible, and available.

The PSA examines environmental, public health and safety, and engineering aspects of the proposed AEC, based on the information provided by the applicant, government agencies (such as the SCAQMD), interested parties, and other sources available at the time the PSA was prepared. Further, the PSA also recommends measures to mitigate significant and potentially significant environmental effects, which take the form of conditions of certification for construction, operation, maintenance, and eventual closure of the project, if approved by the CEC. The PSA describes how the implementation of the conditions of certification would reduce potential adverse impacts to insignificant levels and ensure that the project's emissions are mitigated to less than significant.

The PDOC (engineering evaluation) and proposed revised Title V permit were issued on 6/30/16. The PSA was made available by CEC on July 13, 2016 (http://docketpublic.energy.ca.gov/PublicDocuments/13-AFC-01/TN212284_20160713T160604_Preliminary_Staff_Assessment.pdf).

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), the "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.

<u>Analysis:</u>

Because § 2900 provides that local publicly owned electric facilities shall make a determination regarding compliance with the EPS prior into entering into a covered procurement, SCAQMD need not make a determination.

Thermal efficiency calculations are provided above to demonstrate compliance with *<u>40 CFR 60 Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating</u>*

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 lb CO_2/MWh-HHV-net.

RECOMMENDATION

Based on the above analysis, it is recommended that the FDOC be published following the conclusion of the required review and comment periods for the CEC, EPA, other agencies and public, subject to any comments received during these periods. After the CEC issues the Final Commission Decision, the Permits to Construct may be issued.

ADDENDUM—RESPONSES TO COMMENTS RECEIVED

Letter No. 1

1. VOC BACT for Combined Cycle Units

According to the PDOC "In a letter dated 6/5/15, Julie Lux, Nooter/Eriksen, provided emissions guarantees for NOx, CO, VOC, PM10, PM2.5, and NH3. The vendor has guaranteed that the project can meet a 1 ppm VOC emission limit. The applicant also proposed a 1 PPM VOC limit in the original application. Despite the vendor guarantee the PDOC proposes a 2 ppm VOC limit as BACT for the AEC because allegedly the project cannot meet the 1 ppm VOC limit utilizing SCAQMD approved source tests. The permit provides no evidence of this claim.

The 2 ppm VOC limit is not BACT for VOC emissions. The applicant proposed and demonstrated in his BACT analysis in his previous application for the HBEP that a 1 ppm VOC limit is achievable on this class of combined cycle units and is being achieved on current natural gas fired power plants. The Russell City Energy Center in the BAAQMD has achieved in practice a 1 PPM VOC limit and this represents achieved in practice BACT. The technology is available, feasible, and it has operated in compliance for over 6 months. The PDOC must be revised as BACT for VOC for combined cycle units because it has been demonstrated in practice to be 1.0 ppmvd over 1 hour.

SCAQMD Response

There are a variety of different test methods used to quantify VOC emissions from combustion sources, including EPA Methods 18, 25, and 25A, and CARB Method 100. In the South Coast, the preferred method for gas turbine testing is a modified Method 25.3 for these sources for verification of compliance with VOC BACT. This method is considered exceptionally comprehensive for determining VOC emissions from combustion sources and is designed to minimize condensation issues that may be associated with other test methods.

The SCAQMD has determined that VOC BACT for combined- and simple-cycle turbines is 2.0 ppm at 15% O2, 1-hour average, based on District Method 25.3/modified Method 25.3. The commenter asserts that Russell City Energy Center has achieved in practice a limit of 1 ppm VOC averaged over 1 hour and this represents achieved in practice BACT for combined-cycle turbines. In comment no. 4 below regarding simple-cycle turbines, the commenter similarly asserts that the Marsh Landing and the Mariposa turbines are permitted with a 1 ppm VOC limit, and this limit has been achieved in practice for Marsh Landing. All three facilities are in the Bay Area Air Quality Management District (BAAQMD).

In the Alamitos Energy Center (AEC) PDOC, condition D29.2 specifies source testing requirements for the combined- and simple-cycle turbines for the initial source test, and condition D29.3 specifies source testing requirements for the subsequent periodic source tests that are required to be conducted at least once every three years.

For the PDOC, both permit conditions specify the required source test method for VOC emissions is District Method 25.3. These conditions also state: "For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined SCAQMD may be the following:…." The three-step procedure that follows describes the **modified** Method 25.3, which lists additional requirements to provide improved accuracy at the lower end of the range that were developed by the SCAQMD Source Test Engineering Department.

In response to your comments, both permit conditions will be updated for the FDOC. At the time the permit conditions were developed, the SCAQMD was in the process of transitioning from either using unmodified Method 25.3 or modified Method 25.3 with Method TO-12 analysis for sampling. Source test companies no longer use these two alternatives because, since then, both alternatives have been determined through experience to be not as reliable as modified Method 25.3 (without the use of Method TO-12), as discussed below. These conditions will be revised to require the use of modified Method 25.3 without the alternative of using the outdated TO-12 option for analysis of Summa canisters.

Further, in response to your comments on combined- and simple-cycle turbines, SCAQMD contacted the BAAQMD for BACT and source testing information on Russell City Energy Center, Marsh Landing and Mariposa. BAAQMD indicated BACT is 1 ppm POC at 15% O2, averaged over a 1-hour period, for combined- and simple-cycle turbines. (POC means precursor organic compound and is equivalent to VOC.) Unlike SCAQMD permits, the BAAQMD permits do not provide permit conditions to specify source test methods and do not require a source test protocol to be submitted and approved prior to performing a source test. As requested, BAAQMD provided a description of the source testing method from recent source test reports for Russell City and Mariposa. (BAAQMD indicated Marsh Landing used the same source testing company as Mariposa and likely the same source testing method.)

SCAQMD Source Testing Engineering Department compared the source test methods used for Russel City and Mariposa with modified District Method 25.3 used by the SCAQMD for turbine testing. The Source Test Engineering Department's comments are summarized as follows:

- For both Russell City and Mariposa, the sampling and analysis were performed using Method TO-12—Method for the Determination of Non-Methane Organic Compounds (NMOC) in Ambient Air Using Cryogenic Preconcentration and Direct Flame Ionization Detection (PDFID). The SCAQMD had learned that because Method TO-12 is an ambient concentration method, laboratories were variously modifying the method to one for stack sampling to compensate for the methane and ethane interferences and the higher concentrations in the stack samples. Methane and ethane, defined as non-VOC compounds, are required to be separated from the VOC compounds in the sample. The test results from

TO-12 were inconsistent and it is unclear as to what the methods, modified in various ways by each laboratory, were actually measuring. In response to such situations, SCAQMD has developed modified Method 25.3--Determination of Low Concentration Non-Methane Non-Ethane Organic Compound Emissions from Clean Fueled Combustion Sources to accurately sample and analyze stack exhaust from turbines. For example, TO-12 uses cryogenic preconcentration to try to physically freeze out methane and ethane from the stack sample by adjusting the temperature of the gaseous sample. Since the separation is not precise, if some of the methane and ethane is left in the sample, then the analyzed VOC concentration of the sample is erroneously high. On the other hand, if some of the VOC is removed along with the methane and ethane, then the analyzed VOC concentration is erroneously low. Modified Method 25.3 uses gas chromatography to precisely analyze a gas sample for VOC because gas chromatography provides separate peaks for methane, ethane, and VOC compounds. Based on source test reports received for SCAQMD facilities, source testing companies have been analyzing Summa canisters using the canister analysis portion of AQMD Method 25.3 exclusively based on their experience that it results in more consistent results than the unmodified EPA Method TO-12.

- For Russell City, stack samples were collected in specially-prepared stainless steel (SUMMA) canisters with the internal vacuum kept above 5 inches of mercury (same as 127 mm of mercury) during sampling. This procedure was formerly used by the SCAQMD as modified Method 25.3. In the current version of modified Method 25.3, conditions D29.2 and D29.3 now require the stack samples to be extracted directly into Summa canisters, while maintaining a final canister pressure between 400-500 mm of mercury absolute to minimize condensation issues. The partial vacuum in the canister serves to minimize the amount of water-soluble VOC that is condensed out with the water in the canister and lost from the gaseous portion of the sample. If part of the VOC is condensed out, the gaseous portion that remains and is analyzed will result in erroneously low VOC concentration results (low-bias test results).

- For Mariposa, stack samples were collected into nitrogen purged Tedlar sample bags instead of Summa canisters. The Tedlar bag sampling is from EPA Method 18, which differs from the SCAQMD sampling methods in that a partial vacuum is not created in the sample bag. Without a partial vacuum, the water-soluble VOC condenses out and the analysis of the remaining gaseous portion results in erroneously low VOC concentration results.

- Therefore, the sampling methods for Russell City and Mariposa were different from the sampling method in modified Method 25.3 for SCAQMD. In addition, the sampling methods for Russell City and Mariposa were different from each other.

The SCAQMD is using a different sampling method and analysis than Russell City and Mariposa. The modified Method 25.3 yields consistent results to support the BACT standard of 2 ppmvd VOC at 15% O2, 1-hour averaging. The sampling and analysis methods used for Russell City and Mariposa are from various prior versions of sampling and analysis methods used by the SCAQMD. The measured VOC results from the SCAQMD's modified Method 25.3 are likely to be different from the measured VOC results from BAAQMD. Due to the potential erroneously low readings from methods used by other agencies, the SCAQMD uses modified District Method 25.3. The 2 ppmvd VOC is the lowest achievable as measured by any method.

In footnote 2 on page 2, the commenter asserts that CEC staff is proposing some changes to the SCAQMD conditions to allow for alternative test methods if there is concurrence with the U.S. EPA, ARB and SCAQMD. As seen on pages 4.1-128 thru 4.1-131 of the Preliminary Staff Assessment for the Alamitos Energy Project (PSA)[1] prepared by CEC staff, Conditions of Certification AQ-D10 and AQ-D11 mirror SCAQMD conditions D29.2 and 29.3, respectively. Both CEC and SCAQMD conditions include: "For purposes of this condition, an alternative test method may be allowed for any of the above pollutants upon concurrence by EPA, CARB, and SCAQMD." The inclusion of this provision allows for future refinement of the source test method for VOC and other pollutants, as appropriate.

Please see response to comment no. 3 "BACT for CO for Combined Cycle Units" in which the SCAQMD provides a BACT determination evaluation for the CO and VOC emissions limits for Warren County Power Station, Virginia.

2. BACT/LAER for PM-10/2.5 for Combined Cycle Units

The PDOC allows the facility to emit up to 8.5 pounds per hour per turbine for particulate matter emissions. The PDOC claims to utilize the Oakley Project and mentions the Russell City Energy Center in their BACT analysis. Both projects have lower PM 2.5 emission rates than required by the AEC PDOC. First the Russell City Energy Center has a lower particulate matter limit of 7.5 pounds per hour as approved by the CEC in AQ 19 (h) on August 11, 2010 Approval of the Petition to Amend. According to compliance documents submitted to the Commission Russell City Energy Center has remained in compliance with this condition. This limit was thoroughly litigated at the EAB. It represents achieved in practice BACT.

The Oakley Project which was examined in the AEC BACT analysis utilizes the exact same equipment as proposed for the AEC combined cycle project. The Oakley Project contains a particulate matter limit of 7.4 pounds per hour. BACT for the AEC combined cycle train is 7.5 pounds per hour as achieved by the Russell City Energy Center. It is particularly important that BACT for PM 2.5 be as stringent as possible as the SCAQMD has recently been classified as serious non-attainment for PM 2.5. The PDOC provides no mitigation for 69.52 tpy of PM 2.5 emissions from the project except for offsetting approximately 3 tons of PM 2.5 emissions from the auxiliary boiler.

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1 http://docketpublic.energy.ca.gov/PublicDocuments/13-AFC-01/TN212284_20160713T160604_Preliminary_Staff_Assessment.pdf

<u>*SCAQMD Response*</u>
SCAQMD Rule 1302(h) defines New Source Review (NSR) BACT as follows:

> BEST AVAILABLE CONTROL TECHNOLOGY (BACT) means the most stringent emission limitation or control technique which:
>
> (1) has been achieved in practice [AIP] for such category or class of source; or
>
> (2) is contained in any state implementation plan (SIP) approved by the US EPA approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or
>
> (3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board.

SCAQMD has a separate definition for Prevention of Significant Deterioration (PSD) BACT. SCAQMD Rule 1702(e) defines PSD BACT, in part, as follows:

> 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…

For the AEC project, PM_{10} is subject to NSR BACT applicable to non-attainment areas and PSD BACT applicable to attainment areas, because PM_{10} is not in attainment with the California 24-hr and annual standards but is in attainment with the federal 24-hr standard. **As set forth above, SCAQMD Rules 1302(h) and 1702(e) define NSR BACT and PSD BACT, respectively, in terms of the most stringent emission limitation <u>or</u> control technique, and do not require both types of BACT limits.** On pages 155 and 157 of the PDOC, NSR BACT is determined to be PUC quality natural gas with sulfur content ≤ 1 grain/100 scf for combined-cycle turbines and simple-cycle turbines, respectively. On pages 219 – 221 of the PDOC, PSD BACT is determined by the top-down analysis to be pipeline-quality natural gas with low sulfur content, good combustion practice, and inlet air filtration for both combined-cycle and simple-cycle turbines. The PDOC does not claim to utilize the Oakley Project and did not mention the Russel City Energy Center in the BACT analysis for particulate matter.

The top-down analysis identifies pipeline-quality natural gas with low sulfur content, good combustion practice and inlet air filtration as available combustion control technology/technique, and electrostatic precipitators and baghouses as available add-on control equipment. The analysis explains that electrostatic precipitators and baghouses are typically used to control sources with high particulate matter emission concentrations. Neither of these add-on control technologies is appropriate for use on natural-gas-fired turbines because of the very low levels and small aerodynamic diameter of particulate matter from natural gas combustion. Therefore, electrostatic precipitators and baghouses were not considered technically feasible add-on control equipment. Therefore the only remaining feasible control technologies/techniques are pipeline-quality natural gas with low sulfur content, good combustion practice and inlet air filtration. This determination is in accord with the Clean Fuels Policy adopted by the SCAQMD Governing Board, in January 1988, that included a requirement to use clean fuels as part of BACT/LAER. A clean fuel is one that produces air emissions equivalent to or lower than natural gas for NOx, SOx, VOC, and PM_{10}.

The SCAQMD has not imposed a numerical emissions limit in addition to requiring the control technologies/techniques of pipeline-quality natural gas with low sulfur content, good combustion practice and inlet air filtration because there are no feasible add-on controls. Particulate matter is unlike such pollutants as NOx and CO where the add-on control equipment (SCR and CO catalyst, respectively) can be designed to achieve the required emissions limit with proper operation. The specification of an emission limit for design and the proper operation of the control system are within the control of the operator. Particulate emission rates are subject to variability depending on the instantaneous sulfur content of the fuel, turbine operating parameters, and amount of particulate matter in the ambient air, which are factors generally not within the control of the operator.

The commenter asserts that the 8.5 lb/hr PM_{10} BACT limit for AEC should be lowered to 7.5 lb/hr as achieved by the Russell City Energy Center. The 8.5 lb/hr PM_{10} limit is NOT a BACT limit. As discussed in the PDOC, the purpose of the limit is for determining offsets and air quality impacts. Our review of the permit conditions and source test results for Russell City tentatively confirm the facility is meeting the 7.5 lb/hr limit. The Russel City combined-cycle turbines are Siemens/Westinghouse 501F, rated at 2,038.6 MMBtu/hr maximum rated capacity, located in the City of Hayward, Northern California. The AEC combined-cycle turbines are General Electric, Model 7FA.05, 2275 MMBTU/HR HHV, located in Long Beach, Southern California. As with the AEC turbines, the Russel City turbines are not equipped with add-on control. The turbines at Russell City and AEC are non-identical models with non-identical ratings and located in different geographic locations. These factors may result in different PM_{10} emission rates. For example, assuming the concentration of PM_{10} in the exhaust flow is the same for the AEC and Russell City turbines, the higher rating for the AEC turbines will result in higher exhaust flow and thus higher PM_{10} emissions in pounds per hour. Measured PM_{10} emissions may vary even on identical turbine models with identical ratings in the same or different geographic locations, and may vary on non-identical turbine models with non-identical ratings in the same or different geographic locations, due to these factors, as well as the selection and implementation of test methods by the source testing company.

The commenter further asserts the Oakley Generating Station (OGS) contains a particulate matter limit of 7.4 lb/hr. The OGS project is on hold before construction. Our review of the BAAQMD Evaluation for Renewal of the Authority to Construct (ATC) for the Oakley Generating Station Plant Number 19771, dated August 2013, indicates the ATC does not contain a permit condition that limits the hourly PM_{10} emissions. Condition no. 10 specifies the owner/operator shall fire the Gas Turbines (S-1 and S-2) exclusively on PUC regulated natural gas with a maximum sulfur content of 1 grain per 100 standard cubic feet. The stated basis for this condition is BACT for SO_2 and PM_{10}. Condition no. 43 specifies a facility-wide PM_{10} limit for the operation of the two turbines, auxiliary boiler, and fire pump. The stated basis is "cumulative increase," not BACT. Cumulative increase is used for determining the offsets required. Similarly, the AEC PDOC sets a limit of 8.5 pounds per hour per turbine for particulate matter emissions for the purpose of determining offsets and air quality impacts, not as BACT.

The commenter states that the limit for Russell City Energy Center was thoroughly litigated at the USEPA's Environmental Appeals Board (EAB)[2]. In that case, the EAB issued a partial remand of the EPA's Region 9 PSD air permit for the Pio Pico Energy Center, not the Russell

2 https://yosemite.epa.gov/oa/eab_web_docket.nsf/Filings%20By%20Appeal%20Number/A73AC96F4C0E14CE85257BBB006800F2/$File/Pio%20Pico...36.pdf

City Energy Center, with regard to the particulate emission limit determined as BACT. The relevant part of the remand required Region 9 to consider emission data and BACT limits from Panoche and CPV Sentinel in its BACT analysis and document whether the limits or emission rates observed at these facilities can or cannot be achieved at Pio Pico.

The EAB case discussed BACT in terms of emission limitation pursuant to the definition of federal BACT for the PSD program. CAA §169(3) and 42 U.S.C. §7479(3) define federal BACT, in part, as follows:

> The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant….

CAA §171(3) and 42 U.S.C. §7501(3) define federal LAER, in part, for the NSR program as follows:

> The term "lowest achievable emission rate" means for any source, that rate of emissions which reflects—
>
> (A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (B) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent….

Both federal PSD BACT and LAER are imposed in terms of **emission limitations**. The CAPCOA BACT Clearinghouse Resource Manual: Information on Control Technology and Air Permitting Processes in California[3], dated June 21, 2000, discusses federal versus California control technology requirements. On page 1 of Chapter VII, the manual explains that California Health and Safety Code Section 42300 authorizes delegation of stationary source permitting authority from the state to local air pollution control districts. Further, each district has its own set of definitions and rules, which can vary by district. Some districts used

3 https://www.arb.ca.gov/bact/docs/fedvscal.htm

BACT and LAER definitions out of the federal Clean Air Act, discussed above. However, most districts have adopted PSD and NSR control technology requirements that are different from the federal definitions of control technology requirements. As discussed above, SCAQMD Rules 1302(h) and 1702(3) require an **emission limitation <u>or</u> a control technique.**

The 8.5 lb/hour limit for the combined-cycle turbines is an estimate of the maximum PM_{10} emissions level that would result from using low-sulfur natural gas and provides the basis for offset requirements. As explained on pages 76 and 91 of the PDOC, the total PM_{10} is comprised of the PM_{10} in the turbine exhaust (6.7 lb/hr as guaranteed by Nooter/Eriksen for the AEC) and the ammonium sulfate particulates formed in the selective catalytic reduction system (SCR). A percentage of the SO_2 in the turbine exhaust is assumed to oxidize to SO_3 in the CO catalyst and SCR, and the SO_3 reacts with ammonia in the SCR to form ammonium sulfate particulates. With the addition of the conservatively calculated ammonium sulfates particulates, the 8.5 lb/hr emission rate is considered to be conservative and the actual emissions are likely to be less. In order to ensure sufficient offsets are provided, the assumed emissions rate needs to be conservative, that is, potentially higher than actual emissions.

The commenter states that the PDOC provides no mitigation for 69.52 tpy of PM2.5 emissions from the project except for offsetting approximately 3 tons of PM 2.5 emissions from the auxiliary boiler. As indicated on pages 68 and 161 of the AEC PDOC, SCAQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler repower projects, with the offsets provided from the SCAQMD internal offset accounts. These internal account offsets will cover all emissions increases of PM_{10}. Offsets for $PM_{2.5}$ as distinct from PM_{10} are not required as $PM_{2.5}$ emissions are less than the applicability threshold of Rule 1325, which is distinct for $PM_{2.5}$. On page 183 of the AEC PDOC, Rule 1304.1(a) and (c)(1) state that the applicant is required to pay fees for the offsets provided by the SCAQMD.

3. <u>BACT for CO for Combined Cycle Units</u>

The PDOC proposes a 2 ppm limit for CO emissions. A 2 ppm CO limit is not BACT for CO emissions. Kleen Energy Systems was able to successfully demonstrate compliance with the CO emission limits of 0.9 and 1.5 ppmvd for unfired and fired operation, respectively. This is the appropriate BACT limit for the HBEP not 2 ppm averaged over 1 hour. The Palmdale Hybrid project has a 1.5 ppm CO limit in its PSD permit. Virginia Electric and Power Company's Warren County Facility has permitted limits of 1.2 and 1.3 ppmvd at 15% O2.

<u>SCAQMD Response</u>

On pages 222-223, the AEC PDOC presents Table 76—Summary of Recent CO BACT Limits for Similar Combined-Cycle, Natural Gas-Fired Combustion Turbines. Following that table, four projects with lower CO emissions than 2.0 ppmvd at 15% O2 are discussed. These projects are Kleen Energy Systems, Warren County Power Station, Avenal Energy Project (not included in your comment), and Palmdale Energy Project (Some of the limits on the facility permits for these projects differ from the limits indicated in your comment.)

- Kleen Energy Systems, Connecticut
  From pages 223-224 of the PDOC: "This facility currently has the lowest permit limits for CO. The permit includes CO limits of 0.9 ppm and 1.8 ppm, on a 1-hr averaging basis for operating without and with duct burner, respectively. The initial source tests were performed in June 2011. Based on a November 2011 letter from the Connecticut Department of Energy & Environmental Protection, the facility was able to successfully demonstrate compliance with the CO emission limits of 0.9 and 1.7 ppmvd for unfired and fired operation, respectively.

  It should be emphasized that the Kleen Energy Systems permit provides an exemption from these limits during periods of "shifts between loads." Further, the permit does not specify limits for those periods of shifts between loads, which realistically can comprise a substantial percentage of normal operations. In contrast, the SCAQMD does require BACT during periods of shifts between loads. The Kleen Energy System limits do not meet the definition of BACT as implemented by the SCAQMD for a facility with these operating characteristics."

  Update: There are no updates. It should be noted that the limits do not apply to operation at below 60% load. In contrast, the SCAQMD does require BACT during periods of shifts between loads and operation at below 60% load. As the AEC turbines are equipped with fast start and ramp-up/ramp-down capabilities, load changes are expected to be a regular occurrence. As the minimum turndown for the turbines is 44% load, operation at below 60% load is expected to be a regular occurrence. The permit limits for Kleen Energy are not achieved in practice for facilities where BACT must be met during shifts between loads and at below 60% load. Condition D29.2 requires the initial source testing for combined-cycle turbines to be performed at 45, 75, and 100 percent of maximum load, and for the simple-cycle turbines at 50, 75, and 100 percent of maximum load, because emission rates may vary with load.

- Palmdale Energy Project (formerly Palmdale Hybrid Power Project), California
  From pages 224-225 of the PDOC: "The final PSD permit specifies CO emission limits of 1.5 ppm and 2.0 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively, after a 3-year demonstration period during which the CO emissions limit is 2.0 ppm for operating without and with duct burner. This facility was not constructed.

  The CEC website indicates a Petition to Amend was filed on 7/27/15, and the Amendment Preliminary Staff Assessment was released on 3/23/16 for the revised project, now renamed the Palmdale Energy Project. Pg. 4.1-26 of the PSA indicates CO emission concentrations would be limited to 2.0 ppmvd, which is the same as proposed for the AEC combined-cycle turbines."

Update: The FSA was published on 9/12/16. The limits have not changed from the PDOC.

- Warren County Power Station, Virginia
  From page 224 of the PDOC: "The final PSD permit includes CO emission limits of 1.5 ppm and 2.4 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively. The 1.5 ppm without duct burner is lower than the SCAQMD BACT/LAER limit of 2.0 ppm, but the 2.4 ppm with duct burner is higher than the SCAQMD BACT/LAER limit of 2.0 ppm. Based on publicly available information, commercial operation started in December 2014."

  Update: Following the issuance of the AEC PDOC, the SCAQMD contacted the Virginia Department of Environmental Quality (DEQ) regarding Warren County Power Station. The most recent amended PSD permit, dated 10/24/13, had not revised the CO and VOC limits for operating without and with duct burner. The engineering evaluation indicated the limits had been proposed by the applicant. For CO, the limits remain 1.5 ppmv without duct burner firing and 2.4 ppmv with duct burner firing. For VOC, the limits remain 0.7 ppmvd without duct burner firing and 1.6 ppmvd with duct burner firing. A BACT determination evaluation for the VOC limits is provided here to supplement the response to comment no. 1 "VOC BACT for Combined Cycle Units."

  The only source tests on the three turbines were performed in December 2014.
  The SCAQMD Source Test Engineering Dept. was requested to provide a formal evaluation of the source test protocol (88 pages) and source test report for Turbine 1A (963 pages) for the source test performed on 12/5 – 12/7/2014. The evaluation was to determine whether the data quality met the standards of the SCAQMD.

  The following comments and conclusions are from the SCAQMD Source Test Engineering evaluation for the Warren County protocol and source test report.

  - VOC
    - The VOC testing and analyses were performed according to EPA Method 25A. EPA Method 25A is not a suitable method to measure VOC at the emission limits set forth in the Virginia PSD permit because EPA Method 25A cannot detect oxygenated hydrocarbons such as formaldehyde, and VOC concentrations less than 2 ppm are in the statistical noise of EPA Method 25A.
    - Previous parallel testing on similar gas-fired sourced in the SCAQMD using SCAQMD Method 25.3 have shown results higher than those given by EPA Method 25A. The higher results given by SCAQMD Method 25.3 are most likely due to the ability of Method 25.3 to detect oxygenated hydrocarbons (an ability that EPA

Method 25A does not have) and the actual presence of such hydrocarbons in low concentrations from natural gas-fired turbines. Because of the higher results given by SCAQMD Method 25.3, it is doubtful that any gas turbines could meet the VOC emission limits in the Virginia permit using SCAQMD Method 25.3 to measure VOC. It should be noted that the likely concentrations of oxygenated hydrocarbons will likely cause exceedance of the Virginia permit limits.

- Most of the VOC data points in the report were zero or less. This "negative drifting" of the data is evidence of the presence of oxygenated hydrocarbons. The oxygenated hydrocarbons cause destructive interference with flame ionization detector (FID) methods, i.e., the oxygenated hydrocarbons subtract from the VOC readings. EPA Method 25A is an FID method.
- In order to accurately show compliance with the VOC limits in the Virginia permit, a method that can measure oxygenated hydrocarbons at low concentrations as SCAQMD Method 25.3 must be used. Methods that cannot measure oxygenated hydrocarbons at low concentrations such as EPA Method 25A must not be used or allowed.
- Section 4.2 of the test report states that the sample gas was sent through a condenser in order to dry the sample gas. This would further cause a low bias to the EPA Method 25A VOC data, meaning that some of the VOC is condensed out and lost from the gaseous portion of the sample that is analyzed.
- Some of the reported gaseous emissions from EPA Method 25A cannot be reliably verified or they were performed incorrectly. Since no parallel VOC testing using a method that is suitable for the VOC concentration limits was conducted during the test runs that could possibly confirm or deny the EPA Method 25A data, the reported VOC concentration data should not be used for any purpose, including setting BACT standards, compliance purposes and emissions calculations.

➢ For these reasons, the SCAQMD will not be adopting as VOC BACT the limits of 0.7 ppmvd without duct burner firing and 1.6 ppmvd with duct burner firing found in the Warren County Power Station PSD permit. VOC BACT will remain 2 ppmvd at 15% O_2, without and with duct burner firing.

- <u>CO</u>
  - Some of the reported gaseous emissions fell short of established analytical standards, and the reported emissions have been recalculated upward to default levels for qualitative compliance determination only. This applies to reported CO concentrations. SCAQMD regards the valid reporting range of measurement of a EPA Method 10 analyzer as being 20-95% of the instrument full-scale-range (FSR). Gas measurements (as measured at the stack) falling below this lower limit are adjusted upward to the 20% FSR value for gas concentration Rule/Permit Compliance limit determination only, and adjusted CO values cannot be used

quantitatively for mass emission or emission factor calculations because they are probably overstated.

- The adjusted CO values, summarized in the table below, indicate the turbines without duct burner operation meet the 1.5 ppm CO @ 15% limit.

Unit/Condition	Source Test Report Results (ppm @ 15% O_2)	Adjusted Concentration (ppm @ 15% O_2)	Permit Limits (ppm @ 15% O_2)
Unit 1A w/o duct burning	0.0	< 0.8	1.5
Unit 1 A with duct burning	0.0	< 0.6	2.4
Unit 1B w/o duct burning	0.0	< 1.5	1.5
Unit 1B with duct burning	0.0	< 1.3	2.4
Unit 1C w/o duct burning	0.29	< 1.5	1.5
Unit 1C with duct burning	0.00	< 1.3	2.4

As indicated in the PDOC, achieved-in-practice LAER is based on a minimum of 183 cumulative operating days (6 months). Warren County Generating Station started commercial operation in December 2014, and the only source tests performed were completed that month. The Virginia DEQ has confirmed that each turbine has operated a minimum of 6 months without the duct burner since December 2014. The SCAQMD has obtained and reviewed validation data, including CO CEMS data for CO for the two years of operation which includes operation without the duct burner and with the duct burner, for the three turbines. The SCAQMD has made a BACT determination that CO BACT for combined-cycle turbines is 1.5 ppmvd at 15% O_2.

Upon SCAQMD's request, AES is in the process of securing a written performance guarantee from the equipment vendor to ensure the proposed simple-cycle turbines with oxidation catalyst will comply with the new BACT standard of 1.5 ppmvd CO at 15% O_2 without duct burner.

4. BACT for VOC for LMS-100 Simple-Cycle Units

The PDOC proposes BACT for VOC's of 2 ppm averaged over 1 hour. The BAAQMD determined that the simple cycle Marsh Landing gas turbines would be able to meet a VOC emissions limit corresponding to 1 ppmvd @ 15% O2 averaged over one hour. The simple-cycle Marsh Landing gas turbines were limited to 2.9 lb/hour or 0.00132 lb/MMBtu in the permit conditions; these values correspond to 1 ppmvd @ 15% O2. These limits have been achieved in practice.

Also the BAAQMD in the Mariposa FDOC, "determined that BACT for the simple-cycle gas turbines for VOC is the use of good combustion practice and abatement with an oxidation catalyst to achieve a permit limit for each gas turbine of 0.616 lb per hour or 0.00127 lb/MMbtu, which is equivalent to 1 ppm POC, 1-hr average." BACT for VOC's for the AEC LMS-100 turbines should be established as 1 ppm averaged over 1 hour in the final permit.

SCAQMD Response
The response to comment no. 1 "VOC BACT for Combined Cycle Units," above, addresses both the combined- and simple-cycle turbines.

5. BACT for CO for LMS-100 Simple-Cycle Units

The Applicant has proposed a CO emission limit of 4 ppmvd at 15% O2 averaged over each hour. The district analyzed simple cycle projects in the following table.

Table 78 - Summary of Recent CO BACT Limits for Similar Simple-Cycle, Natural Gas-Fired Combustion Turbines

Facility	Permit Issuance	CO Limit @ 15% O_2
LA City, DWP Scattergood Generating Station, California	2013	4 ppm (1-hr)
CPV Sentinel, California	2012 & 2013	4 ppm (1-hr)
Pio Pico Energy Center, California	2012	4 ppm (1-hr)
Walnut Creek Energy Park, California	2011	4 ppm (1-hr)
TID Almond 2 Power Plant, California	2010	4 ppm (3-hr)
Canyon Power Plant, California	2010	4 ppm (1-hr)
Starwood Power – Midway, California	2008	6 ppm (none)
Panoche Energy, California	2007	6 ppm (3-hr rolling)

Absent from this list is two recently permitted power plants in the BAAQMD. The Mariposa Power Plant utilizing LM -6000 units has a CO BACT limit of 2.0 ppm, which is more stringent than the 4 ppm CO limit proposed for the AEC LMS-100 turbines. Another simple cycle project in the BAAQMD the Marsh Landing Project has a 2 ppm CO limit. The Marsh Landing project utilizes the Siemens SGT6-5000F simple-cycle gas turbines which has a nominal output of 190 MW. The 2.0 ppm CO limit has been achieved in practice on units varying in size from 49 MW to 190 MW in the BAAQMD and represents BACT.

SCAQMD Response
In response to your comment, SCAQMD contacted the BAAQMD for information on Mariposa Energy facility and the Marsh Landing Generating Station that is required to perform a CO BACT determination for simple-cycle turbines. SCAQMD determined that Mariposa Energy is limited to 2 ppmvd at 15% O_2, averaged over any rolling 3-hour period, and source testing since 2014 has demonstrated compliance with that limit. Marsh Landing is limited to 2 ppmvd at 15% O_2, averaged over any 1-hour period. The facility went on-line in the second half of 2013 and has demonstrated compliance with that limit. Therefore, the 2.0 ppmvd at 15% O_2 emission level has been verifiably achieved in practice.

As a result, the SCAQMD agrees with the commenter. BACT for CO for simple-cycle turbines will be revised from 4 ppmvd to 2 ppmvd, both at 15% O_2, averaged over a 1-hour period for the AEC. The 1-hour averaging period for Marsh Landing was selected over the rolling 3-hour averaging period for Mariposa Energy, because it is more stringent and because SCAQMD typically bases BACT on a 1-hour averaging period.

Upon SCAQMD's request, AES has secured a written performance guarantee from BASF, the oxidation catalyst manufacturer, to ensure the proposed simple-cycle turbines with oxidation catalyst will comply with the new BACT standard of 2.0 ppmvd at 15% O2 (see attachment).

6. BACT for PM for LMS-100 Simple-Cycle Units.

The permit for the AEC proposes a 6.24 pound per hour per turbine PM-10 limit for the LMS-100 turbines proposed for the AEC. BACT for particulate matter emissions for LMS-100 turbines was heavily litigated at the EAB recently. The original PSD permit for the Pio Pico Project proposed a 5.5 pound per hour PM limit. After a EAB remand of the permit back to the EPA the final PSD permit for the Pio Pico Project found PM BACT to be 5 pounds per hour for the Pio Pico Project.

More recently the applicant for the Carlsbad Energy Center proposed a 3.5 pound per hour PM rate for the LMS-100 turbine. The CEC ultimately determined that PM 2.5 BACT for the LMS -100 units in Carlsbad was 5 pounds per hour in condition AQ-35. The AEC permit states that, "*In a document dated 6/16/15 Christopher VU, General Electric, provided guarantees for NOx, CO, VOC, PM10, and NH3 based on a GE supplied SCR/CO catalyst.*" The vendor guarantee and recent permitting actions with Pio Pico and Carlsbad Energy Center require that the final permit contain a 5 pound per hour particulate matter limit as BACT.

SCAQMD Response

The response to comment no. 2 "BACT/LAER for PM-10/2.5 for Combined Cycle Units," above, addresses combined- and simple-cycle turbines. The SCAQMD has determined NSR BACT and PSD BACT to be the control technique of using pipeline-quality natural gas with low sulfur content, good combustion practice, and inlet air filtration.

On page 82 of the AEC PDOC—Table 12—Simple-Cycle Turbine Warranted Emissions for Control Systems" lists the warranted emission emissions as 5 lb/hr PM_{10}, but inadvertently omitted "(not including ammonium sulfate particulates formed in the SCR catalyst)." The omitted explanation will be added for the Final Determination of Compliance.

The 6.23 lb/hour limit for the simple-cycle turbines is an estimate of the maximum PM_{10} emissions level that would result from using low-sulfur natural gas and provides the basis for offset requirements. As explained on page 122 of the PDOC, the total PM_{10} is comprised of the PM_{10} in the turbine exhaust (5 lb/hr as guaranteed by General Electric for the AEC) and the ammonium sulfate particulates formed in the selective catalytic reduction system (SCR). With the addition of the conservatively calculated ammonium sulfates particulates, the 6.23 lb/hr emission rate is considered to be conservative and the actual emissions are likely to be less.

7. Rule 1303

Rule 1303(b)(5)(B) requires that all major stationary sources owned or operated by the applicant 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. According to the PDOC, *"In a letter dated 10/23/15, Stephen O'Kane, Manager, AES Alamitos, LLC, certified that all major stationary sources that are owned or operated by AES in California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emissions limitations and standards under the Clean Air Act."* AES is also the owner of the Redondo Beach Power Plant. According to the EPA Compliance and Enforcement website (ECHO) the Redondo Beach Facility is a high priority violator and the facility has been out of compliance with its air quality regulations for 12 quarters in a row.

SCAQMD Response

The EPA Compliance and Enforcement website (ECHO)[4] does indicate the AES Redondo Beach facility is a high priority violator and the facility has been out of compliance with its air quality regulations for 12 quarters. On 10/3/2014, the commenter included the same comment in a document entitled "Helping Hand Tools- Comments: Comments on the PMPD and FDOC on Behalf of Helping Hand Tools" posted on the CEC website for the original Huntington Beach Energy Project[5]. On page 9, the comment states, in part: "AES owns and operates the Redondo Beach Project which has been a High Priority Violator of the clean air act for the last twelve quarters in a row according to the EPA. Accordingly the air permit cannot be issued until the Redondo Beach facility comes into compliance with SCAQMD Rule 1303."

Since the comment period for the FDOC had already passed, the CEC responded to the comment on the PMPD, with input from the SCAQMD, in a document, entitled "Energy Commission Staff's Response and Comments to the Revised Presiding Member's Proposed Decision and Response to Comments"[6] posted on the CEC website. On pages 10-11, the CEC Staff Response states, in part: "Tools cites the information from EPA's ECHO website. However, that information is incorrect. Staff has checked with EPA Region 9 and SCAQMD's enforcement personnel regarding the compliance status of AES Redondo Beach facility. Both

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4 https://echo.epa.gov/detailed-facility-report?fid=110014322170

5 http://docketpublic.energy.ca.gov/PublicDocuments/12-AFC-02/TN203163_20141003T162359_Helping_Hand_Tools_Comments_Comments_on_the_PMPD_and_FDOC_on_Be.pdf

6 http://docketpublic.energy.ca.gov/PublicDocuments/12-AFC-02/TN203223_20141021T143703_Energy_Commission_Staff's_Response_and_Comments_to_the_Revised.pdf

agencies confirm that the Redondo Beach facility is currently in compliance with all permit requirements and no violations are currently open. All the previous violation cases have been addressed and closed, although the ECHO website is not up to date. Therefore, AES is in compliance with Rule 1303 b (5) B requirements, and the issuance of a permit for HBEP permit would not be affected by any potential violations at Redondo Beach or any other AES facility." The CEC's response remains valid.

At that time, CEC staff confirmed with the EPA that the violations were all coming from the SCAQMD database. SCAQMD Title V Administration staff confirmed that the ECHO system does not correctly reflect the compliance status recorded in SCAQMD's database. ECHO updates its information only once a year and the information has been updated since 2014, but counts violations on a quarterly basis. Also, EPA defines a facility as being non-compliant until a District prosecutor assesses a penalty and closes the case, which can be substantially later than when the facility actually comes into compliance.

The SCAQMD website is a better resource because it provides up-to-date compliance status, including for Notices of Violation and Notices to Comply. The Facility Information Detail (FIND) web page can be accessed at http://www3.aqmd.gov/webappl/fim/prog/search.aspx. If you enter the SCAQMD facility ID and select the Compliance tab, you will be able to view Notices of Violation and of Notices to Comply for the facility. From November 18, 2016, the web page for AES Redondo Beach (ID 115536), reproduced below as reference, shows all Notices of Violation (NOV) are cancelled, closed case, rejected or void, except for P60572. Clicking on the P60572 link provides additional details, including that the Follow Up Status is "In Compliance." The reason the case is not closed is that the NOV is awaiting disposition by a District prosecutor. Further, the facility is in compliance with all Notices to Comply, including E27765, which was issued earlier this year. Therefore, AES is currently in compliance with Rule 1303(b)(5)(B) requirements. Prior to issuance of the Permits to Construct, the SCAQMD will confirm that the compliance status of AES has not changed.

Compliance

Facility ID	115536
Company Name	AES REDONDO BEACH, LLC
Address	1100 N. HARBOR DR
	REDONDO BEACH, CA 90277

Notices Of Violation

Notice Number	Notice Issue Date	Violation Date	Disposition Date	Disposition
P28068	4/13/2001	11/17/1999	8/21/2002	Closed Case
P28718	8/28/2001	1/1/1999	2/1/1999	Void
P28719	9/5/2001	1/1/1999	8/21/2002	Closed Case
P37100	1/29/2002	1/1/2000	8/15/2002	Rejected

P37110	5/30/2003	3/2/2003	5/31/2005	Closed Case
P37113	6/4/2003	1/1/2003	5/31/2005	Closed Case
P37136	10/25/2005	1/1/2003	5/23/2006	Closed Case
P43494	8/31/2006	8/9/2006	3/20/2007	Closed Case
P51953	8/14/2008	7/4/2008	12/5/2008	Closed Case
P52177	5/25/2011	1/1/2010	7/17/2012	Closed Case
P52192	6/21/2013	5/25/2012	4/15/2014	Closed Case
P55513	12/4/2009	4/22/2008	4/20/2010	Cancelled
P55516	6/15/2010	4/3/2009	10/28/2010	Closed Case
P60556	11/6/2014	9/28/2013	4/28/2015	Closed Case
P60572	7/6/2016	8/6/2015		

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Notices To Comply

Notice Number	Violation Date	Re-Inspection Date	Status
C56850	11/17/1999	12/16/1999	In Compliance
C57169	12/21/2000	5/3/2001	In Compliance
D04855	1/19/2007	12/18/2007	In Compliance
D21309	10/1/2009	1/5/2011	In Compliance
E00711	1/1/2010	2/11/2010	In Compliance
E00713	1/1/2010	3/8/2011	In Compliance
E09958	2/10/2012	5/11/2012	In Compliance
E09967	1/17/2014	2/18/2014	In Compliance
E27752	6/27/2013	11/6/2014	In Compliance
E27758	1/1/2014	5/22/2015	In Compliance
E27765	2/29/2016	5/31/2016	In Compliance

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8. Alternatives Analysis

Rule 1305 (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. The applicant submitted its AFC analysis which does not contain any information whether the proposed source significantly outweighs the environmental and social cost of the project.

Whether there are cheaper and less environmentally damaging alternatives are never analyzed by any one agency including the CEC and the CPUC. The CPUC determines whether a project is needed and whether the contract is just and reasonable and does not consider other technologies. The CEC determines if other alternatives are available that meet the applicant's objectives but never considers costs and uses the applicant project objectives as the yardstick for eliminating alternatives without ever the examining the cost of the alternatives. No agency other than the air district is tasked with the responsibility to 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.

Energy storage can replace the four LMS-100 peaking units and create a substantial reduction in air pollution and associated health benefits. Energy storage will be more dispatchable than the LMS-100 units and also has the added advantage of storing excess renewable energy during periods of over generation which is expected to occur frequently as California approaches its RPS standards. Energy storage is cheaper on a per MW basis than the proposed AEC LMS-100 units. AES the applicant for the AEC is currently developing a 100 MW battery for use in Los Angeles that is expected to be deployed in 2021 before the proposed LMS-100 units are scheduled to begin operation. While at one time storage was not a feasible alternative it is certainly a feasible alternative for one or all of the LM-100 turbines proposed for this project and must be considered in the Districts alternative analysis. In fact AES is constructing four 100 MW battery storage houses at the AEC site.

SCAQMD Response

The AEC PDOC explains on page 182 that Rule 1303(b)(5)(D) specifies the requirements of Rule 1303(b)(5)(A) may be met through compliance with CEQA, and Rule 2005(g)(3) specifies the requirements of paragraph Rule 2005(g)(2) may be met through CEQA analysis. Both of these rules are SIP-approved by EPA (http://www.aqmd.gov/home/regulations/rules/sip-approved-rules). 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 done by CEC for a project subject to CEC jurisdiction.

The CEC prepared a 927-page Preliminary Staff Assessment (PSA), which includes an environmental assessment of air quality, alternatives, biological resources, cultural resources, hazardous materials management, land use, noise and vibration, public health, socioeconomics, soil & water resources, traffic & transportation, transmission line safety & nuisance, and visual resources, and an engineering assessment of facility design, geology & paleontology, power plant efficiency, power plant reliability, transmission system engineering, waste management, and worker safety & fire protection. The CEC concluded that with implementation of staff's recommended mitigation measures described in the conditions of certification, the AEC would comply with all applicable laws, ordinances, regulations, and standards (LORS).

As the agency responsible for air quality, the SCAQMD performed an evaluation of environmental costs related to air quality by preparing a detailed 289-page PDOC that concluded the proposed AEC, with the required mitigation, will not result in significant air quality impacts and will comply with all applicable federal, state and local air quality rules and regulations. This analysis was considered by CEC staff and incorporated, as appropriate, into the CEC PSA.

CEC uses information provided by the applicant, the SCAQMD, and other sources in preparing its' staff analyses, including its EIR-equivalent analysis.

First, AES and CEC have determined there are no alternative projects or alternative sites or mitigating measures which would offer more protection to the environment than the proposed project without unduly curtailing non-environmental benefits.

Alternatives Study

AES and the CEC provided an alternatives study in the Supplemental Application for Certification and the PSA, respectively. As explained above, the SCAQMD relies on the CEQA analysis, including the alternatives analysis, prepared by the CEC.

Applicant

On pages 6-1 to 6-12 of the Supplemental AFC, AES presents a project objectives list and an evaluation of alternatives, including the "no project" alternative, power plant site alternatives, alternative project design features (alternative natural gas supply pipeline routes, electrical transmission system alternatives, water supply alternatives), technology alternatives (generation technology alternatives, conventional boiler and steam turbine, nuclear, Kalina combined-cycle, internal combustion engines), fuel technology alternatives, NOx control alternatives, **energy storage options**, and waste discharge alternatives. The applicant found that the alternatives considered were either infeasible, unable to reduce or avoid any adverse environmental impacts, or would not attain most of the basic objectives of the project. On page 6-1, the AFC concluded: "This section evaluates reasonable alternatives to the AEC that could feasibly attain most of the project objectives and reduce or eliminate any significant effects of the project. As demonstrated by the analyses contained in this AFC, the project will not result in any significant environmental impacts. Therefore, as detailed in the following sections, there are no alternatives that would be preferred over the proposed project."

CEC

On pages 4.2-1 to 4.2-17 of the PSA, the CEC provides an analysis of alternatives. On pg. 4.2-1, the CEC concludes: "As required by the California Environmental Quality

Act (CEQA), this section evaluates a reasonable range of alternatives to the proposed Alamitos Energy Center (AEC or proposed project) that would feasibly attain most of the basic objectives of the project and would avoid or substantially lessen any of the significant effects of the project."

Instead of merely using the applicant's project objectives as a yardstick as asserted by the commenter, the CEC provided a broad interpretation of the applicant's project objectives, then reviewed the objectives for consistency with the State Water Resources Control Board's *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (OTC Policy), California Independent System Operator (CAISO) planning, state's Renewable Portfolio Standard (RPS), state energy policies and procurement planning, CPUC decisions, and North American Electric Reliability Council and the Western Electricity Coordinating Council reliability standards. The alternatives evaluation included "preferred resources" (energy efficiency, demand response, utility scale and distributed renewable generation, and **energy storage**), alternative sites, and no-project alternative.

On page 4.2-7, the CEC explains that natural gas-fired generation is necessary because preferred resources, including energy storage, cannot ensure reliability: "The state's loading order established by the energy agencies in 2003 calls for meeting new electricity needs first with efficiency and demand response (jointly, demand-side management), followed by renewable energy and distributed generation, and only then with efficient, utility-scale natural gas-fired generation…. In recent years, energy storage has achieved preferred resource status due to its ability to a) absorb over-generation that may occur at high levels of solar penetration, and b) obviate the need for natural gas-fired generation and associated capacity to meet ramping needs during evening hours when solar resource output declines to zero. Preferred resources can provide many of the services provided by dispatchable, natural gas-fired generation. However, where preferred resources cannot ensure reliability, because they lack necessary operating characteristics or are not available in sufficient quantities, the CPUC has found that the procurement of clean, efficient natural gas-fired generation is necessary and is consistent with the state's loading order."

On page 1-5, the CEC concluded: "As required by CEQA staff evaluated a reasonable range of alternatives to the proposed project that would feasibly attain most of the basic objectives of the project and would avoid or substantially lessen any of the significant effects of the project. As a starting point, staff reviewed the alternatives analysis provided by the applicant in the SAFC. The applicant found that the alternatives considered in the SAFC were either infeasible, unable to reduce or avoid any adverse environmental impacts, or would not attain most of the basic objectives of the project; staff concurs with the applicant's assessment of their alternatives…. **Staff has not identified a feasible alternative that would be environmentally superior to the proposed AEC [**bold added**].**"

The commenter asserts that a criteria in the alternatives analysis is the relative price of the proposed project and alternatives. As discussed below, the relative price ("cheaper") is not included in the criteria of environmental and social cost.

Energy Storage as Feasible Alternative

The commenter has focused on energy storage as an alternative and asserts that energy storage is feasible to replace up to four of the proposed simple-cycle turbines. Both AES and CEC found energy storage not to be a feasible alternative to replace any of the simple-cycle turbines. The commenter has not provided an analysis to support his assertion that energy storage is a feasible alternative.

On page 6-11 of the Supplemental AFC, AES explains: "However, at this time, these [battery and capacitor] devices have not been deployed at a scale that would effectively substitute the 1,040 MW of generating capacity of this project for extended periods of time. Utility scale battery energy storage systems at scales in the 100's of MWs are limited in capacity to 4 to 8 hour duration. Natural gas turbine technology can provide generating capacity constantly."

On pages 4.2-9 and 4.2-10 of the PSA, the CEC states: "As California increasingly relies on wind and solar resources to meet its energy needs and environmental goals, other energy resources are increasingly called upon to 'balance the system.' Expected changes in wind and solar output over the course of a day and random swings due to changing weather conditions require construction and operation of more flexible, dispatchable natural gas-fired generation to compensate for the variations in wind and solar output[1]. Energy storage cannot replace generation as a source of energy because it requires injections of energy in excess of the amounts that are discharged when the stored energy is needed. However, energy storage can replace generation capacity by being charged during non-peak hours and discharged on peak, in lieu of dispatching natural gas-fired generation." Footnote 1 states: "In some systems (in the Pacific Northwest, for example), there is sufficient dispatchable hydroelectric energy to balance a wind- and solar-intensive generation fleet. The scale of wind and solar development in California, however, is such that energy storage is expected to absorb surplus generation during midday hours, as well as use energy generated during the day to reduce the need for energy and capacity from natural gas-fired generation resources during evening hours".

In response to the SCAQMD's request for more information regarding the AES battery storage projects, AES indicated it is developing a 100 MW Battery Energy Storage System (BESS) at the Alamitos Generating Station site, with an expected online date of 1/1/2021, in response to a power purchase agreement award from Southern California Edison (SCE). AES is in the process of permitting the BESS through the local jurisdiction to accommodate 300 MWs of storage capacity for potential future expansion. The BESS is not an alternative to the electrical generation capability of the simple-cycle turbines, but a complement. Through dispatch orders from the California Independent System Operator (CAISO), SCE will determine when the simple-cycle turbine(s) will be called upon to generate electricity (dispatched) and when the BESS will be called upon to be discharged to meet electrical demand. In general, the more expensive source of energy is less competitive. This means the simple-cycle turbines, once installed, will be available when needed, but may not be called upon to be dispatched. Thus the combined-cycle turbines, simple-cycle turbines and BESS each will serve a different role in maintaining an efficient and reliable electrical grid, with the combined-cycle block scheduled for first fire on 10/1/19 and the simple-cycle block for 6/1/21. As California builds out its renewable generation and energy storage facilities in response to the renewable energy requirements of Senate Bill 350 to increase the percentage of renewable energy from 33 percent to 50 percent by 2030, the role of the combined- and simple-cycle turbines will evolve over time.

Second, the SCAQMD and CEC have evaluated impacts and imposed mitigation to ensure that the adverse impacts of the proposed facility have been avoided to the maximum extent possible.

<u>SCAQMD</u>
The SCAQMD's evaluation of air quality impacts and imposition of required mitigation measurements are detailed in the PDOC, and summarized below.

- Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) will be required to limit NOx, CO, VOC, PM_{10}, SOx, and ammonia (NH_3) emissions from the combustion equipment.
  - The combined- and simple-cycle turbines each will be controlled by dry low-NOx combustor and selective catalytic reduction system for NOx and an oxidation catalyst for CO and VOC.
  - The auxiliary boiler will be controlled by low NOx burner, flue gas recirculation, and selective catalytic reduction system for NOx, and good combustion practice for CO.
  - BACT emission levels for NOx, CO, VOC, and NH_3 for the combined- and simple-cycle turbines, and NOx, CO, and NH3 for the auxiliary boiler are specified by permit condition. SCAQMD has carefully reviewed and responded to the commenter's comments on BACT levels for VOC, PM_{10}, and CO for combined- and simple-cycle turbines, above.
  - BACT for PM_{10} and SOx for the combined- and simple-cycle turbines, and VOC, PM_{10} and SOx for the auxiliary boiler require the use of pipeline quality natural gas with an annual average hydrogen sulfide content of no greater than 0.25 grain per 100 scf. Natural gas is the cleanest and lowest greenhouse gas-emitting fossil fuel available.

- The combined- and simple-cycle turbines are equipped with NOx and CO CEMS, and the auxiliary boiler is equipped with a NOx CEMS.
- The combined- and simple-cycle turbines and the auxiliary boiler are required to pass an initial source test for NOx, CO, SOx, VOC, PM_{10}, $PM_{2.5}$, and NH_3 before the Permits to Construct may be converted to Permits to Operate.
- Subsequent to the initial source test, the combined- and simple-cycle turbines are required to pass a source test for SOx, VOC and PM_{10} at least every three years. The auxiliary boiler is required to pass a source test for CO pursuant to the testing frequency specified in SCAQMD Rule 1146. The turbines and boiler are required to pass the NH3 source test at least quarterly during the first twelve months of operation and at least annually thereafter.

o Best Available Control Technology for Toxics (T-BACT) requires an oxidation catalyst to limit toxic emissions from the combined- and simple-cycle turbines.

o Offsets will be provided for the increase in criteria pollutants for the combustion equipment.
- For the combined- and simple-cycle turbines, AES will pay for the PM_{10}, SOx, and VOC offsets from the SCAQMD internal account pursuant to Rule 1304.1. The Rule 1304(a)(2) replacement exemption is for modeling and offsets. Offsets become available only upon the permanent shutdown (retirement) of a utility boiler. Condition F52.1 requires a detailed SCAQMD-approved retirement plan for the permanent shutdowns.
- For the auxiliary boiler, AES has provided emission reduction credits (ERCs) for PM_{10}, SOx, and VOC emissions.
- For the turbines and auxiliary boiler, AES will provide RECLAIM Trading Credits (RTCs) for the NOx emissions pursuant to RECLAIM regulations.

o SCAQMD Planning, Rule Development & Area Sources (PRDAS) staff reviewed the applicant's dispersion modeling analysis, including the health risk assessment results, by independently reproducing the modeling analysis, to verify compliance with SCAQMD rules and in support of the CEC's CEQA analysis.
- The fumigation modeling determined that there are no shoreline fumigation occurrences and the inversion break-up impacts, combined with worst-case background concentrations, do not exceed the most stringent of the state and national ambient air quality standards.
- For the normal operation impacts for the auxiliary boiler, the dispersion modeling determined that, for attainment pollutants, NO_2, CO, SO_2, PM_{10} (federal standard), the modeled peak impacts plus the worst-case background concentrations do not exceed the most stringent air quality standards. For non-attainment pollutants where the background concentrations exceed the ambient air quality standards, the modeled peak impacts do 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. The modeling was performed to demonstrate compliance with Rule 1303.

- For the commissioning impacts for the combined-cycle turbines, the commissioning impacts for the simple-cycle turbines, and the normal operation impacts for the AEC facility, the dispersion modeling determined that, for attainment pollutants, the modeled peak impacts plus the worst-case background concentrations do not exceed the most stringent air quality standards. For non-attainment pollutants, the modeled peak impacts do not cause an exceedance of the Rule 1303 significant change thresholds. The modeling was performed for informational purposes and in support of CEC's CEQA analysis.
- The health risk assessment analysis determined that each combined-cycle turbine, each simple-cycle turbine, and the auxiliary boiler are in compliance with the required Rule 1401 standards for maximum individual cancer risk, acute index, and chronic index. The health risk assessment for the facility determined compliance with the Rule 1401 standards and was performed for informational purposes and in support of CEC's CEQA analysis.

- SCAQMD Planning, Rule Development & Area Sources (PRDAS) staff reviewed the applicant's air quality impacts analysis and visibility impairment analysis for Prevention of Significant Deterioration (PSD) compliance.
  - For the normal operation of the AEC facility, the dispersion modeling determined that the maximum predicted impacts for annual NO_2, 1-hr and 8-hr CO, and 24-hr and annual PM_{10} are below the respective Class II Significance Impact Levels (SILs). Therefore, these impacts are less than significant.
  - The maximum predicted 1-hour NO_2 impact of 31.3 µg/m^3 exceeds the Class II SIL of 7.52 µg/m3, with a radius of impact with predicted concentrations greater than 7.52 µg/m^3 of 1.5 km. Therefore, the cumulative impacts of the AEC and competing sources are required to be assessed for all receptors where the AEC impacts alone exceeded the 1-hour NO_2 SIL. Pursuant to the SCAQMD Planning, Rule Development & Area Sources Modeling Review Memo, dated 5/20/16, which is attached as an appendix to the PDOC, the cumulative impacts analysis shows the 1-hour NO_2 impact from the project plus cumulative projects plus background is 251.3 µg/m^3, which exceeds the 1-hour NO_2 NAAQS of 188 µg/m^3. The review memo explains that an examination of each facility's contributions to the modeled exceedances shows that Alamitos' maximum contributions to the modeled exceedances is 6.9 µg/m^3, which is less than the 1-hour NO_2 SIL of 7.52 µg/m^3. Therefore, Alamitos' impacts are less than significant and do not cause or contribute to the modeled exceedance.
  - 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. Because the factor is calculated to be greater than 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 Federal Land Manager. The visibility and deposition modeling analysis was submitted to the National Park Service and the Forest Service for review. The 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. The Forest Service indicated they reviewed the AEC project application package and have no comments.

- To evaluate the potential impacts on Class I areas near the AEC site, the maximum predicted impacts of the AEC were compared against the Class I SIL for NO_2 (annual) and PM_{10} (24-hour and annual). Since the impacts at 50 km are 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.
- To evaluate the potential for visibility impairment (e.g., plume blight) associated with AEC, a quantitative visibility analysis for Class II areas within 50 km of AEC was performed using the VISCREEN plume modeling program. The criteria for Class I areas was used, because there are currently no thresholds for visibility impacts on Class II areas. Therefore, the evaluation is presented solely for informational purposes Because the VISCREEN Tier I modeled results for each Class II area did not exceed the criterion for color contrast or plume contrast, AEC will not adversely affect visibility at these or other nearby Class II areas.

- For the combined- and simple-cycle turbines, permit conditions limit CO_2 emissions in terms of tons per year per turbine on a 12-month rolling average basis and in lbs per gross megawatt-hours to ensure compliance with greenhouse gas BACT and with 40 CFR 60 Subpart TTTT-Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units.

- Maximum monthly emission limits and annual emission limits, where appropriate, based on commissioning, normal operation, start-ups, and shutdowns, are imposed by permit condition for the combustion equipment to ensure compliance with offset, ambient air quality modeling, and health risk assessment requirements. Commissioning is limited in duration for total hours and hours without control. Startups and shutdowns are limited in number, duration, and emissions per event.

- SCAQMD has determined the proposed AEC, with implementation of the imposed mitigation measures to reduce air impacts to less than significant, will comply with all applicable federal, state and local air quality rules and regulations.

California Energy Commission
The CEC staff's evaluation of impacts, including on the environmental justice (EJ) population, and imposition of required mitigation measurements are detailed in the PSA.

- Executive Summary
  On pg. 1-6, the PSA concludes: "Staff concludes that with implementation of staff's recommended mitigation measures described in the conditions of certification, the AEC would comply with all applicable laws, ordinances, regulations, and standards (LORS). Staff also concludes that for all
  areas, significant adverse direct, indirect, and cumulative impacts would not occur. In the technical area of Air Quality, additional information is needed to demonstrate that applicable LORS would be met, and all impacts would be mitigated to less than significant." Subsequent to the publication of the PSA, SCAQMD confirmed that AES has provided the offset credit for SO_2 and successfully completed the public notice requirements pursuant to SCAQMD Rule 212 requirements. Therefore, the additional information has been provided to demonstrate that applicable LORS would be met.

  On pg. 1-32, the PSA concludes: "The staff for the topics of Air Quality, Hazardous Materials Management, Noise and Vibration, Soil and Water Resources, Traffic and Transportation, Visual Resources, and Waste Management has proposed conditions of certification to reduce project impacts to less than significant. Therefore, with implementation of these conditions, impacts would be reduced to less than significant for any population in the project's six-mile radius, including the EJ population."

  On the same page, the PSA concludes: "Land Use, Public Health, and Transmission Line Safety and Nuisance staff concludes that the project impacts related to their technical area would be less than significant and therefore would have a less than significant impact to any population in the project's six mile radius, including the EJ population."

- Air Quality
  On pg. 4.1-1, the PSA concludes: "Staff concludes that the proposed Alamitos Energy Center (AEC or project) does not comply with all applicable laws, ordinances, regulations and standards (LORS) or with California Environmental Quality Act (CEQA) requirements because offset credits for SO2 have not been identified and proper noticing of the proposed project to parents of nearby school children has not yet been completed. Once these two items are addressed, Staff concludes that with the adoption of the attached conditions of certification, the proposed AEC would not result in significant air quality related impacts during project construction or operation, and that the AEC would comply with all applicable federal, state and South Coast Air Quality Management District (SCAQMD or District) air quality LORS." Subsequent to the publication of the PSA, SCAQMD confirmed that AES has provided the offset

credit for SO_2 and successfully completed the public notice requirements pursuant to SCAQMD Rule 212 requirements.

On pg. 4.1-69, the PSA states: "Staff has considered the minority population surrounding the site and reviewed **Socioeconomics Figure 1** (see the **Socioeconomics** and **Executive Summary** sections of this document for further discussion of environmental justice), which shows the minority population within portions of the 6 mile buffer zone is greater than 50
percent, thus qualifying as an environmental justice population."

On the same page, the PSA concludes: "The staff-proposed CEQA mitigation measures noted as conditions of certification would reduce the proposed facility modifications' direct and cumulative **Air Quality** impacts to a less than significant level, including impacts to the environmental justice population. Therefore, there are no **Air Quality** environmental justice issues related to the proposed facility modifications and no minority or low-income populations would be significantly or adversely impacted."

See PSA for the evaluation of impacts, including on the environmental justice (EJ) population, and imposition of required mitigation measurements, for the areas of :

- Biological Resources
- Cultural Resources
- Hazardous Materials Management
- Land Use
- Noise and Vibration
- Public Health
- Socioeconomics
- Soil and Water Resources
- Traffic and Transportation
- Transmission Line Safety and Nuisance
- Visual Resources
- Facility Design
- Geology & Paleontology
- Power Plant Efficiency
- Power Plant Reliability
- Transmission System Engineering
- Waste Management, and
- Worker Safety and Fire Protection

Based on the CEC analysis in their PSA, the SCAQMD concludes that the adverse impacts of the proposed facility have been avoided to the maximum extent possible.

Third, a cost benefit analysis of the environmental and social cost balanced against the social, economic, and environmental benefits of the project demonstrate that the latter outweigh the former.

Environmental Impact Costs
The SCAQMD and CEC have evaluated environmental and social cost and imposed mitigation measures to ensure that the adverse impacts of the proposed facility have been avoided to the maximum extent possible, as discussed in detail above.

Social, Economic, Environmental Benefits
AES and the CEC discussed social, economic, and environmental benefits in the Supplemental Application for Certification[7] and the PSA, respectively.

Applicant
On pages 1-8 to 1-9 of the Supplemental AFC, AES discusses key benefits of the AEC project, including:

- Provide operationally flexible generating capacity and ancillary electrical services (voltage support, spinning reserve, inertia) to the Los Angeles Basin Local Reliability Area in general, and specifically to the western Los Angeles Basin sub-area, to serve reliability needs and peak southern California energy demand.
- Meet demand for new generation caused in large part by the closure of the San Onofre Nuclear Generating Station and the anticipated retirement of older, natural-gas-fired generation currently using once-through ocean water cooling, such as the existing Alamitos Generating Station, by December 31, 2020.
- Provide fast starts and ramp-up/ramp-down capability that allow AEC turbines to shut down when not needed, in contrast to the existing steam utility boilers which need to be maintained on stand-by load.
- Provide superior thermal efficiency as compared to the existing steam utility boilers.
- Support local electrical reliability and grid stability to allow the integration of intermittent, renewable energy into the electrical grid and enable attainment of California's Renewable Energy Portfolio Standards (RPS).
- Serve the western Los Angeles Basin load center without constructing new transmission facilities.
- Use substantially less fresh water than the existing Alamitos Generating Station has historically used. The existing steam utility boilers generate power with steam only, whereas the proposed turbines generate power mechanically and with steam.
- Result in reduced visual impact compared to the existing Alamitos Generating Station due to AEC's shorter exhaust stacks.

7 http://docketpublic.energy.ca.gov/PublicDocuments/13-AFC-01/TN206427-1_20151026T143702_Alamitos_Energy_Center_Supplemental_AFC.pdf

- Avoid potential impacts to critical habitats and other wildlife areas by locating the project on the brownfield site of the existing Alamitos Generating Station.
- Minimize potential land use impacts by reusing existing infrastructure.
- Provide economic benefit of between approximately $1.1 billion and $1.3 billion in capital cost, approximately $132.29 million in local purchases of materials and supplies during construction, and approximately $8,312,000 per year of local operational expenditures.
- Employ an average of 191 workers over the 56-month construction period and permanent average workforce of 36 for the operating facility.

<u>California Energy Commission</u>
The CEC discusses the public benefits related to greenhouse gas emissions and water resources.

On pg. 4.1-155 and 4.1-156 of the PSA, the CEC describes the public benefits of the project related to greenhouse gas emissions:

"The AEC would burn natural gas for fuel and thus produce GHG emissions that contribute cumulatively to climate change, but it would also have a beneficial impact on system operation and facilitate a reduction in GHG emissions in several ways:

- When dispatched, the AEC would displace less efficient (and thus higher GHG-emitting) generation. Because the project's GHG emissions per megawatt-hour (MWh) would be lower than those power plants that the project would displace, the addition of the AEC would contribute to a reduction of Western Electricity Coordinating Council system GHG emissions overall and the GHG emission rate average.
- The AEC would provide fast start and dispatch flexibility capabilities necessary to integrate expected and desired additional amounts of variable renewable generation (also known as "intermittent" energy resources) to meet the state's renewable portfolio standard (RPS) and GHG emission reduction targets.
- The AEC would replace capacity and generation mostly provided by aging, high GHG emitting power plants, including the existing Alamitos Generating Station that will likely be retiring in order to comply with the State Water Resource Control Board's (SWRCB) policy on the use of once through cooling (OTC).
- The AEC would replace less efficient generation in the South Coast local reliability area required to meet local reliability needs, reducing the GHG emissions associated with providing local reliability services and facilitating the retirement of aging, high GHG-emitting resources in the area. (footnotes omitted)"

On pg. 4.10-21 of the PSA, the CEC describes the noteworthy public benefits of the project related to water resources:

- "The proposed project would reduce the amount of potable water used relative to baseline conditions. The reduction in water use would be about 272 AFY.
- The proposed project would result in approximately 0.24 mgd reduction in discharge of industrial wastewater to the San Gabriel River and ultimately the Pacific Ocean, and a similarly proportional decrease in pollutant loading, which would result in an improvement of the water quality in the Pacific Ocean and the Alamitos Bay.
- The proposed project would utilize dry cooling which significantly reduces potential water consumption. The project would also reuse a portion of the blowdown water from the HRSGs and combustion turbines which would result in reduction of water consumption and wastewater discharges. This would, along with utilization of dry cooling, significantly reduce impacts to water resources compared to older technologies such as OTC."

Therefore, the SCAQMD concludes that the many benefits outweigh the environmental impacts of the project, which have been avoided or minimized through application of stringent mitigation measures and compliance with all applicable federal, state and local rules and regulations.

9. <u>Collateral Impacts from use of Ammonia</u>

The PDOC proposes SCR for the control of NOx emissions from the AEC. The PDOC selects SCR over other technologies but fails to discuss the collateral impacts from the use of ammonia in the SCR. The Huntington Beach power plant owned by AES has a urea to ammonia conversion unit. Currently urea pellets are transported and converted to ammonia onsite at the power plant. Use of urea pellets eliminates the impacts of transportation and storage of large amounts of ammonia for use in the SCR. AES recognizes the importance of the use of urea at its power plant. On the AES website it states that Huntington Beach is, ***"the first plant in the nation to use a urea to ammonia conversion system — eliminating the need to transport ammonia through our community."*** A catastrophic accidental release from the ammonia storage tanks can be prevented by the use of urea at the AEC site and one of the collateral impacts from the use of SCR can be eliminated. SCAQMD district staff also recognizes the dangers of ammonia transportation and storage. SCAQMD staff stated in its analysis of rule 1105.1, *"a reduction in the use of ammonia in response to PR 1105.1, will reduce the current existing risk setting associated with deliveries (i.e., truck and road accidents) and onsite or offsite spills for each of the refineries that use ammonia."*

The storage of large amounts of aqueous ammonia also presents security issues related to terrorist attacks requiring additional security onsite to prevent such incidents. The use of urea pellets eliminates that risk. The FDOC should require the use of urea and prevent the hazards from the transportation, storage, and use of aqueous ammonia and possible terrorist implications.

It is certainly technically feasible as the Huntington Beach Power plant owned by AES already utilizes the urea system. It is obviously available as it is in use at the HBEP.

SCAQMD Response

On pages 6-10 and 6-11, the Supplemental AFC explains urea conversion technology was considered and rejected as an alternative to aqueous ammonia, as follows: "Urea conversion technology uses solid urea (prill) in a reactor with steam to convert the urea to aqueous ammonia, which is typically stored in a tank for use by the SCR system during upsets in the process and plant startup activities. Although the urea conversion technology has been employed for power plants for a number of years, it only eliminates the need to truck aqueous ammonia to the site, because onsite ammonia storage is always included in the system design. Furthermore, the urea conversion process has a higher energy demand over an aqueous ammonia system as a result of consuming steam as part of the process. Finally, the urea process has proven to have poor reliability and slow response times, and it produces an inconsistent concentration of ammonia. The AEC combustion turbines are designed to be fast-start and fast-ramp units that require precise control of ammonia concentrations for emissions control. Therefore, urea conversion was considered and rejected." This assessment was based on AES's operating experience with Units 1-4 at the existing Huntington Beach Generating Station, which uses a urea-to-ammonia conversion system to supply ammonia to the selective catalytic reduction systems (SCRs) for these utility boilers.

The presence of aqueous ammonia storage tanks at this AES site will not be a new occurrence. The existing Alamitos Generating Station has four existing ammonia tanks, 20,000 gallons capacity each, storing 29 weight per cent aqueous ammonia, to supply aqueous ammonia to the SCRs for Utility Boilers Units 1, 2, 3, and 5. The AEC is proposing two ammonia tanks, 40,000 gallons capacity, storing 19 weight per cent aqueous ammonia. The storage capacity at the facility remains 80,000 gallons, but the concentration of the aqueous ammonia will be reduced from 29% to 19%.

An assessment of risks of ammonia transport is properly a part of the CEQA analysis. The California Energy Commission, as the lead agency under the CEQA equivalent process used for power plant licensing, performed a hazardous materials management analysis on pages 4.5-1 to 4.5-41 of the PSA. On page 4.5-1, the CEC staff concluded the proposed AEC's storage and use of hazardous materials at the site, including aqueous ammonia, would not present a significant impact to the public, with the adoption of the proposed conditions of certification. The proposed project would comply with all applicable laws, ordinances, regulations, and standards.

The offsite consequence analysis to assess potential impacts associated with an accidental release of aqueous ammonia and proposed engineering and administrative controls are discussed on pages 4.5-8 to 4.5-12 of the PSA. CEC staff performed an offsite consequence analysis, through the use of an EPA-approved plume modeling program, for a spill from the tanks. The modeling indicated that there was a very small potential of ammonia concentrations of 75 ppm, the level of significance, to reach just offsite to the north, south, east and west. Staff therefore proposed that the secondary containment exposure area be limited to 50 square feet for both tanks to ensure that the plume concentrations of 75 ppm would not migrate offsite and would not pose a significant risk to any off-site members of the public. The proposed conditions of certification include requiring the secondary containment structure to incorporate essential design elements to prevent a worst-case spill from producing significant off-site impacts, and the implementation of a safety management plan that would include the use of both engineering and administrative controls. The administrative controls include the development by AES of a worker health and safety program, a safety management plan for the delivery of all liquid hazardous materials including aqueous ammonia, a risk management plan for aqueous ammonia, and a hazardous material business plan.

The risk assessment for the transportation of the aqueous ammonia by tanker truck is found on pages 4.5-12 to 4.5-14 of the PSA. CEC staff used a transportation risk assessment model to calculate the probability of an accident resulting in a release of a hazardous material due to delivery from the freeway to the facility via Studebaker Road. The CEC staff believes that the risk of exposure to significant concentrations of aqueous ammonia during transportation to the facility is insignificant because of the remote possibility that an accidental release of a sufficient quantity would occur would be very unlikely. The proposed conditions of mitigation include the use of only the specified and California Highway Patrol-approved route to the site.

Site security issues are discussed on pages 4.5-15 to 4.5-16. The conditions of certification provide requirements for a site-specific Construction Site Security Plan and a site-specific Operation Plan. The goal of the conditions is to provide for the minimum level of security for power plants necessary for the protection of California's electrical infrastructure from malicious mischief, vandalism, or domestic/foreign terrorist attacks.

10. <u>Secondary Particulate formation from Ammonia Emissions</u>

According to the PDOC the AEC has the potential to emit 98.85 tons per year of ammonia and 10.19 tons per year of SOx. Offsets are not provided for either pollutant. SOx is a known precursor to secondary particulate matter formation. It is also well documented that ammonia emissions in the South Coast Air Quality Management District lead to the formation of secondary particulate. [The SCAQMD has performed modeling for its rule 1105.1 that demonstrates that 1.5 tons of ammonia emitted can form from 1.5 tons to 6 tons of secondary particulate a day. SCAQMD has successfully defended its environmental analysis for its Rule 1105.1 in court. The projects 98.5 tons of ammonia emissions per year can lead up to formation of 98.5 to 588 tons per year of secondary particulate according to the districts own analysis for Rule 1105.1.]

This is a very important issue in this permit. The PDOC proposes to limit PM emissions to 69.52 tons per year but with the secondary formation of PM from the ammonia slip and SOx the project will obviously emit more than 100 tons per year of PM 2.5 and therefore is required to meet the requirements of Appendix S.

The FDOC should analyze permits that limit ammonia slip to less than 5 ppm and determine if it is feasible to meet a lower ammonia slip limit for this facility. Several recent permits have contained potential lower ammonia slip limits based on the projects actual ammonia emissions over a trial period generally 2 years. The Energy Commission Staff has recommended that projects consider continuous ammonia monitors because the BAAQMD has established this as an optional means of verification in the license for the Marsh Landing Generating Station (District Application 18404, Final Determination of Compliance, June 2010). The District should add a similar requirement to the HBEP ATC.

SCAQMD Response

The PDOC indicates the AEC has the potential to emit 98.85 tons per year of ammonia, which is based on an ammonia slip concentration that is continuously 5 ppmv. These emissions are conservative because the ammonia slip is lower than 5 ppmv when the catalyst is new and increase over the life of the catalyst. In addition, the emissions are based on maximum permitted annual hours. It is unlikely, however, that the turbines will be operated at the maximum permitted hours because of the integration of higher amounts of renewable energy onto the southern California electrical grid. Offsets are not provided because the SCAQMD requires BACT/LAER but not offsets for ammonia emissions in Regulation XIII (Rule 1303).

Moreover, Rule 1325, which is specific to $PM_{2.5}$, does not include ammonia as a precursor in the SIP-approved version. 80 Fed Reg 24821 (May 1, 2015). On November 4, 2016, Rule 1325 was amended to include ammonia as a precursor but this is not effective until August 14, 2017, or EPA approval of the November 4, 2016 amendment, whichever is later.

The PDOC indicates the AEC has the potential to emit 10.19 tons per year of SOx, which is based on an average of 0.25 grains/100 scf average total sulfur content in the natural gas. These emissions are conservative because the fuel sulfur content has historically been lower than 0.25 grains/100 scf. In addition, the emissions are based on maximum permitted annual hours, but it is unlikely, however, that the turbines will be operated at the maximum permitted hours. The comment asserts that offsets are not provided for SOx. As clarified on pages 68 and 161 of the AEC PDOC, SCAQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler repower projects, but the offsets are provided from the SCAQMD internal offset accounts. If AEC is approved, then AES will be required to pay for offsets from the SCAQMD internal offset accounts for SOx for both combined- and simple-cycle turbines, as explained and calculated on pages 185-194 of the PDOC. Because the auxiliary boiler is not exempt from offsets per Rule 1304(a)(2), pages 178-180 of the PDOC explains that AES is required to provide 1 lb/day SOx ERC. Since the issuance of the PDOC, AES has provided the offset credit. Therefore, the SCAQMD has provided mitigation for the SOx emissions from the project.

The comment states that the PDOC proposes to limit PM emissions to 69.52 tons per year but with the secondary formation of PM from the ammonia slip and SOx, the project will obviously emit more than 100 tons per year of $PM_{2.5}$ and therefore is required to meet the requirements of Appendix S. As a point of clarification, if the AEC were a new facility, then it would be appropriate to use the potential to emit for the AEC to determine whether the AEC is subject to Rule 1325. Since the AEC is a modification to an existing facility, the appropriate criterion is the net emissions increase, which is the difference between the AEC potential to emit and the existing facility's (Alamitos Generating Station) actual emissions. On page 198, the PDOC shows the net increase is 58.61 tons per year. However, as noted above, ammonia is not currently a precursor in Rule 1325. Moreover, the project is not subject to Appendix S, which only applies before a nonattainment area has a SIP-approved NSR rule. The NSR Rule 1325 for $PM_{2.5}$ is SIP-approved. EPA's August 24, 2016 $PM_{2.5}$ Implementation Rule, in 81 Fed Reg 58010 (August 24, 2016), allows areas to rely on an existing SIP-approved NSR rule until revisions are approved by EPA.

The commenter asserts that secondary particulate emissions from ammonia and SOx emissions are required to be added to the permitted 69.52 tons per year of directly emitted $PM_{2.5}$/PM_{10} for the purposes of Rule 1325 applicability. The commenter relies on the SCAQMD's analysis of secondary particulate formation performed for the adoption of Rule 1105.1-- Reduction of PM_{10} and Ammonia Emissions from Fluid Catalytic Cracking Units. The reliance on Rule 1105.1, adopted on 11/7/2003, is misplaced because the purpose of that rule is to limit filterable PM_{10} and ammonia slip from existing, new or modified fluid catalytic cracking units at petroleum refineries. This rule does not require offsets for secondary particulate emissions for the purpose of New Source Review (Rule 1303) or for PSD (Rule 1325).
The 69.52 tons/year PM_{10} already includes the formation of primary ammonium sulfate particulates in the SCRs for the combined- and simple-cycle turbines. The PM_{10} emissions level for the combined-cycle turbines is 8.5 lb/hr, comprised of 6.7 lb/hr at the turbine exhaust and 1.8 lb/hr from ammonium sulfates formed in the SCR. The PM_{10} emission rate for the simple-cycle turbines is 6.23 lb/hr, comprised of 5.0 lb/hr at the turbine exhaust and 1.23 lb/hr from ammonium sulfates. The turbine exhaust emission rates were provided in the vendor guarantees and the ammonium sulfates emission rates were calculated by CH_2M Hill, AES's environmental consultant. The ammonium sulfate emissions were conservatively calculated based on turbine technology, maximum fuel sulfur content, emission control equipment and engineering judgment.

The commenter asserts that several recent permits have contained potential lower ammonia slip limits than 5 ppm based on the projects actual ammonia emissions over a trial period generally 2 years, but does not list the projects, or provide any citations to supporting documentation. The SCAQMD's search of the EPA RACT/BACT/LAER Clearinghouse, Statewide Best Available Control Technology (BACT) Clearinghouse, and other databases for lower ammonia slip emission limits for other recently permitted natural gas-fired combustion turbines are summarized as follows:

- Simple-Cycle Turbines
  No facilities with an ammonia slip limit of less than 5 ppmvd were found. Therefore BACT remains 5 ppmvd at 15% O_2.

- Combined-Cycle Turbines
  The EPA RACT/BACT/LAER Clearinghouse shows three facilities with an ammonia slip limit of less than 5 ppmvd at 15% O_2. The following three facilities were shown having an ammonia slip limit of 2 ppmvd at 15% O_2, and a NOx limit of 2.0 ppmvd at 15% O_2.

  1) Kleen Energy Systems, LLC—Commercial operation started in July 2011. The 2.0 ppmvd at 15% O2 has been verified on the EPA RACT/BACT/LAER Clearinghouse database. The permit, dated 7/2/13, indicates a 2.0 ppmvd ammonia slip limit is applicable during steady state operation, and a 5.0 ppmvd ammonia slip limit is applicable during transient operation. Transient operations include cold, warm and hot startups, shut-downs, shifts between loads, fuel switch and equipment cleaning, as well as operation below 60% load. In contrast, the SCAQMD does require BACT during periods of shifts between loads and operation at below 60% load. As AEC turbines are equipped with fast start and ramp-up/ramp-down capabilities, load changes are expected to be a regular occurrence. As the minimum turndown for the turbines is 44% load, operation at below 60% load is expected to be a regular occurrence. The Kleen Energy System limits do not meet the definition of BACT as implemented by the SCAQMD for a facility with these operating characteristics.

     The permit limits for Kleen Energy are not achieved in practice for facilities where BACT must be met during shifts between loads and at below 60% load. Condition D29.2 requires the initial source testing for combined-cycle turbines to be performed at 45, 75, and 100 percent of maximum load, and for the simple-cycle turbines at 50, 75, and 100 percent of maximum load, because emission rates may vary with load.

  2) Salem Harbor Station Redevelopment—Scheduled to start operation in June 2017. The permit, dated 1/30/14, does not include an ammonia slip limit.

  3) CPV Towantic, LLC—Scheduled to be on line in 2018. The 2.0 limit has not been demonstrated to be achieved in practice.

Therefore, the BACT/LAER ammonia slip limit for simple- and combined-cycle turbines remains 5.0 ppmvd at 15% O2.

The commenter asserts that CEC staff has recommended that projects consider continuous ammonia monitors, but the PSA for AEC does not make any such recommendation. The commenter asserts the reason for this recommendation is that BAAQMD established this as an optional means of verification in the license for the Marsh Landing Generating Station, as set forth in the FDOC, dated June 2010, and the SCAQMD should add a similar requirement for the AEC project. The most recent Marsh Landing permit, dated 11/3/2015, includes condition 17.e, which specifies: "The APCO may require the installation on one exhaust point (P-1, P-2, P-3, or P-4, at the owner/operator's discretion) of a CEM designed to monitor ammonia concentrations if the APCO determines that a commercially available CEM has been proven to be accurate and reliable and that an adequate Quality Assurance/Quality Control protocol for the CEM has been established. The District or another agency must establish a District approved Quality Assurance/Quality Control protocol prior to the ammonia CEM being a requirement of this part. The ammonia CEM shall be used to demonstrate compliance with the ammonia emission limit contained in this Part for the gas turbine being monitored." This condition does not establish a continuous ammonia monitor as a viable option. The condition provides a possible option should the technology be developed.

At this time, neither the EPA nor the SCAQMD has developed an approved protocol for ammonia CEMS. The SCAQMD has not certified any ammonia CEMS for determining compliance with permit limits. To predict ammonia slip, the SCAQMD has established the ammonia slip calculation procedures specified in condition no. A195.15 for the combined- and simple-cycle turbines and in condition no. A195.16 for the auxiliary boiler. These conditions require the operator to calculate and continuously record the ammonia slip using the provided equations, which incorporate the NOx CEMS readings. Condition D29.2 requires an initial source test for ammonia (and other pollutants), using a protocol approved by the SCAQMD Source Test Engineering Dept, for the combined- and simple-cycle turbines to confirm that the ammonia slip meets the 5 ppm limit. The source test is required to be approved by the SCAQMD Source Test Engineering Dept before the Permits to Construct may be converted to Permits to Operate. Condition D29.5 establishes the same source testing requirements for the auxiliary boiler. Condition D29.4 requires ammonia slip testing at least quarterly during the first twelve months of operation and at least annually thereafter for the combined- and simple-cycle turbines, and the auxiliary boiler. The facility may request that the equations in conditions A195.15 and A195.16 be adjusted to become a more reliable predictor of ammonia slip by comparing the ammonia slip source test results and the contemporaneously calculated ammonia slip results.

11. <u>Rule 1325</u>

The requirements of rule 1325 are applicable to the AEC because it will emit more than 100 tons per year of PM 2.5 when the precursor emissions of ammonia are considered in conjunction with the permitted 69.52 tons per year of directly emitted PM 2.5. Ammonia emissions of 95 tons per year are expected to create at a minimum 95 tons per year of secondary particulate matter according to the analysis conducted by the SCAQMD for Rule

1105.1. The permit does not analyze secondary PM 2.5 formation from ammonia allegedly because ammonia is now not a significant precursor to PM 2.5. The courts have upheld SCAQMD's Rule 1105.1 analysis conducted to reduce ammonia emissions from oil refineries. It now appears that the district is conveniently ignoring the court and its own Rule 1105.1 analysis to accommodate another polluting power plant in the same location.

SCAQMD Response
The EPA has taken final action to approve the current Rule 1325 into the California SIP, with an effective date of 6/1/15, in 80 Fed Reg 24821 (May 1, 2015). This action to approve Rule 1325 was proposed in 80 FR 8250 (February 17, 2015), and included the exclusion of ammonia as a precursor to $PM_{2.5}$ in the definition of "Precursor" in Rule 1325(b)(8). The EPA discussed that CAA subpart 4 includes section 189(e), which requires the control of major stationary sources of PM_{10} precursors (and hence under the court decision, $PM_{2.5}$ precursors) ''except where the Administrator determines that such sources do not contribute significantly to PM_{10} levels which exceed the standard in the area.'' EPA has identified ammonia as a precursor to the formation of $PM_{2.5}$. The EPA concluded, however, as allowed by CAA section 189(e), the SCAQMD has provided additional information in its staff report and other documents demonstrating major stationary sources of ammonia emissions do not contribute significantly to $PM_{2.5}$ levels exceeding the PM2.5 National Ambient Air Quality Standard (NAAQS) in the South Coast Air Basin nonattainment area. 80 Fed Reg at 8251.

In the final action, the EPA addressed comments submitted by Earth Justice on behalf of Health Advocates, objecting to its proposed approval of Rule 1325 on three grounds. The first ground, supported by three grounds, is relevant here as it objected to the approval of exclusion of ammonia as a precursor. "Health Advocates disagreed with our [EPA's] proposal on three grounds, asserting that (1) EPA's determination that a contribution of 1.7 tons per day (tpd) of ammonia emissions to the ammonia inventory is small is 'unjustified'; (2) EPA has not demonstrated that ammonia emissions do not contribute significantly to PM2.5 NAAQS violations in the South Coast Air Basin; and (3) it was arbitrary and capricious for EPA to consider the trends and actual air quality of PM2.5 in the area. Earthjustice Letter at p.3." 80 Fed Reg 24822.

EPA disagreed with these comments. EPA applied a weight of the evidence approach taking into account several factors to determine if SCAQMD appropriately determined that major stationary sources of ammonia emissions do not contribute significantly to $PM_{2.5}$ nonattainment in the South Coast Air Basin nonattainment area.

The first factor EPA considered is that there are only four existing major stationary sources of ammonia and these four sources' emissions are only a small percentage (1.7%) of the total ammonia inventory for the South Coast $PM_{2.5}$ nonattainment area. Health Advocates did not submit any information or provide an explanation to show that 1.7% is not a small percentage, or indicate what percentage would be justified as being small. EPA continued to consider the 1.7% contribution of ammonia emissions from the four existing stationary sources to be small. 80 Fed Reg 24822.

A second factor EPA considered is whether major stationary sources of ammonia contribute significantly to levels exceeding the $PM_{2.5}$ NAAQS in the area, and whether potential new major stationary sources would be expected to contribute significantly to levels exceeding the $PM_{2.5}$ NAAQS in the area. The SCAQMD provided a dispersion modeling analysis study that supported EPA's determination that existing and new major stationary sources of ammonia would make a relatively minor contribution to levels exceeding the 1997 or 2006 $PM_{2.5}$ NAAQS in the area. 80 Fed Reg 24822.

A third factor EPA considered was the progress the SCAQMD has made and the overall severity of the $PM_{2.5}$ nonattainment problem in the South Coast Air Basin. Health Advocates contends it was arbitrary and capricious to consider this factor. The EPA disagreed. First, EPA's General Preamble in 1992 noted that determinations under CAA section 189(e) are case-by-case and depend on a variety of information that is specific to the area. Second, EPA's proposed $PM_{2.5}$ Implementation Rule recently reiterated that application of section 189(e) should be case-specific and focused on location, including a weight of the evidence approach considering, among other factors, the severity of the nonattainment problem in the area. Therefore, it is appropriate to consider this factor. 80 Fed Reg 24822-24823.
Therefore, Rule 1325 does not currently include ammonia emissions as a precursor to $PM_{2.5.}$ Rule 1325 was amended on November 4, 2016, to include ammonia as a precursor, but that revision is not effective until August 14, 2017, or when EPA approves the November 4 amendment, whichever is later.

Your comment states ammonia emissions of 95 tons per year are expected to create at a minimum 95 tons per year of secondary particulate matter according to the analysis conducted by the SCAQMD for Rule 1105.1. The staff report for the adoption of Rule 1105.1 relied on the regional modeling performed for the 2003 Air Quality Management Plan (AQMP). Since the modeling that was referenced was from a previous AQMP, it is not applicable to today's situation. When it comes to the requirements for permit modeling, historically, there has only been the requirement to model direct emissions from the project, which is what was done for the PDOC. However, EPA is looking into the methodology for performing project-specific photochemical modeling which would cover the impacts from secondary formation. Currently, the guidance for $PM_{2.5}$ permit modeling (which does not apply to non-attainment areas like the South Coast Air Basin) is based on a qualitative and quantitative approach of a project's direct $PM_{2.5}$ emissions and precursor emissions of NOx and SOx. Ammonia is not included. EPA is working on coming up with methodology to address the other precursors, like ammonia when they release their significant impact level (SIL) and model emissions rates for precursors

(MERP). Until then, there is no specific EPA guidance as to how to model project specific secondary formation $PM_{2.5}$ impacts.

12. <u>40CFR 51 Appendix S – Federal PM2.5 New Source Review</u>

A major polluting facility is defined as a facility located in a federal non-attainment area which has actual emissions, or a potential to emit of greater than 100 tons per year, of either PM2.5 or its precursors. According to the public notice for the permit the project can emit 69.52 tpy of direct PM 2.5, 10.19 tons of SOx , and 105.3 tpy of ammonia. When considering the unmitigated ammonia and SOx emissions the project is a major source for PM 2.5. The PDOC concludes that the project is not a major polluting facility because it concludes that ammonia and SOx emissions are not precursors. But recent court rulings require an affirmative showing that ammonia is not a precursor is necessary to conclude that ammonia emissions are not a precursor to PM 2.5. Ironically SCAQMD has performed modeling for its rule 1105.1 that demonstrates that 1.5 tons of ammonia emitted can form from 1.5 tons to 6 tons of secondary particulate a day. SCAQMD has successfully defended its environmental analysis for its Rule 1105.1 in court.

Clean air Act §7513a. defines a major source in a serious non attainment area : For any Serious Area, the terms "major source" and "major stationary source" include 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, at least 70 tons per year of PM–10. The project is allowed to emit up to 69.52 tons per year of PM. When rounded up as required by the CAA the project equals the 70 ton per year major source requirements. SCAQMD has not revised its regulations to comply with this section of the clean air act but is required to do so by August 14, 2017. If the source does not commence construction until August 14, 2017 the source is a major stationary source for particulate matter and is subject to those requirements.

<u>*SCAQMD Response*</u>

At the SCAQMD Governing Board Meeting on October 7, 2016, a public hearing was set for November 4, 2016 to consider amendments to Rule 1325. Amendments to Rule 1325 are proposed to establish appropriate major stationary source thresholds for direct PM2.5 and PM2.5 precursors, including VOC and ammonia, in order to align with the recent reclassification of the South Coast Basin from a “moderate” PM2.5 nonattainment area to a “serious” nonattainment area and with U.S. EPA’s Fine Particulate Matter National Ambient Air Quality Standards implementation rule. The proposed amendments are intended to facilitate SIP approval of the regulations.

The amendments propose to add ammonia and VOC as precursors to $PM_{2.5}$, per Clean Air Act Subpart 4 requirements. The major polluting facility thresholds will be lowered from the current 100 tons per year per pollutant to 70 tons per year per pollutant. These amendments will be effective after August 14, 2017 or upon the effective date of EPA’s approval of these amendments to this rule, whichever is later. U.S. 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 58010 (August 24, 2016). The proposed amendments were adopted without change on November 4, 2016.

13. Environmental Justice

The cities of Long Beach and Hawaiian Gardens have a higher percent of people living below the federal poverty level compared with those in the reference geographies of Long Beach-Lakewood Census County Division (CCD), North Coast CCD, and Anaheim-Santa Ana-Garden Grove CCD. The below poverty level population constitutes an EJ population based on poverty. The permit never mentions the environmental justice population that resides near the AEC so obviously no outreach was conducted in the EJ community.

The SCAQMD has the worst particulate matter problem and one of the worst ozone problems in the entire nation. This project exacerbates the air pollution problem because the project is not required to provide PM 2.5 offsets or SOx offsets due to the district Rule 1304(a)(2) which provides a modeling and offset exemption for utility boiler repower projects. The project in conjunction with other sources also results in a violation of the Federal NO2 standard. The district provides no mitigation for these air quality impacts despite the presence of the environmental justice community near the project site. The districts should deny this permit and prevent further injustice to the EJ community.

SCAQMD Response

On page 1-32 of the PSA, the CEC states: "**Socioeconomics Table 3** shows that the cities of Long Beach and Hawaiian Gardens have a higher percent of people living below the federal poverty level compared with those in the reference geographies of Long Beach-Lakewood Census County Division (CCD), North Coast CCD, and Anaheim-Santa Ana-Garden Grove CCD. Staff concludes that the below poverty-level population constitutes an EJ population based on poverty." This is the same language as appears in the comment.

As explained above, the SCAQMD and CEC has determined that, with the implementation of mitigation measures, any project impact, including to the EJ population, would be reduced to less than significant. On page 1-32 of the PSA, the CEC concludes: "The staff for the topics of Air Quality, Hazardous Materials Management, Noise and Vibration, Soil and Water Resources, Traffic and Transportation, Visual Resources, and Waste Management has proposed conditions of certification to reduce project impacts to less than significant. Therefore, with implementation of these conditions, impacts would be reduced to less than significant for any population in the project's six-mile radius, including the EJ population. On the same page, the CEC continues: "Land Use, Public Health, and Transmission Line Safety and Nuisance staff concludes that the project impacts related to their technical area would be less than significant and therefore would have a less than significant impact to any population in the project's six mile radius, including the EJ population." Therefore, special outreach to the EJ population was not implemented.

The commenter asserts the AEC exacerbates the air pollution problem because the project is not required to provide PM2.5 offsets or SOX offsets due to Rule 1304(a)(2), which provides a modeling and offset exemption for utility boiler repower projects. As clarified on pages 68 and 161 of the AEC PDOC, SCAQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler repower projects, but the offsets are provided from the SCAQMD internal offset accounts. Page 183 of the AEC PDOC quotes Rule 1304.1(a) in part: "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…." Rule 1304.1(a) continues on to state: "Offsets in SCAQMD internal accounts are valuable public goods. The purpose of this rule is to recoup the fair market value of offsets procured by eligible EGFs electing to use such offsets to comply with Rule 1304(a)(2)." If AEC is approved, then AES will be required to pay for offsets from SCAQMD internal offset accounts for PM_{10} (includes $PM_{2.5}$), SOx, and VOC for both combined- and simple-cycle turbines, as explained and calculated on pages 185-194 of the PDOC. Since AEC will be a NOx RECLAIM facility, AES is required to provide RECLAIM Trading Credits (RTCs) under RECLAIM requirements, rather than to purchase NOx offsets through Rule 1304.1. Because the auxiliary boiler is not exempt from offsets per Rule 1304(a)(2), pages 178-180 of the PDOC explains that AES is required to provide 4 lb/day VOC emission reduction credits (ERCs), 1 lb/day SOx ERC, and 5 lb/day PM_{10} ERCs, and RTCs for NOx. Therefore, the SCAQMD has provided mitigation for the emissions from the project.

The commenter asserts that the project in conjunction with other sources also results in a violation of the Federal NO_2 standard. This is not a correct interpretation of the cumulative impact analysis for the AEC and competing sources. Pursuant to the SCAQMD Planning, Rule Development & Area Sources Modeling Review Memo, dated 5/20/16, which is attached as an appendix to the PDOC, page 233 of the PDOC explains the need for the cumulative impacts analysis: "The maximum predicted 1-hour NO_2 impact of 31.3 µg/m^3 exceeds 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. Therefore, 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." Pages 233-235 explain the modeling analysis. Page 235 concludes: "The 1-hour NO_2 impact from the project plus cumulative projects plus background is 251.3 µg/m^3, which exceeds the 1-hour NO_2 NAAQS of 188 µg/m^3. An examination of each facility's contributions to the modeled exceedances shows that Alamitos' maximum contributions to the modeled exceedances was 6.9 µg/m^3, which is less than the 1-hour NO_2 SIL of 7.52 µg/m^3. Therefore, Alamitos' impacts are less than significant and does not cause or contribute to the modeled exceedance."

14. Air Quality Analysis and HRA

Both the air quality analysis and the health risk assessment are defective as nether analysis includes the continued operation of units at the AEC that will not retire upon commissioning of the combined cycle units.

SCAQMD Response

On pages 69-70 of the AEC PDOC, Table 2 – AES Rule 1304(a)(2) Offset Plan shows that AGS Units 1, 2, and 5 are required to be retired upon the completion of the commissioning for the combined-cycle turbines, no later than 12/29/2019. The table shows AGS Unit 3 will not be retired until 12/31/2020, which is prior to the start of commissioning for the simple-cycle turbines on 6/1/2021. Therefore, AGS Unit 3 is the only unit that will not be retired upon commissioning of the combined-cycle units. (For the FDOC, AGS Unit 6 will be retired instead of Unit 5, without any change to schedule. Units 5 and 6 are identical.)

On page 160 of the AEC PDOC, the Rule 1303(b)(1) modeling requirements are summarized as: "The Executive Officer or designee shall, except as Rule 1304 applies, deny the Permit to Construct for any new or modified source which results in a net emission increase of any nonattainment air contaminant at a facility, unless the applicant substantiates with air dispersion modeling that the new facility or modification will not cause a violation, or make significantly worse an existing violation according to Appendix A of the rule, or other analysis approved by the Executive Officer or designee, of any state or national ambient air quality standards at any receptor location in the District."

The ambient ground level concentrations, known as background concentrations, are monitored by a network of SCAQMD air monitoring stations. The background concentrations include emissions from existing facilities, including AGS Units 1, 2, 5 and 3, without the proposed project. For the attainment pollutants, NO_2, CO, SO_2, PM_{10} (federal 24-hour standard), compliance is demonstrated through modeling the worst-case project impacts plus the background concentrations to show that it will not exceed the most stringent air quality standard.

The air quality analysis is not defective because the modeling already takes into account the operation of AGS Unit 3 (as well as Units 1, 2, and 5) in the background concentration. As required by Rule 1303(b)(1) and Rule 2005(c)(1)(B), Table 57 shows the modeled results for the completed AEC project on page 172 of the AEC PDOC. Table 57A shows the modeled results for the Auxiliary Boiler on page 173. Table 59 shows the modeled results for the commissioning of the combined-cycle block on page 175. Table 61 shows the modeled results for the commissioning of the simple-cycle block. It should be noted that the dispersion modeling is based on the maximum emissions from the proposed AEC project and that these modeled impacts are added to the background concentrations. No credits were taken for the reduction in emissions from the units to be retired. Therefore, the air quality analysis is conservative.

On page 200 of the AEC PDOC, the Rule 1401—New Source Review of Toxic Air Contaminants requirements are summarized as: "Rule 1401 specifies limits for maximum individual cancer risk (MICR), and acute and chronic hazard index (HI) from new permit units, and relocations or modifications to existing permit units that emit toxic air contaminants. Because the limits are for each permit unit, the limits are for each turbine and the auxiliary boiler. Rule 2005(j) requires compliance with Rule 1401 for RECLAIM facilities."

The health risk assessment (HRA) is not defective, because Rule 1401 requires assessment for new permit units, and relocations or modifications to existing permit units. Because AGS Unit 3 will not be relocated or modified, an HRA is not required because there will be no change to evaluate. Because an HRA is required on a permit unit basis, an HRA is not required to be performed for the facility upon completion of Phase 1 of the AEC project (existing AGS Unit 3 and two new combined-cycle turbines with associated auxiliary boiler), as suggested by the commenter.

As required by Rule 1401 and 2005(j), Table 68 presents the HRA results for each of the two combined-cycle turbines on page 202 of the PDOC. Table 69 shows the HRA results for the auxiliary boiler on page 203. Table 70 shows the HRA results for each of the four simple-cycle turbines on page 204. Although not required by Rule 1401, Table 70A shows the HRA results for the completed AEC facility comprised of two combined-cycle turbines, the associated auxiliary boiler, and four simple-cycle turbines, on page 205, for CEQA and informational purposes only. It should be noted the HRAs do not take credit for the reduction in toxic emissions resulting from the retirement of AGS Units 1, 2, 5, and 3.

Letter No. 2
Draft Permit to Operate Comments

Page 41 of the Facility Permit to Operate and Page 22 of the PDOC, Condition 1.3.

Page 41 of the Facility Permit to Operate and Page 22 of the PDOC, Condition C1.3 – The start-up restrictions are not consistent with the maximum month emissions, place undue operating restrictions on the equipment without justification, and would result in the equipment being unable to respond to dispatch orders from the local balancing authority. Since the warm and hot start-up emissions and durations are identical and are in all cases less than the emissions from a cold start, there should be no restriction on hot and warm starts other than the total monthly and annual limits on any start condition. The following revisions to Condition C1.3 are necessary:

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~~, the number of warm startups shall not exceed 12 in any calendar month, and the number of hot startups shall not exceed 35 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~~, the number of warm startups shall not exceed 88 in any calendar year,~~ and the total number of ~~hot~~ startups shall not exceed ~~332~~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~~warm~~ startup is defined as a startup which occurs after the combustion turbine has been shut down less than ~~10 hours or more but less than~~ 48 hours. A ~~warm~~non-cold startup shall not exceed 30 minutes. The NOx emissions from a ~~warm~~non-cold startup shall not exceed 17 lbs. The CO emissions from a ~~warm~~non-cold startup shall not exceed 137 lbs. The VOC emissions from a ~~warm~~non-cold startup shall not exceed 25 lbs.

~~For the purposes of this condition, a hot startup is defined as a startup which occurs after the steam turbine has been shut down for less than 10 hours. A hot startup shall not exceed 30 minutes. The NOx emissions from a hot startup shall not exceed 17 lbs. The CO emissions from a hot startup shall not exceed 137 lbs. The VOC emissions from a hot startup shall not exceed 25 lbs.~~

The beginning of a 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.

SCAQMD Response

Your comment indicates the Condition 1.3 restrictions on the hot and warm starts place undue operating restrictions on the equipment without justification. As you may recall, on March 8, 2016, you visited SCAQMD headquarters to deliver and discuss the preliminary information for the revised Application for the Huntington Beach Energy Project, which requested changes to the operating profile for the combined-cycle turbine generators. At that meeting, then-Senior Engineer John Yee and Engineer Chris Perri inquired why AES differentiates between warm and hot starts in their Applications because the emissions and durations for both are identical. Your response was that the CEC requires differentiation and, therefore, AES does as well. In accordance with your explanation, SCAQMD diligently differentiated between hot and warm starts and placed separate restrictions on each.

On June 15, 2016, Nancy Fletcher, CEC, inquired why Condition 1.3 differentiates between warm and hot starts. When informed that you stated the CEC requires differentiation, Ms. Fletcher clarified the CEC requires differentiation only when there is a difference. Because differentiation is not required by the SCAQMD or the CEC when there is no difference in emissions or duration, the proposed revised language is acceptable.

Page 50 of the Facility Permit to Operate and Pages 24 and 38 of the PDOC, Condition 29.2.
Page 54 of the Facility Permit to Operate and Pages 57, 60, and 63 of the PDOC, Condition D29.4.
Page 55 of the Facility Permit to Operate and Page 50 of the PDOC, Condition D29.5.

Page 50 of the Facility Permit to Operate and Pages 24 and 38 of the PDOC, Condition D29.2 – The Facility Permit to Operate requires oxides of sulfur (SOx) testing at the outlet of the selective catalytic reduction (SCR) serving this equipment (the combined-cycle and simple-cycle combustion turbines), whereas the PDOC Condition D29.2 requires SOx testing via a fuel sample. Additionally, the Facility Permit to Operate requires District Method 207.1 or U.S. Environmental Protection Agency (EPA) Method 17 for ammonia (NH_3) testing, whereas the PDOC Condition D29.2 requires District Method 207.1 and 5.3 or EPA Method 17. Please revise the Facility Permit to Operate Condition D29.2 to require SOx testing via a fuel sample and District Method 207.1 and 5.3 or EPA Method 17 for NH_3 testing.

Page 54 of the Facility Permit to Operate and Pages 57, 60, and 63 of the PDOC, Condition D29.4 – The Facility Permit to Operate requires NH_3 testing at the inlet of the SCR serving this equipment (the combined-cycle combustion turbines, simple-cycle combustion turbines, and auxiliary boiler), whereas the PDOC Condition D29.4 requires NH_3 testing at the outlet of the SCR. Please revise the Facility Permit to Operate Condition D29.4 to require NH_3 testing at the outlet of the SCR.

Page 55 of the Facility Permit to Operate and Page 50 of the PDOC, Condition D29.5 – The Facility Permit to Operate requires SOx testing at the outlet of the SCR serving this equipment (the auxiliary boiler), whereas the PDOC Condition D29.5 requires SOx testing via a fuel sample. Additionally, the Facility Permit to Operate requires District Method 207.1 or EPA Method 17 for NH_3 testing, whereas the PDOC Condition D29.5 requires District Method 207.1 and 5.3 or EPA Method 17. Please revise the Facility Permit to Operate Condition D29.5 to require SOx testing via a fuel sample and District Method 207.1 and 5.3 or EPA Method 17 for NH_3 testing.

SCAQMD Response

For conditions D29.2, D29.4, and D29.5, the PDOC is correct. The data input for these conditions will be corrected in the Facility Permit program for the Facility Permit to Operate print-out.

PDOC Comments

Page 89, Worst Case Scenario

Page 89, Worst Case Operating Scenario – The ambient temperature listed as 63.3 degrees Fahrenheit (°F) should be 65.3°F, consistent with data presented throughout the remainder of the PDOC.

SCAQMD Response

The 63.3 ºF will be corrected to 65.3 ºF for the ambient temperature of one set of operating scenarios presented.

Page 95, Start-up of Combined-Cycle Turbines

Page 95, Startup of Combined-Cycle Turbines – The combined-cycle combustion turbine hot and warm start emissions and duration are identical. Therefore, per the comment provided on the Facility Permit to Operate, the SCAQMD should describe these as a single start type (i.e., non-cold) and consolidate emissions presented throughout this section accordingly (see Tables 17, 18, 21, and 25).

SCAQMD Response

The SCAQMD will revise Condition 1.3 to consolidate warm and hot starts into non-cold starts because CEC has provided clarification that it does not differentiate between warm and hot starts unless there is a difference between the two. However, there is no reason to revise the section on start-ups and shutdowns to consolidate emissions for Tables 17, 18, 21, and 25, because this section and the tables accurately reflect the information provided in your revised Applications, submitted on March 30, 2016.

Page 132, Table 40

Page 132, Table 40 – The CO emissions during simple-cycle turbine commissioning should be 50.07 tons per year (tpy), based on the equation presented.

SCAQMD Response

If the BACT for CO had remained 4.0 ppmvd at 15% O_2, the 50.7 tpy would have been corrected to 50.07 tpy for the simple-cycle turbine maximum annual emissions for a commissioning year. As the revised BACT determination has reduced BACT for CO to 2.0 ppmvd, the maximum annual emissions has been revised to 74,931 lb/yr, or 37.47 tpy.

Page 134, Particulate Matter (PM) Calculations

Page 134, Particulate Matter (PM) Calculations – The 30-day average emissions for particulate matter with aerodynamic diameter less than or equal to 10 microns (PM_{10}) should be 154.60 pounds per day (lb/day), consistent with the R2/R1 equation provided.

SCAQMD Response

The 30-day average for PM10 for a simple-cycle turbine will be corrected from 154.65 lb/day to 154.60 lb/day.

Page 140, Oil Water Separator (OWS) Calculations

Page 140, Oil Water Separator (OWS) Calculations – The total containment area for OWS-2 should be 16,117 square feet. The resulting emissions are correct as listed.

SCAQMD Response

The total containment area for the oil/water separator for the simple-cycle turbines (OWS-2) will be corrected from 16,177 ft^2 to 16,117 ft^2. This change does not affect the emissions calculations.

Page 163, Last Paragraph

Page 163, Last Paragraph – AES proposes the following changes to the background concentrations used throughout the analysis, as first indicated in this paragraph:

> For 1-hour federal SO_2, the background concentration should be an average of the maximum values from the 3 most recent years, not the maximum itself. Using data from the North Long Beach monitoring station (South Coastal Los Angeles County 1) for the years 2011 through 2013, this 3-year average should be 30.6 micrograms per cubic meter ($\mu g/m^3$). Note that 2014 data are not available from this station.

SCAQMD Response

PRDAS Staff used the most recent three years of monitoring data available (2012-2014) for SRA 4 South Coastal LA County, comprised of three monitoring stations, to determine the background concentrations. For 1-hour federal SO_2, PRDAS Staff used data from South Coastal LA County 1 for 2012 and 2103, and from South Coastal LA County 3 for 2014 because South Coastal LA County 1 was not in operation for 2014. The average of the maximum values from the three most recent years is 30.1 micrograms per cubic meter (μg/m^3), as correctly reflected in Table 57A on page 173 of the PDOC.

Page 168, Table 53

Page 168, Table 53 – The worst-case emission scenarios provided for 1-hour and 1-hour (federal) SO_2 should be described as follows:

1-hour SO_2: Four turbines in startup, shutdown, and balance of period at ~~minimum~~maximum (~~50%~~100%) load, 28 °F ambient temperature.

1-hour (federal) SO_2: Four turbines in startup, shutdown, and balance of period at ~~minimum~~maximum (~~50%~~100%) load, 65.3 °F ambient temperature.

SCAQMD Response

The worst-case emissions scenarios provided for 1-hour and 1-hour (federal) SO_2 will be corrected from minimum load to maximum load. This change does not affect any of the other parameters in Table 53, including the turbine emission rate.

Page 173, Table 57A

Page 173, Table 57A – For consistency with Table 57, the 1-hour (99th percentile) background SO_2 value of 30.1 μg/m^3 should be revised to 58.2 μg/m^3, unless the background concentrations are revised as recommended above.

SCAQMD Response

The 1-hour (99th percentile) background SO_2 value of 30.1 μg/m^3 is correct in Table 57A. In Table 57, this background value will be corrected to 30.1 μg/m^3, which does not change the conclusion that the total predicted concentration is below the federal standard of 196 μg/m^3.

Page 185, Annual Offset Fee Basis, Calculation c

Page 185, Annual Offset Fee Basis, Calculation c – The Max Allowable Operating Hours Annually should be 4,640 hours per year, as listed later within this calculation.

SCAQMD Response

The "c-Max Allowable Operating Hours Annually" will be corrected from 4612 hr/yr to 4640 hr/yr, as is correctly listed in the calculations two lines down, and in Table 65A.

Page 236, NOx and SO2 Calculations

Page 236, NOx and SO_2 Calculations – The result of the NOx calculation should be 354.11 tpy. Additionally, the SO_2 emission rate used for the simple-cycle combustion turbines should be 0.64 tpy instead of 0.83 tpy, for consistency with data presented in Table 41. Similarly, the SO_2 emission rate used for the combined-cycle combustion turbines should be 3.72 tpy instead of 4.59 tpy, for consistency with data presented in Table 25.

SCAQMD Response

These calculations determine NOx and SO_2 emissions on an annual equivalent basis for the purpose of determining whether visibility and deposition modeling is required for specific Class I areas. The annualized NOx will be corrected from 354,11 tpy to 354.11 tpy. The SO_2 emission rate used for the simple-cycle combustion turbines will be corrected from 0.83 tpy to 0.64 tpy, and the SO_2 emission rate used for the combined-cycle combustion turbines will be corrected from 4.59 tpy to 3.72 tpy. Nevertheless, this does not change the conclusion that visibility and deposition modeling is required.

APPENDIX – PLANNING, RULE DEVELOPMENT & AREA SOURCES (PRDAS) MODELING REVIEW MEMO, DATED 5/20/16

COPY

SOUTH COAST AIR QUALITY M ANAGEMENT SCAQMD

MEMORANDUM

DATE: May 20, 2016

TO: Andrew Lee

FROM: Ian MacMillan

SUBJECT: Modeling Review of AES Alamitos Energy Center Project (Facility ID #115394) (A/N: 579140, 579142, 579143, 579145, 579147, 579150, 579152, 579158, 579160-579170)

As you requested, Planning, Rule Development & Area Sources (PRDAS) staff reviewed the dispersion modeling analysis and health risk assessment (HRA) conducted for the AES Alamitos Energy Center located at 690 North Studebaker Road in the city of Long Beach. The project consists of replacing six utility boilers with one two-on-one Combined-Cycle Gas Turbine (CCGT) power block, one simple cycle power block with four Simple-Cycle Gas Turbines (SCTG), and an auxiliary boiler. The dispersion modeling analysis and HRA (report) and electronic files were submitted for PRDAS staff review along with the modeling request memo dated December 18, 2015. A revised report and electronic files were also submitted for review on January 14, 2016 and again on April 6, 2016.

SUMMARY OF MODELING REVIEW

- **Modeling Conducted Pursuant to SCAQMD Regulations XIII Requirements**
  - ✓ SCAQMD Rule 1304(a)(2) provides an exemption from the modeling requirement of Rule 1303(b)(1) for the installation of the new turbines since AES is permanently retiring their existing electric steam utility boilers. The modeling requirements of Rule 1303(b)(1) do apply to the proposed auxiliary boiler. The modeled impacts from the auxiliary boiler are below all thresholds in Rule 1303.
- **Modeling Conducted Pursuant to SCAQMD Regulation XIV Requirements**
  - ✓ The project's health risks are less than the Rule 1401 cancer and non-cancer permit limits of 10 in one million (for permit units with T-BACT), and hazard index of 1, respectively. The auxiliary boiler's health risks are less than the Rule 1401 cancer and non-cancer permit limits of 1 in one million (for permit units without T-BACT), and hazard index of 1, respectively.
- **Modeling Conducted Pursuant to SCAQMD Regulation XX Requirements**
  - ✓ All equipment in the proposed project is subject to SCAQMD Rule 2005 review for NO_2. Modeled impacts from each piece of equipment are below all ambient air quality thresholds for NO_2.
- **Modeling Conducted Pursuant to Federal Prevention of Significant Deterioration (PSD) Requirements**
  - ✓ The project is subject to PSD regulations for NO_2, PM_{10}, and greenhouse gases (GHG). Although CO was determined not to be subject to PSD, the impacts from CO emissions were reviewed since they were included in the analysis. Impacts were compared to applicable Class I and II significant impact levels (SIL). The project's CO and PM_{10} impacts do not exceed the SIL and no further PSD analysis is needed. Since the project's NO_2 impacts exceeded the 1-hour NO_2 SIL, a cumulative impact assessment was

conducted. The modeled concentration in the cumulative impact analysis exceeded the federal 1-hour NO_2 National Ambient Air Quality Standard (NAAQS). However, the project's contribution to the exceedance is less than the SIL, therefore, the project is not considered a significant source and does not cause or contribute to the modeled NAAQS exceedance. No further PSD analysis is required.

- ✓ The project's impacts on visibility and deposition at the nearest Class I area did not exceed the screening threshold. Additional information is provided in the detailed comments below on an additional analysis requested by EPA Region 9 on visibility in Class II areas.

- **Modeling Conducted Pursuant to CEQA**
  - ✓ SCAQMD is both a responsible agency and a commenting agency under CEQA for this project. As noted above in the memo summary, the modeling analysis conforms to SCAQMD regulations and SCAQMD does not have any comments.

DETAILED COMMENTS ON THE MODELING REVIEW

- **AERMOD Dispersion Modeling Approach**
  - ✓ The applicant utilized AERMOD (version 15181) for the air dispersion modeling, which is the current EPA approved model.
  - ✓ The applicant used meteorological data from the SCAQMD's Long Beach station, which is appropriate for the project.
  - ✓ The AERMOD modeling generally conforms to the SCAQMD's dispersion modeling methodology.
  - ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1 – 6, 9 – 10, and 12 of the latest requesting memos and are assumed to be correct.
  - ✓ The applicant used the monitoring data for SRA 4, South Coastal Los Angeles County monitoring stations. PRDAS staff used the most recent three years of data available (2012-2014) to determine the background concentrations. The predicted modeled impacts were added to the background concentrations for comparison to the ambient air quality standards.
  - ✓ The U.S. EPA approved NO_2 to NO_X conversion ratios of 0.80 and 0.75 were used for evaluating 1-hour and annual NO_2 impacts from the project, respectively.
  - ✓ The receptor grid area covered is adequate to determine the maximum impacts from the project.
  - ✓ Since there are no restrictions on the operating hours for the auxiliary boiler, PRDAS staff's evaluation assumed continuous operations of 8,760 hours/year (24 hours/day, 7 days/week, and 52 weeks/year). For the combined-cycle turbines, the permit was evaluated at 4,640 operating hours per year and 2,358 hours per year for the simple-cycle turbines.
  - ✓ PRDAS staff reproduced the modeling analysis and our results are summarized below.

Modeling Review for Compliance with Applicable Federal, State, and Local Regulations

1. **Federal PSD Air Quality Analyses**

- ✓ The proposed project is subject to PSD review for NO_2 and PM_{10}; therefore, the project's impacts are compared to the corresponding U.S. EPA SILs for each pollutant[1]. CO was determined by AQMD Engineering staff to not be subject to PSD; however, as the analysis was included in the report, PRDAS staff reviewed the analysis and the results are included below.

a. Class I Areas

- ✓ The nearest Class I area to the project site is the San Gabriel Wilderness, which is approximately 53 km away. A radial receptor ring was placed at a distance of 50 km from the project (50 km is the maximum receptor distance of the AERMOD model).
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1 – 6 of the report and are assumed to be correct. The results are summarized in Table A.

Table A – Total Project Operational Impacts to Class I Areas

Pollutant & Averaging Time	Project's Modeled Operational Impact ($\mu g/m^3$)	Class I SIL ($\mu g/m^3$)	Exceeds Class I SIL?
NO_2, Annual	0.0047	0.1	No
PM_{10}, 24-hr	0.056	0.32	No
PM_{10}, Annual	0.0046	0.2	No

b. Class II Areas

- ✓ The project applicant identified four Class II areas in the project vicinity – Crystal Cove State Park, Water Canyon State Park, Chino Hills State Park, and Kenneth Hahn State Park.
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1 – 6 of the report and are assumed to be correct. The results are summarized in Table B.
- ✓ The U.S. EPA established a new 1-hour NO_2 standard of 0.100 ppm (or 188 $\mu g/m^3$) that became effective on April 12, 2010. In order to show compliance with the federal 1-hour NO_2 standard, the applicant used the maximum hourly emissions from startup, shutdown, and normal operations. Given the number of startups and shutdowns, the emissions from these events cannot be considered as intermittent, as described in the U.S. EPA's memo dated March 1, 2011. Emissions from commissioning were not included because commissioning is a once in a lifetime event and the form of the standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations.

[1] Commissioning activities are not to be included per discussion with U.S. EPA Region 9 staff.

Table B – Total Project Operational Impacts to Class II Areas

Pollutant & Averaging Time	Project's Modeled Operational Impact ($\mu g/m^3$)	Class II SIL ($\mu g/m^3$)	Exceeds Class II SIL?
CO, 1-hr	186	2,000	No
CO, 8-hr	44	500	No
NO_2, 1-hr	31.3	7.5 [a]	**Yes**
NO_2, Annual [b]	0.2	1	No
PM_{10}, 24-hr	1.7	5	No
PM_{10}, Annual	0.2	1	No

Note: [a] Interim/Proposed SIL, not yet finalized.
[b] The conversion of NO_X to NO_2 was done using the Tier 2 conversion ratio of 0.75 for annual.

- ✓ The maximum 1-hour NO_2 impact from the proposed project is 31.3 $\mu g/m^3$. This impact exceeds the U.S. EPA 1-hour NO_2 SIL of 7.52 $\mu g/m^3$. Therefore, a cumulative impact assessment is necessary.
- ✓ For the cumulative impact assessment, two facilities (Los Angeles Department of Water and Power's Haynes Generating Station and Beta Offshore) as well as emissions from shipping lane activity off the coast were included in the analysis based on their facility emissions and distance to the project. The conversion of NO_x to NO_2 was done using the Tier 2 ARM, with a value of 0.8 for the 1-hour averaging period. Following the form of the standard, the 1-hour NO_2 impact from the project plus cumulative projects plus background is 251.3 $\mu g/m^3$, which is greater than the federal 1-hour NO_2 standard of 188 $\mu g/m^3$. Examining each facility's contributions to the modeled exceedances, the project's maximum contributions to the modeled exceedances was 6.9 $\mu g/m^3$, which is less than the 1-hour NO_2 SIL of 7.52 $\mu g/m^3$. Therefore, the project is not considered a significant source and does not cause or contribute to the modeled exceedance.

c. <u>Visibility Impact Analysis for Class I and Class II Areas</u>

- ✓ In order to estimate the potential impacts on visibility and deposition at the nearest Class I areas, a screening criteria was used for projects located more than 50 km away from a Class I area. The emissions/distance (Q/D) is calculated using the project's total annual emissions of SO_2, NO_X, PM_{10}, and H_2SO_4 (based on 24-hour maximum allowable emissions) divided by the distance between the project and the nearest Class I area. The project's total annual emissions are 568 TPY. The Q/D ratio is 10.7, which is greater than the threshold of 10; therefore, modeling of visibility and deposition impacts to Class I areas is required.
- ✓ The Air Quality Related Values (AQRV) analysis has been submitted to the Federal Land Manager (FLM) for review and approval.
- ✓ Additionally, the project's impacts on visibility in Class II areas were also analyzed pursuant to EPA Region 9 request. The evaluation below is presented solely for informational purposes as there are no thresholds for visibility impacts on Class II areas. The project utilized the criteria and thresholds for Class I areas, which is conservative. Visibility impacts are based on the calculation of two factors – plume contrast and color

contrast (ΔE) of the plume when compared to the sky and terrain backgrounds. For Class I areas, the criteria used is based on a perceptibility threshold of 0.05 (absolute value) for contrast and 2.0 for ΔE.

- ✓ The project applicant identified four Class II areas in the project vicinity – Crystal Cove State Park, Water Canyon State Park, Chino Hills State Park, and Kenneth Hahn State Park. Using the Level 1 VISCREEN analysis, all of the Class II areas were screened out and do not require further analysis.
- ✓ Currently, there are no established thresholds for Class II areas; therefore, it is not possible to determine if the project presents a significant visibility impact to Class II areas.

2. Rule 2005 Air Quality Analyses

- ✓ The proposed project is subject to SCAQMD Rule 2005 review for NO_2. Each combustion emission unit was modeled separately, and the maximum results are presented below.
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1 – 6 of the report and are assumed to be correct.
- ✓ As shown in Table C, NO_2 modeled concentrations per emission unit, when added to the highest background values, are below applicable ambient air quality standards.

Table C – Impacts for Rule 2005
Maximum Results From Highest Permit Unit For Each Pollutant

Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu g/m^3$)	Background Concentration [a] ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	California AAQS [b] ($\mu g/m^3$)	Federal AAQS [b] ($\mu g/m^3$)	Exceeds Threshold ?
NO_2, 1-hour [d]	13.8	255.5	286.8	339	-	No
NO_2, 1-hour [d]	12.4	146.3	159.1	-	188 [c]	No
NO_2, Annual [d]	0.1	47.6	47.7	57	100	No

Note: [a] Maximum values for NO_2 from SRA 4, South Coastal Los Angeles County monitoring stations for the last three years (2012-2014).
[b] Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted
[c] On April 12, 2010, the U.S. EPA established a new 1-hour NO_2 standard of 100 ppb (188 $\mu g/m^3$). The form of the federal 1-hour NO_2 standard involves a three year average of the 98[th] percentile of the annual distribution of daily maximum 1-hour concentrations.
[d] The conversion of NO_X to NO_2 was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

3. SCAQMD Regulation XIII - Impacts During Normal Operations

- ✓ The auxiliary boiler is subject to the modeling requirements of Regulation XIII and the Rule 1303 thresholds apply.
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1 – 6 of the report and are assumed to be correct.
- ✓ As shown in Table D, the modeled concentrations from the auxiliary boiler, when added to the highest background values, are below the applicable ambient air quality standards.

Table D – Impacts during Normal Operation – Auxiliary Boiler

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration (μg/m³)	Background Concentration [a] (μg/m³)	Total Concentration (μg/m³)	California AAQS [b] (μg/m³)	Federal AAQS [b] (μg/m³)	Exceeds Threshold ?
CO, 1-hr	10	4,237	4,247	23,000	40,000	No
CO, 8-hr	6	2,977	2,983	10,000	10,000	No
NO_2, 1-hr [c]	1.2	255.5	256.7	339	-	No
NO_2, 1-hr [c]	1.1	146.3	147.4	-	188 [d]	No
NO_2, Annual [c]	0.03	47.6	47.63	57	100	No
SO_2, 1-hr	0.5	58.2	58.7	655	-	No
SO_2, 1-hr	0.5	30.1	30.6	-	196 [e]	No
SO_2, 3-hr	0.5	58.2	58.7	-	1,300	No
SO_2, 24-hr	0.1	7.9	8.0	105	-	No
PM_{10}, 24-hr	0.3	59.0	59.3	-	150	No
Non-attainment Pollutant & Averaging Time	**Maximum Modeled Concentration (μg/m³)**	**California AAQS (μg/m³)**	**Federal AAQS (μg/m³)**	**Rule 1303 Thresholds [f] (μg/m³)**		**Exceeds Threshold ?**
PM_{10}, 24-hr	0.3	50	150	2.5		No
PM_{10}, Annual	0.04	20	-	1		No
$PM_{2.5}$, 24-hr	0.1	-	35	2.5		No
$PM_{2.5}$, Annual	0.04	12	12	1		No

Note: [a] Maximum values for CO, NO_2, PM_{10}, and SO_2 from SRA 4, South Coastal Los Angeles monitoring stations for the last three years (2012-2014).
[b] Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted
[c] The conversion of NO_X to NO_2 was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.
[d] On April 12, 2010, the U.S. EPA established a new 1-hour NO_2 standard of 100 ppb (188 μg/m³). The form of the federal 1-hour NO_2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO_2 standard does not apply.
[e] On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard of 75 ppb (196 μg/m³). The form of the federal 1-hour SO_2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.
[f] The South Coast Air Basin is designated non-attainment for the state PM_{10} standards, and state and federal $PM_{2.5}$ standards; therefore, project increments are compared to the significant change thresholds in Rule 1303.

4. SCAQMD Regulation XIV - Health Risk Impacts

- ✓ The applicant performed the risk assessment with the Hot Spots Analysis and Reporting Program Version 2 (HARP2, version 16088).

- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 18, 19, 21, 22, 24, and 25 of the report and are assumed to be correct.
- ✓ As shown in Table E, the peak cancer risk for the proposed project is 1.1 in one million for a resident and 0.1 in one million for a worker. Based on a radius of 0.63 km and a population density of 7,000 persons/km^2, the cancer burden is estimated to be 0.0097. This is below the cancer burden threshold of 0.5.
- ✓ Tables F through H summarize the health risk impacts by permit unit.

Table E – Health Risk Impacts - Total Project

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Resident	1.1 in one million	2.80 E-03	1.76 E-02	10 in one million [a]	1.0	1.0	No
Sensitive	1.0 in one million	2.62 E-03	1.68 E-02	10 in one million [a]	1.0	1.0	No
Worker	0.1 in one million	3.64 E-03	1.88 E-02	10 in one million [a]	1.0	1.0	No

Note: [a] For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million

Table F – Health Risk Impacts – By Permit Unit - CCGT

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Resident	0.5 in one million	1.22 E-03	6.57 E-03	10 in one million [a]	1.0	1.0	No
Sensitive	0.5 in one million	1.71 E-03	5.81 E-03	10 in one million [a]	1.0	1.0	No
Worker	0.02 in one million	1.71 E-03	6.72 E-02	10 in one million [a]	1.0	1.0	No

Note: [a] For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million

Table G – Health Risk Impacts – By Permit Unit - SCGT

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Resident	0.05 in one million	1.26 E-04	1.75 E-03	10 in one million [a]	1.0	1.0	No
Sensitive	0.02 in one million	4.59 E-05	1.64 E-03	10 in one million [a]	1.0	1.0	No
Worker	0.002 in one million	1.37 E-04	3.85 E-03	10 in one million [a]	1.0	1.0	No

Note: [a] For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million

Table H – Health Risk Impacts – Auxiliary Boiler

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Resident	0.01 in one million	2.84 E-05	3.18 E-04	1 in one million [a]	1.0	1.0	No
Sensitive	0.01 in one million	1.94 E-05	1.01 E-04	1 in one million [a]	1.0	1.0	No
Worker	0.001 in one million	9.67 E-05	4.90 E-04	1 in one million [a]	1.0	1.0	No

Note: [a] For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million

5. Fumigation Air Quality Analyses

- ✓ Since there are tall stacks along the shoreline, the shoreline fumigation and inversion break-up impacts of the project were analyzed since during these short term events the maximum impacts could be higher.
- ✓ Both inversion break-up and shoreline fumigation were evaluated in the report for 1-hour NO_2, 1-hour, 3-hour, and 24-hour SO_2, 1-hour and 8-hour CO, and 24-hour PM_{10}. Because these meteorological phenomena do not persist for long periods, only the shorter averaging periods ($\leq$ 8 hrs) should be considered.
- ✓ AERSCREEN (version 15181) was utilized for the analysis. The modeling parameters for the worst-case operating scenarios were used for each of the modeled pollutants and averaging times. AERSCREEN is the model U.S. EPA recommends to analyze impacts from inversion break-up and shoreline fumigation. However, AERSCREEN cannot provide results that correspond to the federal ambient air quality standards for NO_2 and SO_2, due to the form of those standards. For these pollutants, the maximum value is reported in the table below instead of the 98th or 99th percentile, respectively.

- ✓ For all of the sources, shoreline fumigation was not calculated by AERSCREEN as the plume height was below the thermal internal boundary layer heights for the distance to the shoreline.
- ✓ As shown in Table I, inversion break-up impacts, combined with background concentrations, are below the applicable ambient air quality standards.

Table I – Impacts during Normal Operations for Inversion Break-Up – Total Project

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu g/m^3$)	Background Concentration [a] ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	Federal AAQS [b] ($\mu g/m^3$)	California AAQS ($\mu g/m^3$)
CO, 1-hr	414	4,237	4,651	40,000	23,000
CO, 8-hr	138	2,977	3,115	10,000	10,000
NO_2, 1-hr	69.4	255.5	324.9	-	339
SO_2, 1-hr	4.9	58.2	63.1	-	655
SO_2, 3-hr	4.9	58.2	63.1	1,300	-

Note: [a] Maximum values for CO, NO_2, PM_{10}, and SO_2 from SRA 4, South Coastal Los Angeles monitoring stations for the last three years (2012-2014).
[b] Both the California and Federal AAQS values listed are not to be exceeded. The federal NO_2 and SO_2 standards cannot be evaluated with AERSCREEN due to the form of those standards and are not considered in this analysis.

6. Modeling Review of Project Impacts for CEC's CEQA Evaluation

- ✓ SCAQMD is both a responsible agency and a commenting agency under CEQA for this project. As noted above in the memo above, the modeling analysis conforms to SCAQMD regulations and SCAQMD does not have any comments.

a. Impacts During Commissioning

- ✓ The two combined-cycle gas turbines and four simple-cycle turbines are not subject to the modeling requirements of Regulation XIII per Rule 1304(a)(2); therefore the Rule 1303 thresholds do not apply. However, the applicant included a modeling analysis of the impacts from the new turbines and the auxiliary boiler in support of the CEC's CEQA document and PRDAS staff reviewed the modeling in the report.
- ✓ Turbine commissioning is an once-in-a-lifetime event. A total of six scenarios were modeled. Three scenarios were modeled for the two CCTG's, all of which included the auxiliary boiler in normal operation. Three scenarios were modeled for the four SCTG's, all of which included the auxiliary boiler in normal operation as well. The auxiliary boiler will be installed and commissioned prior to the first fire of the combined-cycle gas turbines.
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 9, 10, and 12 of the Engineering Memorandums and are assumed to be correct.

Table J – Impacts during Commissioning for CCGT's and Auxiliary Boiler in Normal Operation

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration (μg/m³)	Background Concentration [a] (μg/m³)	Total Concentration (μg/m³)	California AAQS [b] (μg/m³)	Federal AAQS [b] (μg/m³)	Exceeds Any Threshold?
CO, 1-hr	1,231	4,237	5,468	23,000	40,000	No
CO, 8-hr	835	2,977	3,812	10,000	10,000	No
NO_2, 1-hr [c]	67.6	255.5	323.1	339	- [d]	No
NO_2, Annual [c]	0.3	47.6	47.9	57	100	No
SO_2, 1-hr	2.2	58.2	60.4	655	196 [e]	No
SO_2, 3-hr	1.9	58.2	60.1	-	1,300	No
SO_2, 24-hr	0.6	7.9	8.5	105	-	No
PM_{10}, 24-hr	1.6	59.0	60.6	-	150	No
Non-attainment Pollutant & Averaging Time	**Maximum Modeled Concentration (μg/m³)**	**California AAQS (μg/m³)**	**Federal AAQS (μg/m³)**	**Rule 1303 Thresholds [b] (μg/m³)**		**Exceeds Any Threshold?**
PM_{10}, 24-hr	1.6	50	150	2.5		No
PM_{10}, Annual	0.2	20	-	1		No
$PM_{2.5}$, 24-hr	1.1	-	35	2.5		No
$PM_{2.5}$, Annual	0.2	12	12	1		No

Note: [a] Maximum values for CO, NO_2, PM_{10}, and SO_2 from SRA 4, South Coastal Los Angeles monitoring stations for the last three years (2012-2014).

[b] Since the Rule 1303 thresholds do not apply, the AAQS and Rule 1303 thresholds shown here are for informational purposes only.

[c] The conversion of NO_X to NO_2 was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

[d] On April 12, 2010, the U.S. EPA established a new 1-hour NO_2 standard of 100 ppb (188 μg/m³). The form of the federal 1-hour NO_2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO_2 standard does not apply.

[e] On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard of 75 ppb (196 μg/m³). The form of the federal 1-hour SO_2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.

Table K – Impacts during Commissioning for SCGT's and CCGT's and Auxiliary Boiler in Normal Operation

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu g/m^3$)	Background Concentration [a] ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	California AAQS [b] ($\mu g/m^3$)	Federal AAQS [b] ($\mu g/m^3$)	Exceeds Any Threshold?
CO, 1-hr	470	4,237	4,707	23,000	40,000	No
CO, 8-hr	240	2,977	3,217	10,000	10,000	No
NO_2, 1-hr [c]	61.9	255.5	317.4	339	- [d]	No
NO_2, Annual [c]	0.2	47.6	47.8	57	100	No
SO_2, 1-hr	2.1	58.2	60.3	655	196 [e]	No
SO_2, 3-hr	1.7	58.2	59.9	-	1,300	No
SO_2, 24-hr	0.5	7.9	8.4	105	-	No
PM_{10}, 24-hr	1.7	59.0	60.7	-	150	No
Non-attainment Pollutant & Averaging Time	**Maximum Modeled Concentration ($\mu g/m^3$)**	**California AAQS ($\mu g/m^3$)**	**Federal AAQS ($\mu g/m^3$)**	**Rule 1303 Thresholds [b] ($\mu g/m^3$)**		**Exceeds Any Threshold?**
PM_{10}, 24-hr	1.7	50	150	2.5		No
PM_{10}, Annual	0.2	20	-	1		No
$PM_{2.5}$, 24-hr	1.3	-	35	2.5		No
$PM_{2.5}$, Annual	0.2	12	12	1		No

Note: [a] Maximum values for CO, NO_2, PM_{10}, and SO_2 from SRA 4, South Coastal Los Angeles monitoring stations for the last three years (2012-2014).
[b] Since the Rule 1303 thresholds do not apply, the AAQS and Rule 1303 thresholds shown here are for informational purposes only.
[c] The conversion of NO_X to NO_2 was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.
[d] On April 12, 2010, the U.S. EPA established a new 1-hour NO_2 standard of 100 ppb (188 $\mu g/m^3$). The form of the federal 1-hour NO_2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO_2 standard does not apply.
[e] On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard of 75 ppb (196 $\mu g/m^3$). The form of the federal 1-hour SO_2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.

b. Impacts During Normal Operations

- ✓ The two CCGT's and four SCGT's are not subject to the modeling requirements of Regulation XIII per Rule 1304(a)(2); therefore, the Rule 1303 thresholds do not apply. However, the applicant included a modeling analysis of the impacts from the new turbines and the auxiliary boiler in support of the CEC's CEQA document and PRDAS staff reviewed the modeling in the report.
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Table 1 – 6 of the report and are assumed to be correct.

Table L– Impacts during Normal Operation – Total Project

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration (μg/m³)	Background Concentration [a] (μg/m³)	Total Concentration (μg/m³)	California AAQS [b] (μg/m³)	Federal AAQS [b] (μg/m³)	Exceeds Any Threshold?
CO, 1-hr	186	4,237	4,423	23,000	40,000	No
CO, 8-hr	44	2,977	3,021	10,000	10,000	No
NO_2, 1-hr [c]	31.3	255.5	286.8	339	-	No
NO_2, 1-hr [c]	22.6	146.3	168.9	-	188 [d]	No
NO_2, Annual [c]	0.2	47.6	47.8	57	100	No
SO_2, 1-hr	2.1	58.2	60.3	655	196 [e]	No
SO_2, 3-hr	1.7	58.2	59.9	-	1,300	No
SO_2, 24-hr	0.5	7.9	8.4	105	-	No
PM_{10}, 24-hr	1.7	59.0	60.7	-	150	No
Non-attainment Pollutant & Averaging Time	**Maximum Modeled Concentration (μg/m³)**	**California AAQS (μg/m³)**	**Federal AAQS (μg/m³)**	**Rule 1303 Thresholds [b] (μg/m³)**		**Exceeds Any Threshold?**
PM_{10}, 24-hr	1.7	50	150	2.5		No
PM_{10}, Annual	0.2	20	-	1		No
$PM_{2.5}$, 24-hr	1.3	-	35	2.5		No
$PM_{2.5}$, Annual	0.2	12	12	1		No

Note: [a] Maximum values for CO, NO_2, PM_{10}, and SO_2 from SRA 4, South Coastal Los Angeles monitoring stations for the last three years (2012-2014).
[b] Since the Rule 1303 thresholds do not apply, the AAQS and Rule 1303 thresholds shown here are for informational purposes only.
[c] The conversion of NO_X to NO_2 was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.
[d] On April 12, 2010, the U.S. EPA established a new 1-hour NO_2 standard of 100 ppb (188 μg/m³). The form of the federal 1-hour NO_2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO_2 standard does not apply.
[e] On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard of 75 ppb (196 μg/m³). The form of the federal 1-hour SO_2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.

Modeling staff spent a total of 240 hours on this review. Please direct any questions to Melissa Sheffer at ext. 2346.

cc: Vicky Lee
JW:MS