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Preliminary
Determination of Compliance

Huntington Beach Energy Project

South Coast
AQMD

South Coast Air Quality Management District

February 2014

APPLICANT:

AES Huntington Beach, LLC
21730 Newland St
Huntington Beach, CA 92646
SCAQMD ID# 115389

EQUIPMENT LOCATION:

21730 Newland St
Huntington Beach, CA 92646

EQUIPMENT DESCRIPTION:

Section H of the Facility Permit ID# 115389

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
GAS TURBINE, UNIT NO.1A, COMBINED CYCLE, NATURAL GAS, MITSUBISHI MODEL 501DA, 1498 MMBTU AT 32 DEGREES F WITH DRY LOW NOX COMBUSTOR A/N: 539746 GENERATOR, 132.3 MW GROSS AT 32 DEGREES F GENERATOR, HEAT RECOVERY STEAM TURBINE, STEAM, COMMON WITH GAS TURBINE NOS. 1B AND 1C, 148.7MW GROSS AT 32 DEGREES F	D115 (B116) (B117) (B118)	C120, C121, S123	NOX: MAJOR SOURCE	**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]: CO: 2000 PPM (5) [RULE 407] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK]; SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011]	A63.1, A99.1., A195.6, A195.7, A195.8, A327.1, B61.1, C1.7, C1.8, C1.9, D29.1, D29.2, D29.3, D29.4, D82.1, E193.2, E193.3, E193.4, I296.1, K40.2, K67.5

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
				CH2O: 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	
BURNER, DUCT, NATURAL GAS, 507 MMBTU, LOCATED IN THE HRSG OF TURBINE NO. 1A A/N: 539746	D119		NOX: MAJOR SOURCE	**CO:** 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX:** 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC:** 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM:** 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX:** 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011] **CH2O:** 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	
CO OXIDATION CATALYST, EAS, SERVING GAS TURBINE NO. 1A, WITH 261 MODULES, 2655 CU. FEET OF TOTAL CATALYST VOLUME A/N: 540256	C120	D115			
SELECTIVE CATALYTIC REDUCTION, CORMATECH, TITANIUM./VANADIUM/TUNGSTEN, SERVING UNIT NO.1A, WITH 20 MODULES, 140.8 CU. FEET OF TOTAL CATALYST VOLUME WITH A/N: 540256	C121	D115		**NH3:** 5 PPM (4) [RULE 1303(a)(1)-BACT]	A195.9, D12.6, D12.7, D12.8, E179.3, E179.4, E193.2

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
AMMONIA INJECTION, INJECTION GRID	(B122)				
STACK SERVING UNIT NO. 1A, 120' H. X 18' DIA. A/N: 539746	S123	D115			
GAS TURBINE, UNIT NO.1B, COMBINED CYCLE, NATURAL GAS, MITSUBISHI MODEL 501DA, 1498 MMBTU AT 32 DEGREES F WITH DRY LOW NOX COMBUSTOR A/N: 539747	D124	C129 C130 S132	NOX: MAJOR SOURCE	**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011] **CH2O**: 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	A63.1, A99.1, A195.6, A195.7, A195.8, A327.1, B61.1, C1.7, C1.8, C1.9, D29.1, D29.2, D29.3, D29.4, D82.1, E193.2, E193.3, E193.4, I296.1, K40.2, K67.5
GENERATOR, 132.3 MW GROSS AT 32 DEGREES F	(B125)				
GENERATOR, HEAT RECOVERY STEAM	(B126)				
TURBINE, STEAM, COMMON WITH GAS TURBINE NOS. 1A AND 1C, 148.7MW GROSS AT 32 DEGREES F	(B127)				
BURNER, DUCT, NATURAL GAS, 507 MMBTU, LOCATED IN THE HRSG OF TURBINE NO. 1B A/N: 539746	D128		NOX: MAJOR SOURCE	**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475];	

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
				PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011] **CH2O**: 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	
CO OXIDATION CATALYST, EAS, SERVING GAS TURBINE NO. 1B, WITH 261 MODULES, 2655 CU. FEET OF TOTAL CATALYST VOLUME A/N: 540257	C129	D83			
SELECTIVE CATALYTIC REDUCTION, CORMATECH, TITANIUM./VANADIUM/TUNGSTEN, SERVING UNIT NO.1B, WITH 20 MODULES, 140.8 CU. FEET OF TOTAL CATALYST VOLUME WITH A/N: 540257 AMMONIA INJECTION, INJECTION GRID	C130 (B131)	D83		**NH3**: 5 PPM (4) [RULE 1303(a)(1)-BACT]	
STACK SERVING UNIT NO. 1B, 120' H. X 18' DIA. A/N: 539747	S132	D83			
GAS TURBINE, UNIT NO.1C, COMBINED CYCLE, NATURAL GAS, MITSUBISHI MODEL 501DA, 1498 MMBTU AT 32 DEGREES F WITH DRY LOW NOX COMBUSTOR A/N: 539748 GENERATOR, 132.3 MW GROSS AT 25 DEGREES F GENERATOR, HEAT	D133 (B134) (B135)			**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT. RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT]	A63.1, A991., A195.6, A195.7, A195.8, A327.1, B61.1, C1.7, C1.8, C1.9, D29.1, D29.2, D29.3, D29.4, D82.1,

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
RECOVERY STEAM TURBINE, STEAM, COMMON WITH GAS TURBINE NOS. 1A AND 1B, 155.6MW GROSS	(B136)			**PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011] **CH2O:** 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	E193.2, E193.3, E193.4, I296.1, K40.2, K67.5
BURNER, DUCT, NATURAL GAS, 507 MMBTU, LOCATED IN THE HRSG OF TURBINE NO. 1C A/N: 539748	D137			**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011] **CH2O:** 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	
CO OXIDATION CATALYST, EAS, SERVING GAS TURBINE NO. 1C, WITH 261 MODULES, 2655 CU. FEET OF TOTAL CATALYST VOLUME A/N: 540258	C138				
SELECTIVE CATALYTIC REDUCTION,	C139				

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
CORMATECH, TITANIUM./VANADIUM/TUNGSTEN, SERVING UNIT NO.1C, WITH 20 MODULES, 140.8 CU. FEET OF TOTAL CATALYST VOLUME WITH A/N: 540258 AMMONIA INJECTION, INJECTION GRID	 (B140)				
STACK SERVING UNIT NO. 1C, 120' H. X 18' DIA. A/N: 539748	S141				
GAS TURBINE, UNIT NO.2A, COMBINED CYCLE, NATURAL GAS, MITSUBISHI MODEL 501DA, 1498 MMBTU AT 32 DEGREES F WITH DRY LOW NOX COMBUSTOR A/N: 539768 GENERATOR, 132.3 MW GROSS AT 32 DEGREES F GENERATOR, HEAT RECOVERY STEAM TURBINE, STEAM, COMMON WITH GAS TURBINE NOS. 2B AND 2C, 155.6MW GROSS	D142 (B143) (B144) (B145)			**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011] **CH2O**: 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	A63.1, A99.1., A195.6, A195.7, A195.8, A327.1, B61.1, C1.7, C1.8, C1.9, D29.1, D29.2, D29.3, D29.4, D82.1, E193.2, E193.3, E193.4, I296.1, K40.2, K67.5
BURNER, DUCT, NATURAL GAS, 507 MMBTU, LOCATED IN THE HRSG OF TURBINE NO. 2A A/N: 539768	D146			**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60	

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
				SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011] **CH2O**: 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	
CO OXIDATION CATALYST, EAS, SERVING GAS TURBINE NO. 2A, WITH 261 MODULES, 2655 CU. FEET OF TOTAL CATALYST VOLUME A/N: 540260	C147				
SELECTIVE CATALYTIC REDUCTION, CORMATECH, TITANIUM./VANADIUM/TUNGSTEN, SERVING UNIT NO.2A, WITH 20 MODULES, 140.8 CU. FEET OF TOTAL CATALYST VOLUME WITH A/N: 540260 AMMONIA INJECTION, INJECTION GRID	C148 (B149)			**NH3**: 5 PPM (4) [RULE 1303(a)(1)-BACT]	
STACK SERVING UNIT NO. 2A, 120' H. X 18' DIA. A/N: 539768	S150				
GAS TURBINE, UNIT NO.2B, COMBINED CYCLE, NATURAL GAS, MITSUBISHI MODEL 501DA, 1498 MMBTU AT 32	D151			**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT,	A63.1, A99.1., A195.6, A195.7, A195.8,

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
DEGREES F WITH DRY LOW NOX COMBUSTOR A/N: 539769 GENERATOR, 132.3 MW GROSS AT 32 DEGREES F GENERATOR, HEAT RECOVERY STEAM TURBINE, STEAM, COMMON WITH GAS TURBINE NOS. 2A AND 2C, 155.6MW GROSS	 (B152) (B153) (B154)			RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011] **CH2O**: 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	A327.1, B61.1, C1.7, C1.8, C1.9, D29.1, D29.2, D29.3, D29.4, D82.1, E193.2, E193.3, E193.4, I296.1, K40.2, K67.5
BURNER, DUCT, NATURAL GAS, 507 MMBTU, LOCATED IN THE HRSG OF TURBINE NO. 2B A/N: 539769	D155			**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT. RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011] **CH2O**: 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	
CO OXIDATION	C156				

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
CATALYST, EAS, SERVING GAS TURBINE NO. 2B, WITH 261 MODULES, 2655 CU. FEET OF TOTAL CATALYST VOLUME A/N: 540261					
SELECTIVE CATALYTIC REDUCTION, CORMATECH, TITANIUM./VANADIUM/TUNGSTEN, SERVING UNIT NO.2B, WITH 20 MODULES, 140.8 CU. FEET OF TOTAL CATALYST VOLUME WITH A/N: 540261 AMMONIA INJECTION, INJECTION GRID	C157 (B158)			**NH3**: 5 PPM (4) [RULE 1303(a)(1)-BACT]	
STACK SERVING UNIT NO. 2B, 120' H. X 18' DIA. A/N: 539769	S159				
GAS TURBINE, UNIT NO.2C, COMBINED CYCLE, NATURAL GAS, MITSUBISHI MODEL 501DA, 1498 MMBTU AT 32 DEGREES F WITH DRY LOW NOX COMBUSTOR A/N: 539770 GENERATOR, 132.3 MW GROSS AT 32 DEGREES F GENERATOR, HEAT RECOVERY STEAM TURBINE, STEAM, COMMON WITH GAS TURBINE NOS. 2A AND 2B, 155.6MW GROSS	D160 (B161) (B162) (B163)			**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011] **CH2O:** 0.091 PPMV (8) 40 CFR	A63.1, A99.1., A195.6, A195.7, A195.8, A327.1, B61.1, C1.7, C1.8, C1.9, D29.1, D29.2, D29.3, D29.4, D82.1, E193.2, E193.3, E193.4, I296.1, K40.2, K67.5

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
				63 SUBPART YYYY	
BURNER, DUCT, NATURAL GAS, 507 MMBTU, LOCATED IN THE HRSG OF TURBINE NO. 2C A/N: 539770	D164			**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 2.0 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 12.75 LBS/MMCF NATURAL GAS (1) [RULE 2012] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SOX: 0.6 LBS/MMCF NATURAL GAS (1) [RULE 2011] **CH2O:** 0.091 PPMV (8) 40 CFR 63 SUBPART YYYY	
CO OXIDATION CATALYST, EAS, SERVING GAS TURBINE NO. 2C, WITH 261 MODULES, 2655 CU. FEET OF TOTAL CATALYST VOLUME A/N: 540262	C165				
SELECTIVE CATALYTIC REDUCTION, CORMATECH, TITANIUM./VANADIUM/TUNGSTEN, SERVING UNIT NO.2C, WITH 20 MODULES, 140.8 CU. FEET OF TOTAL CATALYST VOLUME WITH A/N: 540262 AMMONIA INJECTION, INJECTION GRID	C166 (B167)			**NH3**: 5 PPM (4) [RULE 1303(a)(1)-BACT]	

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
STACK SERVING UNIT NO. 2C, 120' H. X 18' DIA. A/N: 539770	S168				
PROCESS 4: AMMONIA STORAGE					
STORAGE TANK, HORIZONTAL, 28'5" L X 6' DIA, AQUEOUS AMMONIA 19%, 24000 GALS A/N: 540255	D169				E144.1, C157.1, E193.7
PROCESS 5: OIL WATER SEPARATION					
OIL WATER SEPARATOR A/N: 549121	D170				

BACKGROUND:

The Huntington Beach Energy Project (HBEP) is a proposed 1,032 MW (nominal) combined cycle power plant to be located at the existing site of the Huntington Beach Generating Station plant in Huntington Beach, approximately 900 feet from the Pacific Ocean. The surrounding area is a mix of residential, wetland preserve, public beach, and industrial, and is bordered by a manufactured home/recreation vehicle park on the west, Huntington Beach Channel and residential areas to the north and east, a tank farm to the north, the Huntington Beach Wetland Preserve/Magnolia Marsh wetlands on the southeast, and the Huntington Beach State Park and the Pacific Ocean to the south and southwest. The entire parcel on which the Huntington Beach Generating Station is located, including the switchyard and tank farm, is approximately 106 acres, and the new plant will be constructed on about 28.6 of those acres. The nearest inhabitants to the proposed project site is a residential area approximately 300-400 feet from the site. The site location map is presented in Figure 1.1. The HBEP plot plan is presented in Appendix G.

The current Huntington Beach facility consists of 4 utility boilers. Boilers 1 and 2 are identical units, each rated at 215 MWs output and 2021 mmbtu/hr input. Boilers 3 and 4 are also identical, each rated at 225 MW output and 2088 mmbtu/hr input. All four boilers are equipped with SCR systems, while Boilers 3 and 4 also have CO oxidation catalysts. The boilers are all fired on natural gas exclusively. The boilers were built in the 1950's. There are two 275 hp diesel-fueled emergency engines installed in 2001 for fire control, a 30,000 gallon urea storage tank, and two urea-to-ammonia converters. The urea is used in the SCR systems, and is converted into ammonia before injection into the boiler exhaust with the use of the urea-ammonia converters. There is also an old peaker turbine (Unit 5) that has been shutdown and no longer operates.

The current ownership of the equipment at the site is split between AES Huntington Beach, LLC which owns Boilers 1 and 2, the two the emergency engines, and the urea storage tank, and Edison Mission Energy, LLC which recently purchased Boilers 3 and 4. AES Huntington Beach is the operator for all the equipment on site.

Boilers 3 and 4 were permanently shutdown in November, 2012, and dismantling will begin in the second quarter 2015. Boilers 1 and 2, along with their SCR systems, urea storage tank, and urea to ammonia reactor will be shutdown concurrent with the new turbines coming on line, and will be dismantled beginning in 4th quarter 2020.

AES has also proposed to shutdown Boiler 6, rated at 1785 mmbtu heat input and 175 MW output, and Boiler 8, rated at 4752.2 mmbtu/hr heat input and 480 MW output, at the AES Redondo Beach facility, as part of this project. Total generating capacity being retired as part of this project is 1,085 MWs.

The proposed new facility will be a combined cycle power plant capable of producing a nominal power output of 1,032 MW net, and consisting of six combustion turbine generators (CTG), six heat recovery steam generators (HRSG) with duct burners, two steam turbine generators (STG), with auxiliary equipment including an aqueous ammonia storage tank.

AES Huntington Beach, LLC, a wholly owned subsidiary of AES Southland Corp. will be the facility owner and operator of the new plant.

The plant will be designed to supply power to the wholesale energy market through the existing substation adjacent to the property (to the north-east). Output will depend on market conditions and dispatch requirements. The plant's expected availability is over 98% on an annual basis, with the actual capacity factor anticipated to be between 35-50%. AES expects the plant to be dispatched at intermediate and minimum loads on a regular basis. Therefore, the plant is designed to have the ability to start quickly - cold starts should be 90 minutes or less, and can operate with only one or two turbines online at any given time.

The following applications for the project were submitted on June 26 and July 18, 2012:

Table 1.1 – Project Application Numbers

Application Number	Equipment Description
539746	Mitsubishi Gas Turbine #1A
539747	Mitsubishi Gas Turbine #1B

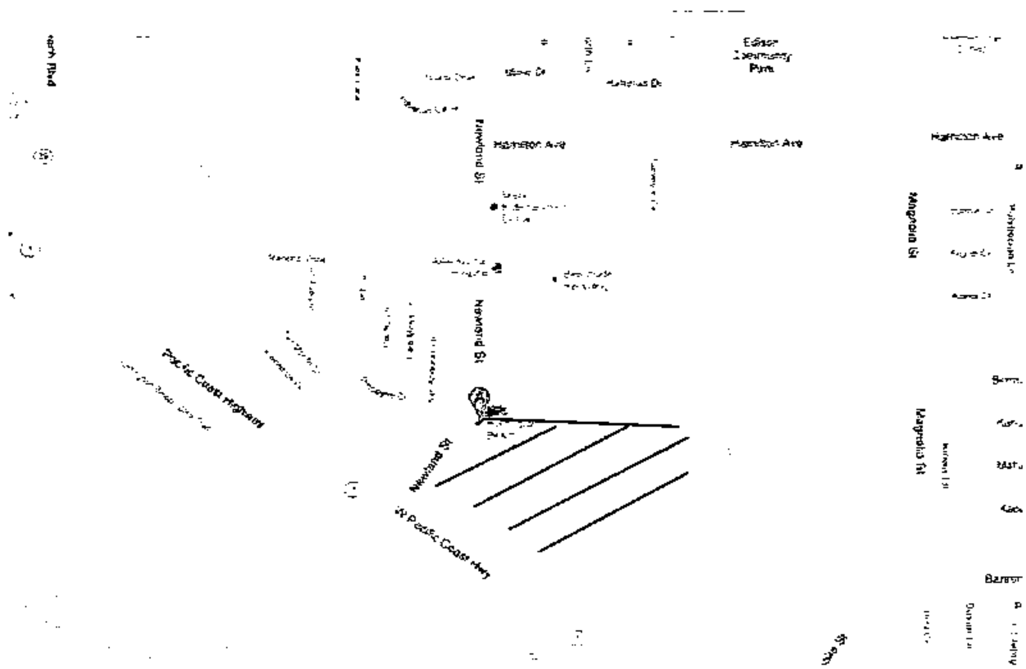
539748	Mitsubishi Gas Turbine #1C
539768	Mitsubishi Gas Turbine #2A
539769	Mitsubishi Gas Turbine #2B
539770	Mitsubishi Gas Turbine #2C
540256	SCR/CO Catalyst #1A
540257	SCR/CO Catalyst # 1B
540258	SCR/CO Catalyst #1C
540260	SCR/CO Catalyst #2A
540261	SCR/CO Catalyst #2B
540262	SCR/CO Catalyst #2C
540255	Aqueous Ammonia Storage Tank
540259	Title V/RECLAIM Significant Revision

The applications were deemed substantially complete on July 24, 2012. Refer to Appendix O for fees paid.

The plant will be evaluated as a significant revision to the existing Title V permit at the AES, Huntington Beach site (facility ID# 115389). The new project is also subject to the NOx and SOx RECLAIM and PSD regulations for NO2, SOx, CO, GHG, and PM10. The plant is considered a major revision to a major stationary source under Regulation XIII, and as such is subject to the full requirements of New Source Review. Other major environmental regulations that apply to the new project are 40 CFR72 – Acid Rain, 40CFR 60 Subpart KKKK – New Source Performance Standards for Gas Turbines, and AQMD Rule 1401 – Toxics. The project is also subject to the California Energy Commissioning licensing procedure and an Application for Certification (AFC) has been submitted with that agency (2012-AFC-02).

Construction of Block 1 (turbines 1A, 1B, and 1C) is scheduled to begin in 1st quarter 2015 and end in the 3rd quarter of 2018. Construction of Block 2 (turbines 2A, 2B, and 2C) is scheduled to begin in the 1st quarter of 2018 and end in the 2nd quarter of 2020.

Figure 1.1 –Site Location



Compliance History

The following information was obtained from the District's Compliance Tracking System for the 5-year period from 1/01/08 to 1/09/14 for the AES Huntington Beach facility.

Notice to Comply D03506
Issued 01/29/09 for failure to submit R218 CO emissions reports and RECLIAM NOx quarterly reports (QCER) in a timely manner. The follow up status is 'in compliance.'

Notice to Comply D03529
Issued 12/01/10 for failure to include all equipment in the RECLAIM quarterly reports (QCER). The follow up status is 'in compliance.'

Notice to Comply E09956
Issued 10/14/11 for failure to comply with testing condition D28.3 and D29.3 including testing for a 60 minute period. The follow up status is 'in compliance.'

Notice of Violation P52182

Issued on 10/27/11 for exceeding the start up NOx limit of 38.4 lbs/hr for Boiler #4. This is a closed case.

There were no complaints associated with the facility for the stated time period in the AQMD database. The facility has also submitted a statement certifying that all facilities owner and operated in the state are currently in compliance with all applicable air quality regulations, as required by Rule 1303.

PROCESS DESCRIPTION:

The gas turbine facility will consist of 6 Mitsubishi 501DA combustion turbine generators (CTG), each rated at 121.8 MW's (nominal), equipped with dry low NOx combustors and evaporative inlet air cooling, 6 heat recovery steam generators (HRSG) each with a 507 MM Btu/hr duct burner, an SCR and an oxidation catalyst, and a two steam turbine generators (STG), each rated at 150.6 MW's (nominal). The plant will be configured in a 'three-on-one' arrangement with one arrangement designated as 'Block 1' and the other as 'Block 2'. Each block is independently operated and will consist of 3 CTGs, 3 HRSGs, and 1 STG.

Each combustion turbine will vent to a stack 120 feet tall. 19% aqueous ammonia for the SCRs will be stored in a 24,000 gallon tank.

The system output will vary depending on the ambient air temperature condition, use of evaporative coolers, amount of auxiliary load, generator power factor, the amount of supplemental firing in the duct burners, and other factors. Additionally, there is a transmission line interconnect limitation at the Huntington Beach plant which restricts the total plant output. At the site low temperature (maximum output case), the plant total output is restricted to 939 MWs. The tables below show the output on a per turbine basis, and each turbine can operate at full load capacity, the limitation is only at the transmission line. So although the potential gross plant output at low temperature conditions would be calculated based on Table 2.1 below as 1,091 MWs (181.835 MWs* 6 turbines), the line restriction limits transmission output to 939 MW.

Table 2.1 Plant Output Per Turbine 3-on-1 Operation

	ISO 59 F- 60% RH (Evaporative Cooling Off)	110 F-8% RH (Evaporative Cooling On)	32 F – 87% RH (Evaporative Cooling Off)	66 F – 58% RH Evaporative Cooling On)
Gas Turbine Heat Input, mmbtu/h HHV	1,388	1,350	1,498	1,403
Total Heat Input, mmbtu/h HHV (w/oduct fire)[1]	1,388	1,350	1,498	1,403
Gas Turbine Gross Output[2], kW	121,435	115,264	132,256	121,840
Steam Turbine Gross Output[3], kW	51,865	43,632	49,579	50,192
Total Gross Power Output[4], kW	173,300	158,896	181,835	172,032
Net Power Output, Kw	167,583	153,352	175,925	166,328
Net Plant Heat Rate, btu/kWh, LHV	7,354	7,814	7,558	7,487
Net Plant Heat Rate, btu/kWh, HHV	8,285	8,803	8,516	8,435
Net Plant Efficiency, %, HHV	41.2	38.8	40.1	40.5

1 there is no duct firing when the plant operating in 3-on-1 mode
2 on a per turbine basis
3 1/3 of the total steam turbine output
4 multiply by 3 to get the output per power block

Table 2.2 Plant Output Per Turbine 2-on-1 Operation

	85 F – 46% RH (Evaporative Cooling On)	66 F – 58% RH (Evaporative Cooling On)
Gas Turbine Heat Input, mmbtu/h HHV	1,354	1,403
Total Heat Input, mmbtu/h HHV (w/duct fire)	1,861	1,910
Gas Turbine Gross Output, kW	115,962	121,840
Steam Turbine Gross Output, kW	49,751	51,320
Total Gross Power Output, kW	165,713	173,160
Net Power Output, Kw	159,682	167,018
Net Plant Heat Rate, btu/kWh, LHV[1]	7,503.9	7,433.9
Net Plant Heat Rate, btu/kWh, HHV[1]	8,479.4	8,400.3
Net Plant Efficiency, %, HHV	40.3	40.7

1 duct burners are used for ramp speed and not for power augmentation, therefore heat rate is calculated assuming no duct firing

Table 2.3 Plant Output Per Turbine 1-on-1 Operation

	85 F – 46% RH (Evaporative Cooling On)	66 F – 58% RH (Evaporative Cooling On)
Gas Turbine Heat Input, mmbtu/h HHV	1,354	1,403
Total Heat Input, mmbtu/h HHV (w/duct fire)	1,861	1,910
Gas Turbine Gross Output, kW	115,962	121,840
Steam Turbine Gross Output, kW	47,192	49,382
Total Gross Power Output, kW	163,154	171,222
Net Power Output, Kw	155,661	163,611
Net Plant Heat Rate, btu/kWh, LHV[1]	7,697.7	7,588.7
Net Plant Heat Rate, btu/kWh, HHV[1]	8,698.4	8,575.2
Net Plant Heat Rate, %, HHV	39.3	39.8

1 duct burners are used for ramp speed and not for power augmentation, therefore heat rate is calculated assuming no duct firing

There will be no new transmission lines or gas lines needed for the project.

Each of the components is discussed in more detail below:

- *Combustion Turbines*

The Mitsubishi 501DA units are rated at 121.8 MW nominal and132.3 MW maximum (@ 32°F) each, and arranged in a three-on-one configuration. Each turbine will be equipped with inlet air filters and coolers. The turbines will combust natural gas exclusively. Total heat input for 6 turbines at nominal conditions is 8,418 mmbtu/hr (HHV), fuel use at these conditions is approximately 8.02 mmcf/hr, based on a natural gas heat content of 1050 btu/cf. Pertinent turbines specs are summarized below:

Table 2.2 Turbine Data

Specification	
CT Manufacturer	Mitsubishi
Model	501DA
Fuel Type	Natural gas
Maximum Power Output	132.3 MW (1 turbine @ 32 deg, no duct firing)
Maximum Heat Input without duct firing	1,498 mmbtu/hr HHV (1 turbine @ 32 deg)
Maximum Fuel Consumption	1.43 mmcf/hr HHV (1 turbine @ 32 deg, 1050 btu/cf)
Maximum Exhaust Flow	46.2 mmcfhr, dry @ 15% O2 (1 turbine @ 32 deg)
Duct Burner Maximum Heat Input	507 mmbtu/hr HHV
Maximum Heat Input with duct firing	2005 mmbtu/hr HHV (1 turbine + DB @ 32 deg)
Combined CT and DB Exhaust Flow	61.8 mmscfh, dry @ 15% O2 (@ 32 deg)
Duct Burner Maximum Fuel Consumption	0.48 mmcf/hr
NOx Combustion Control	DLN 9 ppm
Post Combustion Control	SCR 2.0 ppm 1 hour average
Ammonia Injection Rate per turbine	256.3 lbs/hr maximum
Steam Turbine Output at 63°F Ambient	336.6 MW
Net Plant Heat Rate, LHV	7,354 btu/Kw @ ISO
Net Plant Heat Rate, HHV	8,285 btu/Kw @ ISO
Net Plant Efficiency, HHV	41.2%

The 501DA turbines from Mitsubishi were initially developed by Westinghouse in the late 70's and was based on their W251 product which was the first commercial gas turbine employed in the United States (1949). The 501D turbines first began commercially operating in the early '80's. Later that decade, Westinghouse and Mitsubishi Heavy Industries (MHI) entered into an agreement to co-fabricate the 501 product line, and in 2001, MHI acquired all rights to the 501D turbine design.

The 501D product line has since been upgraded and redeveloped. The turbines AES will be using for the HBEP project deploy the latest generation of the 501D which includes the use of the 501F-class rotor in the D machine which has enabled the fast start and ramp capability.

These turbines are not the most efficient units on the market when compared to other F and G class turbines. However, the applicant anticipates that the operating profile of the plant will include the need for rapid starting and frequent ramping. They have chosen the 501D turbines because the units exhibit fairly consistent heat rates throughout the expected operating range required for HBEP. The anticipated load range for the HBEP is approximately 160 to 528 MW for each 3X1 power island. The heat rate for this operating range is estimated to be 8,800 to 8,140 btu/kWh HHV (38.8% - 41.9%).

Each turbine will exhaust to a Heat Recovery Steam Generator (HRSG). The HRSGs are designed to convert heat from the exhaust gas to produce steam for use in the steam turbine. Exhaust gases enter the HRSG at approximately 1100 deg F. The HRSG's employ a single pressure design. Feed water into the HRSG will be converted to high pressure steam for use in the steam turbine. The steam exists the steam turbine as low pressure steam, enters the air cooled condenser, and is cooled and condensed back into water.

The HRSGs will contain duct burners and the Air Pollution Control (APC) equipment. Each HRSG will vent to a separate exhaust stack.

- *Air Pollution Control (APC) Equipment*

APC equipment will be installed to control NOx, CO, and VOC from the gas turbines. Each APC system will consist of the following: 1) Dry Low NOx (DLN) Burners, 2) SCR, and 3) Oxidation catalyst.

Dry Low NOx Combustor - Each CT will include built-in pollution controls based on a dry combustion design (dry low-NOX combustor) to reduce NOx emissions. This control will reduce NOx emissions to 9 parts-per-million volume dry basis (ppmvd) at 15 percent oxygen (O_2). The dry low NOx control will be fully operational when the turbine reaches a load of approximately 70 percent or more.

Oxidation Catalyst System – An oxidation catalyst will be installed in the HRSG section of the turbine. The catalyst will be designed to reduce exhaust gas CO by about 80-85% to 2.0 ppm or less at 15% O2, and VOC by 65-70% to 1.0 ppm at 15% O2.

Table 2.3 Oxidation Catalyst Data

Specification	
Manufacturer	EAS, Inc
Catalyst Type	Palladium in a honeycomb structure
Catalyst Volume	208.3 ft^3
Catalyst Area	1225.2 ft^2
Reactor Dimensions	20'L X 20'W X 66'H (includes SCR catalyst housing)
Space Velocity	348.4 hr^{-1} based on 72,582 ft^3/hr exhaust
Area Velocity	59.2 ft/hr based on 72,582 ft^3/hr exhaust
CO Removal Efficiency	80-85%
Outlet CO	2.0 ppmvd at 15% O2
VOC Removal Efficiency	65-70%
Outlet VOC	1.0 ppmvd at 15% O2
Minimum operating temperature	500 °F

Selective Catalytic Reduction System – An SCR catalyst will be installed in the HRSG to reduce NOx emissions to 2.0 ppmvd at 15% O2 on a 1 hour average at loads above 60%. The SCR catalyst will be located downstream of the CO catalyst, and will consist of a vanadium/titanium/tungsten type catalyst in a honeycomb structure. Each SCR module is approximately 10' wide X 6.5' high X 2' deep. The modules are arranged two across (20') and 10 high (65') for a total of 20 modules in 1 layer. Total catalyst volume is about

2817 ft3. Aqueous ammonia (ammonium hydroxide at 19% concentration by weight) from the storage tank will be vaporized, diluted with air, and injection into the exhaust through an injection grid. The amount of ammonia injected will vary depending on NOx reduction requirements, but will be approximately a 1:1 molar ratio of ammonia to NOx.

Table 2.4 SCR Catalyst Data

Specification	
Manufacturer	Cormatech
Catalyst Type	Titanium/Vanadium/Tungsten honeycomb
Catalyst Volume	2810.5 ft^3
Catalyst Area	1338.3 ft^2
Reactor Dimensions	20'L X 20'W X 66'H (includes CO catalyst housing)
Space Velocity	25.8 hr^{-1} based on 72,582 ft^3/hr exhaust
Area Velocity	54.2 ft/hr based on 72,582 ft^3/hr exhaust
Ammonia Injection Rate	256.3 lbm/hr
Ammonia Slip	5.0 ppm
Outlet NOx	2.0 ppm at 15%
Guarantee	24,000 hours of operation, or 3 years
SCR/CO catalyst Total Cost	$1.1 million
Operating temperature range	400 °F-650°F

- *Exhaust Stacks*

Each turbine/HRSG will be equipped with identical 19-foot diameter 150.5 feet tall stacks. The stacks will contain sampling ports for exhaust gas testing.

Table 2.5 Stack Data

Specification	
Stack Diameter	19 feet
Stack Height	150' - 6"
Stack Area	283.4 ft^2
Exhaust gas temperature	200 deg F
Exhaust gas volume	48.4 mmscfh @ 105 deg F - 74.3 mmscfh @ 25 deg F, dry @15% O2
Exhaust gas velocity	10.2 feet/min @ 105 deg F – 15.7 feet/min @ 25 deg F

- *Duct Burners*

Each HRSG will be fitted with a duct burner rated at 507 mmbtu/hr HHV. For the HBEP, the duct burners will be used in 2 scenarios. First, in the traditional sense, duct firing will occur to boost peak output during 1-on-1 and 2-on-1 turbine operation. Duct firing will also occur during turbine load ramping to allow quicker transitions to higher output levels. Duct burning will not occur when the turbines are operated in a 3-on-1 mode.

- *Monitoring Systems*

Each turbine will be equipped with continuous stack monitors for NOx, CO, and O2, along with a fuel meter. A data acquisition system is required to collect information from the analyzers and fuel meters to calculate exhaust flows and mass emissions of NOx for transmission through the remote terminal unit (RTU). Other parameters which are required to be measured and recorded include the ammonia injection rate, exhaust temperature prior to the SCR catalyst, CTG output, and pressure drop across the SCR catalyst. A NOx analyzer will be placed upstream of the SCR catalyst for fine tuning the ammonia injection rate and also for use in estimating ammonia slip.

The plant is designed with a full steam bypass; however, the cold and warm start times are limited by the maximum safe temperature ramp rate of the high-pressure drum's metal construction. The bypass is installed to allow rapid depressurization of the steam cycle, it would not be used for normal operations.

- *Ammonia Storage Tank*

The 24,000 gallon ammonia tank will store a 19% aqueous ammonia solution for use in the turbines' SCRs. The tank is a horizontal pressure vessel with a PRVs set at 50 psig. During loading, vapors from the tanks are vented back to the filling truck through the vapor return line. The tank is designed so that under normal operating conditions, the pressure will not exceed the prv setting.

Expected average ammonia use is about 34.2 gallons per hour (256.3 lbs/hr/7.5 lbs/gal) per CTG/HRSG system. At a maximum annual turbine capacity factor of 0.7, estimated annual aqueous ammonia use is 1,258,286 gallons (34.2 X 24 X 365 X 0.7 X 6 turbines), or about 52 tank turnovers per year (1 per week on average).

- *Cooling System*

There are no cooling towers associated with this project. Exhaust steam from the STGs will be condensed in two air-cooled condensers. The air-cooled condenser will utilize two large fans to blow ambient air across finned tubes through which the low-pressure steam flows. The condensate collects in a receiver located under the air-cooled condenser, Condensate pumps will then return the condensate from the receiver back to the HRSGs for reuse.

- *Oil Water Separator*

There will be one new oil water separator (OWS) installed to serve the new power system. The OWS will collect potentially oily wastewater from equipment area wash downs and the HRSG feed water pump skid. The only potential oil contaminant is lubricating oil associated with the gas turbines and associated feed water pumps. Oil will be collected in the OWS and will be removed by vacuum truck before the oil collection section reaches its capacity.

EMISSIONS:

Emissions from the gas turbine will consist of NOx, CO, CO2e, VOC, PM10, PM2.5, and SOx, plus toxics. Emissions are calculated for 4 basic operational modes as follows:

1. commissioning – a 1 time event which occurs following installation and just prior to bringing the turbine online for commercial operation
2. start up – occurs each time the turbine is started
3. normal operation
4. shutdown – occurs each time the turbine is shutdown

Table 3.1 - Operational Scenarios for SGGS

Scenario	Description
Commissioning	The commissioning operation will require each CT to operate individually as well as simultaneously under part load and full load. The testing will be performed on each CT for the purpose of "tuning in" the turbine combustor and control systems. Emissions are expected to be higher than normal operation. The commissioning will take about 491 operating hours per turbine over a period of about 180 days.
Startup	There are 3 types of starts – cold, warm , and hot. Cold starts occur after the turbine has been down for 49 or more hours, and the "start" will last about 1.5 hours (the time to reach proper operating temperature for full DLN, SCR and CO catalyst control). Warm starts occur after the turbine has been down 9 to 49 hours, and will last32.5 minutes. Hot starts occur when the turbine has been down less than 9 hours, and will last 32.5 minutes. Applicant anticipates 24 cold, 150 warm, and 450 hot starts per year, (this equates to about 361 hours per year in start up mode).
Normal Operating	Normal operation is defined as when the turbine is operating at fully controlled levels (ie 2.0 ppm NOx and CO, and 1.0 ppm VOC). The turbines will operate with and without duct burner firing. Total operation in normal mode with duct burner firing is estimated at 470 hrs per year, and without duct burner firing 5900 hrs per year.
Shutdown	During a turbine shutdown, the emission controls will continue to operate down to a level of 60% load. The final 10 minutes of the shutdown process will be partially to completely uncontrolled. There will be a maximum of 624 shutdowns per year(@ 10 minutes each = 62.4 hrs per year).

Operating Schedule
AES has proposed the following operating schedule for the plant:

	Monthly		Annual	
	Maximum # of Events	Maximum Hours of Operation	Maximum # of Events	Maximum Hours of Operation
Hot Starts	60	32.5	450	243.75
Warm Starts	25	13.5	150	81.25
Cold Starts	5	7.5	24	36
Shutdowns	90	15	624	104
Normal Operation without duct firing	///////////	489.5	///////////	5900
Normal Operation with duct firing	///////////	186	///////////	470
TOTAL	///////////	744	///////////	6835

Emission calculations can be referenced in Appendix A.

Hourly Emissions

Table 3.2 Maximum Hourly Emissions Normal Operation (1 Turbine)

Pollutant	Uncontrolled Hourly Emissions (with duct firing)	Uncontrolled Hourly Emissions (without duct firing)	Controlled Hourly Emissions (with duct firing)	Controlled Hourly Emissions (without duct firing)
NOx	66.6	30.3	14.8	11.0
CO	45.0	33.5	9.0	6.7
VOC	5.1	3.8	5.1	3.8
PM10	9.5	4.5	9.5	4.5
SOx	2.78	2.08	2.78	2.08
NH3	////////	////////	13.8	10.3

Uncontrolled emission rates based on DLN without SCR, NOx=9 ppm, CO=10 ppm, VOC=2 ppm

Table 3.3 Maximum Hourly Emissions Start Ups and Shutdowns (1 Turbine)

Pollutant	Cold Start, 90 minutes	Warm Start, 32.5 minutes	Hot Start, 32.5 minutes	Shutdown, 10 minutes
	Lbs/event	Lbs/event	Lbs/event	Lbs/event
NOx	28.7(1)	16.6	16.6	9.0
CO	115.9(1)	46.0	33.6	45.3
VOC	27.9(1)	21.0	20.4	31.0
PM10(3)	6.75	2.44	2.44	0.75
SOx(2)	3.12	1.13	1.13	0.33

(1) The NOx, CO, and VOC emissions in this table are as reported by AES
(2) *SOx based on 2.08 lbs/hr, (no duct firing during start ups or shutdowns)*
(3) *PM10 based on 4.5 lbs/hr (no duct firing during start ups or shutdowns)*

Table 3.4 Highest Single Hour Emissions (1 Turbine)

Pollutant	Operating Scenario	Emissions, lbs/hr
NOx	Cold Start	28.7
CO	Cold Start	115.9
VOC	Shutdown	31.0
PM10	Normal Operation with Duct Firing	9.5
SOx	Normal Operation with Duct Firing	2.78
NH3	Normal Operation with Duct Firing	13.8

Table 3.5 Highest Single Hour Emissions (6 Turbines)

Pollutant	Operating Scenario	Emissions, lbs/hr
NOx	Cold Start	172.2
CO	Cold Start	695.4
VOC	Shutdown	186
PM10	Normal Operation with Duct Firing	57
SOx	Normal Operation with Duct Firing	16.68
NH3	Normal Operation with Duct Firing	82.8

Daily Emissions

Table 3.7 Estimated Daily Emissions (1 Turbine)

Pollutant	Operating Scenario	Uncontrolled Daily Emissions	Controlled Daily Emissions
NOx	1 cold start + 3 hot starts + 4 shutdowns + 18.7 hrs normal with 5 hrs duct firing	895.80	339.20
CO	1 cold start + 3 hot starts + 4 shutdowns + 18.7 hrs normal with 5 hrs duct firing	1081.85	534.69
VOC	1 cold start + 3 hot starts + 4 shutdowns + 18.7 hrs normal with 5 hrs duct firing	290.66	290.66
PM10	24 hr normal with 5 hrs duct firing	133.00	133.00
SOx	24 hr normal with 5 hrs duct firing	53.42	53.42
NH3	24 hr normal with 5 hrs duct firing	///////////	264.70

1 cold start = 1.5 hrs, 3 hot starts = 1.63 hrs, 4 shutdowns = 0.67 hrs ,downtime between starts = 1.5 hrs, remaining time at 100% load with 5 hrs duct firing

Table 3.8 Estimated Daily Emissions (6 Turbines)

Pollutant	Operating Scenario Per Turbine	Controlled Daily Emissions
NOx	1 cold start + 3 hot starts + 4 shutdowns + 18.7 hrs normal with 5 hrs duct firing	2035.20
CO	1 cold start + 3 hot starts + 4 shutdowns + 18.7 hrs normal with 5 hrs duct firing	3208.14
VOC	1 cold start + 3 hot starts + 4 shutdowns + 18.7 hrs normal with 5 hrs duct firing	1743.96
PM10	24 hr normal with 5 hrs duct firing	798
SOx	24 hr normal with 5 hrs duct firing	320.5
NH3	24 hr normal with 5 hrs duct firing	1588.2

1 cold start = 1.5 hrs, 3 hot starts = 1.63 hrs, 4 shutdowns = 0.67 hrs ,downtime between starts = 1.5 hrs, remaining time at 100% load with 5 hrs duct firing

Monthly Emissions

Table 3.9 Monthly Total and 30-Day Average Emissions (1 Turbine)

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	10,501.8	350.1
CO	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	12,776.15	425.9
VOC	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	7,487.2	249.6
PM10	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	4278.00	142.6
SOx	744 hrs normal with 186 hrs duct firing	1677.72	55.92

5 cold starts = 7.5 hrs, 25 warm starts = 13.54 hrs, 60 hot starts = 32.5 hrs, 90 shutdowns = 15 hrs, remaining hours assumed at 100% load (31 days)

Table 3.10 Monthly Total and 30-Day Average Emissions (6 Turbines)

Pollutant	Operating Scenario Per Turbine	Total Monthly Emissions	30-Day Average Emissions
NOx	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	63010.8	2100.6
CO	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	76656.9	2555.4
VOC	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	44923.2	1497.6
PM10	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	25668	855.6
SOx	744 hrs normal with 186 hrs duct firing	10066.32	335.52

Annual Emissions

Table 3.11 Commissioning Emissions (Per Block)

Pollutant	Emissions, 1 Turbine	Total Emissions, 3 Turbines	
	Lbs	Lbs	Tons
NOx	8,282	24846	12.4
CO	112,882	338646	169.3
VOC	14,121	42363	21.2
PM10	2,930	8790	4.4
SOx	1,064	3192	1.6

Table 3.12-Annual Emissions Commissioning Year, 6 Turbines

Pollutant	Normal Emissions, 6 Turbines[1]	Commissioning Emissions, 3 Turbines[2]	Total Annual Emissions	
	Lbs	Lbs	Lbs/yr	Tpy
NOx	298,392.0	24,846.0	323,238.0	161.6
CO	379,691.7	335,646.0	715,337.7	357.7
VOC	229,578.9	42,363.0	271,941.9	136.0
PM10	112,065.0	8790.0	120,855.0	60.4
SOx	54,620.0	3,192.0	57,812.0	28.9
NH3	235,396.0	0	235,396.0	117.7

(1) Includes a full 12 months of Block 1normal operation plus approximately 6 months of normal operation for Block 2.
(2) Block 2 commissioning

Table 3.13 12-Annual Emissions Non-Commissioning Year, 6 Turbines

Pollutant	Total Annual Emissions, 6 Turbines	
	Lbs/yr	Tpy
NOx	528,724.8	264.4
CO	580,972.8	290.5
VOC	34,963.6	17.5
PM10	198,654	99.3
SOx	87,224.4	43.6
NH3	403,536.0	201.8

1- assumes 24 cold starts, 150 warm starts, 450 hot starts, 164 shutdowns, 6370 hours of normal operation (470 hours with duct firing and 5900 w/o duct firing)

Toxic Emissions

Table 3.14 Toxic Emissions

Pollutant	Annual Emissions 1 Turbine, lbs/yr	Annual Emissions 6 Turbines, lbs/yr
Ammonia	8.61E+04	5.17E+05
Acetaldehyde	3.93E+02	2.36E+03
Acolein	6.29E+01	3.77E+02
Benzene	1.18E+02	7.08E+02
1,3 Butadiene	4.23E+00	2.54E+01
Ethyl Benzene	3.14E+02	1.88E+03
Formaldehyde	2.83E+03	1.70E+04
Naphthalene	1.28E+01	7.68E+01
PAH	8.85E+00	5.31E+01
Propylene Oxide	2.85E+02	1.71E+03
Toluene	1.28E+03	7.68E+03
Xylene	6.29E+02	3.77E+03
	Total, lbs/yr	522,227
	Tons/yr	276.1

EVALUATION:

RULE 212-Standards for Approving Permits

This project is subject to Rule 212 public notice requirements because the daily maximum VOC, CO, NOx, and PM10 emissions from the project will all exceed the emissions thresholds specified in subdivision (g) of this rule. The facility is not located within 1000 feet of a school (the closest school is Edison High located approximately 0.6 miles north-east of the site). The District will prepare the public notice and it will contain sufficient information to fully describe the project.

In accordance with subdivision (d) of this rule, 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 documents are included in paragraphs (g)(1), (g)(2), and (g)(3).

In accordance with paragraph (g)(1) of this rule, the District will make the following information available for public inspection at the Huntington Beach Public Library located at 7111 Talbert Ave, Huntington Beach 92648, during the 30-day comment period: public notice, project information submitted by the applicant, and the District's permit to construct evaluation.

In accordance with paragraph (g)(2) of this rule, the public notice will be published in a newspaper which serves the area that will be impacted by the project.

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

After the public notice is published, there will be a 30-day period for submittal of public comments.

RULE 218 – Continuous Emission Monitoring

In order to insure the equipment meets the CO BACT limit as specified in the permit, a CO CEMS will be required by permit condition. The CO CEMS must be certified in accordance with Rule 218. The rule requires submittal of an "Application for CEMS" for approval. Once approved, CEMS data must be recorded and records of the data must be maintained on site for at least 2 years. Additionally, every 6 months a summary of the CEMS data must be submitted to AQMD. Any CEMS breakdowns must also be reported. Compliance with this rule is expected.

RULE 401 – Visible Emissions

This rule limits visible emissions to an opacity of less than 20 percent (Ringlemann No.1), as published by the United States Bureau of Mines. Visible emissions are not expected during normal operation from the turbines or ammonia tank.

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. The turbines and ammonia tank are not expected to create nuisance problems under normal operating conditions.

RULE 403 – Fugitive Dust

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 prohibits emissions of fugitive dust beyond the property line of the emission source. The applicant will be taking steps to prevent and/or reduce or mitigate fugitive dust emissions from the project site. They have proposed the following measures:

Watering unpaved roads and disturbed areas
Limiting onsite vehicle speeds to 10 mph and posting the speed limit
Frequent watering during periods of high winds when excavation/grading is occurring
Sweeping onsite paved roads and entrance roads on an as-needed basis
Replacing ground cover in disturbed areas as soon as practical
Covering truck loads when hauling materials that could be entrained during transit
Applying dust suppressants or covers to soil stockpiles and disturbed areas when inactive for more than 2 weeks

In addition, the applicant will need to implement all Best Available Control Measures listed in Table 1 of the rule.

The installation and operation of the turbines and associated equipment is expected to comply with this rule.

RULE 407 – Liquid and Gaseous Air Contaminants

This rule limits CO emissions to 2000 ppmv. The SO2 portion of the rule does not apply as the natural gas fired in the turbines will be subject to the sulfur limit in Rule 431.1. The CO emissions from the turbines will be controlled by an oxidation catalyst to 2.0 ppmvd at 15% O2. Therefore, compliance with this rule is expected.

RULE 409 – Combustion Contaminants

This rule restricts the discharge of contaminants from the combustion of fuel to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12% CO_2, averaged over 15 minutes. The turbines are expected to meet this limit at the maximum firing load based on the calculations shown below. Compliance will be verified through the initial performance test.

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

A = PM10 emission rate during normal operation, 9.5 lb/hr
B = Rule specified percent of CO2 in the exhaust (12%)
C = Percent of CO2 in the exhaust (approx. 4.29% for natural gas)
D = Stack exhaust flow rate, 61.84E+06 scf/hr (@ 32°F)

$$\text{Grain Loading} = \frac{9.5 \text{ lbs/hr x } [(7000 \text{ grains/lb}) \text{ x } (12/4.29)]}{61.8 \text{ E+06 scf/hr}}$$

$$= \boxed{0.003 \text{ grains/scf}}$$

RULE 431.1 – Sulfur Content of Gaseous Fuels

The natural gas supplied to the turbines is expected to comply with the 16 ppmv sulfur limit (calculated as H2S) specified in this rule. Commercial grade natural gas has an average sulfur content of about 4ppm. The long term (annual) SOx emissions from the turbines are based on 4 ppm or about 0.25 gr/100 cf concentration. The short term (hourly, daily, and monthly) SOx emissions from the turbines are based on 12 ppm or about 0.75 gr/100 cf concentration. A condition will be placed on the permit to require that the sulfur content is measured and recorded to insure compliance. The applicant will also comply with reporting and record keeping requirements as outlined in subdivision (e) of this rule.

RULE 475 – Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment meet a limit for combustion contaminants of 11 lbs/hr or 0.01 gr/scf. Compliance is achieved if either the mass limit or the concentration limit is met. Mass PM10 emissions from each turbine are estimated at 9.5 lbs/hr, and 0.0033 gr/scf during natural gas firing at maximum firing load (see calculations below). Therefore, compliance is expected. Compliance will be verified through the initial performance test as well as ongoing periodic testing.

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

where:
Fd: Dry F factor for fuel type, 8710 dscf/MMBtu
O2: Rule specific dry oxygen content in the effluent stream, 3%
TFD: Total fired duty measured at HHV, 2005 MMBtu/hr (@ 32°F)

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

Stack flow = 8710(20.9/17.9)*2005 = 20.39 mmscf/hr

Combustion particulate = (9.5/20.39E+06)*7000 = 0.0033 gr/scf

RULE 1134 – Emissions of NOx from Gas Turbines
This rule applies to gas turbines, 0.3 MW and larger, installed on or before August 4, 1989. Therefore, as a new installation, the proposed HBEP turbines are not subject to this rule.

RULE 1135 – Emissions of NOx from Electric Power Generating Systems
This rule applies to the electric power generating systems of several of the major utility companies in the basin, including SCE and their successors. The plants which are included in the RECLAIM program are no longer subject to the requirements of this rule.

REGULATION XIII/Rule 2005 – New Source Review
The new turbines are subject to NSR, including BACT, modeling, and offsets. Also, the addition of the turbines to the Huntington Beach plant is considered a major modification to an existing major source. Therefore, the additional requirements for major sources are applicable.

- BACT

BACT is required for all criteria pollutants. For major sources, BACT is determined at the time the permit is issued, and is the Lowest Achievable Emission Rate (LAER), which has been Achieved in Practice. Based on recently issued permits, (including LADWP Scattergood, City of Pasadena, Inland Empire Energy Center, and El Segundo Generating Station) AQMD has determined that BACT for combined cycle gas turbines is as follows:

Table 4.1 Turbine Required BACT

NOx	CO	VOC	PM_{10}	SOx	NH3
2.0 ppmdv @ 15% O2, 1 hour average	2.0 ppmdv @ 15% O2, 1 hour average	2.0 ppmdv @ 15% O2, 1 hour average	Natural gas fuel	Natural gas fuel with fuel sulfur content of no more than 1 grain/100 scf (about 16 ppm)	5.0 ppmdv @ 15% O2, 1 hour average

The applicant is proposing the following emission levels for this project. The emission levels of NOx, CO, VOC, and NH3 in the table are manufacturer guaranteed emissions under normal operating conditions.

TABLE 4.2 – Proposed Control Levels for the HBEP Turbines

NOX	CO	VOC	PM10	SOX	NH3
2.0 ppmvd @ 15% O2, 1 hour average	2.0 ppmvd @ 15% O2, 1 hour average	2.0 ppmvd @ 15% O2, 1 hour average	Exclusive use of natural gas fuel, PM10 emissions of 4.5/9.0 lbs/hr	Exclusive use of natural gas fuel*	5.0 ppmdv @ 15% O2, 1 hour average

**Natural gas provided by the Gas Company is limited to 16 ppm in the South Coast by Rule 431.1. Generally, the actual sulfur content is about 4 ppm (4 ppm corresponds to 0.25 gr/100 scf)*

BACT for the ammonia tank is the use of a pressure vessel equipped with a p/v valve.

- Modeling

The applicant performed dispersion modeling for NO2, CO, SO2, and PM10.

Modeling evaluations were performed using the American Meteorological Society/USEPA AERMOD (version 12345) model and representative meteorological data from the John Wayne Airport meteorological station. Modeling analysis was performed for turbine startups, normal turbine operation, and turbine commissioning operations. A discussion of the modeling procedure and the inputs used in the modeling are shown in Appendix E.

The air basin where the plant will be located is in attainment for NO2, CO, and SO2. PM10 was designated as a federal attainment pollutant in the SCAB on June 26, 2013, however it remains in non-attainment status at the state level and will therefore be evaluated as non-attainment. The compliance determination for NO2, CO, and SO2 is a comparison of the project impact plus the background concentration to show that it does not exceed the AAQS. For PM10, the project impact should not exceed the Significant Increment. The results of the model show that the project will not cause a violation, or make significantly worse an existing violation, of any state or national ambient air quality standard. Model results are summarized in the tables below.

Table 4.3 Model Results – Start up/Shutdown and Normal Operation

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3) (1)	Total Concentration (ug/m3)	NAAQS (ug/m3)	CAAQS (ug/m3)
NO2	1-hour	58.8	140	198.8	NA	339
	Annual	0.5	21.3	21.8	57	57
CO	1-hour	333	3,329	3,662	40,000	23,000
	8-hour	78	2,530	2,608	10,000	10,000
SO2	1-hour	7.1	24.9	32.0	NA	655
	1-hour	7.1	10.7	17.8	196	NA
	24-hour	2.4	5.5	7.9	365	105
PM10	24-hour	4.7	48.0	52.7	NA	150

Table 4.6 Model Results, Commissioning

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3) (1)	Total Concentration (ug/m3)	NAAQS (ug/m3)	CAAQS (ug/m3)
NO2	1-hour	146.3	140	286.3	NA	339
CO	1-hour	5,076	3,329	8,405	40,000	23,000
	8-hour	4,369	2,530	6,899	10,000	10,000

The modeling was reviewed by AQMD modeling staff and deemed acceptable. Refer to the memo from Elaine Chang to Andrew Lee dated December 12, 2013.

- Offsets

The applicant is requesting that the project be evaluated under the Rule 1304(a)(2) – Electric Utility Steam Boiler Replacement exemption. This provision applies to the replacement of a utility steam boiler with combined cycle gas turbine(s), and allows an exemption from modeling and offsets for non-Reclaim pollutants in such cases. The exemption applies on a MW to MW basis. Its purpose was to facilitate the removal of older less efficient boiler/steam turbine technology with newer cleaner gas turbine technology at the utilities, in conjunction with the old Rule 1135. Since the advent of Reclaim, the exemption was expanded to include modifications being conducted in order to comply with Reg. XX rules. Rule 2005 does not provide a similar exemption for NOx.

In order to qualify for the exemption, AES HB is proposing to shutdown 4 boilers in conjunction with the construction of the new HBEP. Those 4 boilers include Boilers 1 and 2 at the Huntington Beach site, as well as Boilers 6 and 8 at AES' Redondo Beach

Generating Facility, located at 1100 N. Harbor Dr, Redondo Beach, CA 90277. The capacity of the boilers being shutdown is shown in the table below:

Unit	Capacity, MW
Boiler 1, HB	215
Boiler 2, HB	215
Boiler 6, RB	175
Boiler 8, RB	480
Total Shutdown Capacity	1085

The shutdown capacity is based on the description of the units as listed in the current AQMD permits.

The capacity of the new units is summarized below:

Total Gross Capacity as Permitted, MW	Total Net Capacity with Transmission Line Restriction, MW	Total Gross Capacity with Transmission Line Restriction, MW
1091	939	972[1]

1 At a temperature of 75-80 °F

Maximum capacity is determined at 32 °F. The plant output is physically restricted by the transmission line out of the facility to 939 MWs net. The plant will be limited to this output by permit condition.

The actual emissions from the 2 units being shutdown at the Huntington Beach facility (Boiler 1 and 2) are shown in Appendix D for reference only.

Under Rule 2005, RTCs to cover the expected emissions of NOx are required to be held for the first compliance year. Additionally, since the NOx PTE after the commissioning year is greater than the facility's initially allocation, the facility is required to hold NOx RTCs for each subsequent year. The Huntington Beach facility is also in the SOx RECLAIM program. Therefore, SOx RTCs are required to be held to cover the first year of operation. Additionally, because the facility opted into SOx RECLAIM after 1994, there is no initial allocation. For this reason, SOx RTCs are required to be held for each compliance year after the first year of operation [paragraph (f)(1)]. RTC requirements are shown in Appendix P.

Other requirements of Rule 1303:

Sensitive Zone Requirements. For this project, ERCs may be obtained from either Zone 1 or Zone 2A.

Facility Compliance. This facility is currently in compliance with all applicable rules and regulations of the District.

Alternative Analysis. The project is subject to the California Energy Commission licensing procedure. Under this procedure, a full analysis of the proposal is conducted, including project alternatives. The project proponent did not consider any alternative generating technologies that do not include natural gas combustion. Therefore, the alternatives to the project that were considered and rejected were as follows:

Conventional Boiler and Steam Turbine
Simple-Cycle Combustion Turbine
Kalina Combined-Cycle
Internal Combustion Engine

An alternative to the proposed site of the power plant was determined to be not necessary because PRC 25540.6 [b] states that if the commission finds 'that the project has a strong relationship to the existing industrial site' .....'it is therefore reasonable not to analyze alternatives sites for the project'.

Protection of Visibility. Net Increase in emissions from the proposed project exceed the 15 tons per year PM_{10} and 40 tons per year NOx thresholds, but the site is not within the specified distance of any Class I areas. Distances to the Class I areas are summarized below:

Table 4.7 Distances to Class I Areas

Federal Class I Area	Threshold Distance (km)	Distance from the HBEP (km)
Cucamonga Wilderness	28	69
San Gabriel Wilderness	29	69
San Gorgonio Wilderness	32	118
San Jacinto Wilderness	28	124
Agua Tibia Wilderness	28	96
Joshua Tree NP	29	180

A visibility analysis was conducted under the PSD regulation.

Statewide Compliance. The applicant has submitted a statement certifying that all AES's stationary sources are currently in compliance with applicable state and federal environmental regulations.

Rule 1304.1 – Electrical Generating Facility Fee for Use of Offset Exemption

The project will utilize the offset exemption of Rule 1304(a)(2) for PM10 and VOC, and is therefore subject to a fee under this rule. The facility has opted to pay an annual fee. The formula for calculating this fee is as follows:

$$[(R_{iA1}\times 100/MW)+R_{iA2}\times(MW-100)/MW]\times OF_i \times PTErep_i \times[(C_{rep}-C_{2YRAvgExisting})/C_{rep}]$$

Where:

Fi	=	Offset fee for pollutant (i)
RiA1	=	Annual Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, annually (Table A1 of the rule)
RiA2	=	Annual Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, annually (Table A2 of the rule)
MW	=	MW of new replacement units
OFi	=	Offset factor pursuant to Rule 1315(c)(2) for extreme non-attainment pollutants and their precursors (Tables A1 and A2 of the rule)
PTErepi	=	permitted potential to emit of new replacement units for pollutant (i), in pounds per day (maximum permitted monthly emissions ÷ 30 days).
Crep	=	maximum permitted annual megawatt-hour (MWh) generation of the new replacement units (maximum rated capacity (MW) X maximum permitted annual operating hours)
C2yravgexisting	=	maximum permitted annual megawatt-hour (MWh) generation of the existing units to be replaced using the last 24 month period immediately prior to issuance of the permit to construct.

The facility will be required to demonstrate compliance with the specific requirements of this rule prior to the issuance of the Permits to Construct for the HBEP Project. The following calculation provides an estimate of the approximate fee that will be required.

The following factors are used in the equation:

Factor	PM10	VOC
PTErep	856 lbs/day	1,497 lbs/day
Ri1A	$997/lb/day	$47/lb/day
Ri2A	$3,986/lb/day	$185/lb/day
OFi	1.0	1.2
MW	1,091 MW	1,091 MW
Crep	6,949,670 MWh	6,949,670 MWh

C2yr	18,959.8 MW	18,959.8 MW

Notes:
1,091 MW is based on low temperature conditions (from Table 2.1 181.835 MW*6 turbines)
PTErep is calculated as follows: PM10 -4,278 lbs/month ÷ 30 = 142.6* 6 turbines = 856 lbs/day, VOC – 7,487.2 lbs/month ÷ 30 = 249.6*6 turbines = 1,497 lbs/day
Crep is calculated as follows: 1,091 MW * 6,370 hrs = 6,949,670 MWh (5,900 w no duct firing, 470 with duct firing, no starts or shutdowns included)
C2yr is taken from Appendix O

PM10

$$F_{PM10} = [(997\times100/1091) + 3620.65\times(1091-100)/1091]\times 1.0 \times856 \times[(6949670-18959.8)/6949670]$$

$$F_{PM10} = [(91.38)+(3288.78)]X(1.0)X(856)X(0.9973)$$

$$F_{PM10} = \$2,885,604.73$$

VOC

$$F_{VOC} = [(47\times100/1091) + 185\times(1091-100)/1091]\times 1.0 \times1497 \times[(6949670-18959.8)/6949670]$$

$$F_{VOC} = [(4.31)+(168.04)]X(1.2)X(1497)X(0.9973)$$

$$F_{VOC} = \$308,773.59$$

RULE 1325 – Federal PM2.5 New Source Review

This rule applies to major polluting facilities, major modifications to a major polluting facility, or any modifications to an existing facility that would constitute a major polluting facility in and of itself. A major polluting facility is defined as a facility which has actual emissions, or a potential to emit of greater than 100 tons per year. A major polluting facility is required to comply with the following requirements:

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

As shown in Appendix L, the total PM2.5 potential to emit resulting from the addition of the 6 turbines will not result in an emissions increase above the 100 ton/year threshold. Therefore, the Huntington Beach facility will continue to be a non-major polluting facility for PM2.5.

RULE 1401 – New Source Review of Toxic Air Contaminants
This rule requires an analysis of the new permit units' impacts due to the release of air toxics. A Tier 4 Health Risk Assessment was performed using CARB's Hotspots Analysis and Reporting Program (HARP, version 1.4f). Model inputs and results are presented in Appendix E. The results show compliance with the limits specified in the rule, and are summarized below:

Table 4.11 Model Results, Individual Unit HRA

	Residential Cancer Risk	Residential Chronic HI	Residential Acute HI
Stack 1	0.42 per million	0.00124	0.0244
Stack 2	0.39 per million	0.00113	0.0291
Stack 3	0.36 per million	0.00104	0.0203
Stack 4	0.46 per million	0.00135	0.00368
Stack 5	0.47 per million	0.00136	0.00897
Stack 6	0.47 per million	0.00136	0.0117
	Worker Cancer Risk	Worker Chronic HI	Worker Acute HI
Stack 1	0.095 per million	0.00154	0.0244
Stack 2	0.095 per million	0.00154	0.0291
Stack 3	0.121 per million	0.00197	0.0203
Stack 4	0.095 per million	0.00154	0.00368
Stack 5	0.095 per million	0.00154	0.00897
Stack 6	0.096 per million	0.00157	0.0117

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

PSD applies to a significant increase in emissions from a major stationary source. For a combined cycle power plant, the major source threshold is 100 tons per year based on actual emissions or potential to emit. If the facility is deemed to be major, Rule 1702 further defines a significant emission increase as 40 tpy or more of NO2 or SO2 or 100 tons per year or more of CO. The existing equipment at the Huntington Beach Generating Station does not constitute a major source, however the addition of the new gas turbines is considered major for NO2, CO and PM10, and is subject to PSD review for these pollutants.

Requirements for a significant emission increase under Rule 1703 include the following:

- Use of BACT [1703(a)(3)(B)]

- Modeling to determine impacts of the project of National and State AAQS and increases over the baseline concentration [1703(a)(3)(C)]
- Analysis of ambient air quality in the impact area [1703(a)(3)(D)]
- Analysis of project impacts on visibility, soil, and vegetation [1703(a)(3)(E)]

Affected Federal Land Managers have the opportunity to review and comment on the proposed project. AQMD has provided the Park Service and Forest Service with copies of the analysis.

The PSD analysis requires the following steps:

1. Determine whether preconstruction monitoring is required
2. Assessment of significance under PSD
3. Determine Ambient Air Quality Impacts
4. Determine Impacts in Class I Areas

The applicant performed modeling which indicated that the maximum 1-hour and 8-hour CO impacts from turbine operations including start ups and shutdowns are 332.6 ug/m3 and 78.3 ug/m3 respectively. These results are below the corresponding US EPA CO Class II SILs of 2,000 ug/m3and 500 ug/m3. Therefore, 1-hour and 8-hour CO increment analyses are not required.

The peak annual NO2 impact from the total project is 0.49 ug/m3. This impact is less than the US EPA NO2 Class II significance impact of level of 1 ug/m3, therefore, no additional PSD analysis is necessary.

For 1-hour NO2 impacts, it was first determined that the peak impact level from the proposed project of 52.2 ug/m3 exceeds the significance impact level of 7.52 ug/m3. Therefore, a cumulative impact assessment is necessary.

For the cumulative impact assessment, three facilities, Orange County Sanitation District's Huntington Beach and Fountain Valley facilities and Beta Offshore as well as emissions from shipping lane activities off the coast were selected to be included based on their facility emissions and distance to the project. Seasonal, by hour-of-day background concentrations from the Costa Mesa monitoring station were used in the modeling. Following the form of the standard, the 1-hour NO2 impact from the project plus cumulative sources plus background is 168.2 ug/m3, which is less than the Federal 1-hour standard of 188 ug/m3. Therefore, no additional PSD analysis is necessary.

Effective July 26, 2013, the South Coast Air Basin has been re-designated to attainment for the 24 hour PM10 NAAQS. The total project's peak 24-hour impact is 4.74 ug/m3, which is less than the Class II SIL of 5 ug/m3, therefore no additional PSD analysis is necessary.

Visibility Analysis

The nearest Class I areas to the project site are the San Gabriel Wilderness and Cucamonga Wilderness areas located approximately 69 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 maximum project impact for annual NO2 at 50 km is 0.02 ug/m3, which is less than the significance level of 0.1 ug/m3.

A screening criteria is acceptable to use for projects located more than 50 km away from a Class I area, in order to estimate the potential impacts on visibility and deposition at these areas. The emissions/distance (Q/D) is calculated using the project's total annual emissions of SO2, NOx, PM10, and H2SO4 (based on 24 hour maximum allowable emissions) divided by the distance between the project and the nearest Class I area. Since the project is limited to an operating profile of 6,835 hours per year, the project's annual emissions of 407.3 tpy are equivalent to 522 tpy. Therefore, the Q/D ratio is 7.6, which is less than the threshold of 10. Thus, modeling of visibility and deposition impacts to Class I areas is not necessary.

The project's impacts on visibility in Class II areas were also analyzed. Currently, there are no thresholds for visibility impacts on Class II areas. The project utilized the criteria and thresholds for visibility impacts on Class II areas. 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 San Mateo Canyon Wilderness Area. The ΔE for Crystal Cove State Park and Water Canyon State Park exceeded the thresholds using the Level I VISCREEN analysis. Therefore a Level 2 VISCREEN analysis was performed for these 2 areas. Using the 5 year meteorological data from the John Wayne Airport, the joint frequency distribution tables were created and were used to determine the worst case single wind speed and stability class required for a VISCREEN analysis. Using the Level 2 VISCREEN analysis, the project's impacts for both contrast and ΔE are less than the thresholds for both Crystal Cove state Park and Water Canyon State Park. Therefore, the proposed project would not be expected to adversely affect visibility at the Class II areas analyzed.

Rule 1714 – PSD for Greenhouse Gases

As of January 2, 2011 Greenhouse gases (GHGs) are a regulated New Source Review pollutant under the PSD permitting program when they are emitted by new sources or modifications to existing sources at amounts equal to or greater than the applicability thresholds of the GHG tailoring rule. The HBEP project will emit over 1 million tons of CO2e, and the contemporaneous increase, after considering the shutdown of Boilers 1 and 2, will exceed 75,000 tons per year. The project is therefore subject to BACT for GHGs (reference Appendix F)

For PSD purposes, GHGs are defined as a single air pollutant consisting of the sum of the following six gases:

Carbon Dioxide (CO2)
Nitrous Oxide (N20)
Methane (CH4)
Hydroflorocarbons
Perfluorocarbons
Sulfur hexafluoride (SF6)

These gases can be summed together as CO2 equivalent, or CO2e, using each gases' global warming potential (GWP). The CO2e limit as set forth in California law SB1368., Under CCR Title 20 Chapter 11 Article 1 is 1,100 $lb/_{net}MWh$. The limit is based on the total annual CO2e emissions from all operations, divided by the total annual net MW generation.

Approximate GHG emissions from the HBEP are calculated in Appendix F and summarized in the following table.

Table F.5 New Turbines GHG PTE

GHG	Hourly Tons Per Turbine @ 2005 mmbtu/hr	Annual Tons Per Turbine @ 66,776,649 mmbtu/yr(1)	Annual Tons 6 Turbines
CO2	117.2	3,903,399	23,420,394
CH4	2.21E-3	73.6	441.6
N2O	2.21E-4	7.4	44.4
Total Mass	117.2	3,903,480	23,420,880
CO2e	117.3	3,907,239	23,443,434

GHG BACT Analysis

EPA has recommended the 5-step "top-down" process to determine BACT for GHGs.

1. Identify all available control options
2. Eliminate technically infeasible options
3. Ranking of controls

4. Economic, energy, and environmental impacts
5. Selecting BACT

Step 1 Identify All Available Control Options

The available CO_2 control technologies, as determined by EPA and Department of Energy, are:

A. Carbon Capture and Sequestration (CCS)
B. Lower Emitting Alternative Technology
C. Thermal Efficiency

The technologies are described and discussed in the next sections.

A. Carbon Capture and Sequestration (CCS)

CCS is a process that captures, transports, and sequesters CO_2 emissions.

Capturing of CO_2 Emissions

Combustion flue gas may be processed for the purpose of separation and capture of carbon dioxide. Amine-based solvent systems are available in commercial use for scrubbing CO_2 from industrial flue gases and process gases. Solid sorbents are also available to capture CO_2 from flue gas through chemical adsorption or physical adsorption. However, based on a recent similar analysis conducted for LADWP Scattergood Generating Station, commercially available systems are not presently available to process flue gas from a commercial power plant.

Transportation of CO2 Emissions

Once captured, CO_2 would have to be transported to a storage site. For geologic sequestration, a pipeline is typically used to transport the CO_2 as a critical fluid to the sequestration location. 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.

Sequestration of CO_2 Emissions

There are several sequestration approaches.

Geologic Sequestration

Under geologic sequestration the captured CO_2 is compressed and transported to a sequestration location. CO_2 is injected into underground at high pressure, and remains a supercritical fluid underground. Over time the CO_2 can dissolve into surrounding water and rocks, creating solid carbonate minerals.

There are several geologic formations identified in California that might provide a suitable site for geologic sequestration. Several sites near the HBEP Project may be the old petroleum production area in Huntington Beach, a formation in the Lower San Joaquin Valley, and possibly a site located in Ventura County. While these sites may eventually prove to be suitable, the geotechnical analyses needed to confirm their suitability have not been conducted. In addition, there are no available pipelines to transport captured CO_2 to the sequestration site.

Ocean Storage

In lieu of injecting CO_2 underground as in geologic sequestration, ocean storage is accomplished by injecting CO_2 into the ocean water typically at depth of greater than 1,000 meters. CO_2 is expected to dissolve or form into a horizontal lens which would delay the dissolution of CO_2 into the surrounding environment.

Mineral Carbonation

Mineral carbonation is the reaction of CO_2 with metal oxides to form metal carbonates. Metal oxides are abundant in silicate minerals and in waste streams. The natural reaction of CO_2 with metal oxides is a very slow process. The reaction time can be increased by enhancing the purity of these metal oxides. Large scale production of metal oxides to meet the demand of electrical generation is very energy and cost intensive.

B. Lower Emitting Alternative Technology

Lower emitting alternative technologies for energy generation are available on the demand side. If demand for energy is reduced a utility's generation capacity can be reduced, thus lowering GHG emissions.

Demand-side resource programs include both energy efficiency, aimed at reducing total energy consumption, and demand response, aimed at reducing peak demand or shifting demand from peak to off-peak periods. Demand response programs include increasing the efficiency of Huntington Beach Energy Project's system capabilities such that energy is dispatched to more effectively track actual demand, and agreements with commercial and industrial customers to curtail load during peak periods. No additional lower emitting alternative technologies are feasible to incorporate into the project without fundamentally changing the business purpose of the Project.

C. Thermal Efficiency

Power generation through fossil fuel combustion is a chemical reaction process. The thermal efficiency is defined as the ratio of the net power produced and the heating values of the fuel. The plant efficiency varies from 30% to over 40%, depending on many factors. 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, and at the time when CO_2 emissions are the highest.

The following factors affect the thermal efficiency of a power plant:

- Thermal dynamic cycle selection, combined cycle versus simple cycle
- Combustion turbine performance, compression ration and turbine design temperature
- Combustion turbine startup time, load transition time
- Steam turbine startup time, load following time
- Fuel selection

The repower project is proposing to combust natural gas, the lowest emitting fossil fuel available. The proposed turbines are operated as a combined cycle generation system (CCGS). The CCGS has a higher cycle thermal efficiency than the simple cycle systems. Energy is recovered in the heat recovery steam generator (HRSG) and is used to generate power in the steam turbine generator (STG). The fast start capability of the turbines minimizes emissions during startup and increases the efficiency of the power plant.

Although new power generating system would emit GHG emissions, the high thermal efficiency of the new power generating equipment and the system build-out of renewable resources in California would result in a net cumulative reduction of GHG emissions from new and existing fossil resources.

With the adoption of Senate Bill 2 on April 12, 2011, California's Renewable Portfolio Standard (RPS) was increased from 20 percent by 2010 to 33 percent by 2020. To meet the new RPS requirements, the amount of dispatchable, high-efficiency, natural gas generation used as regulation resources, fast ramping resources, or load following or supplemental energy dispatches will have to be significantly increased. The construction of the HBEP will aid in the effort to meet California's RPS standard. Finally, the operation of the new power generating system will enhance the overall efficiency of AES's electricity system operation and thereby reduce GHG emissions.

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 determine the technical feasibility. The technology is feasible only when the technology is available and applicable. A technology that is not commercially available for the scale of the project is also considered infeasible. An available technology is applicable if it can reasonably be installed and operated on the proposed project.

A. Carbon Capture and Sequestration (CCS)

The technical feasibility of each step of the CCS is discussed below.

Carbon Capture Technology

Solvent-based capture technology for a commercial scale power plant has only been demonstrated for a fraction of the flue gas. A solvent-based carbon capture process is currently judged to be technologically infeasible for a commercial power plant application.

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. A sorbent-based carbon capture process is currently judged to be technologically infeasible for a natural gas-fired commercial power plant application.

Membrane-based capture technology is commercially available in the chemical industry for CO_2 removal but has not been demonstrated in practice for power generation applications. A membrane-based carbon capture process is currently judged to be technologically infeasible for a commercial power plant application.

CO_2 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.

CO_2 Sequestration

Geologic sequestration has been demonstrated on a pilot scale. However, a number of significant technical issues remain to be resolved before the technology can be applied to a successful commercial scale application at a specific site. At this moment the technical feasibility for geological sequestration for the new power generating system cannot be determined. Therefore CCS using geological sequestration cannot be demonstrated to be technically feasible in practice for the new power generating system.

Ocean storage and its ecological impacts are still in the research phase. It is not commercially available.

Mineral carbonation is technically feasible, as reaction chemistry is well understood. However, the sequestration of CO_2 through mineral carbonation has not been demonstrated on a commercial scale.

Summary of CCS Feasibility

In summary, the post-combustion carbon capture technologies are still in the developmental stage or pilot scale projects. These technologies would not be considered commercially available for the project size of a full-scale commercial power plant. In addition, there are no comprehensive standards in place defining requirements for long term sequestration. Therefore, CCS is not yet demonstrated in practice for a commercial-scale, natural gas fired power plant such as the HBEP. In consideration of the uncertainty in the technical feasibility of CCS and its emergence as a promising technology, CCS is carried forward in this BACT analysis as a potential GHG control technology. However, substantial evidence demonstrates that CCS is not yet demonstrated as technically feasible for the HBEP project.

B. Lower Emitting Alternative Technology

As discussed previously, any of the commercially available low GHG-emitting technologies that could be implemented, are not feasible for this site and would fundamentally alter the business purpose of the emission source. As such, lower emitting alternative technology was not considered as part of the BACT analysis.

C. Thermal Efficiency

The California Senate Bill (SB) 1368 requires the California Public Utilities Commission (CPUC) to establish a GHG emission performance standard for all baseload utilities by February 1, 2007. The California Energy Commission (CEC) was required to establish a similar standard for local publicly owned utilities by June 30, 2007. The CEC has established a GHG performance standard of 1,100 pounds of CO_2 per net MWh for baseload publicly owned electrical utilities. The California Legislature in Assembly Bill (AB) 1613 (2007), as amended by AB 2791 (2008), established a CO_2 Emission Performance Standard (EPS) for combined heat and power facilities of 1,100 lbs CO_2/MWh. In 2010, the CEC promulgated its regulation to implement AB 1613 in its Guidelines for Certification of Combined Heat and Power Systems Pursuant to the Waste Heat and Carbon Emissions Reduction Act (CEC 2010b).

The EPA released a prepublication version of a proposed rule on March 27, 2012 to establish, a new source performance standard (NSPS) for GHG emissions from fossil fuel-fired electric generating units. This standard will require the new fossil fuel-fired power plants to meet an output based standard (based on gross output power) of 1,000 lb CO_2/MWh on an average annual basis. This standard will apply to combined cycle generating systems. At this moment the proposed rule has not been finalized by EPA.

The CCGS will meet the California GHG emission performance standard of 1,100 pounds of CO_2 per net megawatt hour. As calculated in Appendix F, using a conservative annual operating schedule that includes startup, normal operation, shutdown and load factors as low as of 60%, the CCGS will emit CO_2 at a rate of 1054.7 lb CO_2 per net megawatt hour. The GHG emissions will be 876.89 lbs CO_2 per net megawatt hour when the load factor improves to 100%. *This is below the 1,100 lbs CO_2 per net MWh California standard.*

The thermal efficiency for the new power generating system achieved by the state-of-the-art technologies is a technically feasible alternative for reducing GHG emissions from a fossil-fuel fired low efficiency power plant. In conclusion the combustion process inherent in the new power generating system is achieved in practice and is eligible for consideration under Step 3 of the BACT analysis.

Step 3 - Rank Remaining Control Technologies

While carbon capture and sequestration (CCS) was determined to be technically infeasible for the HPEP Project, this option is carried forward in the BACT analysis to Step 3. The rank order of control, starting from the most effective control (1) to the least effective control (2), is as follows:

1. CCS
2. Thermal efficiency

The control effectiveness is discussed below.

A. Carbon Capture and Sequestration (CCS)

Post-combustion capture systems being developed are expected to be capable of capturing more than 90 percent of flue gas CO_2. At an assumed control efficiency of 90 percent, this would be equivalent to an emission rate of 10 percent of the California EPS, or approximately 110 lb CO_2/MWh. This makes CCS the top-ranked technology on a theoretical basis. However, as discussed in Step 2, CCS was found to be technically infeasible for the HBEP Project. In addition. the above assumed CO_2 control efficiency does not take into account the parasitic loss associated with operation of the CCS system and the increased CO_2 emissions that will occur to replace the parasitic energy loss.

B. Thermal Efficiency

Thermal efficiency is capable of lowering GHG emissions, but the potential is much less than CCS on a theoretic basis. As discussed in Section 2, the new power generating system already incorporates increased thermal efficiency in its design by incorporation of state-of-the-art combustion turbines with the addition of RPS startup capability. Since the parasitic load is already relatively low at this facility, further increases to thermal efficiency are not achievable without changing basic objectives of the power project, if at all, and hence are not required by EPA guidelines for GHG BACT.

Step 4 – Evaluating the Most Effective Controls

Step 4 of the BACT analysis is to evaluate the most effective control. This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down approach requires that the evaluation begin with the most effective technology.

A. Carbon Capture and Sequestration (CCS)

Because CCS is considered technically infeasible to apply for the HBEP Project it is not evaluated under this step.

B. Thermal Efficiency

The database review of BACT determinations described above identified six facilities with natural gas-fired combustion turbines for which a GHG BACT analysis was done:

- 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 is 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 a GHG BACT determination 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 Permits for the LADWP Scattergood Generating Station in 2013. The project consists 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 City of Pasadena in 2013. The project consists 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 permits thermal efficiency is the most cost effective control technology for GHG emissions from power plants. The Mitsubishi 501DA combustion turbines are acceptable for GHG PSD permits under the BACT thermal efficiency requirement.

Step 5 – Select BACT

Based on the above analysis, thermal efficiency is the only technically and economically feasible alternative for CO_2/GHG emissions control for the HBEP Project. The current design of the facility meets the BACT requirement for GHG emission reductions.

The BACT limit shall be applicable to the entire operation conditions. Therefore, BACT is determined based on the facility proposed annual operating scenarios that take into consideration of load factor and operating hours. The detailed calculations are included in Appendix F.

Based on calculations of Appendix F the Mitsubishi 501DA combined cycle generating system is expected to generate 1053.7 lbs of CO_2 per net megawatt hours over the course of a typical year and this will be the permit limit. This limit ensures compliance with the California law SB1368 limit of 1,100 lb/$_{net}$MWh. Each turbine will also be subject to the CO2e emission limit of 3,907,239 tons per year. Compliance will be based on a 12-month rolling average as determined by using emission factors and fuel usage.

- Circuit Breakers

EPA in the Pio Pico Energy Center PSD permit requires the circuit breakers be equipped with a leak detection system, and be calibrated according to manufacturer specifications. EPA considers this to be BACT for circuit breakers. EPA further argues that the requirement is not redundant to the CARB regulation to reduce GHG (SF_6) emissions from gas insulated switchgears, California Code of Registers, Subchapter 10, Article 4, §95350-§95359.

A facility condition F52.2 will be added to enforce the BACT requirement for the circuit breakers, using the same language as the EPA permit.

Other PSD Requirements

In addition to the BACT requirement the PSD requirements generally include air quality modeling, ambient monitoring, and additional impact analysis. The modeling analysis shall demonstrate that there will be no violations of any NAAQS or PSD increments. However, because there are currently no NAAQS or PSD increments established for GHGs, the modeling analysis requirement would not apply for GHGs even if PSD is triggered for GHGs. EPA does not require monitoring for GHGs in accordance with Section 52.21(i)(5)(iii) and Section 51.166(i)(5)(iii), and EPA does not require impact analysis from GHGs in the nearby Class I areas. In addition, no offsets are required for CO because this pollutant is in attainment in the South Coast Air Basin.

Rule 2011 – SOx RECLAIM, Monitoring Recording and Recordkeeping Requirements
The turbines will be classified as process units under SOx RECLAIM. As such they are required to measure and record fuel use and calculate mass SOx emissions using the emission factor on the permit, and electronically report emissions on a quarterly basis

Rule 2012 – NOx RECLAIM, Monitoring Recording and Recordkeeping Requirements
The turbines will be classified as major NOx sources under NOx RECLAIM. As such, they are required to measure and record NOx concentrations and calculate mass NOx emissions with a Continuous Emissions Monitoring System (CEMS). The CEMS will include in-stack NOx and O2 analyzers, a fuel meter, and a data recording and handling system. NOx emissions are reported to AQMD on a daily basis. The CEMS system will be required to be installed within 90 days of start up. Compliance is expected.

REGULATION XXX – Title V
The Huntington Beach facility is currently subject to Title V, and is operating under a valid Title V permit issued on May 4, 2011. The addition of the combined cycle plant will be considered a significant revision to the existing Title V permit. AES has submitted a Title V revision application A/N 540259. As a significant revision, the permit is subject to a 30 day public notice and a 45 day EPA review and comment period. The public notice requirements are discussed in more detail under the "Public Notice Requirements" section of this report.

State Regulations

California Environmental Quality Act (CEQA)
The project is subject to the licensing procedure under the California Energy Commission (CEC). This procedure analyzes all aspects of the proposed project, and is subject to a public review and comment period. It is therefore considered equivalent to an Environmental Impact Report, and satisfies the requirements of CEQA. CEC's process will fully evaluate all air quality impacts for the entire project.

Federal Regulations

NSPS for Steam Generators – 40CFR 60 Subpart Da
The fired HRSGs are subject to this subpart because their heat input rating is 507 mmbtu/hr which is greater than the applicability standard of 250 mmbtu/hr in the rule. The emission standards that apply are as follows:

NOx 0.2 lbs/mmbtu
PM 0.015 lbs/mmbtu

SO_2 0.2 lbs/mmbtu

The regulation requires the installation of a CEMS to measure NOx and O2. A CEMS for opacity is not required since the unit burns natural gas exclusively and does not use post-combustion controls for PM or SO2 {60.49Da(u)(2)}. A PM CEMS is optional under 60.49Da(t). In lieu of a PM CEMS, a CO CEMS may be installed. An initial performance test is required.

Anticipated emissions from the gas turbines/duct burners are as follows:

NOx 0.0081 lbs/mmbtu
PM 0.0050 lbs/mmbtu
SO2 0.0015 lbs/mmbtu

The emissions estimates are all lower than subpart Da requirements. Compliance is expected.

NSPS for Steam Generators – 40CFR 60 Subpart Db

The fired HRSG is not subject to this subpart because the combined cycle turbine meets the applicability requirements of subpart KKKK {60.4b(i)}.

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

This regulation has been superseded by 40CFR 60 Subpart KKKK.

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

The turbines are subject to Subpart KKKK because their heat input is greater than 10.7 gigajoules per hour (10 MMBtu per hour) at peak load, based on the higher heating value of the fuel fired. Actual unit rating is 1498E+06 btu/hr (HHV) X 1055 joules/btu = 1580.4 gigajoules/hr. The standards applicable for a natural gas turbine greater than 850 mmbtu/hr are as follows:

NOx: 15 ppm at 15% O2 (0.43 lbs/MWh)
SOx: 0.90 lbs/MWh discharge, or 0.060 lbs/mmbtu potential SO2 in the fuel

Monitoring

The regulation requires that the fuel consumption and water to fuel ratio be monitored and recorded on a continuous basis, or alternatively, that a NOx and O2 CEMS be installed. For the SOx requirement, either a fuel meter to measure input, or a watt-meter to measure output is required, depending on which limit is selected. Also, daily monitoring of the sulfur content of the fuel is required if the fuel limit is selected.

However, if the operator can provide supplier data showing the sulfur content of the fuel is less than 20 grains/100cf (for natural gas), then daily fuel monitoring is not required.

Testing
An initial performance test is required for both NOx and SO2. For units with a NOx CEMS, a minimum of 9 RATA reference method runs is required at an operating load of +/- 25 percent of 100 percent load. For SO2, either a fuel sample methodology or a stack measurement can be used, depending on the chosen limit. Annual performance tests are also required for NOx and SO2.

Compliance with the requirements of this rule is expected.

NESHAPS for Stationary Gas Turbines - 40CFR Part 63 Subpart YYYY
This regulation applies to gas turbines located at major sources of HAP emissions. A major source is defined as a facility with emissions of 10 tpy or more of a single HAP or 25 tpy or more of a combination of HAPs based on the potential to emit. Although the total combined potential HAP emissions from all 6 turbines at the site are about 21 tpy, the formaldehyde emissions from the turbines exceed 10 tpy, therefore, AES Huntington Beach is classified as a major source of HAPs, and is subject to this subpart (calculations can be referenced in Appendix L). Subpart YYYY requires gas turbines to comply with a formaldehyde emission limit in Table 1 of 91 ppbvd measured at 15% O2. In addition, §63.6100 of 40CFR 63 Subpart YYYY requires an operating limitation in Table 2 such that the operator of the equipment maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. The applicable equipment will be conditioned to comply with these requirements.

40 CFR Part 64 – Compliance Assurance Monitoring
The CAM regulation applies to emission units at major stationary sources required to obtain a Title V permit, which use control equipment to achieve a specified emission limit and which have emissions that are at least 100% of the major source thresholds on a pre-control basis. The rule is intended to provide "reasonable assurance" that the control systems are operating properly to maintain compliance with the emission limits. Based on the emission calculations shown in Appendix L, the AES Huntington Beach facility is a major source and the turbine emissions are greater than the major source thresholds for NOx, CO, VOC, and PM10, and the turbines will be subject to an emission limit for each of these pollutants. Control systems are used for NOx, CO, and VOC, but not PM10.

NOx
- Emission Limit – NOx is subject to a 2.0 ppm 1 hour BACT limit.
- Control Equipment – NOx is controlled with the SCR

- ✓ Requirement - As a NOx Major Source under Reclaim, the turbines are required to have CEMS under Rule 2012. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

CO

- ➢ Emission Limit – CO is subject to a 2.0 ppm 1 hour BACT limit.
- ➢ Control Equipment – CO is controlled with the oxidation catalyst.
- ✓ Requirement – The turbines will be required to use a CO CEMS under Rule 218. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

VOC

- ➢ Emission Limit – VOC is subject to a 2.0 ppm 1 hour BACT limit.
- ➢ Control Equipment – VOC is controlled with the oxidation catalyst.
- ✓ Requirement – The oxidation catalyst is effective at operating temperatures above 500°F. The facility is required to maintain a temperature gauge in the exhaust (condition D12.7), which will measure the exhaust temperature on a continuous basis and record the readings on an hourly basis. The exhaust temperature is required to be at least 500°F, (with exceptions for start ups and shutdowns). This will insure that the oxidation catalyst is operating properly.

40 CFR Part 72 - (Acid Rain Provisions)

The facility will be subject to the requirements of the federal acid rain program, because the turbines are utility units greater than 25 MW. The acid rain program is similar to RECLAIM in that facilities are required to cover SO2 emissions with "SO2 allowances" that are similar in concept to RTCs. The Huntington Beach facility was given initial allowance allocations based on the past operation of their boilers. AES can either use those allocations, or if insufficient, must purchase additional allocations to cover the operation of the new turbines. The applicant is also required to monitor SO2 emissions through use of fuel gas meters and gas constituent analyses, or, if fired with pipeline quality natural gas, as in the case of the Huntington Beach facility, a default emission factor of 0.0006 lbs/mmbtu is allowed. SO2 mass emissions are to be recorded every hour. NOx and O2 must be monitored with CEMS in accordance with the specifications of Part 75. Under this program, NOx and SOx emissions will be reported directly to the U.S. EPA. Part 75 requires that the CEMS be installed and certified within 90 days of initial startup. Compliance is expected. Note that Section K of the permit will include the Acid Rain rule references applicable to this facility, specifically Part 72 and Part 73.

Public Notice Requirements

The project is subject to public notice under Rule 212, and Rule 3006. Following are the notice requirements for each rule:

Rule 212

The project is subject to the noticing requirements of paragraph (g). This paragraph requires that notification follow the procedures of 40 CFR51, Section 51.161(b), and 40 CFR124, section 124.10. Rule 212(g) also requires 1) the AQMD analysis and information submitted by the operator must be available for public inspection in an area affected, 2) notice by prominent advertisement in the affected area, and 3) mailing a copy of the notice to EPA, CARB, chief executives of the city and county where the source is located, any land use agencies, State and Federal Land Managers or Indian Governing Body whose lands may be affected by the project.

In addition to the above, Section 124.10 requires that the notice be sent to Federal and State agencies with jurisdiction over fish, shellfish, and wildlife resources and over coastal zone management plans, the Advisory Council on Historic Preservation, State and Historic Preservation Officers.

The applicant must also distribute the notification to all addresses within a ¼ mile radius of the facility.

Rule 3006

In addition to the parties receiving the notice under Rules 212 and Rule 3006 requires the notice be sent to those who request in writing to be on a list and other means determined by the EO to insure adequate notice to the affected public. Rule 3006 also requires that the notice contain 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 South Coast Air Quality Management District 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 who 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.

Title V also allows for a 45 day review and comment period by the U.S. EPA.

A copy of the notice and the mailing list of those sent the notice is included in this file.

RECOMMENDATION:

Based on the forgoing analysis, it is recommended that a Permit to Construct be issued following completion of the 30 day public and 45 day EPA review and comment period and securing all necessary emission offsets. The following conditions shall apply:

CONDITIONS:

FACILITY

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

CONTAMINANT	EMISSIONS LIMIT
PM	Less than 100 TONS IN ANY ONE YEAR

For purposes of this condition, the PM shall be defined as particulate matter with aerodynamic diameter of 2.5 microns or less.

For purposes of demonstrating compliance with the 100 tons per year limit the operator shall determine the PM2.5 emissions for each of the major sources at this facility by calculating a 12 month rolling average using the calendar monthly fuel use data and following emission factors for each turbine PM2.5 = 3.36 lbs/mmcf with no duct firing and PM2.5 = 5.52 lbs/mmcf with duct firing.

The operator shall submit written reports of the monthly PM2.5 compliance demonstrations 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 demonstrations shall be maintained on site for at least five years and made available upon SCAQMD request.
[Rule 1325]

F52.1
This facility is subject to the applicable requirements of the following rules or regulations:

The facility shall submit a detailed retirement plan for the permanent shutdown of Huntington Beach (HB) Boilers 1 and 2 and Redondo Beach (RB) Boilers 6 and 8 describing in detail the steps and schedule that will be taken to render the boilers permanently inoperable. The retirement plan shall be submitted to SCAQMD within 60 days after the Permits to Construct for gas turbine Units 1A, 1B, 1C, 2A, 2B, and 2C are issued.

The retirement plan must be approved in writing by SCAQMD. AES shall not commence any construction of HB Boilers 1 and 2 and RB Boilers 6 and 8 repowering project equipment including gas turbines 1A, 1B, 1C, 2A, 2B, 2C, steam turbines 1 and 2, SCR/CO catalysts for gas turbines 1A, 1B, 1C, 2A, 2B, and 2C, or the oil water separator, before 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.

AES shall provide SCAQMD by December 31, 2018 with a notarized statement that HB Beach Boilers 1 and 2 and RB Boilers 6 and 8 are permanently shutdown and that any re start or operation of the units shall require new Permits to Construct and be subject to all requirements of non-attainment 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 HB Boilers 1 and 2 and RB Boilers 6 and 8, or advise SCAQMD as soon practicable should AES undertake permanent shutdown prior to December 31, 2018.

AES shall cease operation of RB Boilers 6 and 8 within 90 calendar days of the first fire of Units 1A, 1B, or 1C, and AES shall cease operation of HB Boilers 1 and 2 within 90 calendar days of the first fire of Units 2A, 2B, or 2C.
[Rule 1304 – Modeling and Offset Exemption]

F52.2
This facility is subject to the applicable requirements of the following rules or regulations:

For all circuit breakers at the facility utilizing SF6, the operator shall install, operate, and maintain enclosed-pressure SF6 circuit breakers with a maximum annual leak 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 all records of calibrations shall be maintained on site.

The total CO2e emissions from all circuit breakers shall not exceed 6.8 tons per calendar year.
[Rule 1714]

GAS TURBINE

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

CONTAMINANT	EMISSION LIMIT
PM10	4,278.0 LBS IN ANY ONE MONTH
CO	12,776.2 LBS IN ANY ONE MONTH
VOC	7,487.2 LBS IN ANY ONE MONTH

The above limits apply after the equipment is commissioned. The above limits apply to each turbine.

The operator shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 1.47 lbs/mmcf, PM10: 3.36 lbs/mmcf with no DB firing, 5.22 lbs/mmcf with DB firing.

The operator shall calculate compliance with the emission limits for CO after the CO CEMS certification based upon readings from the SCAQMD certified CEMS.
[Rule 1303 – Offsets]

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

CONTAMINANT	EMISSION LIMIT
PM10	2,930 LBS IN ANY ONE MONTH
CO	112,882 LBS IN ANY ONE MONTH
VOC	14,121 LBS IN ANY ONE MONTH

The above limits apply during commissioning. The above limits apply to each turbine.

The operator shall calculate compliance with the emission limit(s) by using fuel use data and the following emission factors: VOC: 21.74 lbs/mmcf, PM10: 4.51 lbs/mmcf, and CO: 173.80 lbs/mmcf.

A99.1

The 327.4 LBS/MMCF NOx emission limits shall only apply during turbine operation prior to CEMS certification for reporting NOx emissions.
[Rule 2012]

A195.6
The 2.0 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.
[Rule 1703-PSD, Rule 2005]

A195.7
The 2.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.
[Rule 1703-PSD]

A195.8
The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent O2, dry. This limit shall not apply during commissioning, turbine start ups and turbine shutdowns.
[Rule 1303(a) – BACT, Rule 1303(b)(1) – Modeling, Rule 1303(b)(2) - Offsets]

A327.1
For the purpose of determining compliance with District Rule 475, combustion contaminants emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.
[Rule 475]

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

Compound	Grains per 100 scf
H2S	Greater than 0.25

This concentration limit is an annual average based on monthly sample 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(b) – Offset]

C1.7
The operator shall limit the number of start ups to no more than 90 in any one calendar month.

The number of cold start ups shall not exceed 5 per months, the number of warm start ups shall not exceed 25 per month, and the number of hot start ups shall not exceed 60 per month.

For the purposes of this condition: A cold start up is defined as a start up which occurs after the steam turbine has been shutdown for 49 hours or more. A cold start up shall not exceed 90 minutes. Emissions from a cold start up shall not exceed the following: NOx - 29 lbs., CO – 116 lbs., VOC – 28 lbs.

A warm start up is defined as a start up which occurs after the steam turbine has been shutdown for 9 – 49 hours. A warm start up shall not exceed 32.5 minutes. Emissions from a warm start up shall not exceed the following: NOx - 17 lbs., CO – 46 lbs., VOC – 21 lbs.

A hot start up is defined as a start up which occurs after the steam turbine has been shutdown for less than 9 hours. A hot start up shall not exceed 32.5 minutes. Emissions from a hot start up shall not exceed the following: NOx - 17 lbs., CO – 34 lbs., VOC – 21 lbs.

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

The operator shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.
[Rule 2005]

C1.8
The operator shall limit the number of shutdowns to no more than 90 in any one calendar month.

Shutdown time shall not exceed 10 minutes per shutdown. Emissions from a shutdown shall not exceed the following: NOx - 9 lbs., CO – 46 lbs., VOC – 31 lbs.

The operator shall maintain records, in a manner approved by the SCAQMD to demonstrate compliance with this condition.
[Rule 2005]

C1.9
The operator shall limit the power output of the plant to no more than 939 MWs

The 939 MW limit is based on the net power output.

The net electrical output shall be measured at the breaker of the transmission system interconnection point in the generation switchyard. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/-0.2 percent.

The net electrical output from each meter shall be recorded at the CEMS DAS

The operator shall maintain records, for a minimum of five years, in a manner approved by the SCAQMD to demonstrate compliance with this condition.

C1.10
The operator shall limit the power output of the plant to no more than 972 MWs

The 972 MW limit is based on the gross power output.

The gross electrical output shall be measured at the each of the 8 generators. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/-0.2 percent.

The gross electrical output from generators shall be recorded at the CEMS DAS

The operator shall maintain records, for a minimum of five years, in a manner approved by the SCAQMD to demonstrate compliance with this condition.

D29.1
The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	1 hour	Outlet of the SCR
CO emissions	District Method 100.1	1 hour	Outlet of the SCR
SOX emissions	Approved District method	District approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR
PM10 emissions	Approved District method	District approved averaging time	Outlet of the SCR
PM2.5	Approved District method	District approved averaging time	Outlet of the SCR
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

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

The test shall be conducted in accordance with an SCAQMD approved test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 45 days before the proposed test date and shall be approved by the SCAQMD 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 test shall be conducted when this equipment is operating at loads of 100, 75, and 50 percent without duct firing, and 100 percent with duct firing.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method is solely for the determination of compliance with theVOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The results shall be reported with two significant digits.

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 1703-PSD, Rule 2005]

D29.2

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

Pollutant 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

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 CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, 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]

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

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	Approved District method	District approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR
PM10 emissions	Approved District method	District approved averaging time	Outlet of the SCR

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

The test shall be conducted and the results submitted to the SCAQMD 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 heat input.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method is solely for the determination of compliance with theVOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The results shall be reported with two significant digits.

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

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 475]

D29.4

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

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
Formaldehyde	Approved District method	1 hour	Outlet of the SCR

The test shall be conducted at least once every year.

The test shall be conducted and the results submitted to the SCAQMD 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 within 10 percent of 100 percent load.

[40 CFR 63 Subpart YYYY]

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

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

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

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

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

[Rule 1303 – BACT, Rule 1703-PSD]

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 startup of the turbine, in accordance with 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 requirements of Rule 2012(h)(2) and 2012(h)(3).
[Rule 1703 – PSD, Rule 2005, Rule 2012]

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

Construction shall commence within 12 months of the date of the permit to construct unless the permit is extended, but in no case should the start of construction exceed 18 months from the date of the permit to construct. Construction shall not be discontinued for a period of 18 months or more.
[Rule 205, 40 CFR Part 52]

E193.2
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

> In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-02 project.

[CEQA]

E193.3
The operator shall install this equipment according to the following requirements:

Total commissioning hours shall not exceed 491 hours of operation for each turbine from the date of initial turbine start up. Total commissioning hours without control shall not exceed 47 hours of operation for each turbine. Only one turbine shall undergo steam blows at any one time and at a load of no more than 50%. During steam blows, the other two turbines in the block shall not be fired. During all other commissioning activities outside of steam blows, a maximum of 2 turbines may be operated at any one time.

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

The operator shall provide SCAQMD with written notification of the initial start up date. Written records of commissioning, start ups, and shutdowns shall be maintained and be made available upon request from SCAQMD.
[Rule 1303 – BACT, Rule 1303 – Offsets, Rule 1703 – PSD, Rule 2005]

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

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 = 60.139 * FF

Where, GHG is the greenhouse gas emissions in tons of CO_2e and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the GHG emissions in pounds per net megawatt-hours on the 12-month rolling average. The GHG emissions from this equipment shall not exceed 3,907,239 tons per year on a 12-month rolling average basis. The calendar annual average GHG emissions shall not exceed 1,053.7 lbs per net megawatt-hours (1,138.0 lbs per net megawatt hours inclusive of equipment degradation).

The operator shall maintain records in a manner approved by the SCAQMD to demonstrate compliance with this condition. The records shall be made available to SCAQMD upon request.
[Rule 1714]

I298.1
This equipment shall not be operated unless the facility holds 19,625 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 83,662 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held.If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.
[Rule 2005]

I298.2
This equipment shall not be operated unless the facility holds 4,733 pounds of SOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the start of operation, the facility holds 13,391 pounds of SOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held.If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.
[Rule 2005]

K40.2
The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 60 days after the source tests required under conditions D29.1, D29.2, and D29.3 are conducted.
Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.
All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute. All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.
Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset]

K67.5
The operator shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

Commissioning hours and type of control and fuel use
Date, time, and duration of each start-up and shutdown, and the type of start up (cold, warm, or hot).
In addition to the requirements of a certified CEMS, natural gas fuel use records shall be kept during and after the commissioning period and prior to CEMS certification
Minute by minute data (NO2 and O2 concentration and fuel flow rate at a minimum) for each turbine start up
Monthly number of hours each turbine is operated with duct firing
Total annual power output in MWs

[Rule 1303(b)(2) - Offsets]

SCR/CO CATALYST

A195.9
The 5 ppmv NH_3 emission limit is averaged over 60 minutes at 15% O_2, dry basis. The operator shall calculate and continuously record the NH_3 slip concentration using the following:

NH_3 (ppmv) = [a–b*c/1E+06]*1E+06/b

where,
a = NH_3 injection rate (lbs/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% O_2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months. The NOx analyzer shall be installed and operated within 90 days of initial start-up.
The operator shall use the above described method or another alternative method approved by the Executive Officer.
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]

D12.6
The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.
The injected ammonia rate shall be maintained within 11.8 gal/min and 33 gal/min except during start ups and shutdowns
[Rule 1303(a)(1) – BACT]

D12.7
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.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.
The exhaust temperature at the inlet of the SCR/CO Catalyst shall be maintained between 500-650 deg F except during start up and shutdowns
[Rule 1303(a)(1) – BACT]

D12.8
The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.
The differential pressure shall be maintained between 1.5 " WC and 3.5 " WC.
[Rule 1303(a)(1) – BACT]

E179.3
For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition Number D12.6
Condition Number D12.7
[Rule 1303(a)(1) – BACT]

E179.4
For the purpose of the following condition numbers, continuous monitoring 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.

Condition Number: D12.8
[Rule 1303(a)(1) – BACT]

E193.2
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-2 project.
[CEQA]

Ammonia Storage Tank

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]

C157.1
The operator shall install and maintain a pressure relief valve set at 50 psig.
[Rule 1303(a)(1)-BACT]

E193.2
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

> In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 12-AFC-2 project.

[CEQA]

Huntington Beach Energy Project
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Appendix A

Turbine Criteria Pollutant Emission Calculations

Normal Operation

- Table A.1 Manufacturer Guaranteed Emissions

Pollutant	Guarantee
NOx	2.0 ppm @15%
CO	2.0 ppm @ 15%
VOC	2.0 ppm @ 15%
PM10	4.5 lbs/hr no duct firing, 9.5 lbs/hr with duct firing
SOx	No guarantee
NH3	5 ppm @ 15%

NOx guarantee is for loads above 60%

Short term (lbs/hr, lbs/day and lbs/month) SOx emissions are based on 12 ppm sulfur in the natural gas (0.75 gr/100 scf), long term (annual) SOx based on 4 ppm sulfur (0.25 gr/100 scf).

Table A.2 Gas Turbine Performance Data

Ambient Conditions	110°F, 7.9% RH	66°F, 58% RH	32°F, 86.7% RH
Fuel Type	Nat Gas	Nat Gas	Nat Gas
Evaporative Cooling On/Off	On	On	Off
O2 Percent (wet exhaust, mole basis)	10.94	11.07	11.30
H2O Percent	10.59	10.09	9.12
Exhaust Temp, °F	358.9	358	362.7°F
CT Gross Output, MW	114.505	121.048	131.469
Gross Heat Rate (HHV)	11,482	11,315	11,106
Turbine Heat Input, mmbtu/hr (HHV)	1,350	1,403	1,498
Turbine Fuel Use, mmscf/hr	1.29	1.34	1.43
Duct Burner Heat Rate, mmbtu/hr	507	507	507
Duct Burner Fuel Consumption, mmscf/hr	0.48	0.48	0.48
Stack Exhaust Flow, acfm	1093.4	1132.4	1209.7
Stack Exhaust Flow, ft3/hr (dry, @15%O2)	62,874,000	64,698,000	67,841,000
Gross Output, MW (1 CTG)	158.896	172.032	181.835
Net Output, MW (1 CTG)	153.352	166.328	175.925
	NOx		
Concentration, ppmv @ 15% O2	2.0	2.0	2.0
Hourly Emissions, lb/hr	15.02	15.46	16.21
Daily Emissions, lb/day	360.48	371.04	389.04
lbs/mmcf (incl DB)	8.49	8.49	8.49
lbs/mmbtu (incl DB)	0.0081	0.0081	0.0081
lbs/gross MW-hr (1 CTG)	0.095	0.090	0.089
Lbs/net MW-hr (1 CTG)	0.098	0.093	0.092
	CO		
Concentration, ppmv @ 15% O2	2.0	2.0	2.0
Hourly Emissions, lb/hr	9.15	9.41	9.87
Daily Emissions, lb/day	219.6	225.84	236.88
lbs/mmcf (incl DB)	5.17	5.17	5.17
lbs/mmbtu (incl DB)	0.0049	0.0049	0.0049
	VOC		
Concentration, ppmv, @ 15% O2	1.0	1.0	1.0
Hourly Emissions, lb/hr	2.61	2.69	2.82
Daily Emissions, lb/day	62.64	64.56	67.68
lbs/mmcf (incl DB)	1.47	1.47	1.47
lbs/mmbtu (incl DB)	0.0014	0.0014	0.0014

Table A.2 Normal Operation Emissions (continued)

Ambient Conditions	110°F, 7.9% RH	65.8°F, 65% RH	32°F, 86.7% RH
Fuel Type	Nat Gas	Nat Gas	Nat Gas
Evaporative Cooling On/Off	On	On	Off
O2 Percent (dry exhaust)	10.94	11.07	11.30
H2O Percent	10.59	10.09	9.12
Exhaust Temp, °F	358.9	358	362.7°F
CT Gross Output, MW	114.505	121.048	131.469
Gross Heat Rate (HHV)	11,482	11,315	11,106
Turbine Heat Input, mmbtu/hr (HHV)	1,350	1,403	1,498
Turbine Fuel Use, mmscf/hr	1.29	1.34	1.43
Duct Burner Heat Rate, mmbtu/hr	507	507	507
Duct Burner Fuel Consumption, mmscf/hr	0.48	0.48	0.48
Stack Exhaust Flow, dscfm	1093.4	1132.4	1209.7
Stack Exhaust Flow, ft3/hr (dry, @15%O2)	62,874,000	64,698,000	67,841,000
Gross Output, MW (1 CTG)	158.896	172.032	181.835
Net Output, MW (1 CTG)	153.352	166.328	175.925
		SOX	
Concentration, ppmv, @ 15% O2	0.27	0.27	0.27
Hourly Emissions, lb/hr	2.83	2.91	3.05
Daily Emissions, lb/day	67.92	69.84	73.2
lbs/mmcf (incl DB)	1.60	1.60	1.60
lbs/mmbtu (incl DB)	0.0015	0.0015	0.0015
		PM10	
Hourly Emissions, lb/hr (not incl DB)	4.50	4.50	4.50
Daily Emissions, lb/day	108	108	108
Hourly Emissions, lb/hr (incl DB)	9.50	9.50	9.50
lbs/mmcf (not incl DB)	3.49	3.36	3.15
lbs/mmcf (incl DB)	5.37	5.22	4.97
lbs/mmbtu (not incl DB)	0.0033	0.0032	0.0030
lbs/mmbtu (incl DB)	0.0051	0.0050	0.0047
		NH3	
Concentration, ppm	5	5	5
Hourly Emissions, lb/hr	14.1	14.5	15.2
Daily Emissions, lb/day	338.4	348.0	364.8

- *calculated using combined heat input turbine + DB * 8170 * 3.54*
- *emissions are assumed to be maximum permitted levels for each case*

Exhaust gas calculation:

1209.7(1-.0912)(520/362.7+460)	=	*694.9E−3 cfm. dry @ stack O2*		
694.9E+3[(20.9-11.30)/(20.9-15)]*	=	*1130.7E+3 dscfm*	=	*67.841 mmscfh*

SOx calculation:

*SOx concentration is based on a fuel H2S content of 0.75 grains/100 scf (approximately 12 ppm) which converts to SOx per mmcf fuel as follows: 0.75 grains/ 100 scf(lb/7000 grains)(64 lbs/lb-mole SO2/34 lbs/lb-mole H2S)(1E6 cf/mmcf) = 2.02 lbs/mmcf. The actual emission rates used by AES assumes a 30% conversion of SO2 to SO3 (from oxidation catalyst): 2.02*0.7 = 1.41 lbs/mmcf*

Emission Rates Normal Operation

The following calculation procedure will be used to estimate the highest hourly emission rate (low temperature case) and the average hourly emission rate (annual average temperature case) during normal operation. Although the emissions differ from what is reported by AES in Table A.2, the calculations below are based on a standard F factor methodology.

Low Temperature Case				
Heat Input @ 32 deg F, turbine	=	1498 mmbtu/hr		
Heat Input @ 32 deg F, duct burner	=	507 mmbtu/hr		
Exhaust flow @ 32 deg F w/o DB	=	1498*8710*3.54	=	46.2 mmscf/hr
Exhaust flow @ 32 deg F w/DB	=	2005*8710*3.54	=	61.8 mmscf/hr
Fuel use @ 32 deg F w/o DB	=	1498/1020	=	1.47 mmscf/hr
Fuel use @ 32 deg F w/DB	=	2005/1020	=	1.97 mmscf/hr

Average Temperature Case				
Heat Input @ 66 deg F, turbine	=	1403 mmbtu/hr		
Heat Input @ 66 deg F, duct burner	=	507 mmbtu/hr		
Exhaust flow @ 66 deg F w/o DB	=	1403*8710*3.54	=	43.3 mmscf/hr
Exhaust flow @ 66 deg F w/DB	=	1910*8710*3.54	=	58.9 mmscf/hr
Fuel use @ 66 deg F w/o DB	=	1403/1020	=	1.38 mmscf/hr
Fuel use @ 66 deg F w/DB	=	1910/1020	=	1.87 mmscf/hr

Table A.3 Maximum Hour

Pollutant	Concentration	Mass Emission Rate w/o DB	Mass Emission Rate w/ DB
	ppm	lbs/hr	lbs/hr
NOx(1)	9.0/2.0	30.3/11.0	66.6/14.8
CO(1)	10.0/2.0	33.5/6.7	45.0/9.0
VOC	2.0	3.8	5.1
PM10	////////	4.5	9.5
SOx	0.27 (1.41 lbs/mmcf)	2.08	2.78
NH3	5.0	10.3	13.8

(1) with DLN only/DLN + SCR

Sample Calculations:

NOx w/DB DLN+SCR (2.0 ppm*61.8 mmscf/hr*46 lbs/lb-mole)/385 cf/lb-mole= 14.8 lbs/hr

SO2 w/oDB (0.27 ppm*46.2 mmscf/hr*64.1 lbs/lb-mole)/385 cf/lb-mole = 2.08 lbs/hr

Table A.4 Average Hour

Pollutant	Concentration	Mass Emission Rate w/o DB	Mass Emission Rate w/ DB
	ppm	lbs/hr	lbs/hr
NOx(1)	9.0/2.0	46.6/10.3	63.3/14.1
CO(1)	10.0/2.0	31.5/6.3	42.8/8.6
VOC	2.0	3.6	4.9
PM10	////////	4.5	9.5
SOx	0.27 (1.41 lbs/mmcf)	1.9	2.6
NH3	5.0	9.6	13.0

(2) with DLN only/DLN + SCR

Sample Calculations:

NOx w/DB DLN+SCR (2.0 ppm*58.9 mmscf/hr*46 lbs/lb-mole)/385 cf/lb-mole= 14.1 lbs/hr

Start Up Operation

There are 3 basic types of starts – cold, warm, and hot. A cold start up is defined as a start of the CT that occurs when the system is at ambient temperature, which would typically occur after a period of 49 hours or more from the last shutdown. The turbine will ramp to 70% load within 10 minutes from the fuel initiation, and the Dry Low NOx (DLN) combustors will reduce NOx to 9 ppm within 8-9 minutes. The SCR will become functional after about 12.5 minutes, and begin to control NOx emissions at about a 70% efficiency. Typically, the BACT emission levels will be achieved within 60 minutes from the beginning of a cold start. The total time to reach the baseload operating rate is conservatively expected to take 90 minutes.

A warm start occurs after a shutdown lasting 9 to 49 hours. The warm start will take about 32.5 minutes to complete.

A hot start occurs after a shutdown of less than 9 hours. Approximate time to complete a hot start is also 32.5 minutes.

The steam turbine generator produces power in approximately 20 minutes for a warm or hot start and in 85 minutes for a cold start from the time fuel combustion is initiated.

The turbines can be shutdown in 10 minutes.

HBEP anticipates about 24 cold, 150 warm, and 450 hot starts per year.

The combustion turbine (CT) start up is initiated by mechanically turning the compressor/turbine rotor to a starting speed. Once rotor starting speed is achieved, fuel combustion is initiated and, after a short stabilization period, the rotor speed is accelerated to rated speed (3,600 revolutions per minute), or full speed – no load (FSNL) condition. After FSNL is achieved, the CT electrical generator is synchronized to the phase of electrical grid and the turbine load is increased. At approximately 70 percent turbine load, the dry low nitrogen oxides (NOX) combustors revert from the starting mode to the pre-mix mode where they are capable of achieving 9 parts per million (ppm) NOX and 10 ppm CO emissions.

The steam bypass system is used to match the steam conditions to the steam turbine (ST) requirements and a de-coupling of the HRSG from the ST, which enables the short and simplified start-up and operation of the unit. After the CT is started, the HRSGs start producing steam. When the steam is of sufficient quantity and quality, steam is gradually introduced to the ST. Each HRSG is fitted with a non-return valve and steam sparge line that provides a small amount of steam to the off-service HRSG(s) within the power block. This minimizes the amount of time needed to warm the other HRSG(s) within the power block, allowing the selective catalytic reduction and CO catalysts to reach nominal operating temperature quickly. It is expected that, during staged operation (meaning at least one CT is operating), these components will be maintained at nominal temperature reducing the time required for a start up and minimizing start up emissions.

Shutdown of the power island is fully automatic. Once a shutdown is initiated, the operating CT is unloaded; the generator breakers open automatically and the CT initiates a cool-down and coast-down cycle. Simultaneously, as the CT load is reduced, HRSG steam production is reduced and eventually the steam pressure is reduced. To achieve the fast start times, an ST shutdown is desired from the highest possible pressure to ensure the HRSG remains hot or warm. After CT and ST are electrically disconnected from the grid, the turbine control systems will automatically engage a turning gear; after the turbine rotors have coasted to a stop, the power block will be ready to re-start.

Following is a minute-by minute accounting of the cold start up operation.

Table A.5 Cold Start Emissions Data

Time minutes	CT Load %	Exhaust Flow dcf/min @15%	NOx ppm @ 15%	CO ppm @ 15%	VOC ppm @ 15%r	NOx lbs/min	CO lbs/min	VOC lbs/min	NOx lbs	CO lbs	VOC lbs
0-5	varies	varies	varies	varies	varies	0.44	4.2	0.82	2.20	21.0	4.1
5:03	5.62%	155,656	45	2,500	1,000	0.85	28.71	6.58	0.02	0.75	0.11
5:32	10.87%	181,403	45	1,500	600	0.99	20.08	4.60	0.27	7.08	1.62
5:56	15.18%	202,387	45	400	200	1.10	5.97	1.71	0.25	3.13	0.76
5.56	15.18%	202,387	45	4,000	2,000	1.10	59.74	17.11	///	///	///
5:62	16.27%	208,099	45	3,500	1,600	1.14	53.75	14.07	0.07	3.40	0.94
5:93	21.81%	234,423	45	2,460	980	1.28	42.55	9.71	0.37	14.93	3.69
6:24	27.33%	262,571	45	1,875	600	1.43	36.33	6.66	0.42	12.23	2.54
6.42	30.63%	279,280	45	1,510	530	1.52	31.12	6.26	0.27	6.07	1.16
6:55	32.83%	290,268	45	1,240	500	1.58	26.56	6.13	0.20	3.75	0.81
6:67	35.05%	302,430	45	980	431	1.65	21.87	5.51	0.19	2.91	0.70
6:92	39.5%	325,520	45	300	300	1.78	7.21	4.13	0.43	3.63	1.20
6.92	39.5%	325,520	45	3,950	1,180	1.78	94.88	16.23	///	///	///
7:48	49.63%	378,290	41	1,960	387	1.88	54.71	6.19	1.02	41.89	6.28
7:79	55.2%	407,871	38	1,100	210	1.88	33.11	3.62	0.58	13.61	1.52
8:10	60.69%	439,473	36	450	30	1.92	14.59	0.56	0.59	7.39	0.65
8:16	61.78%	445,315	36	320	21	1.94	10.52	0.40	0.12	0.75	0.03
8:25	63.42%	454,141	35	190	10	1.93	6.37	0.19	0.17	0.76	0.03
8:25	63.42%	454,141	9	100	10	0.50	3.35	0.19	///	///	///
8:40	66.16%	470,372	9	47	2	0.51	1.63	0.04	0.08	0.37	0.02
8:58	69.43%	489,604	9	10	1	0.53	0.36	0.02	0.09	0.18	0.01
9:00	70%	514,559	9	10	0.2	0.56	0.38	0.004	0.23	0.16	0.01
Total 1st 9 mins									7.57	143.99	26.18
9-12.5	70%	514,559	9.0	10.0	2.0	0.55	0.37	0.043	1.93	1.30	0.15
12.5-60	100%	668,927	2.0	2.0	2.0	0.16	0.097	0.056	7.6	4.61	2.66
Total 1st 60 mins									17.10	149.90	28.99
60-90	100%	668,927	2.0	2.0	2.0	0.16	0.097	0.056	4.80	2.91	1.68
Total 90 min									21.90	152.81	30.67

Table A.6 Cold Start Raw Data

Time minutes	CT Load %	Exhaust Flow dcf/min, uncorrected	NOx ppm uncorrected	CO ppm uncorrected	VOC ppm uncorrected	O2
0-5	varies	varies	varies	varies	varies	varies
5:03	5.62%	500148	14.5	805.1	322.0	14.83
5:32	10.87%	472776	16.9	564.4	225.8	14.79
5:56	15.18%	472776	18.9	168.1	84.1	15.03
5.56	15.18%	473398	18.9	1681.4	840.7	15.24
5:62	16.27%	473398	19.4	1512.7	691.5	15.24
5:93	21.81%	473398	22.0	1200.8	478.4	15.35
6:24	27.33%	474020	24.6	1026.5	328.5	15.43
6.42	30.63%	474643	26.2	880.4	309.0	15.83
6:55	32.83%	475887	27.3	752.4	303.4	16.21
6:67	35.05%	477753	28.4	619.6	272.5	16.88
6:92	39.5%	477753	30.7	204.4	204.4	16.88
6:92	39.5%	478375	30.7	2691.4	804.0	17.17
7:48	49.63%	478375	32.6	1558.0	307.6	17.32
7:79	55.2%	478997	32.7	945.3	180.5	17.46
8:10	60.69%	479619	33.4	417.2	27.8	17.67
8:16	61.78%	480241	33.9	301.0	19.8	18.02
8:25	63.42%	481485	33.6	182.3	9.6	18.35
8:25	63.42%	481485	8.6	95.9	9.6	18.42
8:40	66.16%	481485	9.0	46.8	2.0	18.42
8:58	69.43%	482107	9.3	10.4	1.0	18.68
9:00	70%	483352	9.3	10.3	0.2	19

Based on the data, AES estimated the cold start emissions. They also provided estimates for the warm and hot starts and shutdowns (no data was provided for these scenarios).

Table A.7 Turbine Start Up Emissions

Pollutant	Cold Start, 90 minutes	Warm Start, 32.5 minutes	Hot Start, 32.5 minutes
	Lbs/event	Lbs/event	Lbs/event
NOx	28.7	16.6	16.6
CO	115.9	46.0	33.6
VOC	27.9	21.0	20.4
SOx(1)	3.12	1.13	1.13
PM10(2)	6.75	2.44	2.44

(1) *SOx based on 2.08 lbs/hr, (no duct firing during start ups)*
(2) *PM10 based on 4.5 lbs/hr (no duct firing during start ups)*

Table A.8 Turbine Start Up Emissions (combined 6 turbines)

Pollutant	Cold Start, 90 minutes	Warm Start, 32.5 minutes	Hot Start, 32.5 minutes
	Max	Max	Total
	Lbs/event	Lbs/event	Lbs/event
NOx	172.2	99.6	99.6
CO	695.4	276	201.6
VOC	167.4	126	122.4
SOx	18.72	6.78	6.78
PM10	40.5	14.64	14.64

Shut Down Operation

A shutdown is expected to take about 10 minutes to complete. Following is a summary of the estimated emissions during a shutdown as provide by AES.

Table A.9 Shutdown Emissions Data

Time minutes	CT Load %	NOx ppm @ 15%	CO ppm @ 15%	VOC ppm @ 15%	NOx lbs/min	CO lbs/min	VOC lbs/min	NOx lbs	CO lbs	VOC lbs
0	70	9	10	0.2	0.53	0.36	0.02	0.1	0.1	0.004
0.21	66.16	9	50	2	0.51	1.74	0.04	0.1	0.2	0.01
0.39	63.42	9	100	10	0.50	3.35	0.19	0.1	0.5	0.02
0.39	63.42	35	200	10	1.93	6.70	0.19	—	—	—
0.49	61.78	36	350	22	1.94	11.50	0.41	0.2	0.9	0.03
0.57	60.69	36	450	30	1.92	14.59	0.56	0.2	1	0.04
0.92	55.2	38	1100	215	1.88	33.11	3.71	0.7	8.3	0.75
1.28	49.63	41	2000	400	1.88	55.83	6.40	0.7	16	1.82
1.94	39.5	45	4000	1200	1.78	96.08	16.51	1.2	50.1	7.56
1.94	39.5	45	300	300	1.78	7.21	4.13	—	—	—
2.23	35.05	45	1000	433	1.65	22.32	5.53	0.5	4.3	1.4
2.38	32.83	45	1250	500	1.58	26.77	6.13	0.2	3.7	0.88
2.52	30.63	45	1600	540	1.52	32.97	6.37	0.2	4.2	0.88
2.73	27.33	45	1875	600	1.43	36.33	6.66	0.3	7.3	1.37
3.09	21.81	45	2500	1000	1.28	43.25	9.91	0.5	14.3	2.98
3.45	16.27	45	3500	1600	1.14	53.75	14.07	0.4	17.5	4.32
3.52	15.18	45	4000	2000	1.10	59.74	17.11	0.1	4	1.09
3.52	15.18	45	400	200	1.10	5.97	1.71	—	—	—
3.8	10.87	45	1500	600	0.99	20.08	4.60	0.3	3.6	0.88
4.14	5.62	45	2500	1000	0.85	28.71	6.58	0.3	8.3	1.9
4.48	0.51	45	3500	1600	0.71	33.47	8.76	0.3	10.6	2.61
4.51	0	45	1000	400	0.69	9.38	2.15	0	0.6	0.16

4.51	0	45	1000	400	0.69	9.38	2.15	---	—	---
9.51	0	45	1000	400	0.69	9.38	2.15	3.5	46.9	10.7
Totals								9.7	202.4	39.4

Table A.10 Turbine Shutdown Emissions

Pollutant	Shutdown, 10 minutes	
	1 Turbine	6 Turbines
	Lbs/event	Lbs/event
NOx	9.0	54.0
CO	45.3	271.8
VOC	31.0	186.0
PM10	0.75	4.5
SOx	0.33	1.98

(1) *The NOx, CO, and VOC emissions in this table are as reported byAES, they not match the numbers calculated in Table A.8.*

(2) *SOx based on 2.08 lbs/hr, (no duct firing during shutdowns)*

(3) *PM10 based on 4.5 lbs/hr (no duct firing during shutdowns)*

Daily Emissions

Daily emissions are calculated assuming the following emission rates per turbine:

Table A.11 Maximum Emission Rates (1 Turbine)

	NOx	CO	VOC	PM10	SOx	NH3
Normal Operations Controlled w/DB(lbs/hr)	14.8	9.0	5.1	9.5	2.78	13.8
Normal Operations Controlled w/o DB (lbs/hr)	11.0	6.7	3.8	4.5	2.08	10.3
Normal Operations Uncontrolled w/DB (lbs/hr)	66.6	45.0	5.1	9.5	2.78	0
Normal Operations Uncontrolled w/o DB (lbs/hr)	30.3	33.5	3.8	4.5	2.08	0
Cold Start (total lbs)	28.7	115.9	27.9	6.75	3.12	0
Warm Start (total lbs)	16.6	46.0	21.0	2.44	1.13	0
Hot Start (total lbs)	16.6	33.6	20.4	2.44	1.13	0
Shutdown (total lbs)	9.0	45.3	31.0	0.75	0.33	0

Uncontrolled emission rates based on DLN without SCR, NOx=9 ppm, CO=10 ppm, VOC=2 ppm

Daily emissions are calculated on a per turbine and a per plant basis for 3 scenarios. The first assuming 1 cold start up and shutdown in the day, and the remaining hours at full load, with 5 hours of duct firing, the second assuming 1 cold start up, 3 hot starts, 4 shutdowns, and the remaining hours at full load, with 5 hours of duct firing and 30 minutes of downtime between each hot start, and the third assuming 24 hrs at full load operation with 5 hours of duct firing.

Table A.12 Controlled Daily Emissions (1 Turbine)

		Emissions, lbs					
	Duration	NOx	CO	VOC	PM10	SOx	NH3
Scenario 1							
Cold Start	1.5	28.7	115.9	27.9	6.75	3.12	0
Normal Operation (includes 5 hrs DB)	22.33	264.63	161.11	91.35	125.49	49.95	247.50
Shutdown	0.17	9.0	45.3	31.0	0.75	0.33	0
TOTAL	24	302.33	322.21	150.25	132.99	53.40	247.50
Scenario 2							
Cold Start	1.5	28.7	115.9	27.9	6.75	3.12	0
Normal Operation (includes 5 hrs DB)	18.7	224.70	136.79	77.56	109.15	42.40	210.11
Shutdown (4)	2.72	36.0	181.2	124.0	3.0	1.32	0
Downtime	1.5	0	0	0	0	0	0
Hot Start (3)	1.62	49.8	100.8	61.2	7.32	3.39	0
TOTAL	24	339.20	534.69	290.66	126.22	50.23	210.11
Scenario 3							
Normal Operation (includes 5 hrs DB)	24	283.00	172.30	97.70	133.00	53.42	264.70

Sample Calc:
*NOx, normal operation scenario 1 = 14.8 lbs/hr*5 + 11.0 lbs/hr*17.33 = 264.63 lbs*
*PM10 normal operation, scenario 2 = 9.5 lbs/hr *5 + 4.5 lbs/hr*13.7 = 109.15 lbs*
*VOC normal operation, scenario 3 = 5.1 lbs/hr*5 + 3.8 lbs/hr*19 = 97.70 lbs*

Table A.13 Uncontrolled Daily Emissions (1 Turbine)

		Emissions, lbs				
	Duration	NOx	CO	VOC	PM10	SOx
Scenario 1						
Cold Start	1.5	28.7	115.9	27.9	6.75	3.12
Normal Operation (includes 5 hrs DB)	22.33	858.10	805.56	91.35	125.49	49.95
Shutdown	0.17	9.0	45.3	31.0	0.75	0.33
TOTAL	24	895.80	966.76	150.25	132.99	53.40
Scenario 2						
Cold Start	1.5	28.7	115.9	27.9	6.75	3.12
Normal Operation (includes 5 hrs DB)	18.7	748.11	683.95	77.56	109.15	42.40
Shutdown (4)	2.72	36.0	181.2	124.0	3.0	1.32
Downtime	1.5	0	0	0	0	0
Hot Start (3)	1.62	49.8	100.8	61.2	7.32	3.39
TOTAL	24	862.61	1081.85	290.66	126.22	50.23
Scenario 3						
Normal Operation (includes 5 hrs DB)	24	908.70	861.50	97.70	133.00	53.42

Sample Calc:
*NOx normal operation, scenario 1 = 66.6 lbs/hr*5 + 30.3 lbs/hr*17.33 = 858.10*
*NOx normal operation, scenario 2 = 66.6 lbs/hr*5 + 30.3 lbs/hr*13.7 = 748.11*

Table A.14 Controlled Daily Emissions, (6 Turbines)

		Emissions, lbs					
	Duration	NOx	CO	VOC	PM10	SOx	NH3
Scenario 1							
Cold Start	1.5	172.2	695.4	167.4	40.5	18.72	0
Normal Operation (includes 5 hrs DB)	22.33	1587.78	966.66	548.1	752.94	299.7	1485
Shutdown	0.17	54	271.8	186	4.5	1.98	0
TOTAL	24	1813.98	1933.26	901.5	797.94	320.4	1485
Scenario 2							
Cold Start	1.5	172.2	695.4	167.4	40.5	18.72	0
Normal Operation (includes 5 hrs DB)	18.7	1348.2	820.74	465.36	654.9	254.4	1260.66
Shutdown (4)	2.72	216	1087.2	744	18	7.92	0
Downtime	1.5	0	0	0	0	0	0
Hot Start (3)	1.62	298.8	604.8	367.2	43.92	20.34	0
TOTAL	24	2035.2	3208.14	1743.96	757.32	301.38	1260.66
Scenario 3							
Normal Operation (includes 5 hrs DB)	24	1698	1033.8	586.2	798	320.5	1588.2

Table A.15 Maximum Controlled/Uncontrolled Daily Emissions (1 Turbine)

Pollutant	Operating Scenario	Uncontrolled Daily Emissions	Controlled Daily Emissions
NOx	See Below	908.70	339.20
CO	1 cold, 3 hot, 4 shutdowns, remaining hours normal	1081.85	534.69
VOC	1 cold, 3 hot, 4 shutdowns, remaining hours normal	290.66	290.66
PM10	24 hr normal	133	133
SOx	24 hr normal	53.42	53.42
NH3	24 hr normal	//////////////	264.70

For NOx, the maximum uncontrolled emissions result from the 24 hr normal operation scenario, while the maximum controlled emissions result from the 1 cold, 3 hot, 4 shutdown scenario.

Table A.16 Maximum Controlled Daily Emissions (6 Turbines)

Pollutant	Operating Scenario	Controlled Daily Emissions
NOx	1 cold, 3 hot, 4 shutdowns, remaining hours normal	2035.2
CO	1 cold, 3 hot, 4 shutdowns, remaining hours normal	3208.14
VOC	1 cold, 3 hot, 4 shutdowns, remaining hours normal	1743.96
PM10	24 hr normal	798
SOx	24 hr normal	320.5
NH3	24 hr normal	1588.2

Monthly Emissions

Table A.17 Expected Monthly/Annual Operation

AES provided the following expected operating profile of the plant:

Event	Duration/month(1)	Duration/yr(2)
Cold Start	7.5	36
Warm Start	13.5	81.25
Hot Start	32.5	243.75
Shutdown	15	104
100% Load @ 68.5 deg F w/o DB	489.5 hrs	5900
100% Load @ 68.5 deg F with DB	186 hrs	470
Total Hrs	744	6835

(1) Based on 5 cold starts (1.5 hrs each), 25 warm starts (32.5 min each), 60 hot starts (32.5 min each), and 90 shutdowns (10 min each) per month

(2) Based on 24 cold starts (1.5 hrs each), 150 warm starts (32.5 min each), 450 hot starts (32.5 min each), and 624 (10 min each) shutdowns per month

Monthly emissions and the 30 Day Averages are calculated for 2 scenarios, one assuming the maximum starts and shutdowns are based on the above operating profile, and the second assuming no start ups or shutdowns. For the second scenario, 186 hrs of duct burning is assumed, with the remaining hours in the month (31 days, 744 hrs), assumed to be without duct firing. The following factors are used:

Table A.18 Emission Factors for 30 Day Calculation

	lbs/hr or lbs/event					
Event	NOx	CO	VOC	PM10	SOx	NH3
Cold	28.7	115.9	27.9	6.75	3.12	0
Warm	16.6	46.0	21.0	2.44	1.13	0
Hot	16.6	33.6	20.4	2.44	1.13	0
Shutdown	9.0	45.3	31.0	0.75	0.33	0
Normal @ 68.5 deg F w/o DB	11.0	6.7	3.8	4.5	2.08	10.3
Normal @ 68.5 deg F w DB	14.8	9.0	5.1	9.5	2.78	13.8

Table A.19 30 Day Emissions /Scenario 1/, Start Ups and Shut Downs (1 Turbine)

			Emissions					
Event	Duration, hrs/month	# of events	NOx	CO	VOC	PM10	SOx	NH3
Cold	7.5	5	143.5	579.5	139.5	33.75	15.6	0
Warm	13.5	25	415	1150	525	61	28.25	0
Hot	32.5	60	996	2016	1224	146.4	67.8	0
Shutdown	15	90	810	4077	2790	67.5	29.7	0
Normal @ 68.5 deg F W/O DB	489.5	######	5384.5	3279.65	1860.1	2202.75	1018.16	5041.85
Normal @ 68.5 deg F W/ DB	186	######	2752.8	1674	948.6	1767	517.08	2566.8
	Total, lbs/month		10501.8	12776.15	7487.2	4278.4	1676.59	7608.65
	Average lbs/day		350.1	425.9	249.6	142.61	55.89	253.6

Table A.20 30 Day Emissions /Scenario 2/ No Starts (1 Turbine)

			Emissions					
Event	Duration, hrs/month	# of events	NOx	CO	VOC	PM10	SOx	NH3
Normal @ 68.5 deg F W/O DB	558	//////	6138	3738.6	2120.4	2511	1160.64	5747.4
Normal @ 68.5 deg F W/ DB	186	//////	2752.8	1674	948.6	1767	517.08	2566.8
	Total, lbs/month		8890.8	5412.6	3069	4278	1677.72	8314.2
	Average lbs/day		296.36	180.42	102.3	142.6	55.92	277.14

Table A.21 30 Day Emissions (1 Turbine)

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	10,501.8	350.1
CO	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	12,776.15	425.9
VOC	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	7,487.2	249.6
PM10	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	4278.00	142.6
SOx	744 hrs normal with 186 hrs duct firing	1677.72	55.92

5 cold starts = 7.5 hrs, 25 warm starts = 13.54 hrs, 60 hot starts = 32.5 hrs, 90 shutdowns = 15 hrs, remaining hours assumed at 100% load (31 days)

Table A.22 30 Day Emissions (6 Turbines)

Pollutant	Operating Scenario Per Turbine	Total Monthly Emissions	30-Day Average Emissions
NOx	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	63010.8	2100.6
CO	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	76656.9	2555.4
VOC	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	44923.2	1497.6
PM10	5 cold starts+25 warm starts+60 hot starts+90 shutdowns+489.5 hrs normal w/o DB + 186 hrs normal with DB	25668	855.6
SOx	744 hrs normal with 186 hrs duct firing	10066.32	335.52

5 cold starts = 7.5 hrs, 25 warm starts = 13.54 hrs, 60 hot starts = 32.5 hrs, 90 shutdowns = 15 hrs, remaining hours assumed at 100% load (31 days)

Table A.23 Monthly Commissioning Emissions

Event	NOx	CO	VOC	PM10	SO2
Individual Commissioning	11114	501260	7698	984	78
Combined Commissioning (1 turbine)	7290	96204	1920	1848	335
Total lbs	18404	597464	9618	2832	413

The total emissions for PM10 and SOx during commissioning will be less than 1 month of normal operation because fuel use is lower during commissioning. For VOC, the total commissioning emissions will be 9618 lbs (7698 + 1920) for 1 turbine. However, the commissioning operation will be conducted over several months, therefore, on average, the monthly VOC emissions during commissioning will be lower than normal operation. CO emissions will be higher during commissioning, however CO offsets are not required because the basin is in attainment.

Appendix B
Commissioning and Annual Emissions

Each turbine will go through a series of tests during commissioning to prepare for commercial operation. The commissioning is expected to take up to 180 days for each 3X1 power block. During that time, the turbines will be operated about 491 hours. Some of those hours will be with DLN, SCR and oxidation control, others with no control.

Table B.1 Summary of Commissioning Emissions

Each turbine will undergo the following tests

Activity	Duration (hours)	CT Load (%)	Fuel Use		Pollutant Emission Rates (per turbine), lbs/hr			Total Emissions (per turbine), lbs				
			mmscf/hr	mmscf/activity	NOx	CO	VOC	NOx	CO	VOC	SO2	PM10
FSNL	4	5	0.059	0.235	48.53	1709.13	383.83	194.1	6836.5	1535.3	7.9	18.0
Steam Blows[1]	27	50	0.588	15.882	109.69	3169.39	373.13	2961.5	85573.6	10074.5	53.2	121.5
Set Unit HRSG &Steam Safety Valves	16	100	1.375	22.08	41.95	28.37	1.71	671.2	454.0	27.4	31.5	72.0
DLN Emissions Tuning	12	100	1.375	16.506	10.49	7.09	1.15	125.8	85.1	13.7	23.6	54.0
Emissions Tuning	12	70	1.014	12.165	7.82	5.29	1.15	93.9	63.5	13.7	23.6	54.0
Emissions Tuning	12	100	1.375	16.506	10.49	7.09	1.15	125.8	85.1	13.7	31.7	114.0
STG Bypass Valve Tuning HRSG Blowdown	12	40	0.471	5.647	25.97	1372.55	161.34	311.7	16470.6	1936.1	23.6	54.0
STG Bypass Valve Tuning HRSG Blowdown	12	75	1.073	12.871	8.19	5.54	1.15	98.3	66.5	13.7	23.6	54.0
STG Bypass Valve Tuning HRSG Blowdown	12	100	1.375	16.506	10.49	7.09	1.15	125.8	85.1	13.7	23.6	54.0
Verify STG on Turning Gear, Combined	12	75	1.073	12.871	8.19	5.54	1.15	98.3	66.5	13.7	23.6	54.0

Blows Finalize Bypass Valve Tuning												
Verify STG on Turning Gear, Combined Blows Finalize Bypass Valve Tuning	12	100	1.375	16.506	10.49	7.09	1.15	125.8	85.1	13.7	23.6	54.0
CT Baseload Testing	12	75	1.073	12.871	8.19	5.54	1.15	98.3	66.5	13.7	23.6	54.0
Load STG/Combined Cycle (3X1)	24	100	1.375	33.012	10.49	7.09	1.15	251.7	170.2	27.5	47.3	108.0
Combined Cycle Testing	24	100	1.375	33.012	16.50	17.00	1.15	396.0	408.0	27.5	47.3	108.0
STG Load Test	24	75	1.073	25.741	8.19	5.54	1.15	196.5	132.9	27.5	47.3	108.0
Commission Duct Burners	24	100	1.873	44.491	10.49	7.09	3.35	401.7	410.2	80.4	63.4	228.0
Refire Unit with Duct Burners	12	100	1.873	22.471	10.49	7.09	1.15	200.8	205.1	13.7	31.7	114.0
Source Testing	168	100	1.375	231.082	7.00	7.09	1.15	1176.0	1191.7	192.5	387.2	1176.0
Water Wash & Performance Preparation	24	100	1.375	33.012	10.49	7.09	1.15	251.7	170.2	27.5	47.3	108.0
Performance Testing	24	100	1.375	33.012	10.49	7.09	1.15	251.7	170.2	27.5	47.3	108.0
CALISO Certification	12	100	1.375	33.012	10.49	7.09	1.15	125.8	85.1	13.7	31.7	114.0
TOTALS	491	//////	25.295	649.491	//////	//////	//////	8282	112,882	14,121	1,064	2,930

(1) Steam blow for the first CTG is expected to last 40 hours, steam blows for the 2 remaining CTGs are expected to last 20 hrs each.
Shaded activities are controlled by DLN, SCR and oxidation catalyst.
PM10 based on 4.5 lbs/hr, SOx based on 1.97 lbs/hr

Table B.2 Combined Commissioning

All three turbines will operate during the following tests (these emissions are accounted for in Table B.1 for each individual turbine)

Activity	Duration (hours)	CT Load (%)	Pollutant Emission Rates, lbs/hr per turbine			Total Emissions (3 turbines), lbs				
			NOx	CO	VOC	NOx	CO	VOC	SOx	PM10
CTG Testing FSNL	4	5	48.53	1709.13	383.83	582.3	20509.5	4605.9	23.7	54
Steam Blows(1)	27	50	109.69	3169.39	373.13	8884.5	256720.8	30223.5	159.6	364.5
Set unit HRSG and steam safety valves	16	100	41.95	28.37	1.71	2013.6	1362	82.2	94.5	216
STG Bypass Valve Tuning HRSG Blowdown	12	40	25.97	1372.55	161.34	935.1	49411.8	5808.3	70.8	162
TOTALS	59	//////	226.14	6279.44	920.01	12415.5	328004.1	40719.9	348.6	796.5

(1) Steam blow for the first CTG is expected to last 40 hours, steam blows for the 2 remaining CTGs are expected to last 20 hrs each.
Shaded activities are controlled by DLN, SCR and oxidation catalyst.
PM10 based on 4.5 lbs/hr, SOx based on 1.97 lbs/hr

Table B.3 Total Commissioning Emissions (Per Block)

Pollutant	Per Turbine	Total 3 Turbines		Emission Factors for Commissioning
	Lbs	Lbs	Tons	lbs/mmcf
NOx	8,282	24846	12.4	12.75
CO	112,882	338646	169.3	173.80
VOC	14,121	42363	21.2	21.74
PM10	2,930	8790	4.4	4.51
SO2	1,064	3192	1.6	1.64

Emission factors based on per turbine emissions ÷ 649.491 mmcf fuel use.

Annual emissions are estimated for both a commissioning year, and for a normal year after commissioning. Block 1 and Block 2 will not be commissioned simultaneously, and not in the same year (Block 1 construction is estimated to be completed 1st half of 2018 while Block 2 construction won't be completed until the 2nd half of 2019). Therefore, to estimate the maximum 12 month emissions during a commissioning year, it will be assumed that Block 1 will be operating normally while Block 2 is being commissioned. Block 2 will then begin normal operation for the balance of the 12 months (approximately 6 months).

Table B.4 12-Annual Emissions, Commissioning Year

Operating Mode	# of Events	Hours	Emissions Per Turbine, lb/hr or lbs/event					Emissions Per Turbine, lbs				
			NOx	CO	VOC	PM10	SOx	NOx	CO	VOC	PM10	SOx
Commissioning Block 2	1	491	////////	////////	////////	////////	////////	8282.0	111882.0	14121.0	2930.0	1064.0
Cold Starts Block 2	12	18	28.7	115.9	27.9	6.75	3.12	344.4	1390.8	334.8	81	37.44
Warm Starts Block 2	75	60.625	16.6	46.0	21.0	2.44	1.13	1245	3450	1575	183	84.75
Hot Starts Block 2	225	121.875	16.6	33.6	20.4	2.44	1.13	3735	7560	4590	549	254.25
Shutdowns Block 2	312	52	9.0	45.3	31.0	0.75	0.33	2808	14133.6	9672	234	102.96
Normal Operation (no duct firing) Block 2	////////	2950	11.0	6.7	3.8	4.5	2.08	2961	2956.7	2953.8	2954.5	2952.08
Normal Operation (w/duct firing) Block 2	////////	235	14.8	9.0	5.1	9.5	2.78	249.8	244	240.1	244.5	237.78
Cold Starts Block 1	24	36	28.7	115.9	27.9	6.75	3.12	688.8	2781.6	669.6	162	74.88
Warm Starts Block 1	150	81.25	16.6	46.0	21.0	2.44	1.13	2490	6900	3150	366	169.5
Hot Starts Block 1	450	243.75	16.6	33.6	20.4	2.44	1.13	7470	15120	9180	1098	508.5
Shutdowns Block 1	624	104	9.0	45.3	31.0	0.75	0.33	5616	28267.2	19344	468	205.92
Normal Operation (no duct firing) Block 1		5900	10.3	6.3	3.6	4.5	1.9	60770	37170	21240	26550	11210
Normal Operation (w/duct firing) Block 1		470	14.1	8.6	4.9	9.5	2.6	6627	4042	2303	4465	1222
				TOTAL EMISSIONS, 6 TURBINES				309861	707693.7	268119.9	120855	54372.18

Notes:

*The total emissions for all 6 turbines is calculated by taking the sum of (Block 2 emissions*3 + Block 1 emissions*3)*

Emission rates for normal operation are based on annual average temperature from Table A.4

Table B.5 12-Annual Emissions, Non-Commissioning Year

Operating Mode	# of Events	Hours	Emissions Per Turbine, lb/hr or lbs/event					Emissions Per Turbine, lbs				
			NOx	CO	VOC	PM10	SOx	NOx	CO	VOC	PM10	SOx
Cold Starts	24	36	28.7	115.9	27.9	6.75	3.12	688.8	2781.6	669.6	162	74.88
Warm Starts	150	81.25	16.6	46.0	21.0	2.44	1.13	2490	6900	3150	366	169.5
Hot Starts	450	243.75	16.6	33.6	20.4	2.44	1.13	7470	15120	9180	1098	508.5
Shutdowns	624	104	9.0	45.3	31.0	0.75	0.33	5616	28267.2	19344	468	205.92
Normal Operation (no duct firing)	////////	5900	11.0	6.7	3.8	4.5	2.08	60770	37170	21240	26550	11210
Normal Operation (w/duct firing)	////////	470	14.8	9.0	5.1	9.5	2.78	6627	4042	2303	4465	1222
				TOTAL EMISSIONS 1 TURBINE				83661.8	94280.8	55886.6	33109	13390.8
				TOTAL EMISSIONS, 6 TURBINES				501970.8	565684.8	335319.6	198654	80344.8

Note:
Emission rates for normal operation are based on annual average temperature from Table A.4

Appendix C

Turbine Air Toxic Emission Calculations

Data:

Maximum heat input (w/o duct firing)	1498 mmbtu/hr
Maximum annual hours of operation (w/o duct firing, incl start/shutdown)	6365 hrs/yr
Annual Heat Input (w/o duct firing)	9.5348E+06 mmbtu/yr
Maximum heat input (w/duct firing)	2005 mmbtu/hr
Maximum annual hours of operation (w/duct firing)	470 hrs/yr
Annual Heat Input (with duct firing)	0.9424E+06 mmbtu/yr
Total Annual Heat Input	1.0477E+07 mmbtu/yr
Maximum fuel use (32°F, w/duct firing, 1020 btu/scf)	1.97 mmcf/hr
Annual Hours of Operation	6835 hrs/yr
Total Annual Fuel Use	1.346E+04 mmcf/yr

Table C.1 Toxic Emissions

Pollutant	Emission Factor		Maximum Hourly Emission Rate, lbs/hr	Annual Emissions 1 Turbine, lbs/yr
Ammonia	256.3	Lbs/hr	256.3	1.63E+06
Acetaldehyde	4.00E-05	Lbs/mmbtu	8.02E-02	4.19E+02
Acrolein	3.62E-06	Lbs/mmbtu	7.26E-03	3.79E+01
Benzene	3.26E-06	Lbs/mmbtu	6.54E-03	3.42E+01
1,3 Butadiene	4.30E-07	Lbs/mmbtu	8.62E-04	4.51E+00
Ethyl Benzene	3.20E-05	Lbs/mmbtu	6.42E-02	3.35E+02
Formaldehyde	3.60E-04	Lbs/mmbtu	7.22E-01	3.77E+03
Naphthalene	1.30E-06	Lbs/mmbtu	2.61E-03	1.36E+01
PAH	2.20E-06	Lbs/mmbtu	4.41E-03	2.30E+01
Propylene Oxide	2.90E-05	Lbs/mmbtu	5.81E-02	3.04E+02
Toluene	1.30E-04	Lbs/mmbtu	2.61E-01	1.36E+03
Xylene	6.40E-05	Lbs/mmbtu	1.28E-01	6.71E+02
		Total	Lbs/yr	1.64E+06
			Tons/yr	818.5

Notes:

Emission factors from USEPA AP-42 Table 3.1-3, except 1) Formaldehyde, Benzene, and Acrolein emission factors which are from the Background document for AP-42 Section 3.1, Table 3.4-1 for natural gas turbine with CO catalyst.

Appendix D

Existing Facility Emissions

The existing facility consists of utility Boilers 1 and 2. The boilers are natural gas fired, each rated at 2021 mmbtu/hr heat input and 215 MW power output. The boilers are controlled with SCR systems. NOx is limited to 7 ppm on an annual average basis. The facility has submitted operating data for these units for the years 2006-2012 in order for the actual emissions of these units to be calculated. The fuel use data is taken from the CEMS for each unit. The emission factors used to estimate emissions for each unit are based on either CEMS data, source test results, or for SOx, the default emission factor. The following tables summarize the data.

Table D.1 Existing Boilers Emission Factors for Determination of Past Actual Emissions

Pollutant	Boiler 1 Emission Factor	Source	Boiler 2 Emission Factor	Source
NOx	Based on quarterly reports			
VOC	1.64 lbs/mmscf	12/18/11 source test	0.9 lbs/mmscf	11/14/12 source test
CO	0.274 lbs/mmbtu	Average of the 12/11/07 & 4/7/10 source tests for Boiler 1 & 4/6/10 source test for Boiler 2	0.274 lbs/mmbtu	Average of the 12/11/07 & 4/7/10 source tests for Boiler 1 & 4/6/10 source test for Boiler 2
SOx	0.83 lbs/mmscf	AQMD Form B-1 factor	0.83 lbs/mmscf	AQMD Form B-1 factor
PM10	1.86 lbs/mmscf	11/14/12 source test	2.1 lbs/mmscf	11/14/12 source test

Table D.2 Boiler #1 Past Actual Emissions

Year	Month	Fuel Use		VOC	CO	NOx	SOx	PM10
		mmscf	mmbtu	lbs	lbs	lbs	lbs	lbs
2006	1	407.004	423,631	675.3	116074.8	1634.5	341.7	765.8
	2	265.227	278,762	442.4	76380.9	1788.68	223.9	501.7
	3	392.303	409,101	652.9	112093.8	1582.08	330.4	740.5
	4	232.038	241,815	385.0	66257.4	1078.55	194.8	436.6
	5	229.015	239,988	379.4	65756.6	2031.57	192.0	430.3
	6	520.065	537,329	854.5	147228.2	2642.09	432.4	969.1
	7	649.615	671,764	1071.8	184063.3	4262.46	542.4	1215.6
	8	502.797	522,844	830.2	143259.1	2813.85	420.2	941.6
	9	520.696	540,025	863.7	147967.0	2994.04	437.1	979.5
	10	110.059	115,464	183.8	31637.2	688.93	93.0	208.4
	11	0	0	0.0	0.0	0.001	0.0	0.0
	12	339.456	358,490	570.4	98226.3	2062.64	288.7	646.9
	Total	4,168.275	4,339,213	6,909	1,188,945	23,579	3,497	7,836
2007	1	303.849	321,496	508.7	88089.9	1851.5	257.5	577.0
	2	217.609	230,442	362.6	63141.2	1311.5	183.5	411.2
	3	220.094	207,060	326.6	56734.4	1517.7	165.4	370.6
	4	246.911	256,470	404.6	70272.7	1267.7	204.7	458.8
	5	434.789	449,468	711.8	123154.3	4395.4	360.3	807.3
	6	455.443	468,999	742.3	128505.6	2856.1	375.7	841.9
	7	632.248	652,179	1037.9	178697.2	3795.4	525.3	1177.1

	8	678.326	699,416	1112.7	191640.0	6743.8	563.1	1261.9
	9	515.686	531,704	848.6	145686.8	2605.6	429.5	962.4
	10	697.769	721,747	1148.5	197758.7	4283.2	581.2	1302.5
	11	166.762	174,913	278.3	47926.0	667.5	140.9	315.7
	12	337.352	352,360	560.8	96546.7	1853.9	283.8	636.0
	Total	4,906.838	5,066,254	8,043	1,388,154	33,149	4,071	9,122
	Ave	4,537.557	4,702,734	7,476	1,288,549	28,364	3,784	8,479
2008	1	672.600	702,197	1116.3	192401.9	3313.93	564.9	1266.0
	2	421.174	442,719	705.8	121304.9	2243.96	357.2	800.5
	3	371.327	385,900	615.8	105736.6	2232.81	311.6	698.4
	4	343.682	356,504	569.6	97682.0	1956.42	288.3	646.0
	5	468.231	482,431	771.8	132186.0	2280.49	390.6	875.3
	6	560.233	578,166	918.8	158417.5	2781.3	465.0	1042.1
	7	547.447	568,483	899.3	155764.5	2460.9	455.1	1019.9
	8	672.694	697,211	1104.3	191035.7	3470.28	558.9	1252.4
	9	630.731	657,646	1041.2	180194.9	3182.01	527.0	1180.9
	10	705.653	732,043	1161.4	200579.9	3934.89	587.8	1317.2
	11	25.848	26,743	42.3	7327.6	135.55	21.4	48.0
	12	287.835	301,886	475.7	82716.7	1458.62	240.8	539.5
	Total	5,707.455	5,931,929	9,422	1,625,348	29,451	4,769	10,686
	Ave	5,307.147	5,499,092	8,733	1,506,751	31,300	4,420	9,904
2009	1	451.398	483,738	761.6	132544.3	1869.18	385.4	863.8
	2	199.963	207,552	329.0	56869.3	901.33	166.5	373.2
	3	365.795	388,010	612.3	106314.6	1641.89	309.9	694.5
	4	19.511	28,900	45.7	7918.5	115.71	23.1	51.8
	5	97.675	101,536	160.5	27820.9	735.38	81.2	182.1
	6	380.054	397,002	627.2	108778.6	3304.13	317.4	711.3
	7	492.397	510,609	807.5	139906.7	4546.2	408.7	915.8
	8	417.756	432,306	688.8	118452.0	3517.27	348.6	781.2
	9	651.862	672,062	1072.0	184145.0	3496.79	542.5	1215.8
	10	463.555	480,363	762.8	131619.5	2799.55	386.1	865.1
	1	208.561	246,883	391.3	67646.1	2073.59	198.1	443.8
	12	191.013	200,937	317.6	55056.8	2509.78	160.7	360.2
	Total	3,939.540	4,149,898	6,576	1,137,072	27,511	3,328	7,459
	Ave	4,823.498	5,040,914	7,999	1,381,210	28,481	4,048	9,072
2010	1	281.147	292,572	464.3	80164.7	1802.3	235.0	526.5
	2	122.538	125,979	200.4	34518.4	825.56	101.4	227.3
	3	72.069	73,160	116.8	20045.8	1068.96	59.1	132.5
	4	34.662	35,113	56.4	9620.9	722.05	28.6	64.0
	5	133.687	136,434	219.1	37382.8	1117.37	110.9	248.5
	6	217.850	211,455	337.2	57938.6	2981.13	170.7	382.5
	7	320.019	331,897	529.5	90939.6	2153.41	268.0	600.5
	8	552.545	573,943	916.4	157260.4	3843.57	463.8	1039.3
	9	376.276	391,577	626.1	107292.2	2491.05	316.9	710.1
	10	144.021	150,277	240.8	41175.9	1218.45	121.9	273.1
	11	168.833	122,933	197.2	33683.6	1047.48	99.8	223.7
	12	80.603	84,034	134.3	23025.3	849.42	68.0	152.4
	Total	2,504.250	2,529,374	4,039	693,048	20,121	2,044	4,580
	Ave	3,221.895	3,339,636	5,307	915,060	23,816	2,686	6,020

2011	1	62.763	60,156	96.3	16482.8	444.53	48.7	109.2
	2	0	0	0.0	0.0	0	0.0	0.0
	3	6.074	7,373	11.9	2020.3	1312.12	6.0	13.5
	4	400.181	413,469	664.0	113290.5	2494.6	336.1	753.1
	5	283.706	290,452	467.5	79583.9	4987.65	236.6	530.2
	6	440.604	451,166	726.1	123619.6	5510.48	367.5	823.5
	7	633.652	648,876	1039.8	177791.9	3892.44	526.3	1179.3
	8	409.049	418,914	671.4	114782.3	3641.22	339.8	761.4
	9	307.224	314,013	503.2	86039.5	2504.27	254.6	570.7
	10	114.327	117,214	187.5	32116.6	968.99	94.9	212.7
	11	112.735	115,873	185.8	31749.2	1293.79	94.0	210.7
	12	42	43	0.1	11.8	0.27	0.0	0.1
	Total	**2,770.357**	**2,837,549**	**4,554**	**777,488**	**27,050**	**2,305**	**5,164**
	Ave	**2,637.304**	**2,683,462**	**4,296**	**735,268**	**23,586**	**2,174**	**4,872**
2012	1	0.0	0	0.0	0.0	0.0	0.0	0.0
	2	161.435	166,143	264.8	45578.5	7418.61	134.0	300.3
	3	105.458	108,533	173.0	29774.3	2794.12	87.5	196.2
	4	350.268	557,829	888.9	153031.2	3796.91	449.9	1008.2
	5	351.224	424,521	676.5	116460.2	5655.08	342.4	767.2
	6	305.425	474,294	755.8	130114.6	7262.46	382.5	857.2
	7	289.921	192,818	307.3	52896.4	9010.13	155.5	348.5
	8	494.545	433,370	690.6	118887.8	8257.04	349.5	783.2
	9	571.910	390,080	621.6	107012.0	6466.24	314.6	705.0
	10	781.90	80,470	128.2	22075.7	417.97	64.9	145.4
	11	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	12	133.084	0.0	218.3	37574.1	1118.87	110.5	247.5
	Total	**5,750.375**	**2,828,058**	**4,725**	**813,405**	**52,197**	**2,391**	**5,359**
	Ave	**4,260.366**	**2,832,804**	**4,640**	**79,5447**	**39,624**	**2,348**	**5,262**

Average based on 2 year

Table D.3 Boiler #2 Past Actual Emissions

Year	Month	Fuel Use		VOC	CO	NOx	SOx	PM10
		mmscf	mmbtu	lbs	lbs	lbs	lbs	lbs
2006	1	321.978	335,132	293.2	91826.1	1629.97	270.4	684.0
	2	316.957	333,132	290.1	91278.2	2000.67	267.6	676.9
	3	209.156	218,113	191.0	59762.9	1174.6	176.2	445.8
	4	201.079	209,552	183.1	57417.2	1000.53	168.8	427.2
	5	305.730	320,378	278.0	87783.6	1483.71	256.3	648.6
	6	404.434	417,860	364.7	114493.7	2391.05	336.3	850.9
	7	621.365	642,551	562.6	176058.9	4088.98	518.8	1312.7
	8	429.007	446,112	388.8	122234.6	2217.99	358.5	907.1
	9	371.036	384,810	337.7	105437.9	2199.78	311.5	788.1
	10	223.785	234,776	205.1	64328.6	1660.34	189.1	478.5
	11	307.661	319,584	278.6	87566.0	1906.81	256.9	650.0
	12	59.656	63,001	55.0	17262.2	245.76	50.7	128.3
	Total	**3,771,844**	**3,925,001**	**3,428**	**1,075,450**	**22,000**	**3,161**	**7,998**

2007	1	170.410	180,307	156.6	49404.3	1932.9	144.4	365.3
	2	54.312	57,515	49.7	15759.2	339.0	45.8	115.9
	3	106.226	99,936	86.5	27382.3	1539.6	79.8	201.9
	4	204.232	212,138	183.6	58125.9	1249.8	169.4	428.5
	5	110.161	113,880	99.0	31203.2	925.1	91.3	230.9
	6	82.673	85,134	73.9	23326.6	1092.1	68.2	172.5
	7	187.422	193,330	168.8	52972.4	1273.0	155.7	394.0
	8	349.310	360,171	314.4	98686.7	3723.8	290.0	733.7
	9	125.819	129,727	113.6	35545.1	1623.5	104.8	265.1
	10	185.850	192,236	167.9	52672.7	1055.9	154.8	391.7
	11	0	0	0.0	0.0	0.0	0.0	0.0
	12	72.235	75,449	65.9	20673.0	759.1	60.8	153.8
	Total	1,648.650	1,699,823	1,480	465,751	15,514	1,365	3,453
	Ave	2,710.247	2,812,412	2,454	770,601	18,757	2,263	5,726
2008	1	596.616	622,869	543.4	170666.2	2929.25	501.1	1267.9
	2	343.143	360,696	315.6	98830.8	2758.95	291.0	736.3
	3	176.403	183,327	160.5	50231.5	1164.86	148.0	374.6
	4	12.658	13,130	11.5	3597.7	196.32	10.6	26.9
	5	153.690	158,350	139.0	43388.0	1047.49	128.2	324.4
	6	608.896	628,387	548.0	172178.0	3560.37	505.4	1278.8
	7	452.107	469,480	407.6	128637.4	2707.65	375.9	951.0
	8	574.419	595,354	517.5	163127.0	3378.68	477.2	1207.4
	9	259.296	270,361	234.9	74078.9	1345.8	216.6	548.1
	10	545.225	565,616	492.5	154978.8	3626.42	454.2	1149.1
	11	159.461	164,984	143.3	45205.6	753.58	132.1	334.3
	12	250.079	262,287	226.8	71866.6	1504.78	209.2	529.2
	Total	4,131.993	4,294,841	3,741	1,176,787	24,974	3,450	8,728
	Ave	2,890.322	2,997,332	2,610	821,269	20,244	2,407	6,091
2009	1	0	0	0.0	0.0	0	0.0	0.0
	2	343.636	356,678	310.3	97729.7	1902.09	286.2	724.1
	3	100.160	106,243	92.0	29110.5	569.11	84.9	214.7
	4	71.211	105,478	91.4	28901.0	331.27	84.3	213.3
	5	145.475	151,226	131.2	41435.9	1113.81	121.0	306.1
	6	125.660	131,264	113.8	35966.2	915.11	104.9	265.5
	7	665.351	689,960	598.8	189049.1	4248.27	552.2	1397.2
	8	575.819	595,875	521.0	163269.9	4621.21	480.5	1215.8
	9	717.388	739,619	647.4	202655.6	4016.72	597.1	1510.7
	10	293.475	304,116	265.0	83327.8	1861.07	244.4	618.4
	11	0.051	60	0.1	16.4	0	0.0	0.1
	12	10.512	11,058	9.6	3029.8	64.79	8.8	22.4
	Total	3,048.738	3,191,577	2,781	874,492	19,643	2,564	6,488
	Ave	3,590.366	3,743,209	3,261	1,025,639	22,309	3,007	7,608
2010	1	13.481	14,029	12.2	3843.9	229.87	11.3	28.5
	2	179.756	184,804	161.3	50636.4	1094	148.8	376.4
	3	662.330	672,356	589.0	184225.5	3903.02	543.2	1374.4
	4	144.194	146,070	128.8	40023.1	1032.39	118.8	300.6
	5	195.590	199,608	175.9	54692.7	1377.58	162.2	410.4
	6	300.317	291,501	255.1	79871.2	3485.62	235.3	595.3
	7	406.176	421,251	368.8	115422.8	2331.56	340.1	860.5

	8	625.435	649,657	569.2	178005.9	3937.9	525.0	1328.2
	9	330.827	344,280	302.1	94332.8	1894.1	278.6	704.8
	10	88.886	92,747	81.6	25412.6	436.42	75.2	190.3
	11	0.044	32	0.0	8.7	0.18	0.0	0.1
	12	5,339	5,566	4.9	1525.1	72.82	4.5	11.4
	Total	**2,952.375**	**3,021,901**	**2,649**	**828,001**	**19,795**	**2,443**	**6,181**
	Ave	**3,000.557**	**3,106,739**	**2,715**	**851,246**	**19,719**	**2,504**	**6,335**
2011	1	14.056	13,472	11.8	3691.3	185.47	10.9	27.6
	2	106.169	101,824	89.8	27899.8	1500.59	82.8	209.5
	3	278.364	337,906	299.0	92586.2	1777.49	275.7	697.6
	4	37.870	39,127	34.5	10720.9	274.72	31.8	80.5
	5	22.156	22,683	20.0	6215.1	333.27	18.5	46.7
	6	250.102	256,098	226.2	70170.7	2667.85	208.6	527.7
	7	547.540	560,695	493.1	153630.4	3952.23	454.7	1150.6
	8	552.538	565,863	497.7	155046.5	5011.13	459.0	1161.2
	9	402.546	411,441	361.8	112734.9	5205.98	333.7	844.2
	10	287.825	295,093	259.1	80855.5	2764.63	239.0	604.6
	11	261.011	268,277	236.1	73507.9	3899.59	217.7	550.8
	12	328.531	340,574	298.4	93317.4	4236.25	275.2	696.3
	Total	**3,088.708**	**3,213,053**	**2,828**	**880,377**	**31,809**	**2,608**	**6,597**
	Ave	**3,020.542**	**3,117,477**	**2,738**	**854,189**	**25,802**	**2,525**	**6,389**
2012	1	368.745	379,499	331.9	104109.1	4899.35	306.1	774.4
	2	576.575	593,390	518.9	162786.6	5543.86	478.6	1210.8
	3	700.052	720,468	630.0	197648.4	7185.58	581.0	1470.1
	4	123.418	196,553	171.9	53921.2	1430.62	158.5	401.1
	5	583.942	705,805	617.2	193625.9	5097.79	569.2	1440.2
	6	468.252	727,148	635.9	199480.8	5817.53	586.4	1483.7
	7	443.085	294,683	257.7	80841.2	7953.6	237.7	601.3
	8	603.752	529,068	462.7	145141.0	7549.64	426.7	1079.6
	9	595.486	406,160	355.2	111423.3	6371.91	327.6	828.8
	10	558.382	574,666	502.5	157650.1	2535.32	463.5	1172.6
	11	412.050	424,067	370.8	116335.6	2259.07	342.0	865.3
	12	316.606	325,839	284.9	89388.6	2775.45	262.8	664.9
	Total	5750.345	5,877,346	5,139.6	1,612,351.8	59,419.72	4,740.1	11,992.8
	Ave	4,419.527	4,545,200	3,984	1,246,364	45,614	3,674	9,295

Average based on 2 year

Boiler 1 and 2 Rolling 2 Year Average Summary

VOC, tons			CO, tons			NOx, tons			SOx, tons			PM10, tons		
Unit1	Unit2	Total	Unit1	Unit2	Total	Unit1	Unit2	Total	Unit1	Unit2	Total	Unit1	Unit2	Total
4.37	1.63	6.00	753.38	512.82	1266.2	15.65	12.90	28.55	2.21	1.50	3.71	4.95	3.80	8.75

Appendix E

Modeling

The proposed projects will result in the release of 5 criteria pollutants plus toxics. Modeling is required to determine the impacts on ambient air quality and visibility from the release of NOx, SOx, CO, and PM10. Also, a health risk assessment is required for toxics. Modeling for the criteria pollutant impacts was conducted based on both an individual and combined basis from the 6 new turbines, and on an individual equipment basis for the HRA.

Meteorological data from the John Wayne airport station was used. Although the District's Costa Mesa meteorological station is closer to the project site, the data from the John Wayne airport station was deemed appropriate for this project because of the following factors:

a) Surface characteristics at John Wayne airport are more similar to the project site
b) John Wayne airport data is more current
c) John Wayne airport has less missing data
d) Costa Mesa data is problematic

Background concentrations were determined using North Coastal Orange County monitoring station data for the last 5 years (2008-2012).

The stack parameters and emission rates used in the modeling, and the model results are summarized in the following tables:

Criteria Pollutant Modeling

<u>Start Up/Shutdown and Normal Operations</u>

To determine the turbine impacts during a start up, shutdown, and full load normal operations, a screening level model was performed for 3 temperature conditions (110, 66, and 32 deg F) and 5 different load scenarios (start up, 80%, 90%, 100% without duct firing, and 100% with duct firing) for a total of 15 different scenarios to determine the worst case impacts. Once the worst case impacts were determined per pollutant, the stack parameters for that case in combination with the emission rates as shown in Table E.1 were used in the refined model.

Table E.1 Modeled Stack Parameters - Start Up/Shutdowns and Normal Operation

		Stack Diameter, m	Stack Ht, m	Stack Temp, K	Exhaust velocity, m/s	Reference Case #
NOx	1 hour	5.49	36.6	461	15.4	15
	Annual	5.49	36.6	471	23.6	15
CO	1 hour	5.49	36.6	461	15.4	15
	8 hour	5.49	36.6	461	15.4	15
SO2	1 hour	5.49	36.6	455	21.8	11
	3 hour	5.49	36.6	455	21.8	11
	24 hour	5.49	36.6	455	21.8	11
PM10/PM2.5	24 hour	5.49	36.6	455	21.8	11
	Annual	5.49	36.6	460	16.7	10

Case 10 = 66 deg F. 70% load. Case 11 = 110 deg F 100% load with duct firing. Case 15 = 110 deg F 70% load

Table E.2 Modeled Emission Rates - Start Up/Shutdowns and Normal Operation

Averaging Time	Worst-case Emission Scenario	Pollutant	Emissions Per Turbine, lbs/hr
1-hour	NOx: All turbines in start up mode	NOx	25.5
	CO: All turbines in start up mode	CO	115
	SOx: 100% load with duct firing, 110°F ambient temperature	SOx	2.45
3-hour	SOx: Continuous 100% load operation with duct firing, 110°F ambient temperature	SOx	44.1
8-hour	CO: One cold start, two warm starts, 3 shutdowns, and remainder of period at 70% load	CO	45.4
24-hour	PM10/PM2.5: continuous 100% load operation with duct firing	PM10	9.5
	SOx: continuous 100% load operation with duct firing, 110°F ambient temperature	SOx	2.45
Annual[1]	NOx, PM10, PM2.5: All turbines operate at 100% load for 6,370 hours (5,900 without duct firing, 470 with duct firing), 24 cold starts, 150 warm starts, 450 hot starts, and 624 shutdowns	NOx	9.22
		PM10	3.79

1 – the annual operating scenario is revised from the original proposal of 5,000 hrs/yr without duct firing and 1200 hrs/yr with duct firing. As a result, the corresponding emissions change from 40.9 tpy to 40.4 tpy NOx and from 18.0 tpy to 16.6 tpy PM10/PM2.5

Table E.3 Model Results – Start up/Shutdown and Normal Operation

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3) [1]	Total Concentration (ug/m3)	NAAQS (ug/m3)	CAAQS (ug/m3)
NO2	1-hour	58.8	140	198.8	NA	339
	Annual	0.5	21.3	21.8	57	57
CO	1-hour	333	3,329	3,662	40,000	23,000
	8-hour	78	2,530	2,608	10,000	10,000
SO2	1-hour	7.1	24.9	32.0	NA	655
	1-hour	7.1	10.7	17.8	196	NA
	24-hour	2.4	5.5	7.9	365	105
PM10	24-hour	4.7	48.0	52.7	NA	150

Commissioning

NOx and CO during commissioning were modeled on a worst case scenario where 1 power block is undergoing commissioning (steam blows) while the other power block is operating under normal conditions. A permit condition will be placed in the permit which restricts the commissioning operation to 1 turbine undergoing steam blows at no more than 50% load while the other 2 turbines in the power block are not operating. Additionally, all other commissioning activities would be restricted to no more than 2 turbines undergoing fired commissioning activities simultaneously.

Table E.4 Modeled Emission Rates, Commissioning

Turbine Operating Scenario	Pollutant	Averaging Period	Emissions Per Turbine, lbs/hr	
			Commissioning	Start Up
3 turbines undergoing commissioning (steam blows @ 50% load), 3 turbines undergoing cold start up	NOx	1-hour	109.7	25.5
	CO	1-hour	3,169	115
		8-hour	3,169	115

Table E.5 Stack Parameters – Commissioning

Turbine Operating Scenario	Averaging Period	Stack Temp, K	Exhaust Velocity, m/s	Exhaust Flow, m^3/s
3 turbines, 50% load steam blows	1-hour	465.9	9.90	234.2
	8-hour	465.9	9.90	234.2
3 turbines, cold start up	1-hour	461	15.4	364.4
	8-hour	461	15.4	364.4

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3) (1)	Total Concentration (ug/m3)	NAAQS (ug/m3)	CAAQS (ug/m3)
NO2	1-hour	146.3	140	286.3	NA	339
CO	1-hour	5,076	3,329	8,405	40,000	23,000
	8-hour	4,369	2,530	6,899	10,000	10,000

PSD, Deposition, and Visibility Analysis

Because of the distance from the project site to the nearest Class I areas is > 50 km, the facility used a screening calculation to show that a visibility and deposition analysis is not required for Class I areas. The facility was however, required to perform a visibility analysis for impacts on Class II areas, which they did using VISCREEN. Because it was determined that the project impacts exceeded the US EPA 1-hour NO2 significant impact level of 7.52 ug/m3, a cumulative PSD model was performed for NO2 impacts using AERMOD and the stack parameters and turbine emission rates of Tables E.1 and E.2.

Table E.6 Model Results, Cummulative NO2 Impacts

Pollutant	Averaging Period	Total Concentration (ug/m3)	NAAQS (ug/m3)
NO2	1-hour	168.2	188

Table E.7 Model Inputs, Visibility

Pollutant	Emission Rate, TPY (6 Turbines)
NO2	242.3
PM10	16.6

Table E.7 Model Results, Visibility

	Level of Acceptable Change = 5%		
Predicted % Change in Light Extinction Coefficient			
Class I Area	2001	2002	2003
San Gorgonia Wilderness	7.82*	4.77	3.15
San Jacinto Wilderness	2.02	2.90	2.16
Agua Tibia Wilderness	1.88	1.87	2.43
Joshua Tree National Park	2.82	1.45	2.70

Table E.8 Tier I VISCREEN Results

Class II Area	Min Dist.	Max Dist	Modeled Parameter	Sky	Terrain	Significance Threshold
Crystal Cove SP	12.5	18.4	Color Difference Index (Delta E)	3.961	7.746	2
			Contrast (C)	-0.041	0.042	0.05
Water Canyon SP	33.6	42.9	Color Difference Index (Delta E)	1.732	2.326	2
			Contrast (C)	-0.018	0.021	0.05
Chino Hills SP	35.8	41.6	Color Difference Index (Delta E)	1.437	1.612	2
			Contrast (C)	-0.015	0.017	0.05
San Mateo Canyon Wilderness Area	44.3	57.6	Color Difference Index (Delta E)	1.083	1.564	2
			Contrast (C)	0.011	0.015	0.05

Since the Tier I results exceeded the threshold for Crystal Cove and Water Canyon, a Tier II assessment was performed for these areas.

Table E.9 Tier II VISCREEN Results

Class II Area	Min Dist.	Max Dist	Modeled Parameter	Sky	Terrain	Significance Threshold
Crystal Cove SP	12.5	18.4	Color Difference Index (Delta E)	0.319	0.687	2
			Contrast (C)	0.003	0.004	0.05
Water Canyon SP	33.6	42.9	Color Difference Index (Delta E)	0.586	0.797	2
			Contrast (C)	0.006	0.007	0.05

Air Toxics Health Risk Assessment (HRA)

A Tier 4 HRA was performed for the project using CARB's Hotspots Analysis and Reporting Program (HARP, version 1.4f).

Table E.8 Modeled Emission Rates For HRA

Pollutant	Emission Factor	Emissions per Turbine	
	lbs/mmbtu	lbs/hr	lbs/yr
Ammonia	5 ppm	1.32E+01	8.61E+04
Acetaldehyde	4.00E-05	8.02E-02	3.93E+02
Acolein	6.40E-06	1.28E-02	6.29E+01
Benzene	1.20E-05	2.41E-02	1.18E+02
1,3 Butadiene	4.30E-07	8.62E-04	4.23E+00
Ethyl Benzene	3.20E-05	6.42E-02	3.14E+02
Formaldehyde	7.10E-04	5.77E-01	2.83E+03
Naphthalene	1.30E-06	2.61E-03	1.28E+01
PAH	2.20E-06	1.80E-03	8.85E+00
Propylene Oxide	2.90E-05	5.81E-02	2.85E+02
Toluene	1.30E-04	2.61E-01	1.28E+03
Xylene	6.40E-05	1.28E-01	6.29E+02

Hourly emission rates based on 2,005 mmbtu/hr (maximum turbine heat input with duct burner firing at low temp). annual emission rates based on 1,403 mmbtu/hr for 6,365 hrs/yr and 1,910 mmbtu/hr for 470 hrs/yr (turbine and duct burner heat inputs at annual average temp).

Table E.9 Modeled Stack Parameters for HRA

Parameter	Hourly Impacts (case # 15)	Annual Impacts (case # 10)
Stack Diameter, m	5.49	5.49
Stack Height, m	36.6	36.6
Stack Temp, K	461	460
Stack Velocity, m/s	15.4	16.7

Case 10 = 66 deg F, 70% load. Case 15 = 110 deg F 70% load

Table E.10 Model Results – HRA

	Residential Cancer Risk	Residential Chronic HI	Residential Acute HI
Stack 1	0.42 per million	0.00124	0.0244
Stack 2	0.39 per million	0.00113	0.0291
Stack 3	0.36 per million	0.00104	0.0203
Stack 4	0.46 per million	0.00135	0.00368
Stack 5	0.47 per million	0.00136	0.00897
Stack 6	0.47 per million	0.00136	0.0117
	Worker Cancer Risk	**Worker Chronic HI**	**Worker Acute HI**
Stack 1	0.095 per million	0.00154	0.0244
Stack 2	0.095 per million	0.00154	0.0291
Stack 3	0.121 per million	0.00197	0.0203
Stack 4	0.095 per million	0.00154	0.00368
Stack 5	0.095 per million	0.00154	0.00897
Stack 6	0.096 per million	0.00157	0.0117

Appendix F

Greenhouse Gases

Out of the six GHG pollutants:

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

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

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

Table F.1 GHG Emission Factors

GHG	Emission Factor, natural gas		GWP
	kg/mmbtu	lbs/mmscf	
CO2	53.02	120,160	1.0
CH4	1.0E-03	2.27	21
N2O	1.0E-04	0.227	310

The emission factors in kg/mmbtu are converted to lbs/mmcf assuming the default HHV of 1028 btu/cf from 40 CFR98 Subpart C Table C-1. 1 kg = 2.2046 lbs.

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

CO2e = CO2 + 21*CH4 + 310*N2O

Or, using fuel consumption (F):

CO2e = 120,160*F + 2.27*21*F + 0.227*310*F = 120,278*F (in lbs)

CO2e = 60.139*F (in tons)

Existing Sources

There are 2 existing sources of GHG emissions at the Huntington Beach site, Boilers 1 and 2. The following data will be used in the GHG PTE calculations for these units:

PTE

Maximum Rating

Boiler 1 2021 mmbtu/hr
Boiler 2 2021 mmbtu/hr

Table F.2 Boilers 1 and 2 GHG PTE

Pollutant	Boiler 1, tons		Boiler 2, tons	
	Hourly	Annual	Hourly	Annual
CO2	118.2	1,028,783	118.2	1,028,783
CH4	2.23E-03	19.4	2.23E-03	19.4
N2O	2.23E-04	1.94	2.23E-04	1.94
Total Mass	118.2	1,028,804	118.2	1,028,804
CO2e	118.3	1,029,792	118.3	1,029,792

Actual Emissions

The data from Appendix E is used to calculate the past actual emissions.

Table F.3 Boilers 1 and 2 GHG Actual Emissions

	2006	2007	2008	2009	2010	2011
Boiler 1						
heat input, mmbtu	4,339,213	5,066,254	5,931,929	4,149,898	2,529,374	2,837,549
CO2, lbs	507,201,461	592,183,750	693,370,676	485,072,829	295,653,195	331,675,121
CH4, lbs	4,341.4	5,068.5	5,934.1	4,152.1	2,531.6	2,839.8
N2O, lbs	956.6	1,116.9	1,307.8	914.9	557.6	625.6
Total Mass, tons	253,603	296,095	346,689	242,539	147,828	165,839
CO2e, tons	253,795	296,318	346,950	242,722	147,940	165,964
Boiler 2						
heat input, mmbtu	3,925,001	1,699,823	4,294,841	3,191,577	3,021,901	3,213,053
CO2, lbs	458,785,093	198,688,727	502,014,911	373,056,708	353,223,638	375,566,992
CH4, lbs	3,927.2	1,702.0	4,297.0	3,193.8	3,024.1	3,215.3
N2O, lbs	865.3	374.7	946.8	703.6	666.2	708.3
Total Mass, tons	229,395	99,345	251,010	186,530	176,614	187,785
CO2e, tons	229,568	99,420	251,199	186,671	176,747	187,927

New Turbines

PTE

The annual operating schedule is used to calculate the annual heat input as follows:

Table F.4 - New Turbines Annual Operating Schedule

Event	Duration/yr[1]	Heat Input[2]
Cold Start	36	*(included below)*
Warm Start	81.25	*(included below)*
Hot Start	243.75	*(included below)*
Shutdown	104	*(included below)*
100% Load @ 68.5 deg F w/o DB	5900	1711.1[3] (includes start ups/shutdowns)
100% Load @ 68.5 deg F with DB	470	507
Total Per Turbine	6835	66,776,649

(1) Based on 24 cold starts (1.5 hrs each), 150 warm starts (32.5 min each), 450 hot starts (32.5 min each), and 624 (10 min each) shutdowns per month

*(2) DB heat input = 507 mmbtu/hr, turbine heat input without DB, including start up and shutdowns = 1744.3 mmbtu/hr (given). Total annual heat input = 507*470 + 1744.3*(5000 + 361)*

(3) Given

Table F.5 New Turbines GHG PTE

GHG	Hourly Tons Per Turbine @ 2005 mmbtu/hr	Annual Tons Per Turbine @ 66,776,649 mmbtu/yr	Annual Tons 6 Turbines
CO2	117.2	3,903,399	23,420,394
CH4	2.21E-3	73.6	441.6
N2O	2.21E-4	7.4	44.4
Total Mass	117.2	3,903,480	23,420,880
CO2e	117.3	3,907,239	23,443,434

Estimated Actual Annual Emissions Including All Operations

AES HB provided data on the expected heat rates for different load scenarios and different configurations. For each configuration (1X1, 2X1, and 3X1), AES provided heat rates for 5 different power outputs ranging from about 50-60% load up to 100% load. The 100% load configurations include duct firing for 1X1 and 2X1 configurations, but not for the 3X1 configuration, since the duct burners do not operate at 100% load in a 3X1 configuration. AES HB also provided the expected number of hours the plant would operate under each scenario, and heat rates for start ups and shutdowns.

The overall average heat rate is then obtained by taking the average heat rate for each configuration multiplied by the hours of operation for each configuration (shown in Tables F.9-F.11), including start ups and shutdowns, and dividing by the total annual hours of operation. The heat rates during start up and shutdown are much higher than during normal operation because the units are operating in simple cycle mode with no steam generation.

The data is presented below:

1 Power Block

Table F.6 – Heat Rates 1 on 1 Configuration

Net Plant Power	kW	116997	130750	144285	161150	203570 w/DB
Net Heat Rate, LHV	Btu/kW-hr	7969	7796	7669	7578	7979
Estimated Gross Heat Rate, LHV	Btu/kW-hr	7730	7562	7439	7351	7740
Estimated Net Heat Rate, HHV	Btu/kW-hr	8766	8576	8436	8336	8777

Table F.7 – Heat Rates 2 on 1 Configuration

Net Plant Power	kW	241081	268702	295720	329459	367913 w/DB
Net Heat Rate, LHV	Btu/kW-hr	7733	7587	7484	7413	7683
Estimated Gross Heat Rate, LHV	Btu/kW-hr	7501	7359	7259	7191	7453
Estimated Net Heat Rate, HHV	Btu/kW-hr	8506.3	8345.7	8232.4	8154.3	8451.3

Table F.8 – Heat Rates 3 on 1 Configuration

Net Plant Power	kW	363249	367918	403656	443066	492265
Net Heat Rate, LHV	Btu/kW-hr	7698	7681	7575	7492	7440
Estimated Gross Heat Rate, LHV	Btu/kW-hr	7467	7451	7348	7267	7217
Estimated Net Heat Rate, HHV	Btu/kW-hr	8467.8	8449.1	8332.5	8241.2	8184

2 Power Blocks

Table F.9 – Heat Rates 1 on 1 Configuration (325 hrs/yr)

Net Plant Power	kW	233954	261500	288570	322300	407140 w/DB
Net Heat Rate, LHV	Btu/kW-hr	7969	7796	7669	7578	7979
Estimated Gross Heat Rate, LHV	Btu/kW-hr	7730	7562	7439	7351	7740
Estimated Net Heat Rate, HHV	Btu/kW-hr	8765.9	8575.6	8435.9	8335.8	8776.9
Average power output, kW = 302,693				**Average net heat rate, HHV = 8578**		

Table F.10 – Heat Rates 2 on 1 Configuration (4160 hrs/yr)

Net Plant Power	kW	482162	537404	591440	658918	735826 w/DB
Net Heat Rate, LHV	Btu/kW-hr	7733	7587	7484	7413	7683
Estimated Gross Heat Rate, LHV	Btu/kW-hr	7501	7359	7259	7191	7453
Estimated Net Heat Rate, HHV	Btu/kW-hr	8506.3	8345.7	8232.4	8154.3	8451.3
Average power output, kW = 601,150			**Average net heat rate, HHV = 8338**			

Table F.11 – Heat Rates 3 on 1 Configuration (1898 hrs/yr)

Net Plant Power	kW	726498	735836	807312	886132	984530
Net Heat Rate, LHV	Btu/kW-hr	7698	7681	7575	7492	7440
Estimated Gross Heat Rate, LHV	Btu/kW-hr	7467	7451	7348	7267	7217
Estimated Net Heat Rate, HHV	Btu/kW-hr	8467.8	8449.1	8332.5	8241.2	8184
Average power output, kW = 828,062			**Average net heat rate, HHV = 8335**			

Table F.12 Heat Rates Start Ups and Shutdowns

Start Up Heat Rate	18267 btu/kWh	361 hours
Shut Down Heat Rate	16520 btu/kWh	104 hours

The overall average heat rate is determined by the following equation:

Overall net heat heat = [(Avg Heat Rate X # of Hours for 1X1 Configuration) + (Avg Heat Rate X # of Hours 2X1 Configuration) + (Avg Heat Rate X # of Hours 3X1 Configuration) + (Heat Rate X # of Hours Start Ups) + (Heat Rate X # of Hours Shutdowns)]/Total Annual Hours of Operation

Overall net heat rate = (8578 btu/kWh*325 hrs + 8338 btu/h*4160 hrs +8335 btu/kWh*1898 hrs + 18267 btu/kWh*361 hrs + 16520*104 hrs)/(5900+470+361+104 hrs) = 9013.3 btu/kWh

(Using the same calculation procedure, the overall gross heat rate = 8,779.7)

CO_2
9013.3 btu/kWh * 1000 kWh/MWh * 1*10-6 MMBtu/Btu * 53.02 kg CO_2/MMBtu-HHV * 2.205 lb/kg = 1,053.7 lb CO_2/MWH

CH_4
9013.3 btu/kWh * 1000 kWh/MWh * 1*10-6 MMBtu/Btu * 1*10-3 kg CO_2/MMBtu-HHV * 2.205 lb/kg *21 = 0.42 lb CO_2/MWH

N2O
9013.3 btu/kWh * 1000 kWh/MWh * 1*10-6 MMBtu/Btu * 1*10-4 kg CO2/MMBtu-HHV * 2.205 lb/kg * 310 = 0.62 lb CO2/MWH

1,053.7+0.42+0.62 = 1,054.7 lb CO2e/netMWH @ HHV (no equipment degradation)

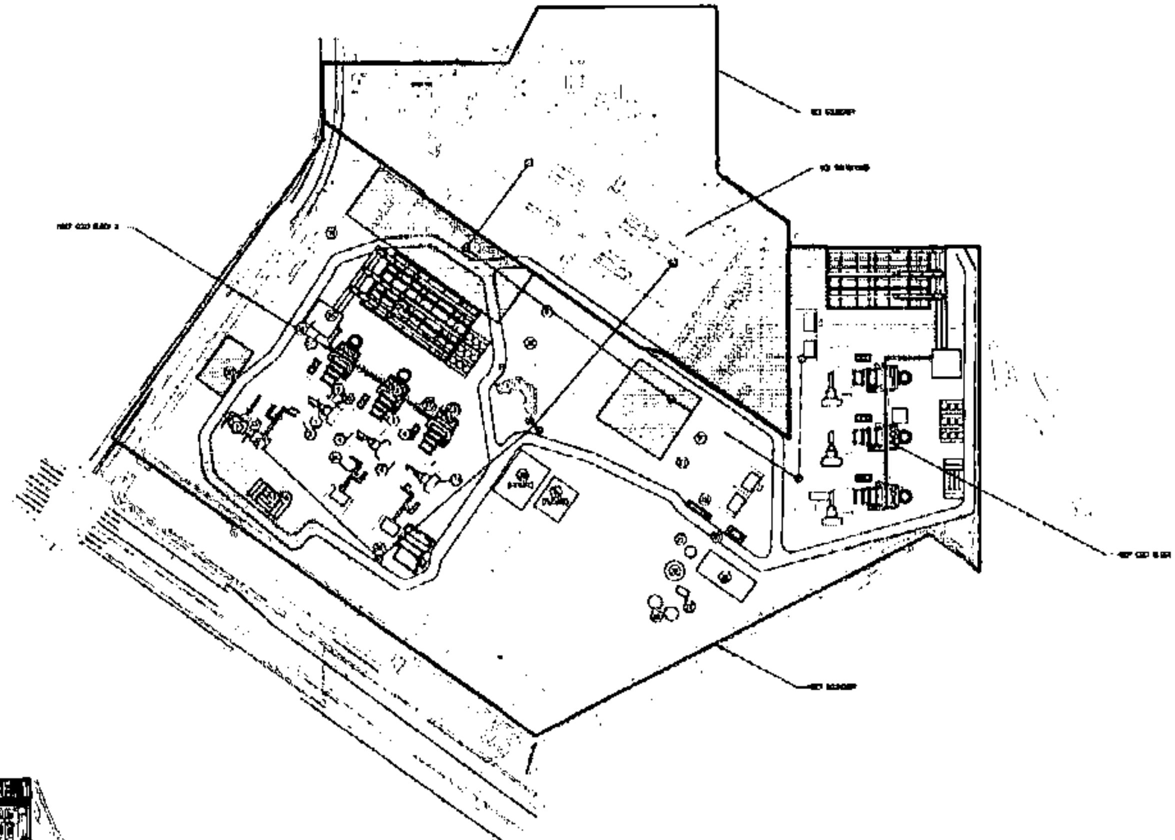
Assuming an 8% equipment degradation, the estimated heat rate and CO2e emissions are

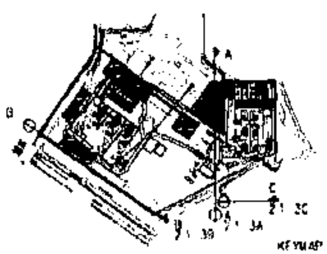
Heat Rate with equipment degradation	9013.3 btu/kw-hr*1.08 =	9734.4 btu/kw-hr
CO2e with equipment degradation	1,053.7*1.08 =	1138.0 lb CO2e/netMWH @ HHV

- SF6

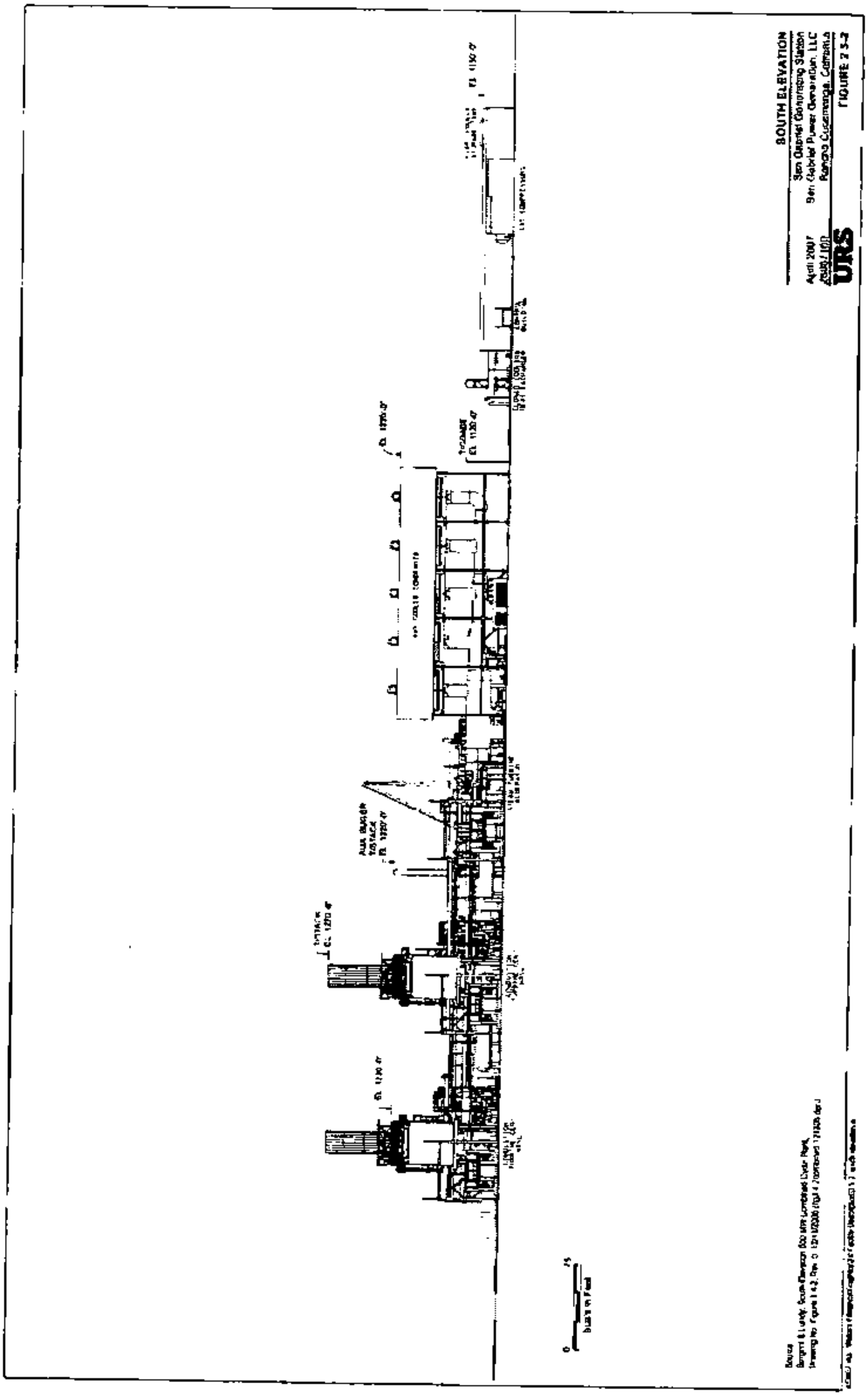
The facility has indicated that there will be about 624 pounds of sulfur hexafluoride (SF6) contained within the HBEP circuit breakers. The leak rate assumed by HBEP is 0.1 percent per year, therefore, the expected emissions would be 0.624 pounds per year, or 6.8 tons per year of CO2e assuming a global warming potential for SF6 of 23,900.

Appendix G – Facility Plot Plan

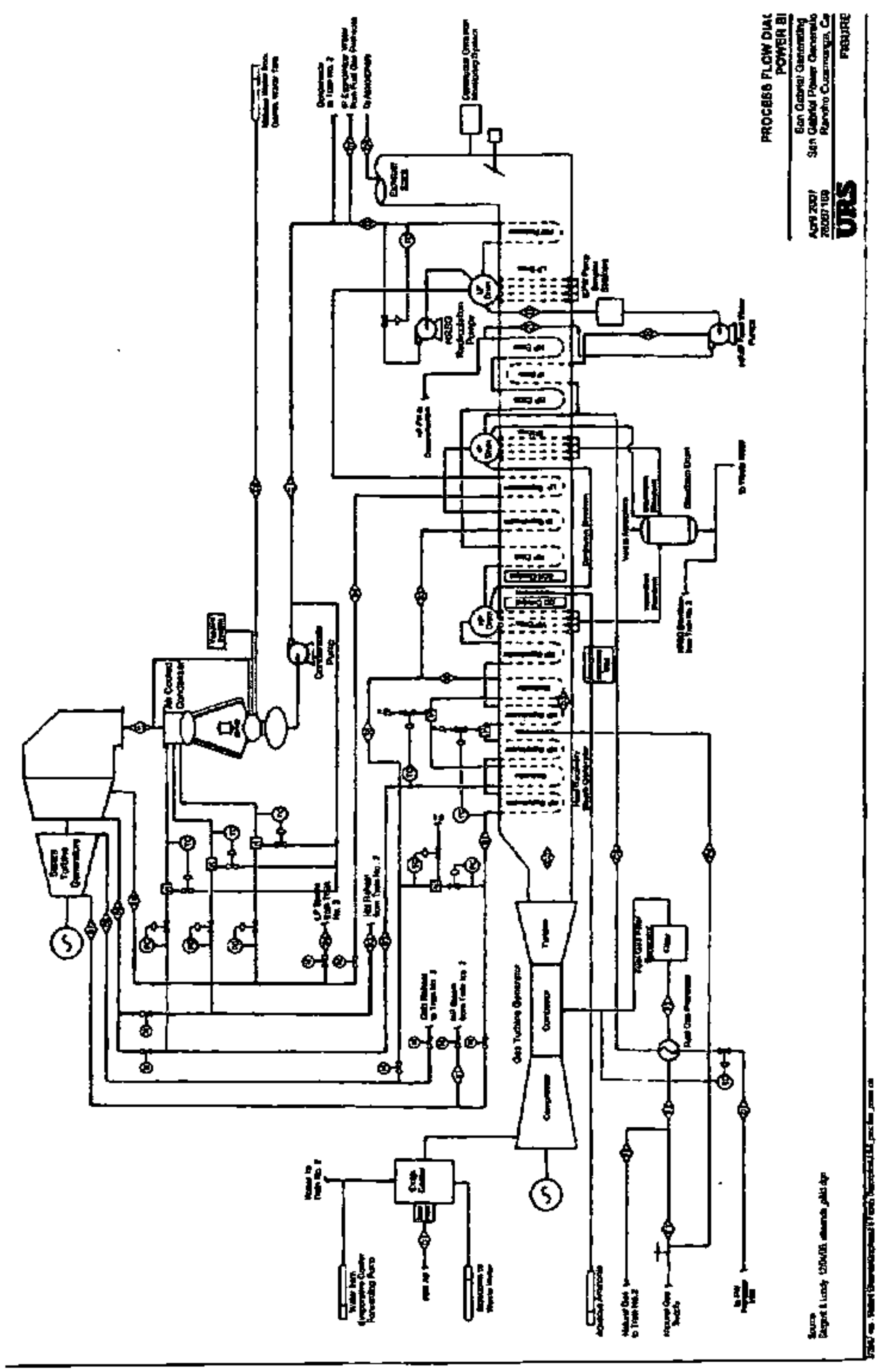




Appendix H – Elevation View



Appendix 1 – Process Flow

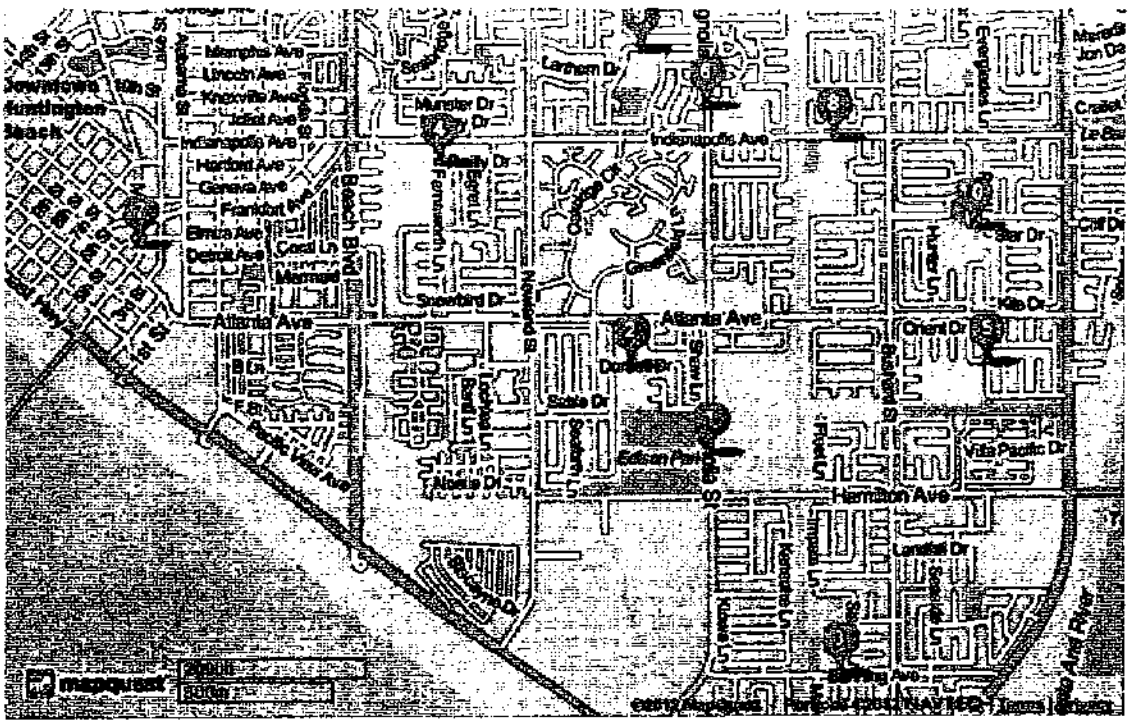


Appendix J

Nearest Schools

The following schools (K-12) were determined to be located within the vicinity of the proposed project:

	School	Location	Approx Distance from SGGS
1	Edison High	21400 Magnolia St	0.6 miles NE
2	William E Kettler School	8750 Dorsett Dr	0.65 miles NE
3	John H Eader School	9291 Banning Ave	0.91 miles SE
4	John R Peterson Elementary	20661 Farnsworth Lane	1.18 miles NW
5	Brethren Christian Jr/Sr High	21141 Strathmoor Lane	1.39 miles NE
6	St Simon and St Jude Elementary	20400 Magnolia St	1.14 miles NE
7	Sacred Heart Institute School	419 Main St	1.45 miles NW
8	Isaac L Sowers Middle School	9300 Indianapolis Ave	1.48 miles NE
9	S A Moffett Elementary	8900 Burlcrest Dr	1.5 miles N
10	Robert H Burke School	9700 Levee Dr	1.57 miles NE



Atlanta Ave
Hamilton Ave
Indianapolis Ave
Pacific View Ave
Beach Blvd
mapquest

Appendix K

Facility Reported Emissions

The following tables summarize the annual emissions reported to AQMD by the facility for the most recent 2 year period:

Table K.1 Reported Criteria Emissions

Pollutant	Emissions, tpy	
	2011	2012
NOx	38.834	55.818
CO	443.266	669.180
VOC	8.458	4.972
PM10	14.051	8.680
SOx	4.237	3.566

Table K.2 Reported Toxic Emissions

Pollutant	Emissions, lbs/yr	
	2011	2012
Ammonia	13653.598	9734.850
Benzene	17.359	14.866
Formaldehyde	36.768	31.211
Naphthalene	3.062	2.587
PAHs	1.021	0.860
1,3 Butadiene	0.005	0.067

These emissions are for the total facility and include operation of the utility boilers, the 2 emergency generators, and smaller unpermitted equipment used at the site.

Appendix L

Major Source Determinations

The following data is used in the calculations:

Table L.1

Pollutant	Uncontrolled[1]		Controlled[1]		Cold Start	Warm Start	Hot Start	Shutdown
	With DB	W/O DB	With DB	W/O DB				
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/event	lbs/event	lbs/event	lbs/event
NOx	30.3	66.6	14.8	11.0	28.7	16.6	16.6	9.0
CO	33.5	45.0	9.0	6.7	115.9	46.0	33.6	45.3
VOC	5.1	3.8	5.1	3.8	27.9	21.0	20.4	31.0

(1) From Table A.3

Table L.2

Pollutant	With DB	W/O DB	Cold Start	Warm Start	Hot Start	Shutdown
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr
PM10/PM2.5	9.5	4.5	4.5	4.5	4.5	4.5
SOx	2.78	2.08	1.97	1.97	1.97	1.97

Table L.3

Event	# of Events Per Year	Duration, Each	Total Annual Duration
		minutes	hours
Cold Start	24	90	36
Warm Start	150	32.5	81.25
Hot Start	450	32.5	243.75
Shutdown	624	10	104

Table L.4

Operating Mode	Hours Per Year
With Duct Firing	470
Without Duct Firing	5,900
Start up/shutdown	465

1. 40CFR 64 CAM

For purposes of 40CFR 64, CAM Regulation, a major source is defined as a source or group of sources with pre-control potential to emit (PTE) emission levels exceeding those in Part 70 and Part 71.

Table L.5

Pollutant	Pre-Control PTE, tpy			Major Source?
	Per Turbine	Total 6 Turbines	Threshold	
NOx	113.2	679.0	10	Y
CO	135.9	815.6	50	Y
VOC	32.1	192.7	10	Y
PM10	16.6	99.3	70	Y
SOx	7.3	43.6	100	N

Sample Calculation:

NOx = 5,900 hrs *(30.3 lbs/hr) + 470 hrs (66.6) + 24 cold starts (28.7 lbs/start) + 150 warm starts (16.6 lbs/start) + 450 hot starts (16.6 lbs/start) + 624 shutdowns (9.0 lbs/shutdown)

PM10 = 5,900 hrs (4.5) + 470 hrs (9.5) + 36 hrs (4.5) + 81.25 hrs (4.5) + 243.75 hrs (4.5) + 104 hrs (4.5)

2. 40CFR 63 - NESHAPS

For NESHAPS, a major source is defined as a site that emits or has the potential to emit 10 tpy or more of any single HAP, or 25 tpy or more of any combination of HAPs (HAP being defined as one of the 187 air contaminants listed in the Section 112(b)(1), which does not include ammonia). See Appendix D for the calculations.

Table L.6 Total TAC Facility Emissions

Pollutant	Emission Factor	Emissions Per Turbine	Total Emissions, 6 Turbines
	lbs/mmbtu	lbs/yr	lbs/yr
Acetaldehyde	4.00E-05	4.19E+02	2.51E+03
Acrolein	3.62E-06	3.79E+01	2.28E+02
Benzene	3.26E-06	3.42E+01	2.05E+02
1,3 Butadiene	4.30E-07	4.51E+00	2.70E+01
Ethyl Benzene	3.20E-05	3.35E+02	2.01E+03
Formaldehyde	3.60E-04	3.77E+03	2.26E+04
Naphthalene	1.30E-06	1.36E+01	8.17E+01
PAH	2.20E-06	2.30E+01	1.38E+02
Propylene Oxide	2.90E-05	3.04E+02	1.82E+03
Toluene	1.30E-04	1.36E+03	8.17E+03
Xylene	6.40E-05	6.71E+02	4.02E+03
		Total, lbs/yr	4.19E-04
		Tons/yr	20.9

3. PSD

For purposes of PSD, the major source threshold for a fossil fuel fired steam electric plant with a heat input greater than 250 mmbtu/hr is the actual or potential to emit 100 tpy of any regulated NSR pollutant less any emission reduction from shutdown or modification. If the source 'in and of itself' is a major source, ie > 100 tpy, then netting is not allowed. For GHG emissions, the major source threshold is EITHER 75,000 tpy CO2e AND a net increase greater than 0 tpy total GHG mass if the source is subject to PSD for another regulated pollutant ('anyway' sources). Or, for an existing major source of GHG's, the modification is major if it results in an increase of 75,000 tpy CO2e AND a net increase of GHG mass greater than 0 tpy. For an existing minor source of GHG's, the modification is major if it results in an increase of 100,000 tpy CO2e AND a net increase greater than 100 tpy GHG.

Table L.7

Pollutant		PTE, tpy		Major Source?
	Per Turbine	Total 6 Turbines	Threshold	
NOx	46.8	280.8	100	Y
CO	54.7	328.0	100	Y
SOx	7.3	43.6	100	N
PM2.5	16.6	99.3	100	N
CO2e[1]	3,907,239	23,443,434	100,000	Y

(1) From Table F.5

NOx = 5,900 hrs *(11.0 lbs/hr) + 470 hrs (14.8 lbs/hr) + 24 cold starts (28.7 lbs/start) + 150 warm starts (16.6 lbs/start) + 450 hot starts (16.6 lbs/start) + 624 shutdowns (17.8 lbs/shutdown)

PM10 = 5,900 hrs (4.5 lbs/hr) + 470 hrs (9.5 lbs/hr) + 36 hrs (4.5 lbs/hr) + 81.25 hrs (4.5 lbs/hr) + 243.75 hrs (4.5 lbs/hr) + 104 hrs (4.5 lbs/hr)

Appendix M

RECLAIM Reporting Emission Factor Determination

The facility is required to report NOx emissions based on the emission factor in the permit for any operation which occurs before initial certification of the CEMS (after certification or 180 days after installation whichever occurs first, missing data procedures are used). The facility will most likely certify its CEMS during or shortly after commissioning is completed. Therefore, the factor will be based on the total expected emissions during commissioning as follows:

Table M.1

Total Turbine Emissions During Commissioning	Total Turbine Fuel Use During Commissioning	Reclaim Reporting Factor
8,282 lbs	649.491 mmcf	12.75 lbs/mmcf

The facility is required to measure and record fuel use during commissioning.

Appendix N

Existing Units Historical Power Generation

Table N.1

Year	Month	HB1	HB2	RB6	RB8
2013	6	28703	42995	2134	11786
	5	28008	50924	3239	24982
	4	9467	17438	0	0
	3	20752	51668	0	0
	2	48920	61251	0	0
	1	20133	51273	0	0
2012	12	12677	30465	0	0
	11	0	42836	429	0
	10	7669	54102	2830	0
	9	57427	55833	5666	0
	8	45847	57913	12331	38147
	7	23496	40518	3986	0
	6	25026	42939	16986	0
	5	30144	56032	16548	8298
	4	32653	11939	20898	16549
	3	9207	69164	516	2601
	2	11467	55294	1344	0
	1	0	34478	385	0
2011	12	5	30304	0	0
	11	10886	24505	1420	0
	10	11287	27070	1913	0
	9	28584	36329	4245	936
	8	40898	53095	3560	0
	7	63608	52024	1159	0
Unit Average		23619.3	43766.2	4149.5	4304.1
Overall Average					18959.8

Appendix O

Summary of Applications and Processing Fees

The following table summarizes the application submittals and associated processing fees.

Table O.1

A/N	Submittal Date	Equip	Bcat	Fee Sch	Fee
539746	June 26, 2012	Gas turbine #1A	053349	G	$15,811.76
539747	June 26, 2012	Gas turbine #1B	053349	G	7,905.88
539748	June 26, 2012	Gas turbine #1C	053349	G	7,905.88
539768	June 26, 2012	Gas turbine #2A	053349	G	7,905.88
539769	June 26, 2012	Gas turbine #2B	053349	G	7,905.88
539770	June 26, 2012	Gas turbine #2C	053349	G	7,905.88
540256	July 17, 2012	SCR/CO Catalyst #1A	81	C	3,440.06
540257	July 17, 2012	SCR/CO Catalyst #1B	81	C	1,720.03
540258	July 17, 2012	SCR/CO Catalyst #1C	81	C	1,720.03
540260	July 17, 2012	SCR/CO Catalyst #2A	81	C	1,720.03
540261	July 17, 2012	SCR/CO Catalyst #2B	81	C	1,720.03
540262	July 17, 2012	SCR/CO Catalyst #2C	81	C	1,720.03
540255	July 17, 2012	Ammonia Storage	210900	A	1,364.63
540259	July 17, 2012	Title V Revision	555009	C	1,789.12
				Total	$70,535.12

The facility will also be required to pay a fee for the public notice, and for the modeling review. There may also be a fee if there is a request for a public hearing. These fees will be billed to the facility after the permit is issued:

	Current Rate
Public Notice	$1,204.05
Modeling Review(1)	4162.67
PSD Review	1,993.22
Total	$7,359.94

(1) Plus T&M @ $119.06/hr if above 35 hours

Total submitted $70,535.12

Note that there are also fees for the CEMS application, which are invoiced separately by the ASTM group.

Appendix P

RECLAIM Trading Credit Requirement

- NOx

In accordance with Rule 2005 the facility is required to set aside sufficient RECLAIM Trading Credits (RTC) to cover the NOx emissions from the first year operation. Additionally, since the NOx PTE after the commissioning year is greater than the facility's initially allocation, the facility is required to hold NOx RTCs for each subsequent year.

During the 1st year, the turbines will be undergoing commissioning for approximately 6 months. Therefore, the NOx emissions for the 1st year of operation assume 6 months of commissioning and 6 months of normal operation for each turbine. The emissions are shown in Appendix B Table B.4 (the sum of the 1st 7 rows of NOx under the heading 'Emissions Per Turbine'), and summarized below.

	Turbine 1A	Turbine 1B	Turbine 1C	Turbine 2A	Turbine 2B	Turbine 2C
NOx	19,625	19,625	19,625	19,625	19,625	19,625

The total NOx RTC requirements are:

NOx RTC, 1st year = 117,750 lb/year

After the first year, commissioning will be completed, and the anticipated annual NOx emissions are (Appendix B Table B.5, sum of NOx under the heading 'Emissions Per Turbine'):

	Turbine 1A	Turbine 1B	Turbine 1C	Turbine 2A	Turbine 2B	Turbine 2C
NOx	83,662	83,662	83,662	83,662	83,662	83,662

The total NOx RTC requirements are:

NOx RTC, subsequent years = 501,972 lb/year

- ➢ The current NOx RTC holding for the Huntington Beach facility is 179,740 lbs/yr. The initial NOx RTC allocation for this facility is 231,926 lbs/yr.

- SOx

Rule 2005 paragraph (f)(1) requires that for a facility modification which increases the annual allocation to a level greater than the starting allocation, offsets are required for the first year of operation, and each subsequent year. Since the facility opted into SOx RECLAIM, there was no initial allocation for SOx. Therefore, any increase is considered subject to the holding requirement for all compliance years. During the 1st year, the turbines will be undergoing commissioning for approximately 6 months. Therefore, the SOx emissions for the 1st year of operation assume 6 months of commissioning and 6 months of normal operation for each turbine. The emissions are shown in Appendix B Table B.4 (the sum of the 1st 7 rows of SOx under the heading 'Emissions Per Turbine'), and summarized below.

	Turbine 1A	Turbine 1B	Turbine 1C	Turbine 2A	Turbine 2B	Turbine 2C
SOx	4,733	4,733	4,733	4,733	4,733	4,733

The total SOx RTC requirements are:

SOx RTC, 1st year = 28,398 lb/year

After the first year, commissioning will be completed, and the anticipated annual SOx emissions are (Appendix B Table B.5, sum of SOx under the heading 'Emissions Per Turbine'):

	Turbine 1A	Turbine 1B	Turbine 1C	Turbine 2A	Turbine 2B	Turbine 2C
SOx	13,391	13,391	13,391	13,391	13,391	13,391

The total SOx RTC requirements are:

SOx RTC, subsequent years = 80,346 lb/year

- The current SOx RTC holding for the Huntington Beach facility is 8,454 lbs/yr.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

MEMORANDUM

DATE: December 12, 2013

TO: Andrew Lee

FROM: Elaine Chang

SUBJECT: Modeling Review of AES Huntington Beach Energy Project (A/N's 539746-8 & 539768-70)

As you requested, Planning, Rule Development & Area Sources (PRA) staff reviewed the modeling conducted for the AES Huntington Beach Energy Project located in the city of Huntington Beach. The June 2012 dispersion modeling analysis and health risk assessment (report) and electronic files were submitted for our review along with the modeling request memo dated November 1, 2012. Since the original submittal, there have been revisions to the project's modeling based on the use of John Wayne airport meteorological data. Our comments on the modeling conducted in the revised analysis dated October 18, 2013 are as follows:

- **AERMOD Dispersion Modeling**
  - ✓ The applicant utilized AERMOD (version 12345) for the air dispersion modeling, which is the current EPA approved model and requires hourly meteorological data.
  - ✓ The applicant used meteorological data from the John Wayne airport station, which is appropriate for the project. Although the District's Costa Mesa meteorological station is closer to the project site, meteorological data from the John Wayne airport was used instead because of the following factors:
    a) Surface characteristics at John Wayne airport are more similar to the project site – the surface roughness at John Wayne airport in the predominant wind direction (i.e. from the SW quadrant) is more similar to the project site than the Costa Mesa station.
    b) John Wayne airport data is more current – the period of record at John Wayne airport is 2008-2012, compared to 2005-2009 at Costa Mesa.
    c) John Wayne airport has less missing data – the John Wayne airport meteorological data meets the EPA requirement that no more than 10% data is missing per quarter.
    d) Costa Mesa data is problematic – the percent of calm winds at Costa Mesa can vary from 0% to 38% (0 hrs to 16,848 hrs) depending on how the data is processed.
  - ✓ The AERMOD modeling generally conforms to the District's dispersion modeling methodology.
  - ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1, 2, 4, 5, 7, and 8 of the requesting memo. These are assumed to be correct.
  - ✓ The applicant used the monitoring data for SRA 18, North Coastal Orange County (No. 3195) monitoring station for the last five years (2008-2012) to determine the background concentrations. The predicted modeling 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 are assumed for evaluating 1-hour and annual NO_2 impacts from the project, respectively.

- ✓ The model results for NO_2, CO, SO_2, and PM_{10} for the proposed project are presented in the applicant's report. PRA staff reproduced the modeling analysis.
- ✓ The proposed project is not subject to the modeling requirements of Regulation XIII per Rule 1304(a)(2). However the impacts discussed next are compared to National Ambient Air Quality Standards (NAAQS), California Ambient Air Quality Standards (CAAQS), and applicable federal Prevention of Significant Deterioration (PSD) significant impacts levels (SILs).

- **Impacts During Turbine Commissioning**
  - ✓ Turbine commissioning is a once-in-a-lifetime event. The maximum emissions will occur when power block 1 is operational and power block 2 is undergoing commissioning activities. The applicant has agreed to permit conditions during commissioning in order to reduce the project's impacts. The permit conditions would restrict steam blow at 50% load (commissioning activity that has the highest emission rate) to no more than one (1) turbine at a time with the other two (2) turbines in the power block not being fired. Additionally, all other commissioning activities would be restricted to no more than two (2) turbines undergoing fired commissioning activities simultaneously.
  - ✓ The peak 1-hour and 8-hour CO project impacts during commissioning plus the worst-case background are 8,405 $\mu g/m^3$ and 6,899 $\mu g/m^3$, respectively. These impacts are less than the state 1-hour and federal 8-hour CO standards of 23,000 $\mu g/m^3$ and 10,000 $\mu g/m^3$, respectively.
  - ✓ The peak 1-hour NO_2 project impact during commissioning plus the worst-case background is 286.3 $\mu g/m^3$, which is less than the state 1-hour NO_2 standard of 339 $\mu g/m^3$.

- **Impacts During Turbine Operations**
  - ✓ The peak CO, NO_2, SO_2, and PM_{10} impacts presented here are those that are predicted to occur during turbine startups, turbine shutdowns, and normal turbine operations.
  - ✓ Peak 1-hour and 8-hour CO impacts plus the worst-case background are 3,662 $\mu g/m^3$ and 2,608 $\mu g/m^3$ respectively, which are less than the state 1-hour and federal 8-hour CO standards of 23,000 $\mu g/m^3$ and 10,000 $\mu g/m^3$.
  - ✓ The peak 1-hour and annual NO_2 impacts plus worst-case background are 198.8 $\mu g/m^3$ and 21.8 $\mu g/m^3$, which is less than the state annual NO_2 standards of 339 $\mu g/m^3$ and 57 $\mu g/m^3$, respectively.
  - ✓ The peak 1-hour and 24-hour SO_2 impacts plus the worst-case background are 32.0 $\mu g/m^3$ and 7.9 $\mu g/m^3$, respectively. These impacts are less than the state 1-hour and 24-hour SO_2 standards of 655 $\mu g/m^3$ and 105 $\mu g/m^3$, respectively.
  - ✓ On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard. The applicant used the maximum AERMOD predicted 1-hour SO_2 concentration for the total project and added it to the 99th percentile background concentration (form of the federal standard), which is conservative. The peak 1-hour SO_2 impact is 17.8 $\mu g/m^3$, which is less than the federal 1-hour SO_2 standard of 196 $\mu g/m^3$.

- ✓ The total project's peak 24-hour PM_{10} impact plus the worst-case background is 52.7 $\mu g/m^3$, which is less than the federal 24-hour standard of 150 $\mu g/m^3$.
- ✓ Background PM_{10} air quality in the impact area exceeds the state 24-hour and annual PM_{10} standards. The peak 24-hour and annual PM_{10} impacts for the total project are 4.74 $\mu g/m^3$ and 0.27 $\mu g/m^3$, respectively.

- **Federal PSD Air Quality Analyses**
  - ✓ The proposed project is subject to PSD review for CO and NO_2.
  - ✓ Peak 1-hour and 8-hour CO impacts, during turbine operations including startups and shutdowns, are 332.6 $\mu g/m^3$ and 78.3 $\mu g/m^3$, respectively, which are below the corresponding U.S. EPA CO Class II SILs of 2,000 $\mu g/m^3$ and 500 $\mu g/m^3$. Therefore, 1-hour and 8-hour CO increment analyses are not required.
  - ✓ The maximum annual NO_2 impact from the total project is 0.49 $\mu g/m^3$. This impact is less than the U.S. EPA NO_2 Class II significance impact level of 1 $\mu g/m^3$; therefore, no additional PSD analysis is necessary.
  - ✓ 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; therefore, commissioning emissions can be excluded.
  - ✓ The maximum 1-hour NO_2 impact from the proposed project is 52.2 $\mu g/m^3$. This impact exceeds the U.S. EPA 1-hour NO_2 significance impact level of 7.52 $\mu g/m^3$. Therefore, a cumulative impact assessment is necessary.
  - ✓ For the cumulative impact assessment, three facilities (Orange County Sanitation District's Huntington Beach and Fountain Valley facilities and Beta Offshore) as well as emissions from shipping lane activity off the coast were selected to be included based on their facility emissions and distance to the project. Seasonal, by hour-of-day background concentrations from the Costa Mesa monitoring station were used in the modeling. Following the form of the standard, the 1-hour NO_2 impact from the project plus cumulative projects plus background is 168.2 $\mu g/m^3$, which is less than the federal 1-hour NO_2 standard of 188 $\mu g/m^3$; therefore, no additional PSD analysis is necessary.
  - ✓ Effective July 26, 2013, the South Coast Air Basin has been redesignated to attainment for the 24-hour PM_{10} national ambient air quality standard. The total project's peak 24-hour impact is 4.74 $\mu g/m^3$, which is less than the Class II SIL of 5 $\mu g/m^3$; therefore, no additional PSD analysis is necessary.

- **Application of HARP for the Health Risk Impacts**
  - ✓ The applicant performed the risk assessment with the Hot Spots Analysis and Reporting Program (HARP, version 1.4f). The District HRA procedures require HARP to be used in Tier 4 risk assessments.
  - ✓ PRA staff re-ran the HARP model using the applicant provided data and reproduced the applicant's estimates. The impacts summarized here are for the entire project, which is more conservative than for each permit unit.
  - ✓ The peak cancer risk for the proposed project is 2.35 in one million for a resident and 0.49 in one million for a worker. Based on a radius of 2.8 km and a population density of 4,000 persons/km^2, the cancer burden is conservatively estimated to be 0.23. The peak chronic and acute hazard indices for the proposed project are 0.008 and 0.069, respectively. These total facility risks are less than the Rule 1401 cancer and non-cancer permit limits of 10 in one million (for permit units with T-BACT), cancer burden of 0.5, and hazard index of 1, respectively. Therefore, the cancer and non-cancer risks are less than the Rule 1401 permit limits.

- **Visibility Impact Analysis for Class I and Class II Areas**
  - ✓ The nearest Class I areas to the project site are the San Gabriel Wilderness and Cucamonga Wilderness areas located approximately 69 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 maximum project impact for annual NO_2 at 50km is 0.02 μg/m^3, which is less than the significant impact level of 0.1 μg/m^3.
  - ✓ In order to estimate the potential impacts on visibility and deposition at the nearest Class I area, 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. Since the project is limited to an operating profile of 6,835 hours per year, the project's annual emissions of 407.3 tpy are actually an annual equivalent of 522 tpy. Therefore, the Q/D ratio is 7.6, which is less than the threshold of 10; thus, modeling of visibility and deposition impacts to Class I areas are not necessary.
  - ✓ Additionally, the project's impacts on visibility in Class II areas were also analyzed. Currently, 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 San Mateo Canyon Wilderness Area. Using the Level 1 VISCREEN analysis, only the ΔE for Crystal Cove State Park and Water Canyon State Park exceeded the thresholds; thus a Level 2 VISCREEN analysis is warranted. Using the 5-year meteorological data from the John Wayne airport, the joint frequency distribution tables were created and were used to determine the worst-case single wind speed and stability class required for a Level 2 VISCREEN analysis. Using the Level 2 VISCREEN analysis, the project's

impacts for both contrast and ΔE are less than the thresholds for both Crystal Cove State Park and Water Canyon State Park. Therefore, the proposed project would not be expected to adversely affect visibility at the Class II areas analyzed here.

Modeling staff spent a total of 260 hours on this review. Please direct any questions to Thomas Chico at ext. 3149.

TC:JB

cc: Chris Perri ✓
Ian MacMillan