DOCKETED

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TN #:	201023
Document Title:	South Coast Air Quality Management District's Preliminary Determination of Compliance
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PALEN SOLAR POWER PROJECT
PRELIMINARY DETERMINATION OF COMPLIANCE

APPLICANT:

Palen Solar Electric Generation Station (PSEGS)
1999 Harrison Street, Suite 2150
Oakland, CA 94612

Contact: Mr. Charles Turlinski (510) 550-8161
SCAQMD Facility ID: 174021
Facility type: NOx RECLAIM, Title V, Title IV

EQUIPMENT LOCATION:

Corn Spring Road
Desert Center, CA 92239

SOLAR POWER GENERATING FACILITY CONSISTING OF:

Section H of the Facility Permit

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: EXTERNAL COMBUSTION					
System 1: BOILERS					
BOILER, AUXILARY NO. 1, NATURAL GAS, RENTECH, MODEL CUSTOM WITH ONE COMBUSTION BURNER, 249 MMBTU/HR WITH FLUE GAS RECIRULATION A/N: 549379	D1	C2	NOX: MAJOR SOURCE	**CO: 25**.0 PPMV NATURAL GAS (4) [**Rule 1703 (a)(2)-BACT, 10-7-1988**]; **CO:** 2000 PPMV (5) [**Rule 407, 4-2-1982**]; CO :400 PPMV NATURAL GAS (5**), RULE 1146, 11-17-2000**, *RULE 1146, 9-5-2008*] **NOX** 5 PPMV NATURAL GAS (4)[**Rule 1703 (a)(2)-PSD-BACT, 10-7-1988**]; [**Rule 2005-6-3-2011**], NOX: 11.55 LB/MMCF NATURAL GAS (1)[**RULE 2012, 5-6-2005**], NOX: 6.53 LB/MMCF NATURAL GAS (1)[**RULE 2012, 5-6-2005**]; **NOX**: 80 PPMV NATURAL GAS (8) [**40CFR60 Subpart Db, 1-**	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A327.1, , B61.1, C1.1,C1.2, C1.3,C1.4, D12.1, D29.1, D29.2, D82.1, D82.2, E193.1, E448.1, H23.1, H23.2, H23.3 I298.1, K40.1, K67.1, K67.2

				28-2009] NOX: 92.40 LB/MMCF NATUAL GAS (1)[**RULE 2012, 5-6-2005**]**PM**: 0.01 GRAIN/DSCF Natural gas (5) [**Rule 475, 10-8-1976,** *Rule 475, 8-7-1978*]; **PM**: 0.1 GRAIN/DSCF Natural gas (5a) [**Rule 409, 8-7-1981**]; **PM10**: 11 LB/HR Natural gas (5B) **[Rule 475, 10-8-1976**, *Rule 475, 8-7-1978*]:NOX: 83.96 LB/MMCF NATURAL GAS (1)[**RULE 2012, 5-6-2005**] **SO2**: (9) [**40 CFR 72-Acid Rain Provisions, 11-24-1977**	
CO OXIDATION CATALYST NO. 1, EMERACHEM, 10 CUBIC FEET OF TOTAL CATALYST VOLUME, DEPTH 0 FT 2 IN; WIDTH: 8 FT 10 IN; HEIGHT 6 FT 9 IN A/N: 553874	C2	D1 C3			
SELECTIVE CATALYTIC REDUCTION NO. 1, CORMETECH, MODEL CUSTOM WITH 89 CUBIC FEET OF TOTAL CATALYST VOLUME, DEPTH 1 FT 6 IN; WIDTH: 8 FT 10 IN; HEIGHT 6 FT 9 IN; WITH AMMONIA INJECTION GRID A/N: 553874	C3	S5 C2		**NH3:** 5.0 PPMV Natural gas (4) [**Rule 1303(a)-BACT, 5-10-1996**, *Rule 1303 (a), 12-6-2002*]	A195.6, D12.3 D12.4, D12.5 E179.1, E179.2, E193.1
STACK NO.1, DIAMETER 6 FT 0 IN, HEIGHT 120 FT, A/N 553874	S5	C3			
BOILER, AUXILARY NO. 2, NATURAL GAS, RENTECH, MODEL CUSTOM WITH ONE COMBUSTION BURNER, 249 MMBTU/HR WITH FLUE GAS RECIRULATION A/N: 549380	D6	C7	NOX: MAJOR SOURCE	**CO: 25**.0 PPMV NATURAL GAS (4) [**Rule 1703 (a)(2)-BACT, 10-7-1988**]; **CO:** 2000 PPMV (5) [**Rule 407, 4-2-1982**]; CO 400 PPMV NATURAL GAS (5**), RULE 1146, 11-17-2000**, *RULE 1146, 9-5-2008*] **NOX** 5 PPMV NATURAL GAS (4)[**Rule 1703 (a)(2)-PSD-BACT, 10-7-1988**]; [**Rule 2005-6-3-2011**], NOX: 11.55 LB/MMCF NATURAL GAS (1)[**RULE 2012, 5-6-2005**], NOX: 6.53 LB/MMCF NATURAL GAS (1)[**RULE 2012, 5-6-2005**]; **NOX:** 80 PPMV NATURAL GAS (8) [**40CFR60 Subpart Db, 1-28-2009**]	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A327.1, , B61.1, C1.1,C1.2, C1.3,C1.4, D12.1, D29.1, D29.2, D82.1, D82.2, E193.1, E448.3, H23.1, H23.2, H23.3 I298.2, K40.1, K67.1, K67.2

				PM: 0.01 GRAIN/DSCF	

EQUIPMENT DESCRIPTION (continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: EXTERNAL COMBUSTION					
System 1: BOILERS					
				Natural gas (5) [**Rule 475, 10-8-1976,** *Rule 475, 8-7-197*8]; **PM**: 0.1 GRAIN/DSCF Natural gas (5a) [**Rule 409, 8-7-1981**]; **PM10**: 11 LB/HR Natural gas (5B) **[Rule 475, 10-8-1976**, *Rule 475, 8-7-197*8] NOX: 92.40 LB/MMCF NATURAL GAS (1)[**RULE 2012, 5-6-2005];** NOX: 83.96 LB/MMCF NATURAL GAS (1)[**RULE 2012, 5-6-2005** **SO2**: (9) [**40 CFR 72-Acid Rain Provisions, 11-24-1977**]	
CO OXIDATION CATALYST NO. 2, EMERACHEM, 10 CUBIC FEET OF TOTAL CATALYST VOLUME, DEPTH 0 FT 2 IN; WIDTH: 8 FT 10 IN; HEIGHT 6 FT 9 IN A/N: 553875	C7	D6 C8			
SELECTIVE CATALYTIC REDUCTION NO. 2, CORMETECH, MODEL CUSTOM WITH 89 CUBIC FEET OF TOTAL CATALYST VOLUME, DEPTH 1 FT 6 IN; WIDTH: 8 FT 10 IN; HEIGHT 6 FT 9 IN; WITH AMMONIA INJECTION GRID A/N: 553875	C8	S10 C7		**NH3:** 5.0 PPMV Natural gas (4) [**Rule 1303(a)-BACT, 5-10-1996**, *Rule 1303 (a), 12-6-200*2]	A195.6, D12.3 D12.4, D12.5 E179.1, E179.2, E193.1
STACK NO. 2, DIAMETER 6 FT 0 IN, HEIGHT 120 FT, A/N 549379	S10	C8			
BOILER, NIGHT PRESERVATION, NO. 1, NATURAL GAS, 10.5 MMBTU/HR WITH FLUE GAS RECIRCULATION, WITH LOW NOX BURNER LOW NOX BURNER, CLEAVER BROOKS, MODEL CBEX ELITE, 10.5 MMBTU/HR	D11		PROCESS UNIT	**CO: 25**.0 PPMV NATURAL GAS (4) [**Rule 1703 (a)(2) PSD-BACT, 10-7-1988]**; **CO:** 2000 PPMV Natural gas (5) [**Rule 407, 4-2-1982**]; CO 400 PPMV NATUAL GAS (5A**), RULE 1146,**	A63.2, A195.1, A195.3, A327.1,, B61.1, C1.5,C1.6, C1.7, D12.1, D29.3, H23.1, H23.4, E448.1 I298.3, K67.5

A/N: 549381 A/N: 549381				**11-17-2000**, *RULE 1146, 9-5-2008*] 9 PPMV NATURAL GAS (3) [**Rule 2012, 5-6-2005**] , **NOX** 9 PPMV NATURAL GAS (4) [**Rule 2005-5-6-2011**, **Rule 1703 (a)(2) PSD-BACT, 10-7-1988]** **PM**: 0.1 GRAIN/DSCF (5A) NATURAL GAS [**Rule 409, 8-7-1981**]	

EQUIPMENT DESCRIPTION (continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: EXTERNAL COMBUSTION					
System 1: BOILERS					
BOILER, NIGHT PRESERVATION,NO. 2, NATURAL GAS, 10.5 MMBTU/HR, WITH FLUE GAS RECIRULATION, WITH LOW NOX BURNER. LOW NOX BURNER, CLEAVER BROOKS, MODEL CBEX ELITE, 10.5 MMBTU/HR A/N: 549383	D12		PROCESS UNIT	**CO: 25**.0 PPMV NATURAL GAS (4) [**Rule 1703 (a)(2) PSD-BACT, 10-7-1988**]; **CO:** 2000 PPMV Natural gas (5) [**Rule 407, 4-2-1982**]; CO 400 PPMV NATURAL GAS (5A**), RULE 1146, 11-17-2000**, *RULE 1146, 9-5-2008*] 9 PPMV NATURAL GAS (3) [**Rule 2012, 5-6-2005**] , **NOX** 9 PPMV NATURAL GAS (4) [**Rule 2005-5-6-2011**, **Rule 1703 (a)(2) PSD-BACT, 10-7-1988]** **PM**: 0.1 GRAIN/DSCF (5A) NATURAL GAS [**Rule 409, 8-7-1981**]	A63.2, A195.1, A195.3, A327.1,, B61.1, C1.5,C1.6, C1.7, D12.1, D29.4, H23.1, H23.5, E448.1 I298.3, K67.5

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 2: INTERNAL COMBUSTION					
System 1: EMERGENCY ENGINES					
INTERNAL COMBUSTION ENGINE, EMERGENCY, POWER, NO. 1, DIESEL FUEL, CATERPILLAR, MODEL 3516C, LEAN BURN, 12 CYCLINDERS, , WITH AFTERCOOLER, TURBOCHARGER, 3633 BHP A/N: 549387 GENERATOR, 2500 KW	D13		NOX: PROCESS UNIT	**NOX+NMHC:** 4.8 GM/BHP-HR DIESEL (4) [**RULE 1303(a), 5-10-1996**; *RULE 1303(a) 12-6-2002*, **RULE 2005, 6-3-2011**]; **NOX+NMHC:** 4.8 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII, 6-28-2011**]; **NOX:** 222 LB/1000 GAL DIESEL (1) [**RULE 2012, 5-5-2005**] **CO:** 2.6 GM/BHP-HR DIESEL (4) [**RULE 1703 (a)(2)-PSD-BACT, 10-7-1988]**, **CO:** 2.6 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII, 6-28-2011]** **PM:** 0.15 GM/BHP-HR DIESEL (4) [**RULE 1303(a)-BACT, 5-10-1996,** *Rule 1303(a), 12-6-2002*] , **PM:** 0.15 GM/BHP-HR DIESEL (8)) [**40CFR 60 Subpart IIII, 6-28-2011]** **PM:** 0.15 GM/BHP-HR DIESEL (5) [*RULE 1470, 5-4-2012*] **SOX:** 0.005 GM/BHP-HR DIESEL (4) [**RULE 1303(a)(1)-BACT,5-10-1996,** *Rule 1303(a), 12-6-2006*], HAP:(10)[40 CFR 63 Subpart ZZZZ, 3-9-2011]	B61.2,C1.8, C1.9, C1.10, C1.11, D12.2, E193.1, E448.2 E448.3, H23.5 I298.5,K67.3, K67.4

INTERNAL COMBUSTION ENGINE, EMERGENCY, POWER, NO. 2, DIESEL FUEL, CATERPILLAR, MODEL 3516C, LEAN BURN, 12 CYCLINDERS, , WITH AFTERCOOLER, TURBOCHARGER, 3633 BHP A/N: 549389 GENERATOR, 2500 KW	D15		NOX: PROCESS UNIT	**NOX+NMHC:** 4.8 GM/BHP-HR DIESEL (4) [**RULE 1303(a), 5-10-1996**; *RULE 1303(a) 12-6-2002*, **RULE 2005, 6-3-2011**]; **NOX+NMHC:** 4.8 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII, 6-28-2011**]; **NOX:** 222 LB/1000 GAL DIESEL (1) [**RULE 2012, 5-5-2005**] **CO:** 2.6 GM/BHP-HR DIESEL (4) [**RULE 1703 (a)(2)-PSD-BACT, 10-7-1988]**, **CO:** 2.6 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII, 6-28-2011]** **PM:** 0.15 GM/BHP-HR DIESEL (4) [**RULE 1303(a)-BACT, 5-10-1996,** *Rule 1303(a), 12-6-2002*] , **PM:** 0.15 GM/BHP-HR DIESEL (8)) [**40CFR 60 Subpart IIII, 6-28-2011]** **PM:** 0.15 GM/BHP-HR DIESEL (5) [*RULE 1470, 5-4-2012*] **SOX:** 0.005 GM/BHP-HR DIESEL (4) [**RULE 1303(a)(1)-BACT,5-10-1996,** *Rule 1303(a), 12-6-2006*]; HAP:(10)[40 CFR 63 Subpart ZZZZ, 3-9-2011]	B61.2,C1.8, C1.9, C1.10, C1.11, D12.2, E193.1, E448.2 E448.3, H23.5 I298.6,K67.3, K67.4
INTERNAL COMBUSTION ENGINE, EMERGENCY, POWER, NO. 3, DIESEL FUEL, CATERPILLAR, MODEL C9, LEAN BURN, 6 CYCLINDERS, WITH AFTERCOOLER, TURBOCHARGER 398 BHP A/N: 549390	D17		NOX: PROCESS UNIT	**NOX+NMHC:** 3.0 GM/BHP-HR DIESEL (4) [**RULE 1303(a), 5-10-1996**; *RULE 1303(a) 12-6-2002*, **RULE 2005, 6-3-2011**]; **NOX+NMHC:** 3.0 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII, 6-28-2011**]; **NOX:** 132 LB/1000 GAL DIESEL (1) [**RULE 2012, 5-5-2005**]**CO:** 2.6 GM/BHP-HR DIESEL (4) [**RULE 1703 (a)(2)-PSD-BACT, 10-7-1988]**, **CO:** 2.6 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII, 6-28-2011]PM:** 0.15 GM/BHP-HR DIESEL (4) [**RULE 1303(a)-BACT, 5-**	B61.2,C1.8, C1.9, C1.10, C1.11, D12.2, E193.1, E448.2 E448.3, H23.5 I298.7,K67.3, K67.4

GENERATOR, 250 KW				**10-1996,** *Rule 1303(a), 12-6-2002*] , **PM:** 0.15 GM/BHP-HR DIESEL (8)) [**40CFR 60 Subpart IIII, 6-28-2011]** **PM:** 0.15 GM/BHP-HR DIESEL (5) [*RULE 1470, 5-4-2012*] **SOX:** 0.005 GM/BHP-HR DIESEL (4) [**RULE 1303(a)(1)-BACT,5-10-1996,** *Rule 1303(a), 12-6-2006*]; HAP:(10)[40 CFR 63 Subpart ZZZZ, 3-9-2011]	
INTERNAL COMBUSTION ENGINE, EMERGENCY FIRE PUMP, NO. 1, DIESEL FUEL, CLARKE, MODEL JX6H-UFAD88, LEAN BURN, 6 CYCLINDERS, WITH AFTERCOOLER, TURBOCHARGER, 617 BHP A/N: 549384	D19		NOX: PROCESS UNIT	**NOX+NMHC:** 3.0 GM/BHP-HR DIESEL (4) [**RULE 1303(a), 5-10-1996**; *RULE 1303(a) 12-6-2002*, **RULE 2005, 6-3-2011**]; **NOX+NMHC:** 3.0 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII, 6-28-2011**]; **NOX:** 120 LB/1000 GAL DIESEL (1) [**RULE 2012, 5-5-2005**]**CO:** 2.6 GM/BHP-HR DIESEL (4) [**RULE 1703 (a)(2)-PSD-BACT, 10-7-1988**], **CO:** 2.6 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII, 6-28-2011]PM:** 0.15 GM/BHP-HR DIESEL (4) [**RULE 1303(a)-BACT, 5-10-1996,** *Rule 1303(a), 12-6-2002*] , **PM:** 0.15 GM/BHP-HR DIESEL (8)) [**40CFR 60 Subpart IIII, 6-28-2011]** **PM:** 0.15 GM/BHP-HR DIESEL (5) [*RULE 1470, 5-4-2012*] **SOX:** 0.005 GM/BHP-HR DIESEL (4) [**RULE 1303(a)(1)-BACT,5-10-1996,** *Rule 1303(a), 12-6-2006*]; HAP:(10)[40 CFR 63 Subpart ZZZZ, 3-9-2011]	B61.2,C1.8, , C1.2, C1.11, C1.12 D12.2, E193.1, E448.2 E448.3, H23.5 I298.8 ,K67.3, K67.4
INTERNAL COMBUSTION ENGINE, EMERGENCY FIRE PUMP, NO. 2, DIESEL FUEL, CLARKE, MODEL JX6H-UFAD88, LEAN BURN, 6 CYCLINDERS, WITH AFTERCOOLER, TURBOCHARGER, 617 BHP	D20		NOX: PROCESS UNIT	**NOX+NMHC:** 3.0 GM/BHP-HR DIESEL (4) [**RULE 1303(a), 5-10-1996**; *RULE 1303(a) 12-6-2002*, **RULE 2005, 6-3-2011**]; **NOX+NMHC:** 3.0 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII,**	B61.2,C1.8, , C1.2, C1.11, C1.12 D12.2, E193.1, E448.2 E448.3, H23.5 I298.9 ,K67.3, K67.4

A/N: 549385				**6-28-2011**]; **NOX:** 120 LB/1000 GAL DIESEL (1) [**RULE 2012, 5-5-2005**] **CO:** 2.6 GM/BHP-HR DIESEL (4) [**RULE 1703 (a)(2)-PSD-BACT, 10-7-1988]**, **CO:** 2.6 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII, 6-28-2011]** **PM:** 0.15 GM/BHP-HR DIESEL (4) [**RULE 1303(a)-BACT, 5-10-1996,** *Rule 1303(a), 12-6-2002*] , **PM:** 0.15 GM/BHP-HR DIESEL (8)) [**40CFR 60 Subpart IIII, 6-28-2011], PM:** 0.15 GM/BHP-HR DIESEL (5) [*RULE 1470, 5-4-2012*] **SOX:** 0.005 GM/BHP-HR DIESEL (4) [**RULE 1303(a)(1)-BACT,5-10-1996,** *Rule 1303(a), 12-6-2006*]; HAP:(10)[40 CFR 63 Subpart ZZZZ, 3-9-2011]	
INTERNAL COMBUSTION ENGINE, EMERGENCY FIRE PUMP, NO. 2, DIESEL FUEL, CLARKE, MODEL JX6H-UFAD88, LEAN BURN, 6 CYCLINDERS, WITH AFTERCOOLER, TURBOCHARGER, 617 BHP A/N: 549386	D21		NOX: PROCESS UNIT	**NOX+NMHC:** 3.0 GM/BHP-HR DIESEL (4) [**RULE 1303(a), 5-10-1996**; *RULE 1303(a) 12-6-2002*, **RULE 2005, 6-3-2011**]; **NOX+NMHC:** 3.0 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII, 6-28-2011**]; **NOX:** 120 LB/1000 GAL DIESEL (1) [**RULE 2012, 5-5-2005**] **CO:** 2.6 GM/BHP-HR DIESEL (4) [**RULE 1703 (a)(2)-PSD-BACT, 10-7-1988]**, **CO:** 2.6 GM/BHP-HR DIESEL (8) [**40CFR 60 Subpart IIII, 6-28-2011]** **PM:** 0.15 GM/BHP-HR DIESEL (4) [**RULE 1303(a)-BACT, 5-10-1996,** *Rule 1303(a), 12-6-2002*] , **PM:** 0.15 GM/BHP-HR DIESEL (8)) [**40CFR 60 Subpart IIII, 6-28-2011], PM:** 0.15 GM/BHP-HR DIESEL (5) [*RULE 1470, 5-4-2012*] **SOX:** 0.005 GM/BHP-HR DIESEL (4) [**RULE**	**B61.2,C1.8, , C1.2, C1.11, C1.12 D12.2, E193.1, E448.2 E448.3, H23.5 I298.10 ,K67.3, K67.4**

				1303(a)(1)-BACT,5-10-1996, *Rule 1303(a), 12-6-2006*];	

Section D of the Facility Permit

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 3: RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE SPECIFIC RULES					
RULE 219 EXEMPT EQUIPMENT, COATING EQUIPMENT, PORTABLE, ARCHITECTURAL COATING	E25			**VOC:** (9) [Rule 1113],[Rule 1171]	K67.6
RULE 219 EXEMPT EQUIPMENT, EXEMPT HAND WIPING OPERATIONS	E26			**VOC:** (9) [Rule 1171]	
RULE 219 EXEMPT EQUIPMENT 300 GALLONS PORTABLE AQUEOUS AMMONIA STORAGE TOTE	E27				

BACKGROUND / HISTORY

The Palen Solar Electric Generating Station (PSEGS) is a new facility which will be located in the Southern California inland desert, off of Corn Spring Road, approximately ¼ mile north of interstate 10, approximately 10 miles east of Desert Center in eastern Riverside County (see the plant layout diagram included in the next page). The project site will occupy 3,794 acres of public lands owned by the Federal Government. PSEGS is proposing to construct and operate a 500 MW solar-electric power generating plant consisting of two 250 MW facilities operating adjacent to each other. Table 1 below shows the applications for Permit to Construct and the corresponding equipment descriptions and permit processing fees.

Table 1 Application Summary

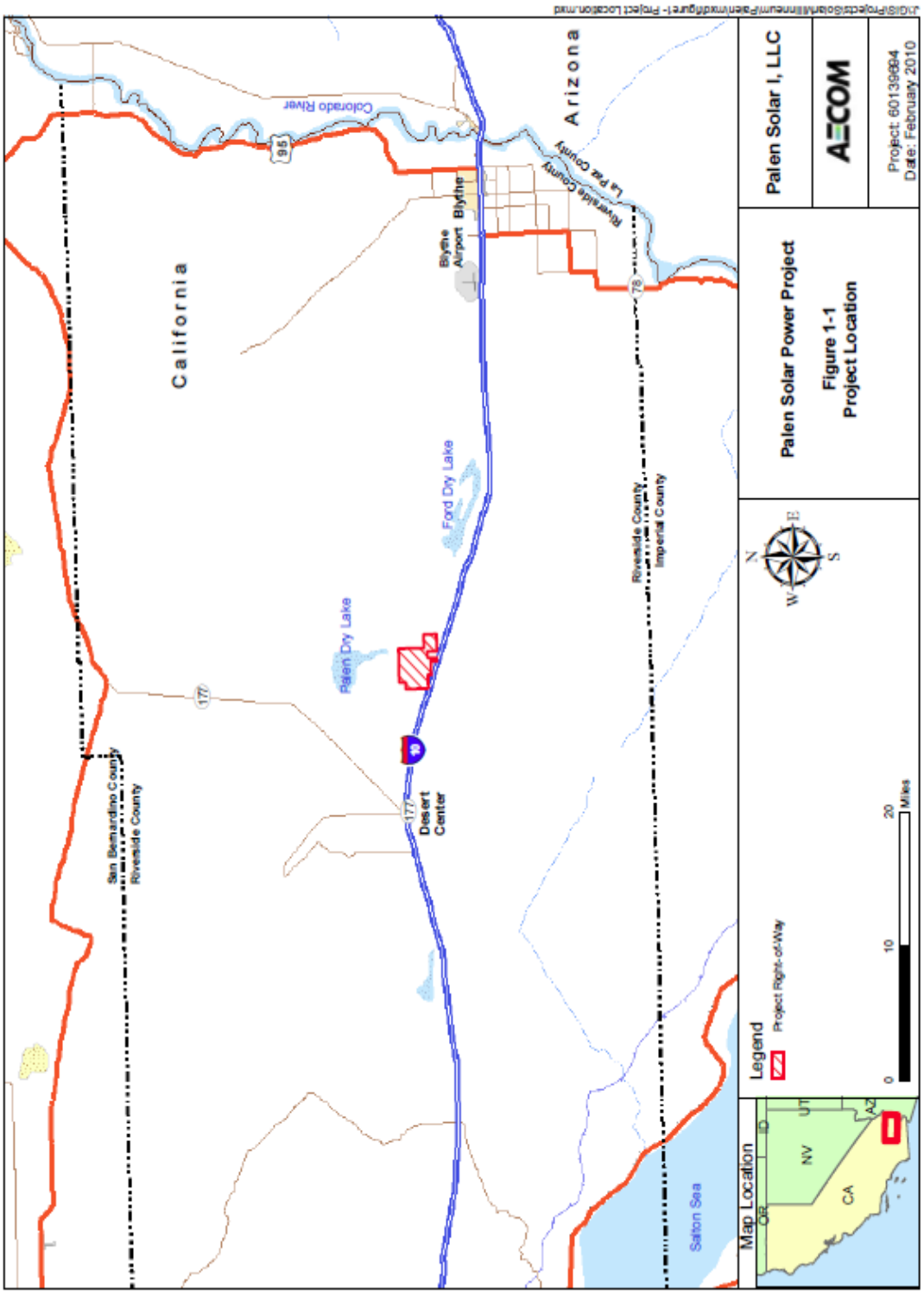
A/N	Equipment	Submittal Date	Deemed Complete	BCAT/ CCAT	Schedule	Base Fee[(a)]	XPP Fee	Total Filing Fees
549379	Auxiliary Boiler no. 1	4/4/13	7/17/13	011005	E	$5,458.60	$2,729.30	$8,187.90
549380	Auxiliary Boiler no. 2	4/4/13	7/17/13	011005	E	$2,729.30	$1,364.65	$4,093.95
549381	Night Preservation Boiler no. 1	4/4/13	7/17/13	011003	C	$3,440.06	$1,720.03	$5,160.09
549383	Night Preservation Boiler no. 2	4/4/13	7/17/13	011003	C	$1,720.03	$860.02	$2580.05
549387	Emergency ICE no. 1	4/4/13	7/17/13	043902	B	$2,174.89	$1,087.45	$3,262.34
549389	Emergency ICE no. 2	4/4/13	7/17/13	043902	B	$1,087.45	$543.7345	$1,631.184
549390	Emergency ICE no. 3	4/4/13	7/17/13	043902	B	$2,174.89	$1,087.45	$3,262.34
549384	Emergency Fire Pump ICE no. 1	4/4/13	7/17/13	044102	B	$2,174.89	$1,087.45	$3,262.34
549385	Emergency Fire Pump ICE no. 2	4/4/13	7/17/13	044102	B	$1,087.45	$543.7345	$1,631.184

549386	Emergency Fire Pump ICE no. 3	4/4/13	7/17/13	044102	B	$1,087.45	$543.7345	$1,631.184
553874	SCR/CO Catalyst no. 1	6/21/13	7/17/13	81	C	$3,508.86	$1,754.43	$5,160.09
553875	SCR/CO Catalyst no. 2	6/21/13	7/17/13	81	C	$1,754.43	$1,754.43	$877.22
549399	RECLAIM/Title V application	6/7/12	7/17/13	555009	-	$1,747.19	-	$1,747.19
							Total	**$61,007.96**

The applications listed in Table 1 above were initially deemed data inadequate on April 26, 2013 because application package were insufficient and information pertaining to the specific equipment was also not included. The applicant submitted the data request to the SCAQMD on 6/14/2013 and made the following changes to the project; Each auxiliary boiler will be vented to a SCR with oxidation catalyst, the operating schedule for the auxiliary boiler has been modified; the night preservation boiler btu rating has been revised to 10.5 mmbtu/hr, there will be a lower CO ppmv limit 25 ppmv for the night preservation boiler; the two large emergency ICE will be Tier II instead of Tier IV. The applications for the SCR was submitted on 6/21/13 and the fees on 6/28/13. The applicant submitted a request to the SCAQMD to opt-in the NOx RECLAIM program on 7/12/13. The SCAQMD deemed the applications data adequate on July 25, 2013.

There will also be an additional fee for the hours of work completed for the air quality analysis. In addition, the project triggers a public notice per Rule 212(g). Therefore, additional fees will be billed to the facility in accordance with Rule 301.

Plant Layout Diagram for the Proposed Palen Solar Power Plant


J:\GIS\Projects\Solar\Linneum\Palen\mxd\Figure 1- Project Location.mxd
Palen Solar I, LLC
AECOM
Project: 60139884
Date: February 2010
Palen Solar Power Project
Figure 1-1
Project Location
Arizona
California
Colorado River
Riverside County
La Paz County
Blythe
Blythe Airport
Ford Dry Lake
Palen Dry Lake
Riverside County
Imperial County
San Bernardino County
Riverside County
Desert Center
Salton Sea
95
78
177
N
S
E
W
Legend
Project Right-of-Way
0
10
20
Miles
Map Location
NV
CA
OR
UT
AZ

PROCESS DESCRIPTION

PSEGS will use Brightsource's solar tower technology to generate electricity. The applicant proposes two independent solar plants each 250 MW (called Solar Plant 1 and Solar Plant 2). Both plants will share common facilities. Each solar field will have a dedicated Solar Receiver Steam Generator (SRSG)/tower, solar field/heliostat array, and a dedicated on-reheat Rankine-cycle steam turbine generator .

Each solar plants will use heliostats-elevated mirrors guided by a tracking system mounted on a pylon-to focus the sun's rays on a SRSG located on a tower near the center of each solar field to create steam to drive a turbine that provides electricity. The solar field and power generation equipment will start each morning after sunrise and will shut down (unless augmented by the auxiliary boiler) when isolation drops below the level required to keep the turbine online. Natural gas Auxilary boilers may be also be used to extend daily power generation. However, on an annual basis, the natural gas used as a supplement to power generation is limited to below 2% of the annual energy output of the project.

Each solar plant includes auxiliary boilers. A start-up boiler (Auxiliary) will be used during he morning start-up cycle to assist the plant in coming up to operating temperature sooner and for augmenting the solar operation when solar energy is reduced or during transient cloudy conditions. Each solar plant also includes a night preservation boiler that will be used to provide steam to the gland systems of the steam turbine and boiler feedwater pump turbine to prevent air ingress overnight and during other shutdown periods when steam is not available form the SRSG. The night preservation boilers do not provide any steam to the turbine to generate electricity.

Solar Field

Each solar field will consist of 85,000 heliostats, 750 foot solar tower and receiver and power block. Each heliostat consists of two mirror with a surface area of 205 square feet. Each heliostat assembly is mounted on a single pylon along with a computer programmed aiming control system that directs the motion of the heliostat to track the movement of the sun.

Generating units

- Each solar tower is 620 feet tall
- The SRSG located on top of the solar tower is 130 feet tall, giving the total height of the solar tower and SRSG 750 feet tall.

- No heliostat will be located closer than 260 feet from the solar tower location.

Steam turbine generator

Each unit would contain a non-reheat, Rankine-cycle, condensing steam turbine generator (STG) with gland steam system, lubricating oil system, hydraulic control system and steam admission/induction valving. High Pressure (HP) steam from the SRSG super heater enters the HP steam turbine section and expands through multiple stages of the turbine, driving a generator to produce electricity. On exiting the Low Pressure (LP) turbine, the steam is directed into the air cooled condenser.

Mirror washing

Regular mirror washing will be performed by a small mirror washing machine. To maintain heliostat performance, heliostat washing is projected to occur up to 24 hours per day (including night time mirror washing), covering the entire solar field weekly. The mirror washing machine, the water pumps are mechanically driven via the "power take-off" coupling on the small tractors that will pull the water wash supply carts. As such, no air permits required from this mobile vehicle. The applicant does not anticipate the use of detergents, soaps, or surfactants at this time because the use of these products will leave a film on the heliostats and will impact efficiency.

Permitted equipment description

Each solar plant will include two natural gas fired boilers to assist with daily start-up of the power generation equipment and to preserve energy in the steam cycle during the evenings.

Each solar plant will have the following permitted equipment

- One 249 mmbtu/hr natural gas fired auxiliary boiler used for start up and cycle augmentation
- One 10.5 mmbtu/hr natural gas fired night preservation boiler used to maintain system water temperatures at night.
- One 3633 hp emergency electrical generator
- One 617 hp emergency fire pump engine

Common facilities area

A common facilities area will be located on the southwestern corner of the site to locate administration, warehouse, and maintenance complex and will have the following permitted equipment

- One 617 hp emergency fire pump engine
- One 398 hp emergency electrical generator

EMISSION CALCULATIONS

Brief overview of the boiler operation

Normally the emissions determination from boilers is routinely done at the SCAQMD. The boilers are evaluated at 100% load for full time for the month and year. However for PSEGS there are two types of boilers. The auxiliary boilers (249 mmbtu/hr) are used during the daytime to augment the heating of the water to maintain a minimum temperature before the Solar Plant goes on line. During the night time, small boilers (10.5 mmbtu/hr) are used to maintain a minimum temperature of the water

Auxiliary boilers

Boiler mode
Non-boosting
Turbine Boosting
Hot/emergency starts
Cold start
Very cold start

- Non-boost mode is the ideal operation for the boiler. The boiler is started in the morning for a few hours and is used to provide pre-heating of the water to the solar receiver steam generator (SRSG) and feed water heating. The boiler is shut-down for about four hours and restarted is re-started for less than hour. This is to provide the boiler to come on line in a quicker time if the solar plant if the solar plant needs a restart due to weather or other conditions. The boiler is re-started in the late afternoon and is used to provide SRSG piping cooling as the solar plant goes off line. The boiler will be off line during the night and will repeat the process the next day.
- Turbine boost mode is used to provide steam to the steam generation for several hours during the day when conditions are not ideal for solar generation. The operation of the turbine

boosting is the same as the non-boosting (see above) except steam is used directly to generate electricity.

- Hot-restart- is used to help the solar plant come on line due a cloud event or emergency trip. The boiler is operated for several hours and is used to provide SRSG panel cooling/heating and feed water heating

- Cold start-the solar plant has been off line for 36 hours and will go through a eight hour restart procedure.

- Very cold start- solar plant has been off line for 80 hours and will go through a 16 hour restart procedure.

Night Preservation Boilers

These boilers are used to maintain a minimum temperature of the water during the evening hours.

Auxiliary Boilers

The auxiliary boilers will be operated under the following assumptions and are the basis for emission calculations

- Natural gas will be the only fuel used by the boilers;

- Boilers will be vented to SCR and controlled NOx concentration of 5 ppmv burners and CO concentration of 25 ppmv;

- There are multiple modes of operations as listed in the tables below

- Annual operation of each boiler will be based on 316 mmcf annual fuel usage (see emissions calculations for details). The maximum fuel usage is based on boosting mode (220 day/yr), non-boosting mode (120 day/yr), 10 cold starts, 5 very cold starts and 60 boosting/emergency starts per year

- The maximum fuel usage per month is 41 mmcf annual fuel usage (see emissions calculations for details). The maximum fuel usage is based on boosting mode (29 day/mon), 1 cold start, 1 very cold starts and 29 boosting/emergency starts per month

- 100 percent of the PM10 emissions are PM2.5

The criteria pollutant emission factors used for the NOx and CO emission estimates are based $\leq$ 5 ppmv and $\leq$ 25 ppmv respectively, each at 3% O2, dry basis. The PM10 and VOC emission factors are based on vendor performance warranties, and the SOx emission factor was base on 0.75 gr/100 cf of gas (0.002101 lb/MMBTU). Boiler criteria pollutant emissions for a single boiler and two

boilers are shown in the calculation sheets at the end of this engineering evaluation and summarized in Tables 7 below, respectively (Note 30-DA means 30-day average emissions).

One natural gas fired auxiliary boilers are proposed for each power block. The boilers will be used during the morning start-up cycle to assist the power generation equipment in coming up to operating temperature more quickly and for augmenting the solar operation when solar energy diminishes or during transient cloudy conditions.

1 Modes of operation for the boiler

A. Turbine Boosting mode operation

This mode of operation is used to provide additional steam to be sent to the steam generator to generate electricity during days when solar generation is not optimal (basically the same as non-boosting mode (see section B below), but with the addition of steam generation for the steam turbine) . The boiler is started at 5 am after 12- 14 hours of being shut down the previous evening. This type of start-up is called a "warm start" and will last for 90 minutes and the boiler will be at 17.5% load. The boiler will be operated for additional one hour at 100% load. During this operation the boiler is used to help the solar plant to come on line by providing heated feed water to the system. The boiler is then shut down from 7:30 to noon. At noon the boiler is started. The boiler is operated for 45 minutes at 17.5% load. This is done if there is not enough solar generation, the boiler will be able to augment the solar generation in a minimal time period. The boiler is then shut down from 12:45 to 3:15. The boiler is restarted with a second hot start from 3:15 to 4:00 and is operated at 17.5% load

"Turbine boosting mode", during this operation the boiler will provide steam to the turbine and produce electricity from 4 pm to 6 pm. The applicant estimates less than 2 percent of electrical generation will be from both boilers. The turbine boosting mode is used when there is not ideal conditions of the solar plant to produce electricity. The applicant estimates 30 MWh (average) per day (email dated 7/9/2013 from applicant) when operating in this mode (SRSG and aux boiler are in operation). There is no operation of turbine with only the aux boiler and SRSG off line. From 6 pm to 7 pm is operated for piping cooling prior to going off line for the evening. Table below show the operations of the boiler during this mode

Table , Turbine Boosting Mode

Boiler operations	Boiler load	Adjusted for partial load MMbtu/hr	Schedule	Duration (min)	SCR on line
Start-up (after 12-14 hr shutdown	17.5%	43.6	5:00-6:30	90	No

SRSG panel/feedwater heating (morning with aux steam)	100%	249	6:30-7:30	60	Yes
Aux boiler bottled up (boiler is off line)			7:30-12:00		
Aux boiler restart (after 3-4 hours shutdown)	17.5%	43.6	12:00-12:45	45	No
Aux boiler bottled up			12:45-15:15		
Aux boiler start (after 2-3 hours shutdown)	17.5%	43.6	15:15-16:00	45	No
Turbine boosting mode (with aux boiler steam)	50%	124.5	16:00-16:30	30	Yes
Turbine boosting mode (with aux boiler steam)	100%	249	16:30-17:30	60	Yes
Turbine boosting mode (with aux boiler steam)	80%	199.2	17:30-18:00	30	Yes
SRGS piping cooling (evening) with aux boiler steam)	80%	199.2	18:00-19:00	60	Yes

B. Non-Boosting mode operation

This mode of operation is not used to provide additional steam to generate electricity. The boiler is started at 6:30 am after 12- 14 hour shut down in the evening prior. This type of start-up is called a "warm start" and will last for 90 minutes and the boiler will be at 17.5% load. The boiler will be operated for additional one hour at 100% load. During this operation the boiler is used to help the solar plant to come on line by providing heated feed water to the system. The boiler is shut down from 9:00 to noon. At noon the boiler is started, this start is known as a "Hot start". The boiler is operated for 45 minutes at 17.5% load. This is done if there is not enough solar generation, the boiler will be able to augment the solar generation in a minimal time period. The boiler is then shut down from 12:45 to 3:15. The boiler is restarted with a second hot start from 3:15 to 4:00 and is operated at 17.5% load, then from 4 pm to 5 pm the boiler is operated at 80% load for SRSG piping cooling to prepare the solar plant to come off line. Table below show the operations of the boiler during this

mode.

Table, Non-Boosting Mode

Boiler operations	Boiler load	Adjusted for partial load MMbtu/hr	Schedule	Duration (min)	SCR on line
Start-up (after 12-14 hr shutdown	17.5%	43.6	6:30-8:00	90	No
SRGS panel/feedwater heating (morning with aux stea6m)	100%	249	8:00-9:00	60	Yes
Aux boiler bottled up			9:00-12:00		
Aux boiler restart (after 3-4 hours shutdown)	17.5%	43.6	12:00-12:45	45	No
Aux boiler bottled up			12:45-15:15		
Aux boiler start (after 2-3 hours shutdown)	17.5%	43.6	15:15-16:00	45	No
SRGS piping cooling (evening) with aux boiler steam)	80%	199.2	16:00-16:45	45	Yes

C. Hot start after cloud event/emergency trip

This mode of operation is not used to provide additional steam to generate electricity during unexpected cloudy conditions or after the solar plant had a emergency shut-down trip. . During this mode of operation the boiler generates steam to keep the SRSG panel warm to allow for a fast restart of the plant after its emergency trip. . **The boiler is not used to produce electricity in this mode of operation.** When the boiler is operated in this mode, it is started for 45 minutes at 17.5% load. The boiler will be operated for an additional 30 minutes at 100% load. The boiler then operates for 60 minutes at 30 percent load and for 30 minutes at 100% load. The applicant estimates 60 starts of this type of mode per year. The table below shows the operations of the boiler during this mode.

Table Hot start/emergency trip

Boiler operations	Boiler load	Adjusted for partial load MMbtu/hr	Schedule	Duration (min)	SCR on line
Start-up	17.5%	43.6	Variable	45	No
SRGS panel cooling	100%	249	Variable	30	Yes
Aux boiler is at min load until plant is ready to restart	30%	74.7	Variable	60	Yes
SRGS panel/ feed water heating	100%	249	Variable	30	Yes

D. Cold start

This mode of operation occurs when the SRSG and boiler have not been in operation for one day and two nights due to possible cloudy or windy weather. The boiler is operated in this mode, it is started for 3 hours (the slow start-up times are to avoid thermal shock on the metallurgy for the plant pipes) at 17.5% load. The boiler will be operated for additional 4 hours at 50% load. Then operated for 1 hour at 100% load. Table 5 below show the operations of the boiler during this mode

Table 5 Cold Start

Boiler operations	Boiler load	Adjusted for partial load MMbtu/hr	Schedule	Duration (hr)	SCR on line
Start-up	17.5%	43.6	Variable	3	No
Aux boiler steam for plant system/ piping preheating	50%	125.4	Variable	4	Yes
SRGS panel/ feed water heating	100%	249	Variable	1	Yes

E. Very cold start

This mode of operation occurs when the SRSG and boiler have not been in operation for more than three days or 80 hours due to plant maintenance or bad weather. When the boiler is operated in this

mode, it is started for 4.5 hours (the slow start-up times are to avoid thermal shock on the metallurgy for the plant pipes) are at 17.5% load. The boiler will then be operated for an additional 10 hours at 50% load. The boiler then operates for 1 hour at 100% load. Table 6 below show the operations of the boiler during this mode.

Table 6 Very Cold Start

Boiler operations	Boiler load	Adjusted for partial load MMbtu/hr	Schedule	Duration (hr)	SCR on line
Start-up	17.5%	43.6	Variable	4.5	No
Aux boiler steam for plant system/ piping preheating	50%	125.4	Variable	10	Yes
SRGS panel/ feed water heating	100%	249	Variable	1	Yes

2 Maximum monthly emissions (see Appendix B)

The applicant proposes the following modes of operations to determine the maximum monthly emission (to determine the max. 30 day average for offset determination) will be based on the follow table

Table Worst Case mode of operation for maximum monthly emissions

Boiler mode	Days/mon
Boosting	29
Very cold start	1
Cold start	1
Hot/emergency starts	29

Note, the hot/emergency start will be incorporated into the boosting mode schedule

For the worst case emission determination, the non-boosting mode of operation is not included

(because the emissions are less than turbine boosting mode emissions)

A. Boosting mode emission (per one boiler)

Pollutant	Maximum Daily normal operation 100% load (lb/day)	Maximum Daily start-up/hot start operation 17.5% load no control (lb/day)	Maximum Daily hot start operation 50% load control (lb/day)	Maximum Daily 80% load controlled (lb/day)	Maximum Total Daily (lb/day)	Maximum Total Daily (lb/mon)
NOx	3.097	10.454	0.387	1.858	15.796	458.088
VOC	1.992	0.706	0.249	1.195	4.142	120.121
CO	9.425	19.595	1.178	5.655	35.853	1039.743
PM10	2.490	0.974	0.311	1.494	5.269	152.809
SOx	1.046	0.275	0.131	0.628	2.079	60.301

See calculations sections for details

B. Very cold start mode (per one boiler)

Pollutant	Maximum Daily normal operation 100% load (lb/day)	Maximum Daily start-up operation 17.5% load (lb/day)	Maximum Daily start-up operation 50% load (lb/day)	Maximum Total Daily (lb/day)	Maximum Total Daily (lb/mon)
NOx	1.548	15.681	7.742	24.972	24.972
VOC	0.996	1.059	4.980	7.035	7.035
CO	4.713	29.392	23.563	57.668	57.668
PM10	1.245	1.461	6.225	8.931	8.931
SOx	0.523	0.412	2.616	3.551	3.551

C. Cold start mode emissions (per one boiler)

	Maximum	Maximum	Maximum	Maximum	Maximum

Pollutant	Daily normal operation 100% load (lb/day)	Daily start-up operation 17.5% load no control (lb/day)	Daily normal operation 50% load (lb/day)	Total Daily (lb/day)	Total Daily (lb/mon)
NOx	1.548	10.454	3.097	15.099	15.099
VOC	0.996	0.706	1.992	3.694	3.694
CO	4.713	19.595	9.425	33.733	33.733
PM10	1.245	0.974	2.490	4.709	4.709
SOx	0.523	0.275	1.046	1.844	1.844

D. Emergency/hot start mode (per one boiler)

Pollutant	Maximum Daily normal operation 100% load controlled (lb/day)	Maximum Daily normal operation 30% load controlled (lb/day)	Maximum Daily start-up operation 17.5% load no control (lb/day)	Maximum Total Daily (lb/day)	days/month	Maximum Total Daily (lb/mon)
NOx	1.548	0.465	2.614	4.626	29.000	134.168
VOC	0.996	0.299	0.171	1.466	29.000	42.515
CO	4.713	1.414	4.899	11.025	29.000	319.726
PM10	1.245	0.374	0.244	1.862	29.000	53.998
SOx	0.523	0.157	0.069	0.749	29.000	21.712

E. Total emissions per month and 30 ave (per one boiler)

Pollutant	Maximum monthly boosting (lb/mon)	Maximum monthly very cold start (lb/mon)	Maximum monthly cold start (lb/mon)	Maximum monthly hot start emergency (lb/mon)	Maximum Total Daily (lb/mon)	30DA (lb/day)
NOx	458.088	24.972	15.099	**134.168**	632.327	**21.08**
VOC	120.121	7.035	3.694	**42.515**	173.366	**5.78**

CO	1039.743	57.668	33.733	**319.726**	1450.869	**48.36**
PM10	152.809	8.931	4.709	**53.998**	220.447	**7.35**
SOx	60.301	3.551	1.844	**21.712**	87.408	**2.91**

The applicant based the various modes of operation on annual bases as seen in the table below

Item	Maximum monthly boosting	Maximum monthly very cold start	Maximum monthly cold start	Maximum monthly hot start emergency	Maximum Non-boosting mode
Day/yr	220	5	10	**60**	125

Regulation 13 requires offsets to be based on the worst operating month. The applicant provided the following Table for the worst case month. Note, Non-boosting mode is not included because the emissions are less than boosting mode emissions.

Worst Case mode of operation for maximum monthly emissions

Boiler mode	Days/mon
Boosting	29
Very cold start	1
Cold start	1
Hot/emergency starts	29

F. Maximum annual emissions

The applicant proposes the following modes of operations to determine the maximum annual emission will be based on the follow table

Boiler mode	Days/year
Boosting	220

Very cold start	5
Cold start	10
Hot/emergency starts	60
Non-boosting	125

Per one boiler

Pollutant	Maximum yearly boosting (lb/yr)	Maximum yearly very cold start (lb/yr)	Maximum yearly cold start (lb/yr)	Maximum yearly hot start emergency (lb/yr)	Maximum yearly non-boosting (lb/yr)	Annual Emissions (lb/yr)	Annual Emissions (ton/yr)
day/yr	220	5	10	60	125		
NOx	3475.15	124.86	150.99	277.59	1616.45	5645.04	2.82
VOC	911.27	35.17	36.94	87.96	287.44	1358.78	0.68
CO	7887.70	288.348	337.33	661.50	3391.87	12566.74	6.28
PM10	1159.24	44.66	47.09	111.72	370.75	1733.46	0.87
SOx	457.46	17.75	18.44	44.92	138.95	677.52	0.34

The annual emission is based on the following

- First determine the yearly emission from each mode of operation, by taking the lb/day emissions per pollutant and multiplying the value of the day of operation per year. Repeat the process for each pollutant

- Second sum the annual emissions for each mode of operation to determine the annual emissions

3. Fuel Usage

A. Monthly Fuel usage

The monthly fuel usage per boiler is based on the different modes of operations as outlined below

Boosting mode

boiler load	hr/dy	mmcf
17.50%	3	0.1245
100%	2	0.4743
50%	0.5	0.0593
80%	1.5	0.2846
total		0.9426

Mmcf/load = 249 mmbtu/hr * Load % * hr/dy * (1 mmcf/1050 mmbtu)

Very Cold day mode

boiler load	hr/dy	mmcf
17.50%	4.5	0.1868
100%	1	0.2371
50%	10	1.1857
total		1.6096

Cold day mode

boiler load	hr/dy	mmcf
17.50%	3	0.1245
100%	1	0.2371
50%	4	0.4728
total		0.8359

Hot restart/emergency trip mode

boiler load	hr/dy	mmcf
17.50%	0.75	0.0311
100%	1	0.2371

30%	1	0.0711
total		0.3394

Monthly fuel usage per mode

Pollutant	Maximum monthly boosting (mmcf)	Maximum monthly very cold start (lb/mmcf)	Maximum monthly cold start (mmcf)	Maximum monthly hot start emergency (mmcf)	Maximum Total Daily (mmcf)
mmcf	27.337	1.610	0.836	9.843	39.625

maximum monthly fuel usage = (29 boost days* 0.9426) + (1 cold start *0.8359) + (1 very cold start * 1.6096)+ (29 emergency/hot start* 0.3394)

maximum monthly fuel usage = 40 MMCF

B. Annual Fuel usage (per one boiler)

fuel	Maximum annual boosting (mmcf)	Maximum annual very cold start (lb/mmcf)	Maximum annual cold start (mmcf)	Maximum annual hot start emergency (mmcf)	` annual non-boosting (mmcf)	Annual (MMCF)
mmcf/day	0.943	1.610	0.836	0.339	0.503	
days/yr	220	5	10	60	125	
mmcf/yr	207.38	8.05	8.36	20.36	62.92	307.07

Non boosting mode fuel usage

		mmcf
boiler load	hr/dy	mmcf
17.50%	3	0.1245
100%	1	0.2371
80%	0.75	0.1417
total	3	0.5034

The above non-boosting fuel usage was not included in the worst case emission or fuel usage, but is include in the annual fuel usage

annual fuel usage = (220 boost day/yr *0.943)+ (10 cold start/yr *0.836) + (5 very cold start/yr * 1.610) + (60 emergency/hot start per year *0.339)+ (125 non-boost days/yr * 0.503)

annual fuel usage = 307.07 mmcf/yr = 307 mmcf/yr

Note use 1050 btu/ft3 for determining fuel usage, RECLAIM purpose

The following table list the monthly, yearly and commissions fuel usage, with the appropriate permit conditions

Item	Fuel usage	Units	Permit Condition	Reference
Monthy fuel usage	40	Mmcf/mon	C1.1	Appendix B
Commissioning fuel usage	4.28	Mmcf/month	C1.6	Appendix E
Yearly fuel usage-non commissioning year	307	Mmcf/yr	C1.3	Appendix B
Yearly fuel usage-commissioning year	311	Mmcf/yr	C1.4	Appendix B

3. Commissioning

The applicant is proposing 40 hours of commissioning time as listed below

Hours	Mode	EF	Mmbtu/hr
4	Cold start	SU emissions factors	31.1
4	Warm start	SU emissions factors	31.1
12	Low load	Low load emissions factors	63
12	Med load	High load emissions factors	125
8	High load	High load emissions factors	249

Pollutant	Start-up	Low load	High load	Units	Reference

NOx	0.088	0.011	0.011	Lb/mmbtu	Vendor
VOC	0.0054	0.0054	0.0054	Lb/mmbtu	Vendor
CO	0.146	0.037	0.037	Lb/mmbtu	Vendor
PM10	0.01	0.005	0.005	Lb/mmbtu	Vendor
SOX	0.0021	0.0021	0.0021	Lb/mmbtu	Vendor

Mode	NOx	CO	VOC	SOX	PM10
	Lb/period	Lb/period	Lb/period	Lb/period	Lb/period
SU	21.89	36.32	1.34	0.52	3.78
Low	8.32	27.97	0.0054	4.08	1.59
Med	16.5	55.5	8.1	3.15	7.5
High	21.91	73.7	10.76	4.18	9.96
total	68.62	193.50	0.81	9.44	23.73

Night Preservation Boilers

The auxiliary boilers will be operated under the following assumptions and are the basis for emission calculations

- Natural gas will be the only fuel used by the boilers;
- Boilers will be equipped with ultra-low-NOx (9 parts per million by volume) burners and CO concentration limit of 25 ppmv;
- Normal operation of each boiler will be 14 hours/day at full load
- Annual operation of each boiler will be based on 49.71 mmcf annual fuel usage
- Monthy operation of each boiler will be based on 4.47 mmcf annual fuel usage
- 100 percent of the PM10 emissions are PM2.5

The criteria pollutant emission factors used for the NOx and CO emission estimates are based on ≤ 9

ppmv and ≤ 25 ppmv respectively, each at 3% O2, dry basis. The applicant is proposing to limit the CO concentration to 25 pppmv or less. The PM10 and VOC emission factors are based on AP-42 and vendor performance warranties (0.007451 lb/MMBTU for PM10 and 0.004 lb/MMBTU for VOC, respectively), and the SOx emission factor was base on 0.75 gr/100 cf of gas (0.002101 lb/MMBTU). Boiler criteria pollutant emissions for a single boiler and two boilers are shown in the calculation sheets at the end of this engineering evaluation and summarized in Tables 7 and 8 below, respectively (Note 30-DA means 30-day average emissions).

The boilers are used to keep as much heat as possible in the system during the night.

A. Emissions summary

Pollutant	Emission Factor (lb/MMBTU)	Maximum Hourly (lb/hr)	Maximum Daily (lb/day)	Annual Emissions (lb/yr)	Monthly Emissions (lb/month)	30DA (lb/day)
NOx	0.011109	0.1166	1.633	563.39	50.62	1.69
VOC	0.0040	0.0400	0.588	202.86	18.23	0.61
CO	0.0018	0.1972	2.761	952.59	85.60	2.85
PM10	0.007238	0.0760	1.064	367.08	32.98	1.10
SOx	0.002014	0.0204	0.300	103.50	9.30	0.31

See attachment for calculations details

B. Fuel usage summary

FC = (10,500,000 BTU/hr)(14 hr*100%)(1 scf/1050 BTU)(1 mmcf/1000000 scf) = 0.14 MMCF/DAY
FC = (0.14 MMCF/dy)(31 day/mon) = 4.34 mmcf/mon
FC = (0.14 MMCF/dy)(345 day/yr) = 48.301 mmcf/yr = 48 mmcf/yr

Use 1050 btu/ft3 for RECLAIM purposes

The following table list the monthly, yearly and commissions fuel usage, with the appropriate permit conditions

Item	Fuel usage	Units	Permit Condition	Reference
Monthy fuel usage	4.34	Mmcf/mon	C1.5	Appendix D
Yearly fuel usage	48	Mmcf/yr	C1.7	Appendix D
Commissioning fuel usage	0.11	Mmcf/month	C1.6	Appendix F

C. Commissioning

The applicant is proposing 20 hours of commissioning time as listed below

Hours	Mode	EF	Mmbtu/hr
4	Cold start	Low load emissions factors	2.625
4	Low load	Low load emissions factors	2.625
6	Med load	High load emissions factors	5.25
6	High load	High load emissions factors	10.5

Pollutant	Start-up	Low load	High load	Units	Reference
NOx	0.011	0.011	0.011	Lb/mmbtu	Vendor
VOC	0.0054	0.0054	0.0054	Lb/mmbtu	Vendor
CO	0.018	0.018	0.018	Lb/mmbtu	Vendor
PM10	0.013	0.013	0.013	Lb/mmbtu	Vendor
SOX	0.0021	0.0021	0.0021	Lb/mmbtu	Vendor

Mode	NOx	CO	VOC	SOX	PM10
	Lb/period	Lb/period	Lb/period	Lb/period	Lb/period
total	1.27	2.08	0.62	0.24	1.50

Emergency Fire Water Pump Engines, A/N 549384, 549385 and 549386, each 617 HP

The assumptions made regarding emergency fire pump engine operation are listed below:

- Engines will use ultra-low sulfur (15 parts per million by weight) diesel fuel;
- Engines have Tier 3 Certification;
- Engine emissions are based on 4.2 hours per month testing, not to exceed 50 hours per year, and will be limited to an annual maximum of 200 hr/yr emergency use. The engine will be

limited to 30 min/test in any one hour (CEQA). Note the 200 hr/yr limit is inclusive of the allotted 50 hr/yr for maintenance and testing.

Emission estimates are based on emission factors for EPA Tier 3 certified engines, as determined by the BACT Guidelines for Minor Sources. Emission estimates for SOx are based on estimated fuel use of 34 gallons per hour for each engine with a heating value of 137,000 Btu per gallon and fuel sulfur content of 15 ppm by weight. Fire pump engine criteria pollutant emissions for a single engine per the calculation sheets at the end of this engineering evaluation and summarized in Tables 9, respectively.

Emergency Fire Water Pump Emissions (One Engine)

Pollutant	Emission Factor (gm/bhp-hr)	Hourly (lb/hr)	Annual (lb/yr)	Monthly (lb/month)	30-DA (lb/day)
NOx	2.60	3.533	176.67	14.72	**0.4908**
VOC	0.10	0.136	6.80	0.57	**0.0189**
CO	0.50	0.680	33.98	2.83	**0.0944**
PM10	0.09	0.122	6.12	0.51	**0.0170**
PM2.5	0.09	0.122	6.12	0.51	**0.0170**
SOx		0.0073	0.37	0.03	**0.0010**

Emergency Electrical Generator, A/N 549390, 398 HP (one engine)

The assumptions made regarding emergency electrical generator engine operation are listed below:

- Engine will use ultra-low sulfur (15 parts per million by weight) diesel fuel;
- Engine have Tier 3 Certification, copy in file
- Engine emissions are based on 4.2 hours per month testing, not to exceed 50 hours per year, and will be limited to an annual maximum of 200 hr/yr emergency use. The engine will be limited to 30 min/test in any one hour (CEQA). Note the 200 hr/yr limit is inclusive of the allotted 50 hr/yr for maintenance and testing;

Emission estimates are based on emission factors for EPA Tier 3 certified engines. Emission estimates for SOx are based on estimated fuel use of 20 gallons per hour for each engine and fuel sulfur content of 15 ppm by weight. Emergency electrical generator engine emissions for a single engine are shown in the calculation sheets at the end of the engineering evaluation and summarized in Tables 11.

Emergency Electrical Generator Emission (One Engine)

Pollutant	Emission Factor (gm/bhp-hr)	Hourly (lb/hr)	Annual (lb/yr)	Monthly (lb/month)	30-DA (lb/day)

Emergency Electrical Generator Emission (One Engine)

Pollutant	Emission Factor (gm/bhp-hr)	Hourly (lb/hr)	Annual (lb/yr)	Monthly (lb/month)	30-DA (lb/day)
NOx	2.49	2.183	109.14	9.10	**0.3032**
VOC	0.27	0.237	11.83	0.99	**0.0329**
CO	2.31	2.025	101.25	8.44	**0.2813**
PM10	0.11	0.096	4.82	0.40	**0.0134**
PM2.5	0.11	0.0096	4.82	0.40	**0.0134**
SOx		0.0043	0.22	0.02	**0.0006**

Emergency Electrical Generators, A/N 549387 and 549388, 3633 HP

The assumptions made regarding emergency electrical generator engine operation are listed below:

- Engines will use ultra-low sulfur (15 parts per million by weight) diesel fuel;
- Engines have Tier II certification, copy in file
- Engine emissions are based on 4.2 hours per month testing, not to exceed 50 hours per year, and will be limited to an annual maximum of 200 hr/yr emergency use. The engine will be limited to 30 min/test in any one hour (CEQA). Note the 200 hr/yr limit is inclusive of the allotted 50 hr/yr for maintenance and testing;

Emission estimates are based on emission factors for EPA Tier II certified engines. Emission estimates for SOx are based on estimated fuel use of 179.2 gallons per hour for each engine and fuel sulfur content of 15 ppm by weight. Emergency electrical generator engine emissions for a single engine and two engines are shown in the calculation sheets at the end of the engineering evaluation and summarized in Tables 11.

Emergency Electrical Generator Emissions (One Engine)

Pollutant	Emission Factor (gm/bhp-hr)	Hourly (lb/hr)	Annual (lb/yr)	Monthly (lb/month)	30-DA (lb/day)
NOx	3.70	29.608	1,480.41	123.37	**4.1122**
VOC	0.25	2.001	100.03	8.34	**0.2779**
CO	0.89	7.122	356.10	29.67	**0.9892**
PM10	0.09	0.716	35.81	2.98	**0.0995**
PM2.5	3.70	0.716	35.81	2.98	**0.0995**
SOx		0.0305	1.53	0.13	**0.0042**

Selective Catalytic Reduction/CO Catalyst Systems (A/Ns 553874 and 553875)

The table below shows the specifications for the SCR manufacturer to be used for the Auxiliary boilers.

Table - Selective Catalytic Reduction

Catalyst Properties	Specifications
Manufacturer	Cormetech, Inc
Catalyst Description	Ti V honeycomb single layer structure
Catalyst Model No.	custom
Catalyst Volume	90 ft^3
Guaranteed Life	3 years from contracted delivery.
Space Velocity	34,300 hr^{-1}
Ammonia Injection Rate	1 lb/hr starts at exhaust temp of 550 F (density = 7.48 lb/gal)
Ammonia slip	5 ppmv
NOx removal efficiency	>90%
NOx at stack outlet	5 ppmv at 3% O_2
Exhaust Temperature	550-750°F
Pressure drop	4.5 inches water column
Depth	1'-6"
Width	8-10"
Height	6'-9"

The SCR catalyst will use ammonia injection in the presence of the catalyst to reduce NOx. Diluted ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst module. The subsequent chemical reaction will reduce NOx to elemental nitrogen (N_2) and water, resulting in NOx concentrations in the exhaust gas at no greater than 5 ppmvd at 3% O_2 on a 15 min average. The basis of the SCR system control will employ a PLC commissioned with a proportional feed forward curve (mapping), correlating fuel flow/firing rate to outlet NOx concentration. The firing rate signal will be sent from the boiler Combustion Control system to the SCR PLC. The PLC will then integrate this signal, and thus output a proportional signal to regulate the correct amount of ammonia to be injected into the SCR for NOx control. A Rule 2012 NOx CEMs will be installed at the outlet exhaust of the SCR, but will not be tied into the feed forward system.

Ammonia Slip

item		
Ammonia slip	5	ppmv
Lb/hr	0.68	Lb/hr
Lb/mon	128	Lb/mon
Lb/yr	894	Lb/yr

See appendix L for calculations

CO Oxidation Catalyst

The CO oxidation catalyst will be installed within the catalyst housing which will reduce CO in the exhaust gas to no greater than 25 ppmvd at 3% O_2, on a 15 minute average. The exhaust from each catalyst housing will be discharged from individual 120-foot tall, 6 foot diameter exhaust stacks. Each Auxiliary boiler will have its own individual stack.

The following table lists the specifications for the CO catalyst.

Table - CO Oxidation Catalyst

Catalyst Properties	Specifications
Manufacturer	Emerachem
Model	ADCAT
Catalyst Type	Pt on metal substrate
Catalyst Life	3 years
Volume	10 ft^3
CO removal efficiency	90%
CO at stack outlet	25 ppmvd at 3% O_2
Max inlet temperature	1150 F
Pressure drop	1 inche water column
Depth	2″
Width	8″-10″
Height	6″-9″

Aqueous Ammonia Storage

The applicant will use aqueous ammonia with a concentration of 19 percent by wt. The aqueous ammonia will be stored in 300 gallon portable totes and one tote will be used per boiler. The applicant estimated less than 9 totes will be used per year per boiler. The applicant estimates one tote will be delivered per boiler once every 45 days. Each tote is less than 500 gallons capacity and is Rule 219 (m)(16) exempt from SCAQMD permit.

FACILITY EMISSONS SUMMARIES

Facility 30 day average Emissions Summary

Equipment	Device no.	NOx	VOC	CO	SOx	PM10
Large boiler 1	D1	21.08	5.78	48.36	2.83	7.14
Large boiler 2	D6	21.08	5.78	48.36	2.83	7.14
small boiler 1	D11	1.69	0.61	2.85	0.31	1.10
small boiler 2	D12	1.69	0.61	2.85	0.31	1.10
Large ICE 1	D13	4.11	0.28	0.99	0.00	0.10
Large ICE 2	D15	4.11	0.28	0.99	0.00	0.10
Small ICE	D17	0.30	0.03	0.28	0.00	0.01
Large fire pump 1	D19	0.49	0.02	0.09	0.00	0.02
Large fire pump 2	D20	0.49	0.02	0.09	0.00	0.02
Large fire pump 3	D21	0.49	0.02	0.09	0.00	0.02
totals		**55.53**	**13.42**	**104.97**	**6.48**	**17.22**

Facility Monthly Emissions Summary

Equipment	Device no.	NOx	VOC	CO	SOx	PM10
Large boiler 1	D1	632.33	173.37	1450.87	84.91	214.15
Large boiler 2	D6	632.33	173.37	1450.87	84.91	214.15

small boiler 1	D11	50.62	18.23	85.60	9.30	32.98
small boiler 2	D12	50.62	18.23	85.60	9.30	32.98
Large ICE 1	D13	123.37	100.03	356.10	0.13	2.98
Large ICE 2	D15	123.37	100.03	356.10	0.13	2.98
Small ICE	D17	9.10	0.99	8.44	0.02	0.40
Large fire pump 1	D19	14.72	0.57	2.83	0.03	0.51
Large fire pump 2	D20	14.72	0.57	2.83	0.03	0.51
Large fire pump 3	D21	14.72	0.57	2.83	0.03	0.51
Totals lb/mon		1666	586	3802	189	502
ton/mon		0.83	0.29	1.90	0.09	0.25

Facility Annual Emissions Summary

Equipment	Device no.	NOx	VOC	CO	SOx	PM10
Large boiler 1	D1	5645.04	1358.78	12566.74	658.17	1683.93
Large boiler 2	D6	5645.04	1358.78	12566.74	658.17	1683.93
small boiler 1	D11	563.39	202.86	952.59	103.50	367.08
small boiler 2	D12	563.39	202.86	952.59	103.50	367.08
Large ICE 1	D13	1480.41	6.80	356.10	1.53	35.81
Large ICE 2	D15	1480.41	6.80	356.10	1.53	35.81
Small ICE	D17	109.14	11.83	101.25	0.22	4.82
Large fire pump 1	D19	176.67	6.80	33.98	0.37	6.12
Large fire pump 2	D20	176.67	6.80	33.98	0.37	6.12
Large fire pump 3	D21	176.67	6.80	33.98	0.37	6.12
Totals lb/yr		16,017	3169	27,954	1528	4197
ton/yr		8.01	1.58	13.98	0.76	2.10

RULES EVALUATION

RULE 212-STANDARDS FOR APPROVING PERMITS AND ISSUING PUBLIC NOTICES

Rule 212 requires that a person shall not build, erect, install, alter, or replace any equipment, the use of which may cause the issuance of air contaminants or the use of which may eliminate, reduce, or control the issuance of air contaminants without first obtaining written authorization for such construction from the Executive Officer. Rule 212(c) states that a project requires written notification if there is an emission increase for ANY criteria pollutant in excess of the daily maximums specified in Rule 212(g), if the equipment is located within 1,000 feet of the outer boundary of a school, or if the MICR is equal to or greater than one in a million ($1x10^6$) during a lifetime (70 years) for facilities with more than one permitted unit, source under Regulation XX, or equipment under Regulation XXX, unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million

($10x10^6$) using the risk assessment procedures and toxic air contaminants specified under Rule 1402; or, ten in a million ($10x10^6$) during a lifetime (70 years) for facilities with a single permitted unit, source under Regulation XX, or equipment under Regulation XXX.

FACILITY / EQUIPMENT AND SCHOOL LOCATIONS

The closest kindergarten to grade 12 school is not located within 1,000 feet as stated by the applicant and as determined by Greatschools (http://www.greatschools.org). The following table summarizes the name, location and proximity of nearby schools. A public notice will not be required per section (c)(1).

K-12 Schools Near Facility

Name of School	Address	Distance in miles
Eagle Mountain Elementary	1434 Kaiser Road, Desert Center	2

DAILY EMISSIONS

As shown in table below, the daily emissions from this project does exceed the daily thresholds of Rule 212(g) for NOx; therefore, the project does triggers a public notice for section (c)(2). Rule Implementation Guidance, Rule 212, dated 12/19/2006 section 2 (b)(1) allows the use of the 30 –day average to determine emissions thresholds. There will be permit conditions for each equipment limiting the monthly emissions.

Daily Emissions

Pollutant	Project	R212(g) Daily Threshold	Public Notice triggered ?
NOx	**56**	40	Yes
SOx	6	60	No
PM10	17	30	No
CO	105	220	No
VOC	13	30	No

MAXIMUM INDIVIDUAL CANCER RISK (MICR)

The MICR for each permit unit is less than $1x10^6$, as shown in the discussion under the Regulation XIV section; therefore, a public notice is not required for section (c)(3). The total MICR for the facility is 1.28E-06.

RULE 218 – CONTINUOUS EMISSION MONITORING

The Auxiliary boiler will be required to have CEMS to monitor NOx to verify compliance the Rule 1146 NOx 5 ppm concentration limits and to monitor CO to verify compliance with the 25 ppm concentration limit. A permit condition will require a NOx and CO CEMs to be installed.

RULE 219 – EQUIPMENT NOT REQUIRING A WRITTEN PERMIT PURSUANT TO REGULATION II

PSGS will be installing a wet cooling tower with the project which is exempt from SCAQMD permit per section (d)(3). The applicant will be using 300 gallon totes to store the aqueous ammonia. The totes are exempt from permit per section (m)(16). Therefore, an application for this equipment is not required.

WET COOLING TOWER – RULE 219(d)(3) EXEMPT

The excess heat from the steam turbine unit will be handled with a new wet surface condenser (cooling tower), which will be rated at 4,000 gallons per minute (gpm), with potable water as make-up, and will consist of four cells. The drift factor for the cooling tower will be 0.0005%. The specifications for the cooling tower and the data used to determine the PM10 emissions and toxic emissions for the maximum individual cancer risk (MICR) as well as the calculations are shown below:

Parameter	Value
Manufacturer	TBD
Circulation Rate	4,000 gpm
Hr/dy	12
Hr/yr	4000
Drift Eliminator Efficiency	0.0005 %
Cooling Tower Air Exit Velocity	70.44 m/sec
Cooling Tower Hot Water Temperature	Ambient + 5 degrees K
Number of Cells	4
Cooling stack Diameter	2.69 m
Cooling tower release ht	3.66 m
Maximum total dissolved solids (TDS)	1500 mg/l
Drift rate	10 lb/hr

Cooling Tower PM10 Emissions

PM10 (lbs/day) = circulation rate (gpm) x drift%/100 x density (lb/gal) x [TDS (ppmw)/1E+06] x 720 min/day

= 4000 gal/min * (0.0005/100) * 8.34 lb/gal * (1500/1E+06)* 720 min/dy

= **0.18**

PM10 lb/yr = pm10 lb/dy * hr/yr

= 0.18 lb/dy * 1 dy/ 12 hr * 4000 hr/yr

= 60 lb/yr or 0.3 ton/yr

Cooling Tower Toxic Air Contaminant (TAC) Emissions

Pollutant	Conc. in Water[(a)] (ppm)	Drift[(b)] (gpm)	Emissions[(c)] (lb/hr)	Emissions[(d)] (lb/yr)
Copper	0.01	0.02	1.0E-07	4.0E-04
Beryllium	0.0025	0.02	2.5E-08	1.0E-04

(a) PSGS water quality report.
(b) Drift (gpm) = 4,000 gpm x 0.0005/100 = 0.02 gpm (0.02 gal/min * 60 min/hr * 8.33 lb/gal = 10 lb/hr)
(c) Inorganic compounds calculated on drift only (lb/hr) = Drift (gpm) x 8.34 lb/gal x concentration (ppb)/1E06 x 60 min/hr
(d) Emissions (lb/yr) = Emissions (lb/hr) x 4000 hrs/yr

The cooling tower TAC emissions were used for the Health Risk Assessment (HRA) to determine the MICR and Rule 219 applicability of the cooling tower. The applicant performed a Tier 4 HRA and was reviewed by SCAQMD modeling staff, see results below

HRA Results (wet surface condenser-cooling tower no. 1)

Parameter	MICR
Maximum	7.24EE-13
Risk Threshold w/T-BACT	10EE-6
Comply (Yes/No)	Yes

Parameter	value
Acute	2.57EE-5
Chronic	1.81EE-9
Comply (Yes/No)	Yes

HRA Results (wet surface condenser-cooling tower no. 2)

Parameter	MICR
Maximum	2.82EE-12
Risk Threshold w/T-BACT	10EE-6
Comply (Yes/No)	Yes

Parameter	value
Acute	5.36EE-9
Chronic	1.65EE-7
Comply (Yes/No)	Yes

Tier 4 modeling was done for each cooling tower, the MICRs are different because of the location on the facility

Because MICR is less than the Rule 1401 significance threshold of 1 in a million, the wet surface condenser (cooling tower) is exempt per Rule 219(d)(3).

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. The applicant will use equipment configured with BACT and will be burning natural gas in the boilers Therefore, during normal operation, no visible emissions are expected. The emergency engines complies with BACT and will be using a ultra low sulfur fuel, visible emissions not expected during normal operations. Compliance with this rule is expected.

RULE 402 - Nuisance

A person must 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 endanger the comfort, repose, health or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property. Due to the application of BACT on each emission source and the distance from the emission sources to any potential receptors, the Project will comply with this rule.

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. Such measures include covering loose material on haul vehicles, watering, and using chemical stabilizers when necessary. The facility falls under Large Operations per (c)(21) and will have to file a notification form per

section (e)(1)(A). The CEC will add Air Quality Conditions of Certification AQ-SC3 and AQ-SC4 to address Fugitive dust issues, see PSA dated 6/28/2013

RULE 403.1 - Supplemental Fugitive Dust Control requirements for Coachella Valley sources
The provisions of this rule are supplemental to Rule 403 requirements and shall apply only to fugitive dust sources in the Coachella Valley. The facility is located in the Chuckwalla Valley and thus not subject to the provisions of this regulation

RULE 407 – LIQUID AND GASEOUS AIR CONTAMINANTS
This rule limits CO emissions to 2,000 ppmvd and SO_2 emissions to 500 ppmvd, averaged over 15 minutes. For CO, the natural gas fired boilers the applicant proposes limit of 25 ppmvd @ 15% O_2, for all four boiler boilers. The boilers will be conditioned as such and will be required to verify compliance testing per Rule 1146 and Rule 1303 (a)-BACT. For SO_2, equipment which complies with Rule 431.1 is exempt from the SO_2 limit in Rule 407. The applicant will be required to comply with Rule 431.1 and thus the SO_2 limit in Rule 407 will not apply. Per section (b)(2) the emergency engines are not subject to this Rule.

RULE 409 – COMBUSTION CONTAMINANTS
This rule restricts the discharge of contaminants from the combustion of fuel to 0.1 grain per cubic foot of gas, calculated to 12% CO_2, averaged over 15 minutes. The equipment is expected to meet this limit based on the calculations shown in table 19.

Auxiliary Boiler

	Parameter	Unit	Value	Reference
a	Volumetric Flow Rate, wet	acfm	84965	Vendor Data
b	Exhaust Temperature	°F	420	Vendor Data
d	CO2 Content	%	8.38	Vendor Data
e	PM Emission Rate	lb/hr	1.245;	Vendor Guarantee
f	Exhaust Rate	scf/hr	3,012,395	a x [(460+60)/(460+420)] x 60
g	Grain Loading	**0.004**	gr/dscf	e x 7000 x 12/ (d x f)

Night Preservation Boiler

	Parameter	Unit	Value	Reference
a	Volumetric Flow Rate, wet	acfm	38498	Vendor Data
b	Exhaust Temperature	°F	478	Vendor Data
d	CO2 Content	%	9.2	Vendor Data
e	PM Emission Rate	lb/hr	0.147	Vendor Data
f	Exhaust Rate	scf/hr	128,026	a x [(460+60)/(460+478)] x 60
g	Grain Loading	**0.01**	gr/dscf	e x 7000 x 12/ (d x f)

As shown in above tables, the grain loading is less than the 0.1 gr/dscf required by Rule 409. The emergency engines are not subject to this Rule.

RULE 431.1 - Sulfur Content of Gaseous Fuels

The boilers will use pipeline quality natural gas which will comply with the 16 ppm sulfur limit, calculated as H2S, specified in this rule. Natural gas will be supplied by the Southern California Gas Company. The facility proposed an H2S content of 0.75 gr/100scf, which is equivalent to a concentration of about 12 ppm. It is also much less than the 1 gr/100scf limit typical of pipeline quality natural gas. Compliance is expected. The applicant will comply with the reporting and record keeping requirements as outlined in subdivision (e) of this Rule.

Rule 431.2 – Sulfur Content of Liquid Fuels

Any fuel oil combusted in the emergency engines must comply with the rule limit of 15 ppm sulfur. The emergency engines are required to use a low sulfur oil in the units which complies with the sulfur limits of this rule. The boilers are not using any stand-by fuel, thus are not subject to this Rule.

RULE 474 - Fuel Burning Equipment-Oxides of Nitrogen

A person is not allowed to discharge into the atmosphere from any non-mobile fuel burning equipment NOx in excess of the concentrations specified in the rule. The boilers are not subject to sections (a) or (b).

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 the boiler are estimated at 1.245 lbs/hr, and 0.0034 gr/scf during natural gas firing at maximum firing load (see calculations below). Therefore, compliance is expected.

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

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, 249 MMBtu/hr

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

Stack flow = 8710*(20.9/17.9)*249 = 2.53 mmscf/hr

Combustion particulate = (1.245/2.53E+06)*7000 = 0.0034 gr/scf

Rule 1110.2 - Emissions from Gaseous and Liquid-Fueled Internal Combustion Engines

The purpose of Rule 1110.2 is to reduce NOx, VOC, and CO from internal combustion engines. The diesel emergency engines proposed for this Project are low-usage engines which will each operate less than 200 hours per year and which will be used for firefighting and emergency electrical generation purposes only, and are therefore exempt from the requirements of this rule per section

(i)(2). Elapsed operating time meters will be installed and maintained on each engine to substantiate compliance.

Rule 1146—Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

The purpose of this rule is to limit NOx emissions from boilers, steam generators, and process heaters of greater than 5 MMBtu per hour rated input capacity used in industrial, institutional, and commercial operations with several listed exceptions. The rule specifies NOx limits and CO compliance plans for boilers, steam generators, and process heaters by size process function. The boilers will burn natural gas exclusively and will comply with CO BACT (applicant proposes 25 ppmv for each boiler) which is less than the 400 ppm CO limits in this rule. The applicant is proposing 5 ppmv NOx for the auxiliary boilers and 9 ppmv NOx for the NTP boilers, The applicant proposes to opt-in to RECLAIM. Compliance is expected.

Section (c)(4)—The CO limit is 400 ppmv, corrected to 3% O_2. The two Type I boilers the applicant proposes to limit the CO emissions to 25 ppmv, for all four boilers, see attached burner specification sheet.

Section (c)(6)—The two Type I boilers btu rating is greater than 40 mmbtu/hr. If the heat imput exceeds 200x109 btu per year, then the boilers have to be equipped with a oxides of nitrogen CEMs. The boilers will be subject to RECLAIM CEMs requirements

Section (c)(9)—This paragraph sets forth the requirements for the Rule 1146 compliance plan application. Not applicable.

Section (d)(3)—All parts per million emission limits specified in subdivision (c) are referenced at 3 percent volume stack gas oxygen on a dry basis averaged over a period of 15 consecutive minutes. Te initial source test requires the sampling times to be at least 15 consecutive minutes for maximum and minimum loads. BACT requires 1 hr for normal load.

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

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

Does not apply, the boilers are subject to the RECLAIM and BACT testing requirements.

Section (d)(8)—Any owner or operator of units subject to this rule shall check NOx emissions with a portable NOx, CO and oxygen analyzer according to the Protocol for the

Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Units Subject to South Coast Air Quality Management District Rules 1146 and 1146.1 according to the following schedule:

(A) On or after July 1, 2009, the owner or operator of units subject to paragraph (c)(1) shall check NOx emissions at least monthly or every 750 unit operating hours, whichever occurs later.

Does not apply for NOx monitoring

Section (d)(9)—An owner or operator shall opt to comply with the requirements as applied to CO emissions specified in paragraph (d)(8) or subparagraph:

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

Permit condition requires compliance with Rule 1146. The facility may opt to perform testing with a portable analyzer pursuant to Rule 1146(d)(8), or perform source testing pursuant to (d)(6)(A). Since the applicant is choosing a CO concentration limit of 25 ppmv all four boilers require the same periodic monitoring requirements as NOx monitoring of Rule 1146 section (d)(8).

Reg 13 NEW SOURCE REVIEW (NSR) ANALYSIS

This regulation sets forth pre-construction review requirements for new, modified, or relocated facilities to ensure that the operation of such facilities does not interfere with progress in attainment of the National Ambient Air Quality Standards (NAAQS), and that future economic growth within the District is not unnecessarily restricted. The specific air quality goal of this regulation is to achieve no net increases from new or modified permitted sources of nonattainment air contaminants or their precursors. In addition to nonattainment air contaminants, this regulation also limits emission increases of ammonia and ozone depleting compounds from new, modified or relocated facilities by requiring the use of BACT on each permit unit.

Rule 1303 (b)(1) BACT

The Executive Officer shall deny the Permit to Construct for any new source which results in an emission increase of any non-attainment air contaminant, any ozone depleting compound, or ammonia unless the applicant can demonstrate that BACT is employed for the new source. PSEGS is a new source with a potential for an increase in emissions and therefore, BACT is required. Below is an analysis of the BACT requirements for the major components of the PSEGS. (Note for attainment contaminants, CO and NOx BACT is addressed under Regulation XX and XVII section).

Auxiliary Boiler, 249 MMBTU/hr

Pollutant	Minor Source	Proposed	Comply (Yes/No)
VOC	None	None	Yes
PM10	Natural Gas	Natural gas fired	Yes
SOx	Natural Gas	Natural gas fired	Yes
Ammonia	5 ppmv	5 ppmv	yes

NTP Boiler, 10.5 MMBTU/hr

Pollutant	Minor Source	Proposed	Comply (Yes/No)
VOC	None	None	Yes
PM10	Natural Gas	Natural gas fired	Yes
SOx	Natural Gas	Natural gas fired	Yes

Large Emergency ICE, 3633 bhp (>750 HP)

Pollutant	Minor Source (Tier 2)	Proposed BACT (Tier 3)	Comply (Yes/No)
PM10	0.15 gm/bhp-hr	0.09 gm/bhp-hr	Yes
SOx	Fuel with sulfur content less than or equal to 15 ppm by weight	Fuel with sulfur content less than or equal to 15 ppm by weight	Yes

Emergency Fire Pump, 617 bhp (600≤ bhp < 750)

Pollutant	Minor Source (Tier 3)	Proposed BACT (Tier 3)	Comply (Yes/No)
PM10	0.15 gm/bhp-hr	0.09 gm/bhp-hr	Yes
SOx	Fuel with sulfur content less than or equal to 15 ppm by weight	Fuel with sulfur content less than or equal to 15 ppm by weight	Yes

Small Emergency ICE, 398 bhp (300≤ bhp < 600)

Pollutant	Minor Source (Tier 3)	Proposed BACT (Tier 2)	Comply (Yes/No)
PM10	0.15 gm/bhp-hr	0.11 gm/bhp-hr	Yes
SOx	Fuel with sulfur content less than or equal to 15 ppm by weight	Fuel with sulfur content less than or equal to 15 ppm by weight	Yes

Based on the above tables, the equipment will comply with the current minor source BACT requirements.

Rule 1303 (b)(2) -Offsets

The emissions from the proposed equipment are shown in the Table below:

Facility Exemption Thresholds

Pollutant	Facility PTE 30 day ave	Facility PTE (TPY)	Exemption Thresholds (TPY)	Title V thresholds
Nitrogen Oxides (NOx)	55.53	8.01	4	25
Volatile Organic Compounds (VOC)	13.42	1.58	4	25
Sulfur Oxides (SOx)	6.29	0.76	28	100
Particulate Matter < 10 microns (PM10)	16.74	2.10	4	70
Carbon Monoxide (CO)	104.97	13.98	29	100

As indicated in the above, NOx emissions are greater than the 4 ton per year exemption thresholds shown in the table above. Therefore, the NOx emissions are required to be offset in accordance with Rule 1303(b)(2). The applicant submitted a written request on 7/12/13 to opt-in the NOx RECLAIM program, thus NOx ERC's are not required. The VOC, SOx and PM10 emissions has a Facility Exemption from Rule 1303 (b)(2) per Rule 1304 (d)(1)(A).

In addition, note that the non-RECLAIM pollutants for the emergency internal combustion engines are exempt from offsets under SCAQMD Rule 1304(a)(4). Compliance is expected.

The facility is not subject to Title V based on annual emissions because this project is located in the Mojave Desert Air Basin (MDAB) and the major source thresholds for VOC NOx, SOx, CO and PM10, thus the facility is not a Major Source based on criteria emissions.

Rule 1303 (b)(1) Modeling

The applicant must substantiate with modeling that the new facility or modification will not cause a violation, or make significantly worse an existing violation according to Appendix A of Rule 1303, or other analysis approved by the Executive Officer or designee, of any state or national ambient air quality standards at any receptor location in the District. If the emission from the individual permit units are greater than the amounts in the table below, then modeling is required. (Note that the emissions listed in the table below are for a single night preservation boiler rated at 10.5 MMBTU/hr. The emergency IC engines are exempt from modeling under SCAQMD Rule 1304(a)(4) because they operate less than 200 hours/year

A. Night Preservation Boilers

Rule 1303 (a) Table A-1, Screening Analysis

Night Preservation Boiler, 10.5 MMBTU/hr

Pollutant	Emissions lb/hr	Screening Modeling Thresholds lb/hr	Comply (Yes/No)
NOx	0.1166	0.86	Yes
CO	0.1972	47.3	Yes
PM10	0.0760	5.2	Yes

The emissions from the night preservation boilers are below the screening levels listed in the Table above. Therefore, no additional modeling is required for the night preservation boilers. Compliance with this Rule is met.

B. Auxiliary Boilers

The auxiliary boilers exceed the btu range in Rule 1303 (a) Table A-1, Screening Analysis, thus are subject to Table A-2. PSEGS provided modeling evaluations using the AERMOD dispersion model, version 12345 and five years of meteorological data from 2002 through to 2006 from the Blythe Airport and upper air sounding data collected from Tucson. SCAQMD Modeling staff provided their comments in a memorandum from Mrs. Elaine Change to Mr. Andrew Lee dated August 21, 2013. A copy of this memorandum is contained in the project file. Staff's review of the modeling analysis concluded that the applicant used appropriate EPA AERMOD model along with the appropriate model options in the analysis. The memorandum states that the modeling as performed by the applicant conforms to the District's dispersion modeling requirements and no significant deficiencies in methodology were noted. Therefore compliance with modeling requirements is expected.

Table

Air Quality Impact Summary for Auxiliary Boiler #1 Normal Operating Conditions							
Pollutant	Avg. Period	Modeled Concentration ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	SIL ($\mu g/m^3$)	CAAQS/NAAQS	
						($\mu g/m^3$)	($\mu g/m^3$)
NO_2	1-hr CAAQS	4.3	124.3	128.6	-	339	-
	1-hr NAAQS	1.7	97.8	99.5	7.5	-	188
	Annual	0.006	22.6	22.61	1	57	100
PM_{10}	24-hr	0.169	144.8	144.96	5	50	150
	Annual	0.003	32.7	32.7	1	20	-
CO	1- hr	7.041	3543	3550.04	2000	23,000	40,000
	8- hr	1.618	2000	2001.6	500	10,000	10,000
SO_2	1- hr	1.17	28.6	29.8	7.8	655	196
	3- hr	0.48	28.6	29.1	25	-	1,300
	24- hr	0.101	13.1	13.2	5	105	-

Air Quality Impact Summary for Auxiliary Boiler #2 Normal Operating Conditions							
Pollutant	Avg. Period	Modeled Concentration ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	SIL ($\mu g/m^3$)	CAAQS/NAAQS	
						($\mu g/m^3$)	($\mu g/m^3$)
NO_2	1-hr CAAQS	3.7	124.3	128.0	-	339	-
	1-hr NAAQS	1.4	97.8	99.2	7.5	-	188
	Annual	0.011	22.6	22.61	1	57	100
PM_{10}	24-hr	0.234	144.8*	145.03	5	50	150
	Annual	0.005	32.7	32.71	1	20	-
$PM_{2.5}$	24- hr	0.096	15.7	15.8	1.2	-	35
	Annual	0.005	7.8	7.81	0.3	12	15.0
CO	1- hr	5.986	3543	3549.0	2000	23,000	40,000
	8- hr	2.046	2000	2002.0	500	10,000	10,000
SO_2	1- hr	0.998	28.6	29.6	7.8	655	196
	3- hr	0.45	28.6	29.1	25	-	1,300
	24- hr	0.139	13.1	13.2	5	105	-

The two auxiliary boilers complies with the limits listed in Table A-2, thus compliance with this Rule is met.

RULE 1303(b)(3) – SENSITIVE ZONE REQUIREMENTS

Does not apply

RULE 1303(b)(4) – FACILITY COMPLIANCE

PSEGS is a new facility and is expected to comply with the Rules and Regulations of the District

RULE 1303(b)(5) – ADDITIONAL REQUIREMENTS

Does not apply, PSEGS is not a Major Stationary Source as defined per Rule 1302 (s), the facility emissions for each pollutant are less than 10 tons per year (facility is located in the Mojave Desert Air Basin (MDAB) and the Major Source threshold is 100 tons per year)

RULE 1313(g)– Emission Limitation Permit Conditions

Every permit shall have the following conditions:

(1) Identified BACT conditions;
(2) Monthly maximum emissions from the permitted source.

A. Boilers

Permit conditions limiting maximum fuel usage (install fuel meters) and list emissions limits (excluding NOx)

NOx and CO concentrations limits will be listed in the Emissions & Requirements of the Facility Permit

B. Emergency engines

Permit conditions limiting maximum hours per month for testing and require time meters to be installed.

NOx, VOC, PM and CO g/bhp-hr limits will be listed in the Emissions & Requirements of the Facility Permit

RULE 1325 – FEDERAL PM2.5 NEW SOURCE REVIEW PROGRAM

This rule applies to any new major polluting facility, major modifications to a major polluting facility, and any modification to an existing facility that would constitute a major polluting facility in and of itself; located in areas federally designated pursuant to Title 40 of the Code of Federal Regulations (40 CFR) 81.305 as non-attainment for PM2.5. The proposed facility is not a major source and is not subject to this Rule.

Pollutant	Ton/yr PTE	Triggers Rule 1325?
NOx	8	**No**
PM2.5	2.10	**No**
SOx	1.84	**No**

The above table summarizes the facility's NOx, PM2.5, and SOx emissions. The facility is not a Major Polluting Facility for PM2.5, PM10 or SOx; therefore, this project does not trigger the requirements of Rule 1325.

Rule 1401 – New Source Review of Toxic Air Contaminants

This rule specifies limits for maximum individual cancer risk (MICR), acute hazard index (HIA), chronic hazard index (HIC) and cancer burden (CB) from new permit units, relocations, or modifications to existing permits which emit toxic air contaminants. These requirements are summarized in the Table as follows:

Rule 1401 Requirements

Parameters and Specifications	Rule 1401 Requirements
MICR, without T-BACT	≤ 1EE-6
MICR, with T-BACT	≤ 1EE-5
Acute Hazard Index	≤ 1.0
Chronic Hazard Index	≤ 1.0
Cancer Burden	≤ 0.5

The applicant originally performed a Tier 4 health risk assessment using the Hot Spots Analysis and Reporting Program (HARP, version 1.4f). The analysis included an estimate of the MICR for the nearest residential and commercial receptors, as well as the acute and chronic hazard indices. SCAQMD modeling staff reviewed and concluded that applicant's modeling analysis was consistent with SCAQMD HRA procedures. (see modeling approval memo dated 8/21/2013, copy in file, see Appendix M) the Tier 4 health risk assessment and the results are shown in the tables below (see attachment for TAC emissions calculations)

HRA Results (Auxiliary boiler No. 1)

Parameter	MICR
Maximum	1.81EE-9
Risk Threshold w/T-BACT	10EE-6
Comply (Yes/No)	Yes

Parameter	value
Acute	2.57EE-5
Chronic	7.53EE-7
Comply (Yes/No)	Yes

HRA Results (Auxiliary boiler No. 2)

Parameter	MICR
Maximum	3.76EE-9
Risk Threshold w/T-BACT	10EE-6
Comply (Yes/No)	Yes

Parameter	value
Acute	4.49EE-5
Chronic	1.563EE-6
Comply (Yes/No)	Yes

HRA Results (Night Preservation boiler No. 1)

Parameter	MICR
Maximum	8.41E-10
Risk Threshold w/T-BACT	10E-6
Comply (Yes/No)	Yes

Parameter	value
Acute	8.62E-6
Chronic	1.16E-6

Comply (Yes/No)	Yes

HRA Results (Night Preservation boiler No. 2)

Parameter	MICR
Maximum	1.18E-09
Risk Threshold w/T-BACT	10E-6
Comply (Yes/No)	Yes

Parameter	value
Acute	4.0.62E-6
Chronic	1.62E-6
Comply (Yes/No)	Yes

The emergency engines are exempt from Rule 1401 per section (g)(1)(F). The MICR was determined for informational purposes

HRA Results (Large emergency ICE No. 1)

Parameter	MICR
Maximum	1.35E-07
Risk Threshold w/T-BACT	10E-6
Comply (Yes/No)	Yes

Parameter	value
Acute	n/a
Chronic	n/a
Comply (Yes/No)	Yes

HRA Results (Large emergency ICE No. 2)

Parameter	MICR
Maximum	6.0E-07
Risk Threshold w/T-BACT	10E-6
Comply (Yes/No)	Yes

Parameter	value
Acute	n/a
Chronic	n/a
Comply (Yes/No)	Yes

HRA Results (Small emergency ICE)

Parameter	MICR
Maximum	4.33E-07
Risk Threshold w/T-BACT	10E-6
Comply (Yes/No)	Yes

Parameter	value
Acute	n/a
Chronic	n/a
Comply (Yes/No)	Yes

HRA Results (Large emergency fire pump no. 1)

Parameter	MICR
Maximum	1.39E-08
Risk Threshold w/T-BACT	10E-6
Comply (Yes/No)	Yes

Parameter	value

Acute	n/a
Chronic	n/a
Comply (Yes/No)	Yes

HRA Results (Large emergency fire pump no. 2)

Parameter	MICR
Maximum	3.90E-08
Risk Threshold w/T-BACT	10E-6
Comply (Yes/No)	Yes

Parameter	value
Acute	n/a
Chronic	n/a
Comply (Yes/No)	Yes

HRA Results (Large emergency fire pump no. 3)

Parameter	MICR
Maximum	6.81E-07
Risk Threshold w/T-BACT	10E-6
Comply (Yes/No)	Yes

Parameter	value
Acute	n/a
Chronic	n/a

RULE 1401.1 – REQUIREMENTS FOR NEW AND RELOCATED FACILITIES NEAR SCHOOLS

The purpose of this rule is to provide additional health protection to children at schools or schools under construction from new or relocated facilities emitting toxic air contaminants. This rule applies to new and relocated, but not to existing facilities. Applications for Permit to Construct/Operate from such new or relocated facilities shall be evaluated under this rule using the list of toxic air contaminants in the version of Rule 1401 that is in effect at the time the application is deemed complete. The proposed facility is not located within 1000 feet of any school; therefore, the requirements of this rule are not applicable

Rule 1470-Requirements for Stationary Diesel-Fueled Internal Combustion and Other CI Engines

PAR 1470 was amended by the AQMD's Governing Board on May 4, 2012.

1470 (b)(47)-New CI engine installed after 2005.

1470 (b)(57)-The engines are not located within 1000 feet of a school (K-12)

1470 (b)(60)- Each engine is not located within 50 meters of a sensitive receptor

1470 (c)(1)-Requires ultra low sulfur be used in this equipment 1/2006, but Rule 431.2 requires the use of this fuel at this time.

1470 (c)(2)(A)-Does not apply, engine not located within 1000 feet of a school

1470 (c)(2)(C)(i)-Limit the testing to no more than 50 hours per year.

1470 (c)(2)(C)(v)-The engine is beyond 1000 feet of any school, thus this section does not apply.

1470 (c)(2)(C)(vi)- Limits the PM emissions to less than 0.15 g/bhp-hr. (does not apply to fire pumps

Item	PM	PM limit	Compliance
	G/bhp-hr	G/bhp-hr	
a/n 549387	0.09	0.15	Yes
a/n 549389	0.09	0.15	Yes
a/n 549390	0.11	0.15	yes

1470 (c)(2)(C)(vii) (Table 2)-The equipment does comply,

Item	HP	NOx +VOC	CO
		G/bhp-hr	G/bhp-hr
a/n		4.8	2.6
a/n 549387	3633	3.95	0.89
a/n 549389	3633	3.95	0.89
Compliance		Yes	Yes

Item	HP	NOx +VOC	CO
		G/bhp-hr	G/bhp-hr
a/n		3.0	2.6
a/n 549390	398	2.76	2.31
Compliance		Yes	Yes

1470 (c)(2)(D)(i)(I) (Table 3)-The equipment does comply (this section applies to fire pumps)

Item	HP	NOx +VOC	CO	PM
		G/bhp-hr	G/bhp-hr	G/bhp-hr
a/n		3.0	2.6	0.15
a/n 549384	617	2.70	0.50	0.09
a/n 549385	617	2.70	0.50	0.09
a/n 549385	617	2.70	0.50	0.09
Compliance		Yes	Yes	Yes

1470 (c)(2)(D)(i)(III)-limit testing to 50 hours per year-BACT

1470 (d)(7)(A)-Require time meter to be installed

1470 (d)(7)(A)-Records are kept for at least 36 months (Title V facility, require records to be kept for five years)

REGULATION XVII-Prevention of Significant Deterioration

On July 25, 2007 SCAQMD and EPA have signed a new Partial PSD Delegation Agreement intended to delegate the authority and responsibility to SCAQMD for issuance of initial PSD permits and for PSD permit modifications where the applicant does not seek to use the emissions calculation methodologies promulgated in 40 CFR 52.21 (NSR Reform) but not set forth in SCAQMD Regulation XVII. The Partial Delegation agreement also does not delegate authority and responsibility to SCAQMD to issue new or modified PSD permits based on Plant-wide Applicability Limits (PALS) provisions of 40 CFR 52.21. Therefore, consistent with the Partial Delegation Agreement, for all new and modified PSD permits, AQMD will only use Regulation XVII as the bases for the PSD analysis. The SEDAB, where the project is to be located, is in attainment for NOx, SO_2, and CO emissions. Therefore PSD applies to these pollutants. For the proposed project a significant emission increase is 40 tpy or more of NOx or SO_2 or 100 tons per year or more of CO. The emissions from the proposed project will not exceed these thresholds. Therefore a PSD analysis is not required.

Rule 1703(a)(2) requires each permit unit be constructed using BACT for each attainment air contaminant for which there is a net emission increase. The BACT requirements for CO and NOx as well as the applicant's BACT proposals are listed below: As shown below, the equipment will comply with PSD BACT requirements.

Auxiliary Boiler, 249 MMBTU/hr

Pollutant	Minor Source	Proposed	Comply (Yes/No)
CO	≤100 ppmv @ 3% O2, dry	≤25 ppmv @ 3% O2, dry	Yes
NOx	<7 ppmv@ 3% O2 dry	<5 ppmv@ 3% O2 dry	Yes

Night preservation boiler, 10.5 MMBTU/hr

Pollutant	Minor Source	Proposed	Comply (Yes/No)
CO	≤100 ppmv @ 3% O2, dry	≤25 ppmv @ 3% O2, dry	Yes
NOx	<12 ppmv@ 3% O2 dry	<9 ppmv@ 3% O2 dry	Yes

Large Emergency ICE, 3633 bhp (>750 HP)

Pollutant	Minor Source BACT (Tier 2)	Proposed (Tier 2)	Comply (Yes/No)
CO	2.6 gm/bhp-hr	0.89 gm/bhp-hr	Yes
NOx+VOC	4.8 gm/bhp-hr	3.95 gm/bhp-hr	Yes

Emergency Fire Pump, 617 bhp (600≤ bhp < 750)

Pollutant	Minor Source BACT (Tier 3)	Proposed (Tier 3)	Comply (Yes/No)
CO	2.6 gm/bhp-hr	0.50 gm/bhp-hr	Yes
NOx+VOC	3.0 gm/bhp-hr	2.7 gm/bhp-hr	Yes

Small Emergency ICE, 398 bhp (300≤ bhp < 600)

Pollutant	Minor Source BACT (Tier 3)	Proposed (Tier 3)	Comply (Yes/No)
CO	2.60 gm/bhp-hr	2.21 gm/bhp-hr	Yes
NOx+VOC	3.0 gm/bhp-hr	2.79 gm/bhp-hr	Yes

Rule 1714 – PSD for Greenhouse Gases

This rule sets forth preconstruction review requirements for greenhouse gases (GHG). The provisions of this rule apply only to GHGs as defined by EPA to mean the air pollutant as an aggregate group of six GHGs: carbon dioxide (CO2), nitrous oxide (N2O), methane (CH4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). All other attainment air contaminants, as defined in Rule 1702 subdivision (a), shall be regulated for the purpose of Prevention of Significant Deterioration (PSD) requirements pursuant to Regulation XVII, excluding Rule 1714. The provisions of this rule shall apply to any source and the owner or operator of any source subject to any GHG requirements under 40 Code of Federal Regulations Part 52.21 as incorporated into this rule. The rule specifies what portions of 40 CFR, Part 52.21 do not apply to GHG emissions, which are identified in Rule 1714(c)(1) as exclusions.

The GHG pollutants of CO2, N2O and CH4 are products of combustion. The use of HFCs, PFCs, and SF6 are associated with equipment that are used for the operation of the facility, such as: HFCs used as heat transfer medium in air condition control equipment, PFCs used as an agent in fire suppression equipment, and SF6 as gas used to insulate transformers as well as in circuit breakers. The facility is expected to follow appropriate procedures to minimize any release of GHGs during installation, operation, and maintenance activities. The purchase of equipment that meet applicable standards and the practice of proper maintenance will ensure compliance for the non-combustion GHG products.

A PSD permit is required, prior to actual construction, of a new major stationary source or major modification to an existing major source as defined in 40 CFR 52.21(b)(1) and (b)(2), respectively. The rule incorporates the EPA rule by reference, so determination of PSD applicability for GHG is done using the EPA's document PSD and Title V Permitting Guidance for Greenhouse Gases, March 2010. The GHG emissions calculated in the tables below, using the heat input data and emission factor, respectively, were used for the project GHG PSD applicability determination.

Maximum Fuel and Heat Input for Potential to Emit

Equipment		Parameter	Unit	Value	Reference
Aux Boiler 1[(a)]	a	Rating	MMBtu/hr	249	Applicant's data and Permit description
	b	Hours	hrs/yr	n/a	n/a
	c	Annual Heat Input	MMBtu/yr	322,422	d x 1020
	d	Annual Fuel Use	MMscf/yr	316.1	Applicants data
Aux Boiler 2[(a)]	e	Rating	MMBtu/hr	249	Applicant's data and Permit description
	f	Hours	hrs/yr	n/a	n/a
	g	Annual Heat Input	MMBtu/yr	322,422	h x 1020
	h	Annual Fuel Use	MMscf/yr	316.1	Applicants data
Night Preservation Boiler 1[(b)]	i	Rating	MMBtu/hr	10.5	Applicant's data and Permit description
	j	Hours	hrs/yr	n/a	n/a
	k	Annual Heat Input	MMBtu/yr	50,704	l x 1020
	l	Annual Fuel Use	MMscf/yr	49.71	Applicants data
Night Preservation Boiler 2[(b)]	m	Rating	MMBtu/hr	10.5	Applicant's data and Permit description
	n	Hours	hrs/yr	n/a	n/a
	o	Annual Heat Input	MMBtu/yr	50,704	p x 1020
	P	Annual Fuel Use	MMscf/yr	49.71	Applicants data
Large ICE 1	q	Fuel Rate	gal/hr	172.9	Applicant's data
	r	Hours	hrs/yr	200	Applicant's data and Permit condition
	s	Annual Fuel Use	gal/yr	34,580	q x r
	t	Annual Heat Input	MMBtu/yr	4772	s x 0.138 MMBtu/gal
Large ICE 2	u	Fuel Rate	gal/hr	172.9	Applicant's data
	v	Hours	hrs/yr	200	Applicant's data and Permit condition
	w	Annual Fuel Use	gal/yr	34,580	u x v
	x	Annual Heat Input	MMBtu/yr	4772	w x 0.138 MMBtu/gal
Fire Pump 1	y	Fuel Rate	gal/hr	34	Applicant's data
	z	Hours	hrs/yr	200	Applicant's data and Permit conditions
	a	Annual Fuel Use	gal/yr	6,800	y x z
	b	Annual Heat Input	MMBtu/yr	938	a x 0.138 MMBtu/gal
Fire Pump 2	c	Fuel Rate	gal/hr	34	Applicant's data
	d	Hours	hrs/yr	200	Applicant's data and Permit condtions
	e	Annual Fuel Use	gal/yr	6,800	c x d
	f	Annual Heat Input	MMBtu/yr	938	e x 0.138 MMBtu/gal
Fire Pump 3	g	Fuel Rate	gal/hr	34	Applicant's data
	h	Hours	hrs/yr	200	Applicant's data and Permit conditions
	i	Annual Fuel Use	gal/yr	6,800	g x h
	j	Annual Heat Input	MMBtu/yr	938	i x 0.138 MMBtu/gal
Small ICE	k	Fuel Rate	gal/hr	20	Applicant's data
	l	Hours	hrs/yr	200	Applicant's data and Permit condition
	m	Annual Fuel Use	gal/yr	4000	k x l
	n	Annual Heat Input	MMBtu/yr	552	m x 0.138 MMBtu/gal

[(a)] Auxliary Boilers 1 and 2 are identical units with the same permit conditions, the applicant set a max. annual fuel usage of 316.1 mmcf (units does not operate max hours of 8760 hr/yr. Permit condition will limit fuel usage)

[(b)] Nigth Preservation Boilers 1 and 2 are identical units with the same permit conditions, the applicant set a max. annual fuel usage of 49.71 mmcf (units does not operate max hours of 8760 hr/yr. Permit condition will limit fuel usage)

GHG Emission Factors for Mass and Carbon Dioxide Equivalent (CO2E)

Fuel	GHG		kg/MMBtu[(a)]	ton/MMBtu (Mass)[(b)]	GWP[(c)]	ton/MMBtu (CO2E)[(d)]
Natural Gas	a	CO2	53.02	5.84E-02	1	5.84E-02
	b	CH4	0.001	1.102E-06	21	2.31E-05

	c	N2O	0.0001	1.102E-07	310	3.42E-05
Diesel	d	CO2	73.96	8.15E-02	1	8.15E-02
	e	CH4	0.003	3.306E-06	21	6.94E-05
	f	N2O	0.0006	6.612E-07	310	2.05E-04

[a] Emission Factors from EPA's Emission Factors for Greenhouse Inventories, November 2011
[b] kg/MMBtu x 1.102E-03 ton/kg
[c] Global Warming Potential (GWP) taken from EPA's Emission Factors for Greenhouse Inventories, November 2011
[d] ton/MMBtu (Mass) x GWP

GHG Emission Rates for Mass and CO2E

Equipment	Mass (tpy)				CO2E (tpy)			
	CO2[a]	CH4[b]	N2O[c]	Total	CO2[d]	CH4[e]	N2O[f]	Total
Aux boiler 1	18,829	0.36	0.04	18,829	18,829	7	11	18,847
Aux boiler 2	18,829	0.36	0.04	18,829	18,829	7	11	18,847
Night preservation boiler 1	2,961	0.05	0.01	2,961	2,961	1	2	2,964
Night preservation boiler 2	2,961	0.05	0.01	2,961	2,961	1	2	2,964
Large ICE 1	389	0.01	0	389	389	0.33	0	389
Large ICE 2	389	0.01	0	389	389	0.33	0	389
Fire pump 1	76	0	0	76	76	0.07	0	76
Fire pump 2	76	0	0	76	76	0.07	0	76
Fire pump 3	76	0	0	76	76	0.07	0	76
Small ICE	45	0	0	45	45	0.04	0	45
			Project Total	**44,631**			**Project Total**	**44,673**

[a] Annual Heat Input MMBtu/yr *{from Table 29}* x CO2 ton/MMBtu (Mass) *{from Table 30}*
[b] Annual Heat Input MMBtu/yr *{from Table 29}* x CH4 ton/MMBtu (Mass) *{from Table 30}*
[c] Annual Heat Input MMBtu/yr *{from Table 29}* x N2O ton/MMBtu (Mass) *{from Table 30}*
[d] Annual Heat Input MMBtu/yr *{from Table 29}* x CO2 ton/MMBtu (CO2E) *{from Table 30}*
[e] Annual Heat Input MMBtu/yr *{from Table 29}* x CH4 ton/MMBtu (CO2E) *{from Table 30}*
[f] Annual Heat Input MMBtu/yr *{from Table 29}* x N2O ton/MMBtu (CO2E) *{from Table 30}*

GHG PSD Applicability Flowchart for Project[a]

Step	GHG PSD Applicability Step	Result	Response
1	Will the permit be issued on or after July 1, 2011	Yes	Go to Step 2
2	Is this modification subject to PSD permitting for a regulated NSR pollutant other than GHGs?	No	Go to Step 3
3	Determine PTE for existing stationary source, before modification, for each of the 6 GHG pollutants. Determine the mass sum and the CO2e sum (using GWP equivalent).	Mass Sum: 44,631 tpy *{Table above}* CO2E Sum: 44,673 tpy *{Table above}*	Go to Step 4
4	Are the PTE for GHG emissions equal or greater than both 100,000 tons per year CO2e and 100 tons per year on mass basis?	No	Go to Step 5
5	Is this a new stationary source subject to PSD for regulated NSR pollutant other than GHDs	No	**GHG emissions not subject to PSD Review**

(a) Flowchart from Appendix A and B. GHG Applicability Flowchart – Modified Sources (On or after July 1, 2011) of EPA's document PSD and Title V Permitting Guidance for Greenhouse Gases, March 2010.

The above table identifies that this project is not subject to PSD analysis for GHG Emissions. Therefore, BACT is not required for GHG.

REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

The facility is exempt from RECLAIM per Rule 2001 (i)(2)(M) and elected to enter the RECLAIM program per Rule 2001 (f).

RULE 2005(b)(1)(A) – BACT

The NOx BACT limit for natural gas fired boilers and emergency engines were discussed in the Regulation XVII PSD NSR BACT section as listed in the table below

Auxiliary Boiler, 249 MMBTU/hr

Pollutant	Minor Source	Proposed	Comply (Yes/No)
NOx	≤7 ppmv @ 3% O2, dry	≤5 ppmv @ 3% O2, dry	Yes

NTP Boiler, 10.5 MMBTU/hr

Pollutant	Minor Source	Proposed	Comply (Yes/No)
NOx	≤12 ppmv @ 3% O2, dry	≤9 ppmv @ 3% O2, dry	Yes

Large Emergency ICE, 3633 bhp (>750 HP)

Pollutant	Minor Source (Tier 2)	Proposed BACT (Tier 3)	Comply (Yes/No)
NOx+NMHC	4.8 gm/bhp-hr	3.95 gm/bhp-hr	Yes

Emergency Fire Pump, 617 bhp (600≤ bhp < 750)

Pollutant	Minor Source (Tier 3)	Proposed BACT (Tier 3)	Comply (Yes/No)
NOx+NMHC	3.0 gm/bhp-hr	2.7 gm/bhp-hr	Yes

Small Emergency ICE, 398 bhp (300≤ bhp < 600)

Pollutant	Minor Source (Tier 3)	Proposed BACT (Tier 2)	Comply (Yes/No)
NOx+NMHC	3.0 gm/bhp-hr	2.79 gm/bhp-hr	Yes

Permit conditions, verification through CEMS and source testing will ensure compliance.

RULE 2005(c)(1)(B) – MODELING

This section of the rule requires a facility that is located in an attainment area for nitrogen dioxide (NO2) to demonstrate through modeling analysis that the proposed NOx emission sources will not cause a violation of the most stringent ambient air quality standards. PSEGS conducted dispersion modeling using the AERMOD model for the maximum project impacts of NO2 emissions. The results of the analysis are shown in the table below.

Rule 2005(c)(1)(B) Modeling Results-Auxiliary Boiler no. 1

Criteria	Operation with maximum impact	Impact (ug/m3)	Background (ug/m3)	Total Impact (ug/m3)	Most Stringent AQ Standard (ug/m3)
NOx, 1-hour (CAAQS)	Start-up hour uncontrolled	4.3	124.3	128.6	339
NOx, 1-hour (NAAQS)	Start-up hour uncontrolled	1.17	97.8	99.5	188
NOx, annual	Maximum operation	0.006	22.6	22.61	57

Table Rule 2005(c)(1)(B) Modeling Results-Auxiliary Boiler no. 2

Criteria	Operation with maximum impact	Impact (ug/m3)	Background (ug/m3)	Total Impact (ug/m3)	Most Stringent AQ Standard (ug/m3)
NOx, 1-hour (CAAQS)	Start-up hour uncontrolled	3.7	124.3	128	339
NOx, 1-hour (NAAQS)	Start-up hour uncontrolled	1.4	97.8	99.2	188
NOx, annual	Maximum	0.011	22.6	22.61	57

Modeling staff provided their comments in a memorandum from Mrs. Elaine Change to Mr. Andrew Lee dated August 21, 2013. A copy of this memorandum is contained in the project file. Staff's review of the modeling analysis concluded that the applicant used appropriate EPA AERMOD model along with the appropriate model options in the analysis. The memorandum states that the modeling as performed by the applicant conforms to the District's dispersion modeling requirements and no significant deficiencies in methodology were noted. Therefore compliance with modeling requirements is expected.

The emergency engines are exempt from modeling per section (k)(5), permit conditions will limit operating time to less than 200 hours in any one year.

RULE 2005(b)(2)(A) – OFFSET (RTC)

The facility is required to demonstrate that it holds sufficient RTCs to offset the annual emission increase for the first year of operation using a 1-to-1 offset ratio. Furthermore, paragraph (b)(2)(B) states that the RTCs must comply with the zone requirements of Rule 2005(e). The repower project is expected to undergo commissioning in Year 2015. Since the facility is located in Zone 2 (Inland, Cycle 1); thus, RTCs may only be obtained from Zones 1 or 2.

PSEGS will be required to purchase the required NOx RTCs from the open market , compliance with Regulation XX, Rule 2005, is expected. The NOx RTC amounts are listed below

Equipment	Device no.	RTC Commissioning yr	RTC Non-commissioning year
Aux boiler no. 1	D1	5714	5645
Aux boiler no. 2	D6	5714	5645
Night preservation boiler no. 1	D11	565	563
Night preservation boiler no. 2	D12	565	563
Large em ice no. 1	D13	5922	5922
Large em ice no. 2	D15	5922	5922
Small em ice	D17	434	434
Emergency fire pump no. 1	D19	707	707
Emergency fire pump no. 2	D20	707	707
Emergency fire pump no. 3	D21	707	707

See Appendix N for RTC determination

Emergency engines annual NOx emissions based on max 200 hours per year operation, not 50 hr/yr testing

RULE 2005(g) – ADDITIONAL REQUIREMENTS

Does not apply, PSEGS is not a Major Stationary Source as defined per Rule 2000 (c)(45), the facility NOx emissions less than 10 tons per year (facility is located in the Mojave Desert Air Basin (MDAB) and the NOx Major Source threshold is 25 tons per year)

RULE 2005(h) – PUBLIC NOTICE

PSEGS will comply with the requirements for Public Notice found in Rule 212. Therefore compliance with Rule 2005(h) is demonstrated.

RULE 2005(i) – RULE 1401 COMPLIANCE.

PSEGS will comply with Rule 1401 as demonstrated in HRA and subsequently reviewed and found to be satisfactory by SCAQMD modeling staff. Compliance is expected.

RULE 2005(j) – COMPLIANCE WITH STATE AND FEDRAL NSR.

PSEGS will comply with the provisions of this rule by having demonstrated compliance with SCAQMD NSR Regulations XIII and Rule 2005-NSR for RECLAIM.

RULE 2012 – RECLAIM, MONITORING, REPORTING, & RECORDKEEPING REQUIREMENTS

Auxiliary boilers

The boiler will be classified as major NOx source under RECLAIM per Rule 2012 (C)(1)(A)(i) with a btu rating less than 500 mmbtu/hr and a fuel usage greater than 90 billion btu per year (max btu/yr is 3.22E+11). As such, per section (c)(2)(A) is 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 SCAQMD on a daily basis. The CEMS system will be required to be installed within 90 days of start up..

Night Preservation Boilers

The boilers will be classified as process unit NOx source under RECLAIM per Rule 2012 (e)(1)(A)(i). Per section (e)(2)(A) install a fuel meter and section (e)(2)(C) accept a emission factor or concentration limit The applicant proposes to accept a concentration limit of 9 ppmv (see email dated 6/24/2013).. Section (e)(2)(E) he concentration limit is measured over one hour. The concentration limit will have to be verified by source test once every five years. Compliance is expected .

Emergency ICEs

The emergency engines will be classified as process unit NOx source under RECLAIM per Rule 2012 (e)(1)(D). Per section (e)(2)(A) install a fuel meter and section (e)(2)(C) accept a emission factor. The emissions factor are listed below .

The engines are process unit, per Rule 2002 Table 1, the equipment is allowed to use a emission factor based on the BACT NOx limit, see below

A. Large emergency ICE

BACT limit (combined NOx+VOC) = 4.8 g/bhp-hr
Fuel rate = 172.9 gal/hr
HP rating = 3633
For RECLAIM purposes, assume VOC is zero and max NOx = 4.8 g/bhp-hr

EF = (4.8 g/bhp-hr)(3633 hp) (1lb/454 g)*(1 hr/172.9 gal)*(1000 gal/1mgal)

EF = 222 lb/mgal

B. Small emergency ICE

BACT limit (combined NOx+VOC) = 4.8 g/bhp-hr
Fuel rate = 20 gal/hr
HP rating = 398
For RECLAIM purposes, assume VOC is zero and max NOx = 3.0 g/bhp-hr

EF = (3.0 g/bhp-hr)(398 hp) (1lb/454 g)*(1 hr/20 gal)*(1000 gal/1mgal)

EF = 132 lb/mgal

C. Fire Pump ICE

BACT limit (combined NOx+VOC) = 3.0 g/bhp-hr
Fuel rate = 34 gal/hr
HP rating = 617
For RECLAIM purposes, assume VOC is zero and max NOx = 3.0 g/bhp-hr

EF = (3.0 g/bhp-hr)(617 hp) (1lb/454 g)*(1 hr/34 gal)*(1000 gal/1mgal)

EF = 120 lb/mgal

INTERIM PERIOD EMISSION FACTORS-AUXILIARY BOILERS
RECLAIM requires a NOx emission factor to be used for reporting emissions during the interim reporting period. The interim period is defined as a period, of no greater than 12 months from initial operation, when the CEMS has not been certified. During this period, the emissions cannot be accurately, monitored, or verified. The emissions during this period are assumed to be at uncontrolled levels. The interim reporting period can be broken down into the two parts which includes the commissioning period in which an uncontrolled emission rate is assumed.

Since PSEGS is included in NOx RECLAIM, an interim period emission factor will be determined. In the event CEMS data is not available, NOx emissions during the interim period will be calculated using monthly fuel usage and the emission factors shown below. There will be two interim period emission factors for NOx.

The first factor will be for use during the commissioning period when the boiler is assumed to be operating at uncontrolled levels and the second factor will be for use after commissioning is complete. The emission factors for NOx are shown in the table below.

Emission Factors for Interim Period for the Aux Boiler

Pollutant	**Controlled NOx**	Uncontrolled NOx
Commissioning Emission Factors (lb/MMscf)	11.55	92.40
Non commissioning Period Emission Factors (lb/MMscf)	6.53	83.96

The commissioning emission factors were provided by the vendor (lb/mmbtu convert to lb/mmcf using 1050 but/ft3) and is only to be used during the commissioning of the auxiliary boilers prior to normal operations

The non-commissioning period emissions factor is to be used when the aux boilers are in normal operations and the NOx RECLAIM CEMs has not been certified or offline.

See Appendix N

REGULATION XXX – Title V

The facility is not subject to Title V based on annual emissions because this project is located in the Mojave Desert Air Basin (MDAB) and the major source thresholds for VOC NOx, SOx, CO and PM10 are not exceeded, see table below

The facility is not subject to Title V based on annual emissions because this project is located in the Mojave Desert Air Basin (MDAB) and the major source thresholds for VOC NOx, SOx, CO and PM10 are not exceeded, see table below

	VOC	NOx	SOx	PM-10	CO	CO2e
Maximum emissions tons/yr	1.58	8.01	0.76	2.10	13.98	44,673
Threshold levels tons/yr	100	100	100	100	100	100000
Threshold exceeded	No	No	No	No	No	no

However the facility is subject to Federal ACID Rain program, thus subject to the Title V program per Rule 3001(b)(c)(3). The initial Title V permit will be processed and the required public notice

will be sent along with the Rule 212(g) Public Notice, which is also required for this project. EPA is afforded the opportunity to review and comment on the project within a 45-day review period.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

The California Energy Commission (CEC) is the lead agencies for the Palen Solar Electric Generation Station (PSEGS) (09-AFC-7) and will be addressing CEQA compliance.

CALIFORNIA AIRBORNE TOXIC CONTROL MEASURE FOR STATIONARY COMPRESSION IGNITION ENGINES.

The ATCM was amended October 2010 and the requirements for Tier 4i and Tier 4 was removed and section 93115.6 (a)(3)(A)(1)(a) Table 1. Table 1 keeps the current Tier 2 and Tier 3 emissions standards for the applicable HP engine group. CARB in November 2010 distributed a regulatory advisory that provided guidance on compliance with the ATCM during the transition period from the current ATCM to the amended ATCM. The ATCM became effective on May 19, 2011 when the California Office of Administrative Law (OAL) approved the CARB rulemaking for the amendments to ATCM. The SCAQMD amended Rule 1470 in May of 2012 to align with the amended ATCM for all pollutants except diesel particulate matter (PM), which is a toxic and cancer causing air contaminant

FEDERAL REGULATIONS

40 CFR Part 63, Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

The final ruling was released on 3/21/2011 and applies to boilers using non-gaseous fuels. For this project the boilers are using natural gas. The boilers meet the definition of gas fired boiler per 40 CFR 63.11237. Per 40 CFR 63.11195 (e) these type of boilers are not subject any requirements of this subpart.

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

This regulation applies to each steam generating unit for which construction, modification, or reconstruction is commenced after June 19, 1984 and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)). Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NO_X standards under this subpart. The proposed boilers are rated at 249 mmbtu/hr and will use natural fired only. As such the rule requires compliance with the following requirements:

§60.42b-SOx Standards- does not apply to boilers firing only natural gas

§60.42c-PM Standards- does not apply to boilers firing only natural gas

§60.44b-NOx Standards

Fuel Type	Nitrogen Oxide (NO_2) Emission Limit	
	ng/J	lb/MMBTU
Natural Gas low heat release	43	0.10

Natural Gas
Use conversion factor of 0.78 to convert lb/mmscf to ppmv
NOx = 0.10 lb/mmBTU * 1,020 BTU/scf * 0.78 = 79.56 ppmv
The boilers will be vented to SCR with a Controlled emission NOx guarantee 5 ppmv, thus the controlled NOx emissions is expected to comply with the NOx limit of this regulation.

§60.44(b)(h)-For purposes of paragraph (i) of this section, the NOx standards under this section apply at all times including periods of start-up, shutdown, or malfunction

This will be listed as a permit condition (A194.4)

§60.44(b)(i)-Except as provided under paragraph (j) of this section, compliance with the emissions limits under this section is determined on a 30-day rolling average basis

This will be listed as a permit condition (A194.4)

§60.49b Reporting and record keeping requirements

§60.49b (a)- The operator shall submit notification of the date of initial start-up, as provided in §60.7

(a)(1) The design heat input capacity of the boilers and the type of fuels to be used by the equipment.

(a)(2)-If applicable, a copy of any federally enforceable requirements that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(ii), 60.44b(c), (d), (e), (i),(j), (k), 60.45b(d), (g), 60.46b(h)(1), or 60.48b(i).

(a)(3)- The annual capacity factor at which the operator anticipated operating the facility based on all fuels fired and based on each individual fuel fired, and

(a)(4)- not applicable

§60.49b(d)(1)-The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12 month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

Permit condition E448.4 will require daily fuel records be keep.

§60.49b (g)The operator of the boilers subject to the NOx standards under 60.44b shall maintain records of the following information for each steam generating unit operating day

(1) Calendar date
(2) The ave hourly NOx emissions rate (exspressed as NO2)(ng/J or lb/mmbtu heat input.
(3) The 30 day average NOx emission rate calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emissions rate for the proceeding 30 steam generating unit operating days.
(4) Identification of the steam unit operating days when the calculated 30-day average NOx emissions rates are in excess of the NOx emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective action taken;
(5) Identifications of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective action taken;
(6) Identification of the times when emissions data have been excluded from the calculations of average emission rates and the reasons for excluding data;
(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.
(8) Identification of the times when the pollutant concentration exceeded full span of CEMs;
(9) Description of any modifications to the CEMs that could affect the ability of the CEMs to comply with Performance Specification 2 or 3; and
(10) Results of daily CEMs drift test and quarterly accuracy assessments as required under Appendix F, Procedure 1 of this part.

§60.49b (h)- The owner or operator of any affected facility in any category listed in paragraph (h)(1) or (2) of this section is required to submit excess emission reports for any excess emission that occurred during the reporting period.

(2) Any affected facility that is subject to the NOx standard of §60.44b, and that:

(i) Combust natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or
(ii) Has an heat input capacity of 250 MMBTU/hr or less and is required to monitor NOx emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operations conditions under §60.48b(g)(2).

(4) For the purposes of §60.48b(g)(1), excess emission are defined as any calculated 30-day rolling average NOx emissions rate, as determined under §60.46b(e), that exceed the applicable emissions limits of §60.44b

§60.49b (i)-The owner or operator of any affected facility subject to the continuous monitoring requirements for NOx under §60.48b shall submit reports containing the information recorded under paragraph (g) of this section.

Compliance is demonstrated.

40 CFR Part 60, Subpart Dc--Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

§60.40c Applicability and delegation of authority

The affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and has a maximum design input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. This subpart is applicable to the proposed 10.5 MMBtu/hr boilers.

§60.42c Standard for sulfur dioxide (SO_2)

Affected facilities that combust coal, oil, or coal and oil with any other fuel are subject to this standard. Thus the proposed natural gas-fired boiler, with no backup fuel, is not subject to this section and the subsequent sections related to this SO_2 standard.

§60.43c Standard for particulate matter (PM)

Affected facilities that combust coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with other fuels are subject to this standard. Thus the proposed natural gas-fired boiler, with no backup fuel, is not subject to this section and the subsequent sections related to this PM standard.

§60.48c Reporting and recordkeeping requirements

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(g)(2) As an alternative to meeting the requirements of (g)(1), the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month. (**permit condition C1.5**)

(g)(3) As an alternative to meeting the requirements of (g)(1), the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

*****To comply with (g)(2), permit condition a non-resettable, totalizing fuel flow meter, and recordkeeping for the monthly fuel usage. **(permit condition D12.1)**

NSPS, application no. 549387 and 549388, emergency ICE 3633 HP

40 CFR Part 60 Subpart IIII--NSPS for Stationary Compression Ignition Internal Combustion Engines

§60.4200(a)—The provision of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) engines as specified in paragraphs (a)(1) through (a)(4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

§60.4200(a)(2)(i) specifies this subpart is applicable to owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE is manufactured after April 1, 2006 and are not fire pump engines. Therefore, this subpart is applicable to the engines under evaluation.

The EPA comment letter, dated 5/23/12, regarding the proposed permit for A/N 529701 for an emergency ICE for US Govt., Veterans Admin Medical Center (ID 5679) indicated permit conditions should include at a minimum the requirements of the following sections.

A. §60.4202(b)(2) provides that for engines with a maximum engine power greater than or equal to 3000 HP and less than 10 liters per cylinder, the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2011.

40 CFR 89.112—Exhaust emission from nonroad engines shall not exceed the applicable exhaust standards in Table 1 of this provision. For an engine rated at 1500 kW for model year 2007 and later, Tier 2 is applicable (6.4 g/kW-hr NMHC + NOx, 3.5 g/kW-hr CO, 0.2 g/kW-hr PM) . The engine comply with these limits, which are the same as the District BACT standards.

Permit condition: the emissions limits are listed in the Emissions & Requirements section of Section H per device

§60.4202(f)(1)—Stationary CI internal combustion engine manufacturers must certify their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 3,700 HP and a displacement of greater than 10 liters per cylinder and less than 30 liters per cylinders. Does not apply the displacement per cylinder is less than 10 liters.

§60.4205(b)—See §60.4202

B. §60.4207(b)—Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

40 CFR 80.510(b)—Except as other specifically provided in this subpart, all NR and LM diesel fuel is subject to the following per-gallon standards:

(1) Sulfur content.
- (i) 15 ppm maximum for NR [nonroad] diesel fuel
- (ii) 500 ppm maximum for LM [locomotive or marine] diesel fuel

Permit condition: Condition no. B61.2 limits diesel fuel sulfur content to 15 ppm, which is the same as BACT.

C. §60.4209(a)— An owner or operator of an emergency stationary CI ICE that does not meet the standards applicable to non-emergency engines must install a non-resettable hour meter prior to start-up of the engine.

Permit condition: Condition no. D12.2 requires a non-resettable hour meter.

D. §60.4209(b)—An owner or operator of a stationary CI ICE equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Permit condition: not applicable, no DPF installed on these engines.

E. §60.4211(a)—An owner or operator who must comply with the emission standards specified in this subpart must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to manufacturer's emission-related written instructions;
(2) Change only those emission-related settings that are permitted by the manufacturer; and
(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply.

Permit condition: Pursuant to EPA guidance, condition E448.3 is added to implement the above requirements regarding the engine (no control device).

F. §60.4211(c)—An owner or operator of a 2007 model year and later stationary CI ICE and must comply with the emission standards specified in §60.4204(b) [non-emergency engine] or §60.4205(b) [emergency engine], or an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to the fire pump engine power rating in table 3 to this subpart and must comply with the emission standard specified in §60.4205(c), must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

Permit condition: Pursuant to EPA guidance, condition no. E448.2 is added to implement the above requirements regarding the engine. As discussed above, the engine is in compliance with the emissions standards specified in 40 CFR 60.4205(b).

G. §60.4211(f)—Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations….

Permit condition: Federal standards allow 100 hours per year for testing and maintenance and no time limit for emergency use. District requirements are more stringent and allow 50 hours for testing and maintenance, and 200 hours total including the 50 hours for testing and maintenance. Condition no. C1.9 implements the more stringent SCAQMD requirements.

H. §60.4214(b)—If the stationary CI ICE is an emergency stationary ICE, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to on-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

Permit condition: Condition no. K67.3 sets forth the recordkeeping requirements.

I §60.4214(c)—If the stationary CI ICE is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Permit condition: not applicable, engine not equipped with DPF.

NSPS, application no. 549390, emergency ICE 398 HP

40 CFR Part 60 Subpart IIII--NSPS for Stationary Compression Ignition Internal Combustion Engines

§60.4200(a)—The provision of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) engines as specified in paragraphs (a)(1) through (a)(4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

§60.4200(a)(2)(i) specifies this subpart is applicable to owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE is manufactured after April 1, 2006 and are not fire pump engines. Therefore, this subpart is applicable to the engines under evaluation.

The EPA comment letter, dated 5/23/12, regarding the proposed permit for A/N 529701 for an emergency ICE for US Govt., Veterans Admin Medical Center (ID 5679) indicated permit conditions should include at a minimum the requirements of the following sections.

Title 40 Part 60 subpart IIII section 60.4205

Emergency CI ICE of model year of 2007 or later with a displacement of less than 30 liters per cylinder has to comply with the non road emissions standards. The engine displacement is 15 liters and the engine complies with Tier 3 emissions limits for this HP range, thus compliance with this Regulation is met. The engine complies with the Tier 3 emissions requirements of this Rule (40 CFR Part 89.112). Permit condition no. 13, Rule tag the NOx+VOC and CO emissions limits to this Rule. For NOx, VOC and PM, Rule tag Rule 1303 (a) which is more stringent.

Per EPA, email dated 5/23/2012, as applicable, the permit conditions should at least include the requirements of these sections:

A. §60.4202(a)(2) provides that for engines with a maximum engine power less than or equal to 3000 HP and less than 10 liters per cylinder, the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007 or later.

40 CFR 89.112—Exhaust emission from nonroad engines shall not exceed the applicable exhaust standards in Table 1 of this provision. For an engine rated at 315 kW for model year 2007 and later, Tier 3 is applicable (4.0 g/kW-hr NMHC + NOx, 3.5 g/kW-hr CO, 0.2 g/kW-hr PM) . The engine comply with these limits, which are the same as the District Tier 3 BACT standards.

Permit condition: The emissions limits are listed in the Emissions & Requirements section of Section H per device

§60.4202(f)(1)—Stationary CI internal combustion engine manufacturers must certify their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 3,700 HP and a displacement of greater than 10 liters per cylinder and less than 30 liters per cylinders. Does not apply the displacement per cylinder is less than 10 liters.

§60.4205(b)—See §60.4202

B. §60.4207(b)—Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must

purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for non-road diesel fuel.

40 CFR 80.510(b)—Except as other specifically provided in this subpart, all NR and LM diesel fuel is subject to the following per-gallon standards:

(1) Sulfur content.

(i) 15 ppm maximum for NR [nonroad] diesel fuel

(ii) 500 ppm maximum for LM [locomotive or marine] diesel fuel

Permit condition: Condition no. B61.2 limits diesel fuel sulfur content to 15 ppm, which is the same as BACT.

C. §60.4209(a)— An owner or operator of an emergency stationary CI ICE that does not meet the standards applicable to non-emergency engines must install a non-resettable hour meter prior to start-up of the engine.

Permit condition: Condition no. D12.2 requires a non-resettable hour meter.

D. §60.4209(b)—An owner or operator of a stationary CI ICE equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Permit condition: Does not apply engine not equipped with DPF.

E. §60.4211(a)—An owner or operator who must comply with the emission standards specified in this subpart must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply.

Permit condition: Pursuant to EPA guidance, condition no. E448.3 is added to implement the above requirements regarding the engine (no control device).

F. §60.4211(c)—An owner or operator of a 2007 model year and later stationary CI ICE and must comply with the emission standards specified in §60.4204(b) [non-emergency engine] or §60.4205(b) [emergency engine], or an owner or operator of a CI fire pump engine that is

manufactured during or after the model year that applies to the fire pump engine power rating in table 3 to this subpart and must comply with the emission standard specified in §60.4205(c), must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

Permit condition: Pursuant to EPA guidance, condition no. E448.2 is added to implement the above requirements regarding the engine. As discussed above, the engine is in compliance with the emissions standards specified in 40 CFR 60.4205(b).

G. §60.4211(e)—Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations….

Permit condition: Federal standards allow 100 hours per year for testing and maintenance and no time limit for emergency use. District requirements are more stringent and allow 50 hours for testing and maintenance, and 200 hours total including the 50 hours for testing and maintenance. Condition no. C1.9 implements the more stringent SCAQMD requirements.

H. §60.4214(b)—If the stationary CI ICE is an emergency stationary ICE, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to on-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

Permit condition: Condition no. K67.3 sets forth the recordkeeping requirements.

I §60.4214(c)—If the stationary CI ICE is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Permit condition: does not apply, no DPF installed on engine.

NSPS, application no. 549384, 549385 and 549386, emergency fire pump, each rated at 617 HP

40 CFR Part 60 Subpart IIII--NSPS for Stationary Compression Ignition Internal Combustion Engines

§60.4200(a)—The provision of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) engines as specified in paragraphs (a)(1) through (a)(4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

§60.4200(a)(2)(ii) specifies this subpart is applicable to owners and operators of fire pump manufactured as certified National Fire Protection Association (NFPA) construction after July 1, 2006. Therefore, this subpart is applicable to the engines under evaluation.

Title 40 Part 60 subpart IIII section 60.4205 (c)

Owners and operators of fire pump engines with a displacement less than 30 liters per cylinder must comply with the emissions standards in table 4 to this subpart for all pollutants.

A. §60.4202(d)(2) beginning the model years in table 3 to this subpart, stationary CI internal combustion engines manufacturers must certify their fire pump stationary CI ICE to the emissions standards in table 4 of this subpart, for all pollutants, for the same model year and NFPA nameplate power.

Table 4 to Subpart IIII of Part 60—Exhaust emission from fire pump engines shall not exceed the applicable exhaust standards in Table 4 of this provision. For an engine rated at 617 HP for model year 2009 and later, Tier 3 is applicable (4.0 g/kW-hr NMHC + NOx, 3.5 g/kW-hr CO, 0.2 g/kW-hr PM) . The engine comply with these limits, which are the same as the District Tier 3BACT standards.

Permit condition: The emissions limits are listed in the Emissions & Requirements section of Section H per device.

B. §60.4207(b)—Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for non-road diesel fuel.

40 CFR 80.510(b)—Except as other specifically provided in this subpart, all NR and LM diesel fuel is subject to the following per-gallon standards:

(1) Sulfur content.

(i) 15 ppm maximum for NR [nonroad] diesel fuel

(ii) 500 ppm maximum for LM [locomotive or marine] diesel fuel

Permit condition: Condition no. B61.2 limits diesel fuel sulfur content to 15 ppm, which is the same as BACT.

C. §60.4209(a)— An owner or operator of an emergency stationary CI ICE that does not meet the standards applicable to non-emergency engines must install a non-resettable hour meter prior to start-up of the engine.

Permit condition: Condition no. D12.2 requires a non-resettable hour meter.

D. §60.4211(a)—An owner or operator who must comply with the emission standards specified in this subpart must do all of the following:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to manufacturer's emission-related written instructions;
(2) Change only those emission-related settings that are permitted by the manufacturer; and
(3) Must the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply.

Permit condition: Pursuant to EPA guidance, condition no. E448.3 is added to implement the above requirements regarding the engine (no control device).

E. §60.4211(c)—An owner or operator of a 2007 model year and later stationary CI ICE and must comply with the emission standards specified in §60.4204(b) [non-emergency engine] or §60.4205(b) [emergency engine], or an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to the fire pump engine power rating in table 3 to this subpart and must comply with the emission standard specified in §60.4205(c), must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

Permit condition: Pursuant to EPA guidance, condition no. E448.2 is added to implement the above requirements regarding the engine. As discussed above, the engine is in compliance with the emissions standards specified in 40 CFR 60.4205(b).

F. §60.4211(e)—Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations….

Permit condition: Federal standards allow 100 hours per year for testing and maintenance and no time limit for emergency use. District requirements are more stringent and allow 50 hours for testing and maintenance, and 200 hours total including the 50 hours for testing and maintenance. Condition no. C1.9 implements the more stringent SCAQMD requirements.

G. §60.4214(b)—If the stationary CI ICE is an emergency stationary ICE, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to on-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

Permit condition: Condition no. K67.3 sets forth the recordkeeping requirements.

NESHAP for a/n 549387, 549388, 549389, 549384, 549385, 549386 and 549390 (all engines at the facility)

40 CFR Part 63 Subpart ZZZZ--NESHAPS for Stationary Reciprocating Internal Combustion Engines

§63.6580 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions.

§63.6585(b) A "major source" is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year.

§63.6585(c) An "area source" is a source that is not a major source. The proposed Solar Power Plant is an area source for HAPs.

§63.6590(a) This subpart applies to each affected source. An "affected source" is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

§63.6590(a)(2)(iii) A stationary RICE located at an area source of HAP emissions is new if construction of the stationary RICE is commenced on or after June 12, 2006. Therefore, the engine under evaluation is new.

§63.6590 (c) provides an affected source that meets any of the criteria in paragraphs (c)(1) through (c)(7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII for compression ignition engines or 40 CFR part 60 subpart JJJJ for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source.

Conclusion: Since the emergency engine is a new compression-ignition RICE located at an area source, it is required to meet 40 CFR Part 60 Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. (See discussion on Subpart IIII, above.), thus compliance with this met, see NSPS section

40 CFR PART 72 – ACID RAIN PROVISIONS

The PSEGS facility is subject to the requirements of the federal Acid Rain program. EPA reviewed 72.6(b)(4)(ii) to determine if the auxiliary boilers met the definition of cogeneration. EPA determined, see email dated 8/26/2013 that the boilers did not meet the definition of cogeneration and the full provision of the ACID Rain regulation applies. The program is similar in concept to RECLAIM in that facilities are required to cover SO2 emissions with SO2 allowances; analogous to NOx RTCs. Per EPA, email dated 8/26/2013, there is no minimum threshold values of SO_2. Facilities with insufficient allowances are required to purchase SO_2 credits on the open market. Appropriate conditions are in Appendix B of the Title V permit. PSEGS is expected to comply with this regulation.

Each Auxiliary boiler is capable of producing steam to be used in the steam generator. The applicant estimates 20 MWe output. The applicant estimates the maximum SOx emission during steam generation to the turbine (Boosting mode) per boiler, see Appendix C for calculations

Hr/dy	2
Number of boosting events per year	220
SOx emissions per event	1.17
SOx emissions per year	257

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. The rule is intended to provide "reasonable assurance" that the control systems are operating properly to maintain compliance with the emission limits. The facility emissions are well below the major source thresholds based on the equipment location, thus is not subject to this Regulation. In addition the two Auxiliary boilers are equipped with a NOx and CO CEMs

RECOMMENDATION(S)

It is recommended that Permit to Construct be issued to the subject equipment. The permits will be subject to the following conditions.

Facility Permit conditions

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

(a) As dark or darker in shade as that designated No.1 on the Ringelmann Chart, as published by the United States Bureau of Mines; or

(b) Of such opacity as to obscure an observer' s view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition. [RULE 401, 3-2-1984; RULE 401, 11-09-2001]

F14.1 The operator shall only use diesel fuel containing the following specified compounds:

COMPOUND	Range	PPM BY WEIGHT
Sulfur	Less than or equal to	15

The operator shall maintain a copy of the MSDS on site
[Rule 431.2]

F10.1 The operator shall not use natural gas containing the following specified compounds:

Compound	Grains per 100 scf
H2S	Greater than 0.750

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]

AUXILIARY BOILERS, A/N 549379 AND 549380 (D1 AND D6)

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

CONTAMINANT	EMISSION LIMIT
PM_{10}	214 LBS IN ANY ONE MONTH
CO	1451 LBS IN ANY ONE MONTH
SOx	85 LBS IN ANY ONE MONTH
VOC	173 LBS IN ANY ONE MONTH

The operator shall calculate the calendar monthly emissions for VOC, PM10 and SOx using the equation below and the following emission factors:

Uncontrolled emission factors: VOC: 5.7 lb/mmcf; PM10: 7.6 lb/mmcf; CO: 157.39 lb/mmcf, and SOx: 2.14 lb/mmcf.

Controlled emission factors: VOC: 4.1 lb/mmcf; PM10: 5.1 lb/mmcf; CO: 19.87 lb/mmcf and SOx: 2.14 lb/mmcf.

The uncontrolled emissions factors are to be used during start-up when the boiler is operating at 17.5% load or less

Monthly Emissions, lb/month = X (E.F.)

Where X = monthly fuel usage in mmcf/month and E.F. = emission factor indicated above.

The operator shall calculate the emission limit(s) for the purpose of determining compliance with the monthly CO limit in the absence of valid CEMS data by using the above equation and the following emission factor(s):

During the commissioning period the, 38.85 lbs CO/mmcf emissions factor to be used during low, medium and high loads. During cold start and warm start 153.30 lb/mmcf is to be used.

After installation of the CO catalyst but prior to CO CEMS certification testing – 19.87 lb CO/mmcf to be used for all modes of operation, excluding start-up operations, boiler restarts, hot restart/emergency trip, boiler cold and very cold start. 157.4 lb CO/mmcf to be used during boiler morning start-up

operations, boiler restarts, hot restart/emergency trip and boiler cold and very cold start.

After CO CEMS certification testing – 19.87 lb/CO mmcf is to be used. After CO CEMS certification test is approved by the SCAQMD, the emissions monitored by the CEMS and calculated in accordance with condition 82.1 shall be used to calculate emissions.

The operator shall provide the SCAQMD with written notification of the date of initial CO catalyst use within seven (7) days of this event.

For the purpose of this condition the boiler shall not commence with normal operation until the commissioning process has been completed. The District shall be notified in writing once the commissioning process has been completed. Normal operations may proceed in the same commissioning month provided the operator follows the requirements listed below.

The operator shall calculate the commissioning emissions for VOC, SOx and PM10 for the commissioning month (beginning of the month to the last day of commissioning) using the equation below and the following emissions factor; VOC: 5.7 lb/mmcf; PM10 5.25 lb/mmcf; and SOx: 2.14 lb/mmcf. For Start-up (cold or warm start) the following emission factors shall be used: PM10:10.5 lb/mmcf

Commissioning Emissions, lb/month = X * EF

Where X = commissioning fuel usage in mmcf/month and E.F = emission factor indicated above.

The commissioning emissions for VOC, SOx, CO and PM10 shall be subtracted from the monthly emissions limits (listed in the table a the top of this condition) and the revised monthly emissions limits will be the maximum emissions allowed for the remaining calendar month.

The operator shall keep records of monthly emissions and the records shall be made available upon request by the Executive Officer.
[Rule 1303 – Offsets]

A99.1 The 5.0 PPM NOx emission limits shall not apply during boiler commissioning, start-ups and emergency trips. The commissioning period shall not exceed 40 total hours. Start-up time shall not exceed the times listed below. Written records of commissioning, start-ups and emergency trips shall be maintained and made available upon request from the Executive Officer.

For this condition a boiler hot/emergency trip start-up is defined as a start-up in which the boiler has been shut down for less than 12 hours. A boiler hot/emergency trip start-up period shall not exceed 45 minutes.

For this condition, a boiler warm start-up is defined as a start-up in which the boiler has been shut down for at least 12 hours but less than 36 hours. A boiler warm start-up period shall not exceed 90 minutes

For this condition a boiler cold start-up is defined as a start-up in which he boiler has been shut down for at least 36 hours but less than 80 hours. A boiler cold start-up period shall not exceed 180 minutes

For this condition boiler very cold start-up is defined as a start-up in which the boiler has been shut down for at least 80 hours. A boiler very cold start-up period shall not exceed 270 minutes

[Rule 1703 (a)(2)-PSD BACT, Rule 2005]

A99.2 The 25 PPM CO emission limits shall not apply during boiler commissioning, start-ups and emergency trips. The commissioning period shall not exceed 40 total hours. Start-up time shall not exceed the times listed below. Written records of commissioning, start-ups and shall be maintained and made available upon request from the Executive

For this condition a boiler hot/emergency trip start-up is defined as a start-up in which the boiler has been shut down for less than 12 hours. A boiler hot/emergency trip start-up period shall not exceed 45 minutes.

For this condition, a boiler warm start-up is defined as a start-up in which the boiler has been shut down for at least 12 hours but less than 36 hours. A boiler warm start-up period shall not exceed 90 minutes

For this condition a boiler cold start is defined as a start-up in which the boiler has been shut down for at least 36 hours but less than 80 hours. A boiler cold start-up period shall not exceed 180 minutes

For this condition boiler very cold start is defined as a start-up in which the boiler has been shut down for at least 80 hours. A boiler very cold start-up period shall not exceed 270 minutes

[Rule 1703 (a)(2)-PSD BACT]

A99.3 The 11.55 LBS/MMCF NOx emission limits shall only apply during the interim reporting period during initial boiler commissioning to report RECLAIM emissions. During start-up or warm start modes the 92.40 lb/mmcf NOx emissions limits shall only apply during the interim reporting period during initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.
[Rule 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]

A99.4 The 6.53 LBS/MMCF NOx emission limits shall only apply during the interim reporting period after initial boiler commissioning to report RECLAIM emissions. During start-up mode operations with a boiler mode not to exceed 17.5%, the 83.96 lb/mmcf NOx emissions limits shall only apply during the interim reporting period during after initial boiler commissioning to report RECLAIM emissions The interim reporting period shall not exceed 12 months from entry into RECLAIM.
[Rule 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]

A195.1 The 25 PPMV CO emission limit(s) is averaged over 15 minutes at 3 percent O2, dry.

[Rule 1703(a)(2)- PSD-BACT]

A195.2 The 5 PPMV NOX emission limit(s) is averaged over 15 minutes at 3 percent O2, dry.

[Rule 2005, Rule 1703(a)(2)- PSD-BACT]

A195.4 The 80 PPMV NOX emission limit(s) is averaged over 30 day rolling average

Per §60.44(b)(h) the NOx standards under this section shall apply all times including periods of start-up, shut-down or malfunction

§60.44(b)(i)-Except as provided under paragraph (j) of this section, compliance with the emissions limits under this section is determined on a 30-day rolling average basis
[40 CFR 60 Subpart Db*]*

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]

A433.1 The operator shall comply at all times with the 5 ppm BACT limit for NOx, except as defined in condition A99.1 and for the following scenario:

Operating Scenario	Maximum Hourly Emission Limit	Operational Limit
Start-up event	3.5 lb/hr	NOx emissions not to exceed 10.5 lbs total per cold start-up per boiler. The boiler shall be limited to 10 cold start-ups per year, with each start-up not to exceed 180 minutes.

[Rule 1703(a)(2)-PSD-BACT, Rule 2005]

A433.2 The operator shall comply at all times with the 5 ppm BACT limit for NOx, except as defined in condition A99.1 and for the following scenario:

Operating Scenario	Maximum Hourly Emission Limit	Operational Limit
Start-up event	3.5 lb/hr	NOx emissions not to exceed 15.7 lbs total per very cold start-up per boiler. The boiler shall be limited to 5 very cold start-ups per year, with each start-up not to exceed 270 minutes.

[Rule 1703(a)(2)-PSD-BACT, Rule 2005]

C1.1 The operator shall limit the fuel usage to no more than 40 mmcf in any one calendar month.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler.

The operator shall record and maintain the amount of all fuel combusted during calendar month. The fuel usage records shall be kept for a period of five years and all records shall be made available to District personnel upon request
[*Rule 1303(b)(2) Offset]*

C1.2 The operator shall limit the fuel usage to no more than 4.28 mmcf in any one calendar month.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler during the commissioning period.

The operator shall record and maintain the amount of all fuel combusted during each calendar month. The fuel usage records shall be kept for a period of five years and all records shall be made available to District personnel upon request
[*Rule 1303(b)(2) Offset]*

C1.3 The operator shall limit the fuel usage to no more than 307 mmcf in any one year.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler during a non-commissioning year.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition. Year is defined as 12-month rolling average. The fuel usage records shall be kept for a period of five years and all records shall be made available to District personnel upon request

[Rule 1401, Rule 1701 (b), Rule 1303 (b)(2)]

C1.4 The operator shall limit the fuel usage to no more than 311 mmcf in any one year.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler during a commissioning year.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition. Year is defined as 12-month rolling average. The fuel usage records shall be kept for a period of five years and all records shall be made available to District personnel upon request

[Rule 1401, Rule 1701 (b), Rule 1303 (b)(2)

D12.1 The operator shall install and maintain a(n) flow meter to accurately indicate the fuel usage being supplied to the boiler.

The operator shall also install and maintain a device to continuously record the parameter being measured
[Rule 1303(b)(2) – Offset, Rule 2012,40 CFR 60.48c(g)(2)]

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	15 minutes	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	15 minutes	Outlet of the SCR serving this equipment
SOX emissions	SCAQMD Laboratory Method 307-91	Not applicable	Fuel Sample
PM emissions	District method 5.1	1 hour minimum	Outlet SCR
NH3 emissions	District method 201.7 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

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 (mmcf/hour), and the flue gas flow rate.

The test shall be conducted in accordance with 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 boiler 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 for each load, while firing at maximum, minimum and low firing rates.

The test shall be conducted for compliance verification of the 25 ppmv CO limit.

The test shall be conducted for compliance verification of the 5 ppmv NOx limit.

The test shall be conducted for compliance verification of the 5 ppmv ammonia slip limit.

Two complete copies of source test reports (include the application number and a copy of the permit in the report) shall be submitted to the District (addressed to south coast air quality management district, attn Roy Olivares, P.O. Box 4941, Diamond bar, CA 91765). The results in writing shall be submitted within 45 days after the source test is completed. It shall include, but not be limited to emissions rate in pounds per hour and concentration in ppmv at the outlet of the boiler.

A testing laboratory certified by the SCAQMD laboratory approval program (LAP) in the required test methods for criteria pollutant to be measured, and in compliance with district rule 304 (no conflict of interest) shall conduct the test

Sampling facilities shall comply with the SCAQMD "guidelines for construction of sampling and testing facilities", pursuant to rule 217. *Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 2005, Reg 1703(a-PSD-BACT]*

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	60 minutes	Outlet of the SCR serving this equipment

The test shall be conducted and the results submitted to the District within 45 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 7 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 BACT concentration limit
[Rule 1303(a)(1) – BACT]

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

CO concentration in ppmv

Concentrations shall be corrected to 3 percent oxygen on a dry basis
The CEMS shall be installed and operated no later than 90 days after initial start-up of the boiler, and in accordance with an approved SCAQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD. Within two weeks of the boiler start-up, the operator shall provide written notification to the District of the exact date of start-up.

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

The CEMS would 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% - %O2 d)][(Qg * HHV)/106], where

K = 7.267 *10^{-8} (lb/scf)/ppm

Cco = Average of four consecutive 15 min. ave. CO concentration, ppm

Fd = 8710 dscf/MMBTU natural gas

$\%O_2$ d = Hourly ave. % by vol. O_2 dry, corresponding to Cco

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

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

[Rule 1703(a)(2)- PSD-BACT, Rule 218]

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

NOx concentration in ppmv

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

The CEMS shall be installed and operating no later than 90 days after initial start-up of the boiler and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of the boiler start-up date, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operating (for BACT purposes only) no later than 90 days after initial start up of the boiler.

[Rule 2005; Rule 2012, Rule 1703]

H23.1 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
CO	District Rule	1146

The operator of this equipment shall comply with source testing requirements in subdivision (D)(6)--compliance determination of rule 1146.

The operator of this equipment shall comply with periodic monitoring requirements of rule 1146 (C)(8).

[Rule 1146]

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

Contaminant	Rule	Rule/Subpart
PM	40CFR60, SUBPART	Db
SOX	40CFR60, SUBPART	Db
NOx	40CFR60, SUBPART	Db

[40CFR 60 SUBPART Db]

E193.1 The operator shall upon completion of 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 09-AFC-7 project *[CEQA]*

E448.1 The operator shall comply with the following requirements

This boiler shall not be operated unless the flue gas recirculation system is in full operation.

The operator shall have the burner equipped with a control system to automatically regulate the combustion air, fuel, and recirculation flue gas as the boiler load varies. This control system shall be adjusted and tuned according to the manufacturer's specifications to maintain its ability to repeat the same performance at the same firing rate.
[Rule 1303 (a), Rule 2005]

E448.4 The operator shall comply with the following requirements

§60.49b Reporting and record keeping requirements and shall include the following

(a)(1) The design heat input capacity of the boilers and the type of fuels to be used by the equipment.

(a)(2)-If applicable, a copy of any federally enforceable requirements that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(ii), 60.44b(c), (d), (e), (i),(j), (k), 60.45b(d), (g), 60.46b(h)(1), or 60.48b(i).

(a)(3)- The annual capacity factor at which the operator anticipated operating the facility based on all fuels fired and based on each individual fuel fired

§60.49b(d)(1)-The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12 month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

§60.49b(g)The operator of the boilers subject to the NOx standards under 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date
(2) The ave hourly NOx emissions rate (expressed as NO2)(ng/J or lb/mmbtu heat input.
(3) The 30 day average NOx emission rate calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emissions rate for the proceeding 30 steam generating unit operating days.
(4) Identification of the steam unit operating days when the calculated 30-day average NOx emissions rates are in excess of the NOx emissions standards under 60.44b, with the reasons for such excess emissions as well as a description of corrective action taken;
(5) Identifications of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective action taken;
(6) Identification of the times when emissions data have been excluded from the calculations of average emission rates and the reasons for excluding data;
(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.
(8) Identification of the times when the pollutant concentration exceeded full span of CEMs;
(9) Description of any modifications to the CEMs that could affect the ability of the CEMs to comply with Performance Specification 2 or 3; and
(10) Results of daily CEMs drift test and quarterly accuracy assessments as required under Appendix F, Procedure 1 of this part.

§60.49b (h)- The owner or operator of any affected facility in any category listed in paragraph (h)(1) or (2) of this section is required to submit excess emission reports for any excess emission that occurred during the reporting period.

§60.49b (i)-The owner or operator of any affected facility subject to the continuous monitoring requirements for NOx under §60.48b shall submit reports containing the information recorded under paragraph (g) of this section.

The operator shall comply with remaining sections of this subpart, if applicable. [40 CFR 60 Subpart Db]

I298.1 This equipment shall not be operated unless the facility holds 5714 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 operations. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at commencement of each compliance year after the start of operation, the facility holds 5645 pounds 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 hold RTCs may be transferred upon their respective expiration dates. His hold amount is addition to any other amount of RTCs required to be held under condition(s)stated in this permit
[Rule 2005

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

Retain all records required by permit for a period of five years and make all records available to district personnel upon request.

The operator shall record and maintain the amount of all fuel combusted during each calendar month. The fuel usage records shall be kept for a period of five years and all records shall be made available to district personnel upon request. [Rule 1303 (b)(2), *40 CFR 60 Subpart Db*]

K67.2 The operator shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use after CEMS certification
Natural gas fuel use during the commissioning period
Natural gas fuel use after the commissioning period and prior to CEMS certification
[Rule 2012]

(SCR/CO Catalyst)a/n 553874 and 553875 (C3 and C8)

A195.6 The 5 ppmv NH3 emission limit is averaged over 60 minutes at 3% O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following:

NH3 (ppmv) = [a-b*c/1EE+06]*1EE+06/b

where,
a = NH3 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 3% O2)

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]

D12.3 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 records shall be kept on site and made available to SCAQMD personnel upon request

The maximum ammonia injection rate shall not exceed 1.9 gal/hr based on 19% aqueous ammonia
[Rule 1303(a)(1) - BACT, Rule 2005]

D12.4 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 records shall be kept on site and made available to SCAQMD personnel upon request

The catalyst temperature range shall be remain between 550 degree F and 750 degree F.

The catalyst inlet temperature shall not exceed 750 degrees F.

The temperature range requirement of this condition does not apply during start-up operations of the boiler listed in condition A99.1.
[Rule 1303(a)(1) - BACT, Rule 2005]

D12.5 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 records shall be kept on site and made available to SCAQMD personnel upon request

The pressure drop across the catalyst and ammonia injection grid shall not exceed 4.5 inches water column
[Rule 1303(a)(1) - BACT, Rule 2005]

E179.1 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 D12.3
Condition Number D12.4
[Rule 1303(a)(1) - BACT, Rule 2005-BACT]

E179.2 For the purpose of the following condition numbers, continuously record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

Condition Number: D12.5
[Rule 1303(a)(1) - BACT, Rule 2005-BACT]

E193.1 The operator shall upon completion of 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 09-AFC-7 project
[CEQA]

E448.5 The operator shall comply with the following requirements

The ammonia injection system shall be placed in full operation as soon as the minimum temperature is reached. The minimum temperature is listed as 550 degrees F. at the inlet to the SCR reactor.
[Rule 1303(a)(1) – BACT, Rule 2005]

NIGHT PRESERVATION BOILERS, A/N 549381 AND 549383 (D11 AND D12)

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

CONTAMINANT	EMISSION LIMIT
PM_{10}	33 LBS IN ANY ONE MONTH
CO	86 LBS IN ANY ONE MONTH
SOx	9 LBS IN ANY ONE MONTH
VOC	18 LBS IN ANY ONE MONTH

The operator shall calculate the calendar monthly emissions for VOC, PM10 and SOx using the equation below and the following emission factors: VOC: 4.2 lb/mmcf; PM10: 7.6 lb/mmcf; CO: 19.72 lb/mmcf and SOx: 2.14 lb/mmcf.

Monthly Emissions, lb/month = X (E.F.)

Where X = monthly fuel usage in mmscf/month and E.F. = emission factor indicated above.

For the purpose of this condition the boiler shall not commence with normal operation until the commissioning process has been completed. The District shall be notified in writing once the commissioning process has been completed. Normal operations may proceed in the same commissioning month provide the operator follows the requirements listed below.

The operator shall calculate the commissioning emissions for VOC, SOx, PM10 and CO for the commissioning month (beginning of the month to the last day of commissioning) using the equation below and the following emissions factor; VOC: 5.67 lb/mmcf; PM10 13.65 lb/mmcf; SOx: 2.14 lb/mmcf and CO: 18.96 lb/mmcf.

Commissioning Emissions, lb/month = X * EF

Where X = commissioning fuel usage in mmcf/month and E.F = emission factor indicated above.

The commissioning emissions for VOC, SOx, CO and PM10 shall be subtracted the monthly emissions limits (listed in the table a the top of this condition) and the revised monthly emissions limits will be the maximum emissions allowed for the remaining month.
[Rule 1303 – Offsets]

A195.1 The 25 PPMV CO emission limit(s) is averaged over 15 minutes at 3 percent O2, dry.
[Rule 1703(a)(2)- PSD-BACT]

A195.3 The 9 PPMV NOX emission limit(s) is averaged over 15 minutes at 3 percent O2, dry.
[*Rule 2005, Rule 1703(a)(2)- PSD-BACT]*

C1.5 The operator shall limit the fuel usage to no more than 4.34 mmcf in any one calendar month.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler.

The operator shall record and maintain the amount of all fuel combusted during each calendar month. The fuel usage records shall be kept for a period of five years and all records shall be made available to district personnel upon request
[*40 CFR 60 Subpart Dc, Rule 1303(b)(2) Offset]*

C1.6 The operator shall limit the fuel usage to no more than 0.11 mmcf in any one commissioning period.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler.

The operator shall record and maintain the amount of all fuel combusted during each calendar month. The fuel usage records shall be kept for a period of five years and all records shall be made available to district personnel upon request
[*40 CFR 60 Subpart Dc, Rule 1303(b)(2) Offset]*

C1.7 The operator shall limit the fuel usage to no more than 48 mmcf in any one calendar year.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler.

The operator shall record and maintain the amount of all fuel combusted during each year. The fuel usage records shall be kept for a period of five years and all records shall be made available to district personnel upon request
[*Rule 1401, Rule 1303 (b(2)]*

D12.1 The operator shall install and maintain a(n) flow meter to accurately indicate the fuel usage being supplied to the boiler.

The operator shall also install and maintain a device to continuously record the parameter being measured
[Rule 1303(b)(2) - Offset, Rule 2012,40 CFR Subpart Dc]

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
NOX emissions	District Method 100.1	15 minutes	Outlet stack
CO emissions	District Method 100.1	15 minutes	Outlet stack
SOX emissions	AQMD Laboratory Method 307-91	Not applicable	Fuel Sample
PM emissions	District method 5.1	1 hour minimum	Outlet stack

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 (mmcf/hour), and the flue gas flow rate.

The test shall be conducted in accordance with 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 boiler 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 for 15 minutes for each load, while firing at maximum, minimum and low firing rates.

The test shall be conducted for compliance verification of the 25 ppmv CO limit.

The test shall be conducted for compliance verification of the 9 ppmv NOx limit.

Two complete copies of source test reports (include the application number and a copy of the permit in the report) shall be submitted to the District (addressed to south coast air quality management district, attn Roy Olivares, P.O. Box 4941, Diamond bar, CA 91765). The results in writing shall be submitted within 45 days after the source test is completed. It shall include, but not be limited to emissions rate in pounds per hour and concentration in ppmv at the outlet of the boiler.

A testing laboratory certified by the SCAQMD laboratory approval program (LAP) in the required test methods for criteria pollutant to be measured, and in compliance with district rule 304 (no conflict of interest) shall conduct the test

Sampling facilities shall comply with the SCAQMD "guidelines for construction of sampling and testing facilities", pursuant to rule 217.

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

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
NOX emissions	District Method 100.1	60 minutes	Outlet stack

The test shall be conducted at least once every five years

The test shall be conducted for compliance verification of the 9 ppmv NOx RECLAIM concentration limit.

[Rule 2012]

H23.1 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
CO	District Rule	1146

The operator of this equipment shall comply with source testing requirements in subdivision (D)(6)--compliance determination of rule 1146.

The operator of this equipment shall comply with periodic monitoring requirements of rule 1146 (C)(8).
[Rule 1146]

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

Contaminant	Rule	Rule/Subpart
PM	40CFR60, SUBPART	Dc
SOX	40CFR60, SUBPART	Dc

[40CFR 60 SUBPART Dc]

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

Retain all records required by permit for a period of five years and make all records available to district personnel upon request.

The operator shall record and maintain the amount of all fuel combusted during each calendar month. The fuel usage records shall be kept for a period of five years and all records shall be made available to district personnel upon request.
[Rule 1303 (b)(2), *40 CFR 60 Subpart Dc*]

E193.1 The operator shall upon completion of 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 09-AFC-7 project
[CEQA]

E448.1 The operator shall comply with the following requirements

This boiler shall not be operated unless the flue gas recirculation system is in full operation.

The operator shall have the burner equipped with a control system to automatically regulate the combustion air, fuel, and recirculation flue gas as the boiler load varies. This control system shall be adjusted and tuned according to the manufacturer's specifications to maintain its ability to repeat the same performance at the same firing rate.
[Rule 1303 (a)]

I298.3 This equipment shall not be operated unless the facility holds 565 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 operations. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at commencement of each compliance year after the start of operation, the facility holds 563 pounds 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 hold RTCs may be transferred upon their respective expiration dates. His hold amount is addition to any other amount of RTCs required to be held under condition(s)stated in this permit
[Rule 2005]

This condition is identical for I293.4 for D12

(Large Emergency engines, a/n 549387 and 549389) D13 and D15

B61.2 The operator shall only use diesel fuel containing th3 following specified compounds:

COMPOUND	Range	PPM BY WEIGHT
Sulfur	Less than or equal to	15

The operator shall maintain a copy of the MSDS on site
[Rule 431.2, Rule 1303 (a)-BACT, Rule 1470, 40 CFR 60 Subpart IIII]

C1.8 The operator shall limit the operating time to no more than 200 hours in any one year.

[*Rule 1110.2, Rule 1304, Rule 1303 (a), Rule 2005, Rule 1470, Rule 1714]*

C1.9 The operator shall limit the operating time to no more than 50 hours in any one year.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing

Operation beyond the 50 hours per year for engine maintenance and testing shall be allowed only in the event of a loss of grid power or up to 30 minutes prior to a rotating outage, provided that the utility distribution company has ordered rotating outages in the control area where the engine is located or has indicated that it expects to issue such an order at a certain time, and the engine is located in a utility service block that is subject to the rotating outage. Engine operation shall be terminated immediately after the utility distribution company advises that a rotating outage is no longer imminent or in effect
[Rule 1303(a)-BACT, *Rule 1304, Rule 2012, Rule 1470]*

C1.10 The operator shall limit the operating time to no more than 4.2 hours in any one month.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing
[*Rule 1304, Rule 2012]*

C1.11 The operator shall limit the operating time to no more than 30 minutes in any one day.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing
[CEQA*]*

D12.2 The operator shall install and maintain a(n) non-resettable elapsed meter to accurately indicate the elapsed operating time of the engine.
[Rule 1110.2, Rule 1304, Rule 1470, Rule 2012, 40 CFR 60 Subpart IIII*]*

E193.1 The operator shall upon completion of 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 09-AFC-7 project.

E448.2 The operator shall comply with the following requirements

The operator shall comply with the emission standards specified in 40 CFR 60.4205(B) by purchasing an engine certified to the emission standards in 40 CFR 60.4205(B), as applicable, for the same model year and maximum engine power. the engine must be installed and configured according to the manufacturer's emission related specifications.
[40 CFR 60.4211(c)]

E448.3 The operator shall comply with the following requirements

The operator shall operate and maintain the stationary engine and control device according to the manufacturer's written emission-related instructions (or procedures developed by the operator that are approved by the engine manufacturer), change only those emission-related settings that are permitted by the manufacturer, and meet the requirements of 40 CFR 89, 94 and/or 1068, as they apply.
[40 CFR 60.4211(a)]

H23.5 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
PM	District Rule	1470
Sulfur	District Rule	431.2

[Rule 431.2, Rule 1470]

I298.5 This equipment shall not be operated unless the facility holds 5922 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 operations. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at commencement of each compliance year after the start of operation, the facility holds 5922 pounds 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 hold RTCs may be transferred upon their respective expiration dates. His hold amount is addition to any other amount of RTCs required to be held under condition(s)stated in this permit
[Rule 2005

CONDITION I128.6 applies to engine no. 2

K67.3 The operator shall keep records in a manner approved by the Executive Officer, for the following parameter(s) or item(s):

Manual and automatic operation and shall list all engine operations in each of the following areas:

A. emergency use
B. MAINTENANCE AND TESTING
C. OTHER (BE SPECIFIC)

In addition, for each time the engine is manually started, the log shall include the date of engine operation, the specific reason for operation, and the totalizing hour meter reading (in hours and tenths of hours) at the beginning and the end of the operation.
[Rule 1110.2, Rule 1470, 40 CFR 60.4214 (b)*]*

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

On or before January 15th of each year, the operator shall record in the engine operating log:

A. the total hours of engine operation for the previous calendar year, and
B. The total hours of engine operation for maintenance and testing for the previous calendar year

Engine operation log(s) shall be retained on site for a minimum of five calendar years and shall be made available to the executive officer or representative upon request.
[Rule 1304]

(Small Emergency engine, a/n 549390) D17

C1.8 The operator shall limit the operating time to no more than 200 hours in any one year.

[*Rule 1110.2, Rule 1304, Rule 1303 (a), Rule 2012, Rule 1470, Rule 1714]*

C1.9 The operator shall limit the operating time to no more than 50 hours in any one year.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing

Operation beyond the 50 hours per year for engine maintenance and testing shall be allowed only in the event of a loss of grid power or up to 30 minutes prior to a rotating outage, provided that the utility distribution company has ordered rotating outages in the control area where the engine is located or has indicated that it expects to issue such an order at a certain time, and the engine is located in a utility service block that is subject to the rotating outage. Engine operation shall be terminated immediately after the utility distribution company advises that a rotating outage is no longer imminent or in effect

[*Rule 1303-BACT, Rule 1304, Rule 2012, Rule 1470]*

C1.10 The operator shall limit the operating time to no more than 4.2 hours in any one month.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing
[*Rule 1304, Rule 2012]*

C1.11 The operator shall limit the operating time to no more than 30 minutes in any one day.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing
[CEAQ*]*

D12.2 The operator shall install and maintain a(n) non-resettable elapsed meter to accurately indicate the elapsed operating time of the engine.
[Rule 1110.2, Rule 1304, Rule 1470, Rule 2012, 40 CFR 60.4209 (a)*]*

E193.1 The operator shall upon completion of 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 09-AFC-7 project.

E448.2 The operator shall comply with the following requirements

The operator shall comply with the emission standards specified in 40 cfr 60.4205(B) by purchasing an engine certified to the emission standards in 40 CFR 60.4205(B), as applicable, for the same model year and maximum engine power. the engine must be installed and configured according to the

manufacturer's emission related specifications.
[40 CFR 60.4211(c)]

E448.3 The operator shall comply with the following requirements

The operator shall operate and maintain the stationary engine and control device according to the manufacturer's written emission-related instructions (or procedures developed by the operator that are approved by the engine manufacturer), change only those emission-related settings that are permitted by the manufacturer, and meet the requirements of 40 CFR 89, 94 and/or 1068, as they apply.
[40 CFR 60.4211(a)]

H23.5 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
PM	District Rule	1470
Sulfur	District Rule	431.2

[Rule 431.2, Rule 1470]

I298.7 This equipment shall not be operated unless the facility holds 434 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 operations. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at commencement of each compliance year after the start of operation, the facility holds 434 pounds 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 hold RTCs may be transferred upon their respective expiration dates. His hold amount is addition to any other amount of RTCs required to be held under condition(s)stated in this permit
[Rule 2005

K67.3 The operator shall keep records in a manner approved by the Executive Officer, for the following parameter(s) or item(s):

Manual and automatic operation and shall list all engine operations in each of the following areas:

A. emergency use
B. MAINTENANCE AND TESTING
C. OTHER (BE SPECIFIC)

In addition, for each time the engine is manually started, the log shall include the date of engine operation, the specific reason for operation, and the totalizing hour meter reading (in hours and tenths of hours) at the beginning and the end of the operation.
[Rule 1110.2, Rule 1470, 40 CFR 60.4214 (b)*]*

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

On or before January 15th of each year, the operator shall record in the engine operating log:

A. the total hours of engine operation for the previous calendar year, and
B. The total hours of engine operation for maintenance and testing for the previous calendar year

Engine operation log(s) shall be retained on site for a minimum of three calendar years and shall be made available to the executive officer or representative upon request.
[Rule 1304]

(Fire Pump engine, a/n 549384, 549385 and 549386) D19, D20, D21

C1.8 The operator shall limit the operating time to no more than 200 hours in any one year.

[*Rule 1110.2, Rule 1304, Rule 1303 (a), Rule 2012, Rule 1470, Rule 1714]*

C1.12 The operator shall limit the operating time to no more than 50 hours in any one year.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing
[*Rule 1110.2, Rule 1304, Rule 2012, Rule 1470]*

C1.10 The operator shall limit the operating time to no more than 4.2 hours in any one month.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing
[*Rule 1303-BACT, Rule 1304, Rule 2012, Rule 1470]*

C1.11 The operator shall limit the operating time to no more than 30 minutes in any one day.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing
[CEQA*]*

D12.2 The operator shall install and maintain a(n) non-resettable elapsed meter to accurately indicate the elapsed operating time of the engine.
[Rule 1110.2, Rule 1304, Rule 1470, Rule 2012, 40 CFR 60.4209 (a)*]*

E193.1 The operator shall upon completion of 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 09-AFC-7 project.

E448.2 The operator shall comply with the following requirements

The operator shall comply with the emission standards specified in 40 cfr 60.4205(B) by purchasing an engine certified to the emission standards in 40 CFR 60.4205(B), as applicable, for the same model year and maximum engine

power. the engine must be installed and configured according to the manufacturer's emission related specifications.
[40 CFR 60.4211(c)]

E448.3 The operator shall comply with the following requirements

The operator shall operate and maintain the stationary engine and control device according to the manufacturer's written emission-related instructions (or procedures developed by the operator that are approved by the engine manufacturer), change only those emission-related settings that are permitted by the manufacturer, and meet the requirements of 40 CFR 89, 94 and/or 1068, as they apply.
[40 CFR 60.4211(a)]

H23.5 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
PM	District Rule	1470
Sulfur	District Rule	431.2

[Rule 431.2, Rule 1470]

I298.8 This equipment shall not be operated unless the facility holds 707 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 operations. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at commencement of each compliance year after the start of operation, the facility holds 707 pounds 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 hold RTCs may be transferred upon their respective expiration dates. His hold amount is addition to any other amount of RTCs required to be held under condition(s)stated in this permit
[Rule 2005

K67.3 The operator shall keep records in a manner approved by the Executive Officer, for the following parameter(s) or item(s):

Manual and automatic operation and shall list all engine operations in each of the following areas:

A. emergency use
B. MAINTENANCE AND TESTING
C. OTHER (BE SPECIFIC)

In addition, for each time the engine is manually started, the log shall include the date of engine operation, the specific reason for operation, and the totalizing hour meter reading (in hours and tenths of hours) at the beginning and the end of the operation.
[Rule 1110.2, Rule 1470, 40 CFR 60.4214 (b)*]*

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

On or before January 15th of each year, the operator shall record in the engine operating log:

A. the total hours of engine operation for the previous calendar year, and
B. The total hours of engine operation for maintenance and testing for the previous calendar year

Engine operation log(s) shall be retained on site for a minimum of three calendar years and shall be made available to the executive officer or representative upon request
[Rule 1304]

(Section D; Device E25)

K67.6 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

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

For architectural applications where no thinners, reducers, or other VOC containing materials are added, maintain semi-annual records consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.
[Rule 1113]

PSGES ENERGY PROJECT
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PALEN SOLAR POWER PROJECT
Appendix A Facility Emissions Summaries

A. Facilty totals 30 days averages

NSR 30 day Ave

Equipment	NOx	VOC	CO	SOx	PM10
Large boiler 1	21.08	5.78	48.36	2.83	7.14
Large boiler 2	21.08	5.78	48.36	2.83	7.14
small boiler 1	1.69	0.61	2.85	0.31	1.10
small boiler 2	1.69	0.61	2.85	0.31	1.10
Large ICE 1	4.11	0.28	0.99	0.00	0.10
Large ICE 2	4.11	0.28	0.99	0.00	0.10
Small ICE	0.30	0.03	0.28	0.00	0.01
Large fire pump 1	0.49	0.02	0.09	0.00	0.02
Large fire pump 2	0.49	0.02	0.09	0.00	0.02
Large fire pump 3	0.49	0.02	0.09	0.00	0.02
totals	55.53	13.42	104.97	6.29	16.74

B. Facilty Monthy Emissions

Equipment	NOx	VOC	CO	SOx	PM10
Large boiler 1	632.33	173.37	1450.87	84.91	214.15
Large boiler 2	632.33	173.37	1450.87	84.91	214.15
small boiler 1	50.62	18.23	85.60	9.30	32.98
small boiler 2	50.62	18.23	85.60	9.30	32.98
Large ICE 1	123.37	100.03	356.10	0.13	2.98
Large ICE 2	123.37	100.03	356.10	0.13	2.98
Small ICE	9.10	0.99	8.44	0.02	0.40
Large fire pump 1	14.72	0.57	2.83	0.03	0.51
Large fire pump 2	14.72	0.57	2.83	0.03	0.51
Large fire pump 3	14.72	0.57	2.83	0.03	0.51
totals	1665.90	585.93	3802.06	188.79	502.16

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PALEN SOLAR POWER PROJECT
Appendix A Facility Emissions Summaries

C. Facilty totals annual emissions

Equipment	NOx	VOC	CO	SOx	PM10
Large boiler 1	5645.04	1358.78	12566.74	658.17	1683.93
Large boiler 2	5645.04	1358.78	12566.74	658.17	1683.93
small boiler 1	563.39	202.86	952.59	103.50	367.08
small boiler 2	563.39	202.86	952.59	103.50	367.08
Large ICE 1	1480.41	6.80	356.10	1.53	35.81
Large ICE 2	1480.41	6.80	356.10	1.53	35.81
Small ICE	109.14	11.83	101.25	0.22	4.82
Large fire pump 1	176.67	6.80	33.98	0.37	6.12
Large fire pump 2	176.67	6.80	33.98	0.37	6.12
Large fire pump 3	176.67	6.80	33.98	0.37	6.12
totals	16016.84	3169.09	27954.04	1527.70	4196.82
ton/yr	8.01	1.58	13.98	0.76	2.10

PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

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Boosting mode

Data:

Emission Rate = Emission Factor (lb/MMBTU) * Heat Input (MMBTU/hr)
NOx = 5 ppm @ 3% O_2, CO = 25 ppm @ 3% O_2
Maximum daily operation of each boiler, see table below
Maximum days/mon is 29 day (for worst case month emissions) and 220 days per year

PM2.5 emissions are equivalent to PM10 emissions
Boilers fired exclusively with natural gas
30DA means 30-day average

One Boiler-load, uncontrolled/controlled hr/dy totals

	Uncontrolled	controlled	mmcf	mmbtu
boiler load	hr/dy	hr/dy		
17.50%	3		0.1245	130.725
100%	0	2	0.474285714	498
50%	0	0.5	0.059285714	62.25
80%		1.5	0.284571429	298.8
total	3	4	0.942642857	989.775

One Boiler-Controlled emissions-100% load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximum Hourly (lb/hr)	Maximum hr/dy	Maximum Daily (lb/day)
NOx	5	ppmv	applicant	0.006219	249	1.5484	2.0000	3.097
VOC	0.004000	lb/MMBTU	applicant	0.004000	249	0.9960	2.0000	1.992
CO	25	ppmv	applicant	0.018926	249	4.7126	2.0000	9.425
PM10	0.004857	lb/MMBTU	vender	0.004857	249	1.2094	2.0000	2.419
SOx	0.002041	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	249	0.5082	2.0000	1.016

PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

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One Boiler-Uncontrolled emissions-17.5% Load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximum Hourly (lb/hr)	hr/dy	Maximum Daily (lb/day)
NOx	64.3	ppmv	applicant	0.079970	43.575	3.4847	3.0000	10.454
VOC	0.005400	lb/MMBTU	AP-42 1.4-2	0.005400	43.575	0.2353	3.0000	0.706
CO	198	ppmv	applicant	0.149894	43.575	6.5316	3.0000	19.595
PM10	0.007238	lb/MMBTU	vender	0.007238	43.575	0.3154	3.0000	0.946
SOx	0.002041	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	43.575	0.0889	3.0000	0.267

One Boiler-Controlled emissions-50% load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximum Hourly (lb/hr)	hr/dy	Maximum Daily (lb/day)
NOx	5	ppmv	applicant	0.006219	124.5	0.7742	0.5000	0.387
VOC	0.004	lb/MMBTU	applicant	0.004000	124.5	0.4980	0.5000	0.249
CO	25	ppmv	applicant	0.018926	124.5	2.3563	0.5000	1.178
PM10	0.0048571	lb/MMBTU	vendor	0.004857	124.5	0.6047	0.5000	0.302
SOx	0.0020408	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	124.5	0.2541	0.5000	0.127

One Boiler-Controlled emissions-80% load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximum Hourly (lb/hr)	hr/dy	Maximum Daily (lb/day)
NOx	5	ppmv	applicant	0.006219	199.2	1.2387	1.5000	1.858
VOC	0.004	lb/MMBTU	AP-42 1.4-2	0.004000	199.2	0.7968	1.5000	1.195
CO	25	ppmv	applicant	0.018926	199.2	3.7701	1.5000	5.655
PM10	0.0048571	lb/MMBTU	vendor	0.004857	199.2	0.9675	1.5000	1.451
SOx	0.0020408	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	199.2	0.4065	1.5000	0.610

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PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

One Boiler-Booster total emissions

Pollutant	Maximum Daily normal operation 100% load (lb/day)	Maximum Daily start-up/hot start operation 17.5% load no control (lb/day)	Maximum Daily hot start operation 50% load control (lb/day)	Maximum Daily 80% load controlled (lb/day)	Maximum Total Daily (lb/day)	Maximum Total Daily (lb/mon)
NOx	3.097	10.454	0.387	1.858	15.796	458.088
VOC	1.992	0.706	0.249	1.195	4.142	120.121
CO	9.425	19.595	1.178	5.655	35.853	1039.743
PM10	2.419	0.946	0.302	1.451	5.119	148.443
SOx	1.016	0.267	0.127	0.610	2.020	58.579

Very Cold day start mode

Data:

Emission Rate = Emission Factor (lb/MMBTU) * Heat Input (MMBTU/hr)

NOx = 5 ppm @ 3% O_2, CO = 25 ppm @ 3% O_2

Maximum daily operation of each boiler is 1 hr/day at full load, 10 hr/dy at 50% load and 4.5 hr/day at 17.5% load

Maximum number of colds start per month is 1 and per year is 5

PM2.5 emissions are equivalent to PM10 emissions

Boilers fired exclusively with natural gas

30DA means 30-day average

One Boiler-load, uncontrolled/controlled hr/dy totals

	Uncontrolled	controlled	mmcf	mmbtu
boiler load	hr/dy	hr/dy		
17.50%	4.5		0.18675	196.0875
100%	0	1	0.237142857	249
50%	0	10	1.185714286	1245
total	4.5	11	1.609607143	1690.0875

PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

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One Boiler-Controlled emissions-100 percent load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	hr/dy	Maximum Hourly (lb/hr)	Maximum Daily (lb/day)
NOx	5	ppmv	applicant	0.006219	249	1.0000	1.5484	1.548
VOC	0.004000	lb/MMBTU	applicant	0.004000	249	1.0000	0.9960	0.996
CO	25	ppmv	applicant	0.018926	249	1.0000	4.7126	4.713
PM10	0.004857	lb/MMBTU	vender	0.004857	249	1.0000	1.2094	1.209
SOx	0.002041	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	249	1.0000	0.5082	0.508

One Boiler-Controlled emissions-50 percent load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	hr/dy	Maximum Hourly (lb/hr)	Maximum Daily (lb/day)
NOx	5	ppmv	applicant	0.006219	124.5	10.0000	0.7742	7.742
VOC	0.004	lb/MMBTU	applicant	0.004000	124.5	10.0000	0.4980	4.980
CO	25	ppmv	applicant	0.018926	124.5	10.0000	2.3563	23.563
PM10	0.004857	lb/MMBTU	vender	0.004857	124.5	10.0000	0.6047	6.047
SOx	0.0020408	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	124.5	10.0000	0.2541	2.541

One Boiler-Uncontrolled emission-17.5 percent load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	hr/dy	Maximum Hourly (lb/hr)	Maximum Daily (lb/day)
NOx	64.3	ppmv	applicant	0.079970	43.575	4.5000	3.4847	15.681
VOC	0.005400	lb/MMBTU	AP-42 1.4-2	0.005400	43.575	4.5000	0.2353	1.059
CO	198	ppmv	applicant	0.149894	43.575	4.5000	6.5316	29.392
PM10	0.007238	lb/MMBTU	vender	0.007238	43.575	4.5000	0.3154	1.419
SOx	0.002041	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	43.575	4.5000	0.0889	0.400

PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

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One Boiler-total emissions-Very Cold start

Pollutant	Maximum Daily normal operation 100% load (lb/day)	Maximum Daily start-up operation 17.5% load (lb/day)	Maximum Daily start-up operation 50% load (lb/day)	Maximum Total Daily (lb/day)	Maximum Total Daily (lb/mon)
NOx	1.548	15.681	7.742	24.972	24.972
VOC	0.996	1.059	4.980	7.035	7.035
CO	4.713	29.392	23.563	57.668	57.668
PM10	1.209	1.419	6.047	8.676	8.676
SOx	0.508	0.400	2.541	3.449	3.449

Cold day start mode

Data:

Emission Rate = Emission Factor (lb/MMBTU) * Heat Input (MMBTU/hr)

NOx = 5 ppm @ 3% O_2, CO = 25 ppm @ 3% O_2

Maximum daily operation of each boiler is 1 hr/day at full load, 4 hr/dy at 50% load and 3 hr/day at 17.5% load

Maximum number of colds start per month is 1 and per year is 10

PM2.5 emissions are equivalent to PM10 emissions

Boilers fired exclusively with natural gas

30DA means 30-day average

One Boiler-load, uncontrolled/controlled hr/dy totals

	Uncontrolled	controlled	mmcf	mmbtu
boiler load	hr/dy	hr/dy		
17.50%	3		0.1245	130.725
100%	0	1	0.237142857	249
50%	0	4	0.474285714	498
total	3	5	0.835928571	877.725

PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

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One Boiler-Controlled emissions-100% load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	hr/dy	Maximum Hourly (lb/hr)	Maximum Daily (lb/day)
NOx	5	ppmv	applicant	0.006219	249	1.0000	1.5484	1.548
VOC	0.004000	lb/MMBTU	applicant	0.004000	249	1.0000	0.9960	0.996
CO	25	ppmv	applicant	0.018926	249	1.0000	4.7126	4.713
PM10	0.004857	lb/MMBTU	vender	0.004857	249	1.0000	1.2094	1.209
SOx	0.002041	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	249	1.0000	0.5082	0.508

One Boiler-Controlled emissions-50% load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	hr/dy	Maximum Hourly (lb/hr)	Maximum Daily (lb/day)
NOx	5	ppmv	applicant	0.006219	124.5	4.0000	0.7742	3.097
VOC	0.004	lb/MMBTU	applicant	0.004000	124.5	4.0000	0.4980	1.992
CO	25	ppmv	applicant	0.018926	124.5	4.0000	2.3563	9.425
PM10	0.0048571	lb/MMBTU	vender	0.004857	124.5	4.0000	0.6047	2.419
SOx	0.0020408	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	124.5	4.0000	0.2541	1.016

One Boiler-Uncontrolled emissiosn-17.5% load

Pollutant	Emission Factor	Units	Referance	Emission Factor (lb/MMBTU)	mmbtu/hr	hr/dy	Maximum Hourly (lb/hr)	Maximum Daily (lb/day)
NOx	64.3	ppmv	applicant	0.079970	43.575	3.0000	3.4847	10.454
VOC	0.005240	lb/MMBTU	AP-42 1.4-2	0.005400	43.575	3.0000	0.2353	0.706
CO	198	ppmv	applicant	0.149894	43.575	3.0000	6.5316	19.595
PM10	0.007238	lb/MMBTU	vender	0.007238	43.575	3.0000	0.3154	0.946
SOx	0.002041	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	43.575	3.0000	0.0889	0.267

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PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

One Boiler-total monthly emissions-Cold start

Pollutant	Maximum Daily normal operation 100% load (lb/day)	Maximum Daily start-up operation 17.5% load no control (lb/day)	Maximum Daily normal operation 50% load (lb/day)	Maximum Total Daily (lb/day)	Maximum Total Daily (lb/mon)
NOx	1.548	10.454	3.097	15.099	15.099
VOC	0.996	0.706	1.992	3.694	3.694
CO	4.713	19.595	9.425	33.733	33.733
PM10	1.209	0.946	2.419	4.574	4.574
SOx	0.508	0.267	1.016	1.791	1.791

Hot restart after cloud event/emergency trip

Data:

Emission Rate = Emission Factor (lb/MMBTU) * Heat Input (MMBTU/hr)

NOx = 5 ppm @ 3% O_2, CO = 25 ppm @ 3% O_2

Maximum daily operation of each boile, see table below

Maximum number of hot re-start per month is 29 and per year is 60

PM2.5 emissions are equivalent to PM10 emissions

Boilers fired exclusively with natural gas

30DA means 30-day average

One Boiler-load, uncontrolled/controlled hr/dy totals

	Uncontrolled	controlled	mmcf	mmbtu
boiler load	hr/dy	hr/dy		
17.50%	0.75		0.031125	32.68125
100%		1	0.237142857	249
30%		1	0.071142857	74.7
total	0.75	2	0.339410714	356.38125

PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

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One Boiler-Controlled emissions-100% load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximum Hourly (lb/hr)	hr/dy	Maximum Daily (lb/day)
NOx	5	ppmv	applicant	0.006219	249	1.5484	1.0000	1.548
VOC	0.004000	lb/MMBTU	applicant	0.004000	249	0.9960	1.0000	0.996
CO	25	ppmv	applicant	0.018926	249	4.7126	1.0000	4.713
PM10	0.004857	lb/MMBTU	vender	0.004857	249	1.2094	1.0000	1.209
SOx	0.002041	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	249	0.5082	1.0000	0.508

One Boiler-Controlled emissions-30% load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximum Hourly (lb/hr)	hr/dy	Maximum Daily (lb/day)
NOx	5	ppmv	applicant	0.006219	74.7	0.4645	1.0000	0.465
VOC	0.004000	lb/MMBTU	applicant	0.004000	74.7	0.2988	1.0000	0.299
CO	25	ppmv	applicant	0.018926	74.7	1.4138	1.0000	1.414
PM10	0.004857	lb/MMBTU	vender	0.004857	74.7	0.3628	1.0000	0.363
SOx	0.002041	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	74.7	0.1524	1.0000	0.152

One Boiler-Uncontrolled emissions-17.5% load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximum Hourly (lb/hr)	hr/dy	Maximum Daily (lb/day)
NOx	64.3	ppmv	applicant	0.079970	43.575	3.4847	0.7500	2.614
VOC	0.005240	lb/MMBTU	AP-42 1.4-2	0.005240	43.575	0.2283	0.7500	0.171
CO	198	ppmv	applicant	0.149894	43.575	6.5316	0.7500	4.899
PM10	0.007238	lb/MMBTU	vender	0.007238	43.575	0.3154	0.7500	0.237
SOx	0.002041	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	43.575	0.0889	0.7500	0.067

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PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

One Boiler-total monthly emissions-Hot Start

Pollutant	Maximum Daily normal operation 100% load controlled (lb/day)	Maximum Daily normal operation 30% load controlled (lb/day)	Maximum Daily start-up operation 17.5% load no control (lb/day)	Maximum Total Daily (lb/day)	days/month	Maximum Total Daily (lb/mon)
NOx	1.548	0.465	2.614	4.626	29.000	134.168
VOC	0.996	0.299	0.171	1.466	29.000	42.515
CO	4.713	1.414	4.899	11.025	29.000	319.726
PM10	1.209	0.363	0.237	1.809	29.000	52.455
SOx	0.508	0.152	0.067	0.727	29.000	21.092

Non-Boosting mode

Data:

Emission Rate = Emission Factor (lb/MMBTU) * Heat Input (MMBTU/hr)

NOx = 5 ppm @ 3% O_2, CO = 25 ppm @ 3% O_2

Maximum daily operation of each boiler, see table below

The applicant estimates 120 of operation in non-boosting mode per year. Durning this operation no steam is used to generate electricty for worst case monthly emisisons, non-boosting mode is **not used**, but will be used for the annual emissions

PM2.5 emissions are equivalent to PM10 emissions

Boilers fired exclusively with natural gas

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PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

One Boiler-load, uncontrolled/controlled hr/dy totals

	Uncontrolled	controlled	mmcf	mmbtu
boiler load	hr/dy	hr/dy		
17.50%	3		0.1245	130.725
100%	0	1	0.237142857	249
80%		0.75	0.141714286	149.4
total	3	1.75	0.503357143	529.125

One Boiler-Controlled emissions-100% load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximum Hourly (lb/hr)	Maximum hr/dy	Maximum Daily (lb/day)
NOx	5	ppmv	applicant	0.006218532	249	1.5484	1.0000	1.548
VOC	0.004	lb/MMBTU	applicant	0.004	249	0.9960	1.0000	0.996
CO	25	ppmv	applicant	0.018925966	249	4.7126	1.0000	4.713
PM10	0.0048571	lb/MMBTU	vender	0.004857143	249	1.2094	1.0000	1.209
SOx	0.0020408	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002040816	249	0.5082	1.0000	0.508

One Boiler-Uncontrolled emissions-17.5% Load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximum Hourly (lb/hr)	hr/dy	Maximum Daily (lb/day)
NOx	64.3	ppmv	applicant	0.079970318	43.4	3.4847	3.0000	10.454
VOC	0.0054	lb/MMBTU	AP-42 1.4-2	0.0054	43.4	0.2353	3.0000	0.706
CO	198	ppmv	applicant	0.149893652	43.4	6.5316	3.0000	19.595
PM10	0.0072381	lb/MMBTU	vender	0.007238095	43.4	0.3154	3.0000	0.946
SOx	0.0020408	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002040816	43.4	0.0889	3.0000	0.267

PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

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One Boiler-Controlled emissions-80% load

Pollutant	Emission Factor	Units	Reference	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximum Hourly (lb/hr)	hr/dy	Maximum Daily (lb/day)
NOx	5	ppmv	applicant	0.006218532	199.2	1.2387	0.7500	0.929
VOC	0.004	lb/MMBTU	AP-42 1.4-2	0.004	199.2	0.7968	0.7500	0.598
CO	25	ppmv	applicant	0.018925966	199.2	3.7701	0.7500	2.828
PM10	0.0048571	lb/MMBTU	applicant	0.004857143	199.2	0.9675	0.7500	0.726
SOx	0.0020408	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002040816	199.2	0.4065	0.7500	0.305

One Boiler-non Booster total emissions

Pollutant	Maximum Daily normal operation 100% load (lb/day)	Maximum Daily start-up/hot start operation 17.5% load no control (lb/day)	Maximum Daily 80% load controlled (lb/day)	Maximum Total Daily (lb/day)
NOx	1.548	10.454	0.929	12.932
VOC	0.996	0.706	0.598	2.300
CO	4.713	19.595	2.828	27.135
PM10	1.209	0.946	0.726	2.881
SOx	0.508	0.267	0.305	1.080

PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

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One Boiler-total max. monthy, daily emissions for boosting, emergency hot start, very cold start and cold start operation modes

Pollutant	Maximum monthly boosting (lb/mon)	Maximum monthly very cold start (lb/mon)	Maximum monthly cold start (lb/mon)	Maximum monthly hot start emergency (lb/mon)	Maximum Total Daily (lb/mon)	30DA (lb/day)
NOx	458.088	24.972	15.099	**134.168**	632.327	**21.08**
VOC	120.121	7.035	3.694	**42.515**	173.366	**5.78**
CO	1039.743	57.668	33.733	**319.726**	1450.869	**48.36**
PM10	148.443	8.676	4.574	**52.455**	214.149	**7.14**
SOx	58.579	3.449	1.791	**21.092**	84.911	**2.83**

One Boiler-total annual emissions for boosting, non-boosting, emergency hot start, very cold start and cold start operation modes

Pollutant	Maximum yearly boosting (lb/yr)	Maximum yearly very cold start (lb/yr)	Maximum yearly cold start (lb/yr)	Maximum yearly hot start emergency (lb/yr)	Maximum yearly non-boosting (lb/yr)	Annual Emissions (lb/yr)	Annual Emissions (ton/yr)
day/yr	220	5	10	60	125		
NOx	3475.153	124.858	**150.994**	**277.588**	1616.448	5645.04	2.82
VOC	911.265	35.174	**36.939**	**87.963**	287.439	1358.78	0.68
CO	7887.704	288.338	**337.325**	**661.503**	3391.869	12566.74	6.28
PM10	1126.120	43.379	**45.745**	**108.528**	360.161	1683.93	0.84
SOx	444.389	17.246	**17.913**	**43.639**	134.981	658.17	0.33

PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

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Determination of Controlled Emission Factors
NOx EF = (5/1,000,000)(8710 scf/MMBTU)(46 lb/mol)(1 mol/379 scf)(20/20-3) = 0.0112 lb/MMBTU
COx EF = (25/1,000,000)(8710 scf/MMBTU)(28 lb/mol)(1 mol/379 scf)(20/20-3) = 0.01893 lb/MMBTU

Pollutant	con.	F-Factor	MW (lb/mol)	MV (scf/mol)	%O2 Corr	EF lb/MMBTU	EF lb/MMcf
R2 NOx	0.000005	8710	46	379	1.176470588	0.00622	6.52945833
R2 CO	0.000025	8710	28	379	1.176470588	0.01893	19.8722645
R1 NOx	0.0000643	8710	46	379	1.176470588	0.07997	83.9688341
R1 CO	0.000198	8710	28	379	1.176470588	0.14989	157.388335
R1 VOC						0.00540	5.7
R2 VOC						0.00400	4.1
PM10						0.00724	7.6
SOx						0.00204	2.14285714

Pollutant	gr/100ft3	HHV btu/ft3	gr/lb	SOxMW(lb/mol)	S MW (lb/mol)	EF lb/mmbtu	EF lb/mmcf
SOx	0.75		7000	64	32	0.002041	
SOx	0.75	1050	7000	64	32		2.142857
PM10 start up							7.600000
PM10 start up		1050				0.007238	
PM10 Normal operations							5.100000
PM10 Normal operations		1050				0.004857	

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PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

SOx EF = (0.75 gr/100 scf)*(1 lb/7000 gr)* (1 scf/1050 btu)(1000000 btu/mmbtu)*(64 lb SOx/32 lbS) = 0.002041 lb/mmbtu
SOx EF = (0.75 gr/100 scf)*(1 lb/7000 gr)(1000000 ft3/mmcf)*(64 lb SOx/32 lbS) = 2.14 lb/mmcf
Startu-up PM10 EF = (7.6 lb/mmcf)(1 mmcf/1000000 scf)(1 scf/1050 btu)(1000000 btu/mmbtu) = 0.007238 lb/mmbtu
Normal operations PM10 EF = (5.1 lb/mmcf)(1 mmcf/1000000 scf)(1 scf/1050 btu)(1000000 btu/mmbtu) = 0.004857 lb/mmbtu (ref vendor)

VOC and PM10 emisson factors based AP-42 table 1.4-2
SOx emission factor per 0.75 gr-H2S/100 scf gas

Monthly Fuel Usage per boiler

Pollutant	Maximum monthly boosting (mmcf)	Maximum monthly very cold start (lb/mmcf)	Maximum monthly cold start (mmcf)	Maximum monthly hot start emergency (mmcf)	Maximum Total Monthly (mmcf)
mmcf	27.337	1.610	**0.836**	**9.843**	39.625

maximium monthy fuel usage = 29 boost days + 1 cold start + 1 very cold start + 29 emergency/hot start

Annual Fuel usage per boiler

fuel	Maximum annual boosting (mmcf)	Maximum annual very cold start (lb/mmcf)	Maximum annual cold start (mmcf)	Maximum annual hot start emergency (mmcf)	annual non-boosting (mmcf)	Annual (MMCF)	Annual (btu/yr)
R1-mmbtu	130.725	196.0875	130.725	32.68125	130.725		
R2 mmbtu	859.05	1494	747	323.7	398.4		
mmcf/day	0.943	1.610	0.836	0.339	0.503		
days/yr	220	5	10	60	125		
mmcf/yr	207.38	8.05	8.36	20.36	62.92	307.07	3.22E+11

annual fuel usage = 220 boost day/yr + 10 cold start/yr + 5 very cold start/yr + 60 emergency/hot start per year+ 125 non-boost days/yr

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PALEN SOLAR POWER PROJECT
Appendix B Auxiliary Boiler Emissions

Annual hours per year

fuel	Maximum annual boosting	Maximum annual very cold start	Maximum annual cold start	Maximum annual hot start emergency	annual non-boosting	Annual
Start-up hr/yr	660.000	22.500	30.000	45.000	375.000	757.50
normal hr/yr	880	55	50	120	218.75	1323.75

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PALEN SOLAR POWER PROJECT
Appendix C Auxiliary Boiler Emissions

Boosting mode-SOx emissions

when operating at boosting mode, the boiler provides steam to the turbine to generate electrictiy
when operating at boosting mode, the maximium hours per day is 2
the number of boosting days per year is 220
heating value 1050 Ref District

One Boiler-load, uncontrolled/controlled hr/dy totals

	Uncontrolled	controlled	mmcf
boiler load	hr/dy	hr/dy	
100%	0	1	0.237142857
50%	0	0.5	0.059285714
80%		0.5	0.094857143
total	0	2	0.391285714

One Boiler-SOx boosting emissions

Pollutant	Emission Factor	Units	Referance	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximun lb/event
SOx	0.002041	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	249	0.5082
SOx	0.0020408	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	124.5	0.2541
sox	0.0020408	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	199.2	0.4065
total lb/event						1.1688
total lb/yr						257.1306

SOx lb/yr = SOx emisisons /day * 220 boosting days/yr

PALEN SOLAR POWER PROJECT
Appendix D NTP Boilers Emissions

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Data:
Emission Rate = Emission Factor (lb/MMBTU) * Heat Input (MMBTU/hr)
NOx = 9 ppm @ 3% O_2, CO = 25 ppm @ 3% O_2
Maximum daily operation of each boiler is 14 hr/day. 13 hours full load, 1 hour Start up load
Maximum annual operation of each boiler is 4830 hrs
days per year operation is 345 days
btu rating is 10,500,000 btu/hr

PM2.5 emissions are equivalent to PM10 emissions
Boilers fired exclusively with natural gas
30DA means 30-day average

hr/dy	14
dy/yr	345

One Boiler

Pollutant	Emission Factor	Units	Referance	Emission Factor (lb/MMBTU)	mmbtu/hr	Maximun Hourly (lb/hr)	Maximum Daily (lb/day)	Annual Emissions (lb/yr)	Monthly Emissions (lb/month)	30DA (lb/day)
NOx	9	ppmv	vendor	0.011109	10.500000	0.1166	1.633	563.39	50.62	1.69
VOC	0.004000	lb/MMBTU	vendor	0.004000	10.500000	0.0420	0.588	202.86	18.23	0.61
CO	25	ppmv	vendor	0.018783	10.500000	0.1972	2.761	952.59	85.60	2.85
PM10	0.007238	lb/MMBTU	AP-42	0.007238	10.500000	0.0760	1.064	367.08	32.98	1.10
SOx	0.002041	lb/MMBTU	0.75 gr-H2S /100scf gas	0.002041	10.500000	0.0214	0.300	103.50	9.30	0.31

PALEN SOLAR POWER PROJECT
Appendix D NTP Boilers Emissions

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Two Boilers

Pollutant	Emission Factor	Units	Emission Factor (lb/MMBTU)	Maximun Hourly (lb/hr)	Maximum Daily (lb/day)	Annual Emissions (lb/yr)	Monthly Emissions (lb/month)	30DA (lb/day)
NOx	9	ppmv	0.0111	0.2333	3.2660	1126.7796	101.2469	3.3749
VOC	0.004	lb/MMBTU	0.0040	0.0840	1.1760	405.7200	36.4560	1.2152
CO	25	ppmv	0.0188	0.3944	5.5223	1905.1829	171.1903	5.7063
PM10	0.0072381	lb/MMBTU	0.0072	0.1520	2.1280	734.1600	65.9680	2.1989
SOx	0.002041	lb/MMBTU	0.0020	0.0429	0.6000	207.0000	18.6000	0.6200

Determination of Emission Factors
NOx EF = (9/1,000,000)(8710 scf/MMBTU)(46 lb/mol)(1 mol/379 scf)(20.9/20.9-3) = 0.0112 lb/MMBTU
COx EF = (25/1,000,000)(8710 scf/MMBTU)(28 lb/mol)(1 mol/379 scf)(20.9/20.9-3) = 0.03785 lb/MMBTU

Pollutant	ppmv	F-Factor	MW (lb/mol)	MV (scf/mol)	%O2 Corr	EF lb/MMBTU	EF lb/MMcf
NOx	0.000009	8710	46	379	1.167597765	0.01111	11.6643849
CO	0.000025	8710	28	379	1.167597765	0.01878	19.7223899
VOC						0.00400	4.2
PM10						0.00724	7.6
SOx						0.00204	2.14285714

Pollutant	gr/100ft3	HHV btu/ft3	gr/lb	SOxMW(lb/mol)	S MW (lb/mol)	EF lb/mmbtu	EF lb/mmcf
SOx	0.75		7000	64	32	0.002041	
SOx	0.75	1050	7000	64	32		2.142857
PM10							7.600000
PM10		1050				0.007238	

PALEN SOLAR POWER PROJECT
NTP Boilers Emissions

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SOx EF = (0.75 gr/100 scf)*(1 lb/7000 gr)* (1 scf/1050 btu)(1000000 btu/mmbtu)*(64 lb SOx/32 lbS) = 0.002041 lb/mmcf
SOx EF = (0.75 gr/100 scf)*(1 lb/7000 gr)(1000000 ft3/mmcf)*(64 lb SOx/32 lbS) = 2.14 lb/mmcf
PM10 EF = (7.6 lb/mmcf)(1 mmcf/1000000 scf)(1 scf/1050 btu)(1000000 btu/mmbtu) = 0.007238 lb/mmbtu

VOC and PM10 emisson factors based AP-42 table 1.4-2
SOx emission factor per 0.75 gr-H2S/100 scf gas

Mass Emissions Sample Calculations (single boiler)
NOx Max Hourly = (10.5 MMBTU/hr)(0.01119 lb/MMBTU) = 0.1175 lb/hr
NOx Max Daily = (0.1166 lb/hr)(14 hr/day)(100%) = 1.63 lb/dy
NOx Monthly = (1.63 lb/day)(31 day/ month) = 50.62 lb/month
NOx Annual = 1.63 lb/dy *345 day/yr = 563 lb/yr = 0.282 ton/yr

NOx 30DA = (1.63 lb/dy)(31 days/mon)(1 month/31 day) =1.69 lb/day

Boiler Fuel Consumption (single boiler)
the applicant is proposing a annual btyu limit of 50715 mmbtu per year(used to determine Rule 1401 compliance), back calculate to determine wk/yr operation

FC = (10,500,000 BTU/hr)(14 hr*100%)(1 scf/1050 BTU)(1 mmcf/1000000 scf) = 0.14 MMCF/DAY
FC = (0.14 MMCF/dy)(31 day/mon) = 4.34 mmcf/mon
FC = (0.14 MMCF/dy)(345 day/yr) = 48.30 mmcf/yr

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PALEN SOLAR POWER PROJECT
Appendix E Auxiliary Boiler Commisioning Emissions

One boiler heating value: 249 mmbtu/hr; 1050 btu/ft3 Ref per District

Proposed hours of operation

hours	mode	EF	load
4	cold start	SU emissions factors	31.1
4	warm start	SU emissions factors	31.1
12	low load	low load emissions factors	63
12	med load	high load emissions factor	125
8	high load	high load emissions factor	249

total

SU emissions factors

Pollutant	Start-up	low load	high load	Units	Referance
NOx	0.088	0.011	0.011	lb/MMBTU	vendor
VOC	0.005400	0.0054	0.0054	lb/MMBTU	vendor
CO	0.1460	0.037	0.037	lb/MMBTU	vendor
PM10	0.010000	0.005	0.005	lb/MMBTU	vendor
SOx	0.002100	0.0021	0.0021	lb/MMBTU	vendor

SU emissions factors

Pollutant	Start-up	low load	high load	Units	Referance
NOx	92.4	11.55	11.55	lb/MMCF	vendor
VOC	5.67	5.67	5.67	lb/MMCF	vendor
CO	153.3	38.85	38.85	lb/MMCF	vendor
PM10	10.5	5.25	5.25	lb/MMCF	vendor
SOx	2.205	2.205	2.205	lb/MMCF	vendor

PALEN SOLAR POWER PROJECT
Appendix E Auxiliary Boiler Commisioning Emissions

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Heat imput during commissioning

Mode	mmbtu/event
SU	248.80
low	756.00
med	1500.00
High	1992.00
total	4496.80
total mmcf	4.28

Aux boiler Commissioning Emissions

Mode	NOx	CO	VOC	SOx	PM10
	lb/period	lb/period	lb/period	lb/period	lb/period
SU	21.89	36.32	1.34	0.52	2.49
Low	8.316	27.972	4.0824	1.5876	3.78
med	16.5	55.5	8.1	3.15	7.5
high	21.912	73.704	10.7568	4.1832	9.96
total	68.62	193.50	24.28	9.44	23.73

PALEN SOLAR POWER PROJECT
Appendix F Night Preservation Boiler Commisioning Emissions

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One boiler 10.5 mmbtu/hr
heat conte 1050 btu/ft3
Proposed hours of operation

hours	mode	EF	load
4	cold start	low load emissions factors	2.625
4	low load	low load emissions factors	2.625
6	med load	high load emissions factor	5.25
6	high load	high load emissions factor	10.5

total

SU emissions factors

Pollutant	Start-up	low load	high load	Units	Reference
NOx	0.011	0.011	0.011	lb/MMBTU	vendor
VOC	0.005400	0.0054	0.0054	lb/MMBTU	vendor
CO	0.0180	0.018	0.018	lb/MMBTU	vendor
PM10	0.013000	0.013	0.013	lb/MMBTU	vendor
SOx	0.002100	0.0021	0.0021	lb/MMBTU	vendor

Pollutant	lb/mmbtu	lb/mmcf
NOx	0.011	11.55
VOC	0.0054	5.67
CO	0.018	18.9
PM10	0.013	13.65
SOx	0.0021	2.205

lb/mmcf = lb/mmbtu * 1050 ft3/mmbtu

Heat imput during commissioning

Mode	mmbtu/event
SU	10.50
low	10.50
med	31.50
High	63.00
total	115.50
total mmcf	0.11

PALEN SOLAR POWER PROJECT
Appendix F Night Preservation Boiler Commisioning Emissions

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Aux boiler Total Commissioning Emissions

Mode	NOx	CO	VOC	SOx	PM10
	lb	lb	lb	lb	lb
total	1.27	2.08	0.62	0.24	1.50

PALEN SOLAR POWER PROJECT
Appendix G Emergency Generator Emissions

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Data:
Standard Conditions: 29.92 inches Hg and 68 degrees Fahrenheit
Manufacturer: Caterpillar, model 3516C, turbocharge/aftercooled, 12 cylinders
Model No.: 9CPXL08.8ESK
Type of Fuel: Diesel w/ 15 ppm sulfur by weight
Rated Power: 3633 bhp
Engine Design: Lean Burn
Maximum Rated Fuel Consumption: 172.9 gph
MW SO2 = 64 lb/lb-mol
MW S = 32 lb/lb-mol
Diesel Density = 7.2 lb/gal
no. of engine 2
VOC and NOx ref a/n 452608
CO and PM ref emissions data sheet, EO U-R-001-3698-1

RECLAIM EF

BACT	4.8	g/bhp-hr
fuel rate	172.9	gal/hr
HP	3633	
lb/mgal	222.15	

lb/mgal = 4.8 g/bhp-hr * 3633 Hp *(1 lb/454 g)(1hr/172.9 gal)(1000 gal/mgal)

Assumptions:
Maximum hours of operation: 50 hr/y
Steady speed, steady load operations

Pollutant	Emission Factor (gm/BHP-hr)	Maximum Rated Power (BHP)	Conversion Factor (gm/lb)	Emission Rate (lb/hr)	Annual Emission Rate (lb/year)	Monthly Emission Rate (lb/month)	30 Day Average (lb/day)
NOx	3.70	3,633	454	29.608	1,480.41	123.37	**4.1122**
VOC	0.25	3,633	454	2.001	100.03	8.34	**0.2779**
CO	0.89	3,633	454	7.122	356.10	29.67	**0.9892**
PM10	0.09	3,633	454	0.716	35.81	2.98	**0.0995**
SOx				0.0305	1.53	0.13	**0.0042**

Mass Emission Sample Calculations (single engine)
NOx Hourly = (4.56 gm/bhp-hr)(2922 bhp)(1 lb/454 gm) = 29.349 lb/hr
NOx Annual = (29.349 lb/hr)(50 hr/yr) = 1,467.44 lb/yr
NOx Monthly = (1,467.44 lb/yr)(1 yr/12 months) = 122.29 lb/month
NOx 30DA = (1,467.44 lb/yr)(1 yr/12 months)(1 month/30 days) = 4.076 lb/day
SOx Hourly = (15/1,000,000)(141.3 gal/hr)(7.2 lb/gal)(64 lb/mol SO2 / 32 lb/mol S) = 0.0.0305 lb/hr
Emissions factors per engnine manufacturer

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PALEN SOLAR POWER PROJECT
Appenidix H Emergency Generator Emissions

Data:
Standard Conditions: 29.92 inches Hg and 68 degrees Fahrenheit
Manufacturer: Caterpillar
Model No.: C9
Type of Fuel: Diesel w/ 15 ppm sulfur by weight
Rated Power: 398 bhp
Engine Design: Lean Burn
Maximum Rated Fuel Consumption: 20 gph
MW SO2 = 64 lb/lb-mol
MW S = 32 lb/lb-mol
Diesel Density = 7.2 lb/gal
number of engine 1
emissions ref a/n 455162

RECLAIM EF

BACT	3	g/bhp-hr
fuel rate	20	gal/hr
HP	398	
lb/mgal	131.50	

lb/mgal = 4.8 g/bhp-hr * 3633 Hp *(1 lb/454 g)(1hr/172.9 gal)(1000 gal/mgal)

Assumptions:
Maximum hours of operation: 50 hr/yr
Steady speed, steady load operations

Pollutant	Emission Factor (gm/BHP-hr	Maximum Rated Power (BHP)	Conversion Factor (gm/lb)	Emission Rate (lb/hr)	Annual Emission Rate (lb/year)	Monthly Emission Rate (lb/month)	30 Day Average (lb/day)
NOx	2.49	398	454	2.183	109.14	9.10	**0.3032**
VOC	0.27	398	454	0.237	11.83	0.99	**0.0329**
CO	2.31	398	454	2.025	101.25	8.44	**0.2813**
PM10	0.11	398	454	0.096	4.82	0.40	**0.0134**
SOx				0.0043	0.22	0.02	**0.0006**

Mass Emission Sample Calculations (single engine)
NOx Hourly = (2.97 gm/bhp-hr)(398 bhp)(1 lb/454 gm) = 2.64 lb/hr
NOx Annual = (2.64 lb/hr)(50 hr/yr) = 130 lb/yr
NOx Monthly = (130 lb/yr)(1 yr/12 months) = 10.85 lb/month
NOx 30DA = (130.18 lb/yr)(1 yr/12 months)(1 month/30 days) =0.3616 lb/day
SOx Hourly = (15/1,000,000)(20 gal/hr)(7.2 lb/gal)(64 lb/mol SO2 / 32 lb/mol S) = 0.00432 lb/hr

PALEN SOLAR POWER PROJECT
Appendix I Emergency Generator Emissions

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Data:
Standard Conditions: 29.92 inches Hg and 68 degrees Fahrenheit
Manufacturer: Clarke
Model No.: JX6H-UfAD88
Type of Fuel: Diesel w/ 15 ppm sulfur by weight
Rated Power: 617 bhp
Engine Design: Lean Burn
Maximum Rated Fuel Consumption: 34 gph
MW SO2 = 64 lb/lb-mol
MW S = 32 lb/lb-mol
Diesel Density = 7.2 lb/gal
number of engine 3

RECLAIM EF

BACT	3	g/bhp-hr
fuel rate	34	gal/hr
HP	617	
lb/mgal	119.91	

lb/mgal =3 g/bhp-hr * 617 Hp *(1 lb/454 g)(1hr/34 gal)(1000 gal/mgal)

Assumptions:
Maximum hours of operation: 50 hr/yr
Steady speed, steady load operations

Pollutant	Emission Factor (gm/BHP-hr	Maximum Rated Power (BHP)	Conversion Factor (gm/lb)	Emission Rate (lb/hr)	Annual Emission Rate (lb/year)	Monthly Emission Rate (lb/month)	30 Day Average (lb/day)
NOx	2.60	617	454	3.533	176.67	14.72	**0.4908**
VOC	0.10	617	454	0.136	6.80	0.57	**0.0189**
CO	0.50	617	454	0.680	33.98	2.83	**0.0944**
PM10	0.09	617	454	0.122	6.12	0.51	**0.0170**
SOx				0.0073	0.37	0.03	**0.0010**

Mass Emission Sample Calculations (single engine)
NOx Hourly = (2.60 gm/bhp-hr)(617 bhp)(1 lb/454 gm) = 3.533 lb/hr
NOx Annual = (3.533 lb/hr)(50 hr/yr) = 177 lb/yr
NOx Monthly = (177 lb/yr)(1 yr/12 months) = 14.72 lb/month
NOx 30DA = (176.67 lb/yr)(1 yr/12 months)(1 month/30 days) =0.4908 lb/day
SOx Hourly = (15/1,000,000)(34 gal/hr)(7.2 lb/gal)(64 lb/mol SO2 / 32 lb/mol S) = 0.007344 lb/hr

PALEN SOLAR POWER PROJECT
Appendix J Boiler TAC Emissions

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A Toxic Air Contaminant Emissions from each Auxiliary boiler

Max Fuel Flow (HHV)	**249.0**	**MMBtu/hr**
Maximum annual fuel usag	**307**	**mmcf**
based on heating value	**1050**	**btu/ft3**
ave hour/yr	1930	hr/yr

Pollutant	Emission Factor (lb/mmcf)	Emission factor source	Hourly Emission Rate (lb/hr)	Annual Emission Rate (lb/yr)
Ammonia *		BACT	0.67	1.29E+03
Acetaldehyde	9.00E-04	AB2588	2.20E-04	2.76E-01
Acrolein	8.00E-04	AB2588	1.95E-04	2.46E-01
Benzene	1.70E-03	AB2588	4.15E-04	5.22E-01
Ethylbenzene	2.00E-03	AB2588	4.88E-04	6.14E-01
Formaldehyde	3.60E-03	AB2588	8.79E-04	1.11E+00
Hexane	1.30E-03	AB2588	3.17E-04	3.99E-01
Toluene	7.80E-03	AB2588	1.90E-03	2.39E+00
Xylenes	5.80E-03	AB2588	1.42E-03	1.78E+00
Propylene	3.78E-03	AB2588	9.23E-04	1.16E+00
PAH	1.00E-04	AB2588	2.44E-05	3.07E-02
Naphthalene	3.00E-04	AB2588	7.32E-05	9.21E-02
Total Annual HAP Emissions per Boiler (ton/yr)				**4.31E-03**

Notes:

- Emission factors obtained from Ventura APCD, AP2588 HAP combustion emissions factorsr uncontrolled natural gas-fired external combustion turbines.
'combustion turbine with a CO catalyst.
- Ammonia emission rate based on an exhaust NH_3 limit of 5 ppmv @ 15% O_2 provided by the
- Used a HHV (Btu/scf) 1020

B Toxic Air Contaminant Emissions from each night preservation boiler

Max Fuel Flow (HHV)	**10.5**	**MMBtu/hr**
Maximum annual fuel usag	**48.3**	**mmcf**

Pollutant	Emission Factor (lb/mmcf)	Emission factor source	Hourly Emission Rate (lb/hr)	Annual Emission Rate (lb/yr)
Acetaldehyde	9.00E-04	AB2588	9.26E-06	4.35E-02
Acrolein	8.00E-04	AB2588	8.24E-06	3.86E-02
Benzene	1.70E-03	AB2588	1.75E-05	8.21E-02
Ethylbenzene	2.00E-03	AB2588	2.06E-05	9.66E-02
Formaldehyde	3.60E-03	AB2588	3.71E-05	1.74E-01
Hexane	1.30E-03	AB2588	1.34E-05	6.28E-02
Toluene	7.80E-03	AB2588	8.03E-05	3.77E-01
Xylenes	5.80E-03	AB2588	5.97E-05	2.80E-01
Propylene	3.78E-03	AB2588	3.89E-05	1.83E-01
PAH	1.00E-04	AB2588	1.03E-06	4.83E-03
Naphthalene	3.00E-04	AB2588	3.09E-06	1.45E-02
Total Annual HAP Emissions per Boiler (ton/yr)				**6.78E-04**

Notes:
- Emission factors obtained from Ventura APCD, AP2588 HAP combustion emissions factorsr
- Used a HHV (Btu/scf) 1020

PALEN SOLAR POWER PROJECT
Appendix K Emergency engine TAC Emissions

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A. Toxic Air Contaminant Emissions from Large Emergency Diesel generator

Rated Horsepower	**3663**	**BHP**
Expected non-emergency usage	**50**	**hr/yr**

Pollutant	CAS	Emission Factor (Power Output) (g/hp-hr)	Emission factor source	Hourly Emission Rate (lb/hr)	Annual Emission Rate (lb/yr)
Diesel Particulate (PM10)	9901	0.09	Vendor guarantee	0.726	36.307

B. Toxic Air Contaminant Emissions from Small Emergency Diesel generator

Rated Horsepower	**398**	**BHP**
Expected non-emergency usage	**50**	**hr/yr**

Pollutant	CAS	Emission Factor (Power Output) (g/hp-hr)	Emission factor source	Hourly Emission Rate (lb/hr)	Annual Emission Rate (lb/yr)
Diesel Particulate (PM10)	9901	0.11	Vendor guarantee	0.096	4.822

C. Toxic Air Contaminant Emissions from Emergency Diesel fire pump

Rated Horsepower	**617**	**BHP**
Expected non-emergency usage	**50**	**hr/yr**

Pollutant	CAS	Emission Factor (Power Output) (g/hp-hr)	Emission factor source	Hourly Emission Rate (lb/hr)	Annual Emission Rate (lb/yr)
Diesel Particulate (PM10)	9901	0.09	Vendor guarantee	0.122	6.116

PALEN SOLAR POWER PROJECT
Appendix L Ammonia Slip emissions from SCR

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Ammonia slip	**5**	**ppmv**
mw	**17**	**hr/yr**
STP Temp	**60**	**F**
DSCFM	**50207**	**ft3/min**
Ft^3/lb-mole	**379.5**	
mw		

Ammonia Slip **0.68 lb/hr**

$$R1(LB/HR) = \frac{PPM_V \times MW_{ave} \times CFM \times 60\,MIN/HR}{1 \times 10^6 \times 379\,FT^3/MOLE}$$

Ammonia emissions per year

hr/yr-ave	1323.75	(based on boiler operating above 17.5% load)
controlled hr/mon	190	
lb/mon	128.37	
NH3yr	894.34	lb/yr

ammonia emissions per year = hr/yr * ammonia slip -lb/hr
ammonia emissions pe rmonth = controlled hr/mon * ammonia slip -lb/hr

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PALEN SOLAR POWER PROJECT
Appendix M NOx RTC Calculations

NOx RECLAIM RTC CALCUATIONS

A. Auxliuary boilers

Annual Fuel usage per boiler

fuel	Maximum annual boosting	Maximum annual very cold start	Maximum annual cold start	Maximum annual hot start emergency	annual non-boosting	Annual (mmbtu/yr)
R1-mmbtu/dy	130.73	196.09	130.73	32.68	130.73	
R2 mmbtu/dy	859.05	1494	747	323.7	398.4	
R1 mmbtu/yr	28759.5	980.4375	1307.25	1960.875	16340.63	49,348.69
R2 mmbtu/yr	188991	7470	7470	19422	49800	273,153.00
days/yr	220	5	10	60	125	

annual RTC per boiler

	lb/mmbtu	lb/mmcf	mmcf/yr	lb/yr
R1-lb/mmcf	0.07997	83.96883	47.00	3,946.43
R2-lb/mmbtu	0.006219	6.529458	260.15	1,698.61
total				5,645.04

lb/mmcf = lb/mmbtu * 1050
lb/yr = NOx lb/mmcf * mmcf/yr

Commissioning emissions

	mmbtu	mmcf	lb/mmbtu	lb/mmcf	lb/commission
start-up	248.80	0.236952	0.088	92.4	21.8944
non start up	4248.00	4.045714	0.011	11.55	46.728
	4496.80				68.6224

RTC	RTC/yr
commission yr	5,714
non commission yr	5,645

PALEN SOLAR POWER PROJECT
Appendix M NOx RTC Calculations

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B. Night Preseravation Boilers

mmbtu/dy	147
mmbtu/yr	50715
mmcf/yr	48.3
lb/mmbtu	0.011109
lb/mmcf	11.66438
lb/yr	563.39

lb/mmcf = lb/mmbtu * 1050
lb/yr = NOx lb/mmcf * mmcf/yr

The boilers are process units and the applicant elected to take a concentration limit of 9 ppmv or reporting purposes (see emial dated 7/24/13)
The emissions and requirments section of the Facility Permit the 9 ppmv NOx is tagged (3), and the boilers has be tested within the first year of operation and every 5 years thereafter.
for NOx reporting use lb/mmcf based on 9 ppm concentration limit

commissioning emissions
mmbtu

	mmbtu	mmcf	lb/mmbtu	lb/mmcf	lb/commission
event	115.50	0.11	0.011	11.55	1.27

RTC	RTC/yr
commission yr	565
non commission yr	563

PALEN SOLAR POWER PROJECT
Appendix M NOx RTC Calculations

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C Emergency engines

	NOx lb/yr	hr/yr	RTC/yr
Large ICE 1	29.61	200	5922
Large ICE 2	29.61	200	5922
Small ICE	2.18	200	437
Fire pump 1	3.53	200	707
Fire pump 2	3.53	200	707
Fire pump 3	3.53	200	707

RTC/yr = NOx lb/hr * 200 hr/yr

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PALEN SOLAR POWER PROJECT
Appendix N NOx RELCAIM Reporting Values

Auxiliary Boiler

A. Non-commissioning start-up and normal operations

Pollutant	lb/MMBTU	lb/MMcf	Reference
R2 NOx	0.006219	6.529458	BACT
R1 NOx	0.07997	83.96883	Vender

lb/MMCF = lb/Mmbtu * 1050 Mmbtu/MMCF

B. Commissioning start-up and normal operations

Pollutant	Start-up	low load and high load	Units	Referance
NOx	0.088	0.011	lb/MMBTU	vendor
NOx	92.4	11.55	lb/mmcf	

lb/MMCF = lb/Mmbtu * 1050 Mmbtu/MMCF

NTB boilers

applicant is proposing a 9 ppmv concentration limit

Emergency Engines

engine	RV-lb/mga	Ref Appendix
Large ICE	222.15	G
Small ICE	131.50	H
Fire pump	119.91	I

APPENDIX IV-O

SOUTH COAST AIR QUALITY M ANAGEMENT DISTRICT

M E M O R A N D U M

DATE: August 21, 2013

TO: Andrew Lee

FROM: Elaine Chang

SUBJECT: Modeling Review of Palen Solar Electric Generating Station (ID: 174021, A/Ns 549379, 449380, 449381, 449383 to 449387, 449389, 449390, 553874, 553876)

As you requested, Planning, Rule Development & Area Sources (PRA) staff reviewed the modeling conducted for the proposed project. The Palen Solar Electric Generating Station project is proposing to install two auxiliary boilers, each with a SCR APC system, two night preservation boilers, and seven emergency internal combustion engines. The applicant has prepared modeling analyses to demonstrate compliance with District rules 1303, 1401, and 2005. The report (revised June 2013) and electronic files were submitted along with the modeling review requesting memo dated July 31, 2013.

Our comments on the modeling conducted in the report are as follows:

- **AERMOD Modeling Analysis**
  - ✓ The applicant utilized AERMOD (version 12345) for the air dispersion modeling, which is the current version and requires hourly meteorological data.
  - ✓ The applicant obtained meteorological data from the Blythe Airport and upper air sounding data collected from Tucson to run AERMET. Data from 2002 to 2006 were used. This is consistent with the EPA recommended methodology to obtain 5-years of meteorological data for use in AERMOD. Although the data is not current, the current years do not meet the 90% data completeness requirement for meteorological data.
  - ✓ The receptor grid spacing and the area covered are adequate to determine the maximum impacts from the facility.
  - ✓ The AERMOD modeling generally conforms to the District's dispersion modeling procedures, except that the Rural option was used instead of the Urban option. The area surrounding the project site is undeveloped; therefore, it is appropriate to use the Rural option.
  - ✓ The source parameters and emission factors used are consistent with the information shown in Table 4.1-19 of the report and in the modeling request memo. The source parameters and emission factors are assumed to be correct.
  - ✓ The applicant has modeled the emissions from the entire project and from each individual permit unit. Although the auxiliary boilers are expected to operate in the day and the night boilers are expected to operate in the night, the applicant modeled the boilers as operating 24 hours a day, using the maximum hourly emission rates, which is a conservative estimate of the actual impacts from the boilers.
  - ✓ The impacts from the entire project are listed here, which is more conservative than the approach to model each permit unit separately, as specified in the Rule.

- ✓ The project site is located in a remote desert area and in close proximity to the Blythe, Indio, and Palm Springs monitoring stations. The applicant used the Riverside monitoring station to supplement the monitoring data for CO and SO2. The applicant used the highest monitoring data from the most recent three years (2009 through 2011) to determine the background concentrations for the criteria pollutants (see Table 4.1-17 in the report). The predicted modeling impacts were added to the background concentrations for comparison to the ambient air quality standards, where appropriate.

- **Rule 1303 – AERMOD Modeling Analysis for CO and PM_{10}**
  - ✓ The model results for PM_{10} and CO for the proposed project are presented in the applicant's report. PRA staff reproduced the modeling analysis and confirmed that the information provided in the report is consistent with our findings when analyzed. The results of PRA staff's analysis are summarized below.
  - ✓ The maximum 1-hour and 8-hour CO impacts plus the worst-case background for the proposed project are 3,852 $\mu g/m^3$ and 2,016 $\mu g/m^3$, 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.
  - ✓ Background PM_{10} air quality in the impact area exceeds the state 24-hour and annual PM_{10} standards; therefore, project increments are compared to the Rule 1303 significance thresholds in Table A-2. The peak 24-hour and annual PM_{10} impacts for the proposed project are 0.40 $\mu g/m^3$ and 0.02 $\mu g/m^3$, respectively. These impacts are less than the Rule 1303 PM_{10} 24-hour and annual significance thresholds of 2.5 $\mu g/m^3$ and 1.0 $\mu g/m^3$, respectively.

- **Rule 2005 – AERMOD Modeling Analysis for NO_2**
  - ✓ The model results for NO_2 for the proposed project are presented in the applicant's report. PRA staff reproduced the modeling analysis and confirmed that the information provided in the report is consistent with our findings when analyzed. The results of PRA staff's analysis are summarized below.
  - ✓ In order to show compliance with the federal 1-hour NO_2 standard, the applicant used the maximum hourly emissions from the auxiliary boilers and night preservation boilers. However, the emissions from the emergency diesel generator were excluded, as described in the US EPA's memo dated March 1, 2011.
  - ✓ The conversion of NO_X to NO_2 was done using Tier 2 methods, by applying a conversion ratio of 0.80 for the 1-hour averaging period and 0.75 for the annual averaging period.
  - ✓ Following the form of the Federal standard, the 1-hour NO_2 impact from the project is 3.52 $\mu g/m^3$. When added to the background concentration, the 1-hour NO_2 impact is 101.32 $\mu g/m^3$, which is less than the federal 1-hour NO_2 standard of 188 $\mu g/m^3$. The peak annual NO_2 impact from the project is 0.10 $\mu g/m^3$. When added to the worst-case background concentration, the peak annual NO_2 impact is 22.7 $\mu g/m^3$, which is less than the federal annual NO_2 standard of 100 $\mu g/m^3$.
  - ✓ The maximum 1-hour NO_2 impact from the project is 177.4 $\mu g/m^3$. When added to the worst-case background concentration, the maximum 1-hour NO_2 impact is 301.7 $\mu g/m^3$, which is less than the state 1-hour NO_2 standard of 339 $\mu g/m^3$. The peak annual NO_2 impact from the project is 0.10 $\mu g/m^3$. When added to the worst-case background