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<td><strong>Submission Date:</strong></td>
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</table>
Mr. Keith Winstead, Project Manager  
Siting, Transmission and Environmental Protection Division  
California Energy Commission  
1516 Ninth Street, MS-15  
Sacramento, CA 95814  

SUBJECT: Alamitos Energy Center (AEC), 13-AFC-01  
Facility Location: 690 N. Studebaker Road, Long Beach, CA 90803

Dear Mr. Winstead:

The South Coast Air Quality Management District (SCAQMD) has received permit applications for the subject project. The applicant is proposing to replace four existing electric utility boiler generator Units 1, 2, 3 and 5 that are older, less efficient units and which have been in operation since the 1950's and 1960's with a new, state of the art and more efficient gas turbine generating system. The new generating system will consist of two natural gas fired GE 7FA.05 combined-cycle turbine generators configured with a shared steam turbine generator and four natural gas fired GE LMS100PB simple-cycle turbine generators. The combined generating capacity of the AEC will be 1094.7 MW (nominal gross). This capacity replaces the generating capacity of the existing Unit 1 (175 MW), Unit 2 (175 MW), Unit 3 (320 MW), and Unit 5 (480 MW) at the Alamitos site. The new AEC will be equipped with air pollution control equipment, which consists of catalysts (selective catalytic reduction and oxidation catalysts). Additional new proposed equipment will include an auxiliary boiler equipped with selective catalytic reduction, two aqueous ammonia storage tanks, and two oil/water separators.

The SCAQMD has evaluated the permit applications and made a preliminary determination that the equipment will comply with all of the applicable requirements of our rules and regulations. Attached for your review and comment is a Preliminary Determination of Compliance (PDOC) that includes the SCAQMD’s engineering analysis. Based on the emission potential, this project is subject to the public notice requirements specified in SCAQMD Rules 212 – Standards for Approving Permits and Issuing Public Notice, 1710 – Prevention of Significant Deterioration Analysis, Notice and Reporting, 1714 – Prevention of Significant Deterioration for Greenhouse Gases, 3006 – Title V Public Participation.

We intend to issue the final permit to construct 1) upon completion of the 30-day public comment and review period and after all pertinent comments have been considered, 2) after receiving the federal land manager’s (Forest Service) determination of impact, 3) after EPA’s 45-day review of the Title V permit significant revision, and 4) upon issuance of a license for the project from the California Energy Commission.
The 45-day EPA review period for this project will be initiated on June 30, 2016 and the public notice period will begin on July 8, 2016.

If you wish to provide comments or have any questions regarding this project, please contact Mr. Andrew Lee at (909) 396-2643/alee@aqmd.gov.

Sincerely,

Laki Tsopulos, Ph.D., P.E.
Deputy Executive Officer
Engineering and Permitting

Enclosures: Public Notice
Draft Facility Permit
PDOC

cc: Stephen O'Kane, AES (w/o attachments)
FACILITY PERMIT TO OPERATE
AES ALAMITOS, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

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<tr>
<td>STORAGE TANK, TANK-1 (COMBINED-CYCLE TURBINES), AQUEOUS AMMONIA 19 PERCENT, 40000 GALS; DIAMETER: 13 FT; LENGTH: 45 FT</td>
<td>D163</td>
<td></td>
<td></td>
<td>C157.1, E144.1, E193.4</td>
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<tr>
<td>STORAGE TANK, TANK-2 (SIMPLE-CYCLE TURBINES), AQUEOUS AMMONIA 19 PERCENT, 40000 GALS; DIAMETER: 13 FT; LENGTH: 45 FT</td>
<td>D164</td>
<td></td>
<td></td>
<td>C157.1, E144.1, E193.4</td>
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**Process 12: INTERNAL COMBUSTION - POWER GENERATION**

**System 1: COMBINED-CYCLE TURBINES (AEC CCGT POWER BLOCK)**

* (1) (1A) (1B) Denotes RECLAIM emission factor
  (2) (2A) (2B) Denotes RECLAIM emission rate
  (3) Denotes RECLAIM concentration limit
  (4) Denotes BACT emission limit
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  (6) Denotes air toxic control rule limit
  (7) Denotes NSR applicability limit
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<td>GAS TURBINE, NO. CCGT-1, COMBINED-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL 7FA.05, 2275 MMBTU/HR HHV AT 28 F, WITH DRY LOW-NOX COMBUSTOR, GE DLN 2.6, WITH A/N:</td>
<td>D165</td>
<td>C169</td>
<td>NOX: MAJOR SOURCE**</td>
<td>CO: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; CO2: 120 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart TTTT, 10-23-2015]; CO2: 1000 LBS/GROSS MWH NATURAL GAS (8) [40CFR 60 Subpart TTTT, 10-23-2015]; NOX: 8.35 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; NOX: 15 PPMV NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006]; NOX: 16.66 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; PM10: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 8.5 LBS/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996];</td>
<td>A63.2, A99.1, A99.2, A195.8, A195.9, A195.10, A327.1, B61.1, C1.3, C1.4, D29.2, D29.3, D82.1, D82.2, E193.4, E193.5, E193.6, E193.7, E193.8, E193.11, E193.12, E193.14, E448.1, I297.1, K40.4</td>
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<td></td>
<td></td>
<td>RULE 1303(b)(2)-Offset, 12-6-2002; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; SO2: (9) [40CFR 72 - Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006]; VOC: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1) -BACT, 12-6-2002]</td>
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<td>HEAT EXCHANGER, HEAT RECOVERY STEAM GENERATOR (HRSG), NO. CCGT-1</td>
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<td></td>
<td></td>
<td>RULE 1303(b)(2)-Offset, 12-6-2002; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; SO2: (9) [40CFR 72 - Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006]; VOC: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1) -BACT, 12-6-2002]</td>
<td></td>
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<tr>
<td>CO OXIDATION CATALYST, NO. CCGT-1, BASF, 265.8 CU. FT.; WIDTH: 26 FT 2 IN; HEIGHT: 71 FT 9.6 IN; LENGTH: 2.1 IN A/N:</td>
<td>C169</td>
<td>D165 C170</td>
<td>RULE 1303(b)(2)-Offset, 12-6-2002; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; SO2: (9) [40CFR 72 - Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006]; VOC: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1) -BACT, 12-6-2002]</td>
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<td>C170</td>
<td>C169 S172</td>
<td>NH3: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]</td>
<td>A195.15, D12.9, D12.10, D12.11, D29.4, E193.4</td>
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<td>STACK, TURBINE NO. CCGT-1, HEIGHT: 140 FT ; DIAMETER: 20 FT A/N:</td>
<td>S172</td>
<td>C170</td>
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<td>C177 S180</td>
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<td>D181</td>
<td>C183</td>
<td>NOX: MAJOR SOURCE**</td>
<td>CO: 50 PPMV NATURAL GAS (4) [RULE 1303(a)(1)] - BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]; CO: 400 PPMV NATURAL GAS (5) [RULE 1146, 11-1-2013]; NOX: 5 PPMV NATURAL GAS (4) [RULE 407, 4-2-1982]; NOX: 38.46 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; PM10: 0.1 GRAINS/SCF NATURAL GAS (1) [RULE 409, 8-7-1981]; VOC: 0.005 LBS/MMBTU NATURAL GAS (4) [RULE 1303(b)(2) - Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]; PM10: 0.007 LBS/MMBTU NATURAL GAS (4) [RULE 1303(b)(2)] - Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]; PM10: 0.1 GRAINS/SCF NATURAL GAS (5) [RULE 409, 8-7-1981]; VOC: 0.005 LBS/MMBTU NATURAL GAS (4) [RULE 1303(b)(2) - Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]</td>
<td>A63.4, A99.5, A195.13, A195.14, C1.7, D29.5, D29.6, D82.3, E193.4, E193.10, H23.7, I297.7, K40.5</td>
</tr>
<tr>
<td>BURNER, NATURAL GAS, JZHC/COEN, MODEL RMB, WITH LOW NOX BURNER, 70.8 MMBTU/HR</td>
<td></td>
<td></td>
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* (1) (1A) (1B) Denotes RECLAIM emission factor  
** (2) (2A) (2B) Denotes RECLAIM emission rate  
(3) Denotes RECLAIM concentration limit  
(4) Denotes BACT emission limit  
(5) (5A) (5B) Denotes command and control emission limit  
(6) Denotes air toxic control rule limit  
(7) Denotes NSR applicability limit  
(8) (8A) (8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)  
(9) See App B for Emission Limits  
(10) See section J for NESHAP/MACT requirements  

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<tr>
<td>Process 12: INTERNAL COMBUSTION - POWER GENERATION</td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>SELECTIVE CATALYTIC REDUCTION, AUXILIARY BOILER, BABCOCK &amp; WILCOX, VANADIUM, 46 CU.FT.; WIDTH: 5 FT 5 IN; HEIGHT: 3 FT 8 IN; LENGTH: 7 FT 3 IN WITH A/N: AMMONIA INJECTION, AQUEOUS AMMONIA</td>
<td>C183</td>
<td>D181 S211</td>
<td>NH3: 5 PPMV (4) RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]</td>
<td>A195.16, D12.15, D12.16, D12.17, D29.4, E193.4</td>
<td></td>
</tr>
<tr>
<td>STACK, AUXILIARY BOILER, HEIGHT: 80 FT; DIAMETER: 3 FT A/N:</td>
<td>S211</td>
<td>C183</td>
<td></td>
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<tr>
<td>System 2: SIMPLE-CYCLE TURBINES (AEC SCGT POWER BLOCK)</td>
<td></td>
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## AES ALAMITOS, LLC

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<td>Process 12: INTERNAL COMBUSTION - POWER GENERATION</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GENERATOR, 100.438 MW GROSS AT 59 F</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO OXIDATION CATALYST, NO. SCGT-1, BASF, MODEL CAMET, 165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 2 FT; LENGTH: 2 FT 1.5 IN</td>
<td>C187</td>
<td>D185 C188</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SELECTIVE CATALYTIC REDUCTION, NO. SCGT-1, CORMETECH, MODEL CMHT, TITANIUM/VANADIUM/TUNGSTEN, 621.96 CU.FT.; WIDTH: 4 FT 11 IN; HEIGHT: 11 FT; LENGTH: 11 FT 6 IN WITH A/N:</td>
<td>C188</td>
<td>C187 S190</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>AMMONIA INJECTION, AQUEOUS AMMONIA</td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>STACK, TURBINE NO. SCGT-1, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN</td>
<td>S190</td>
<td>C188</td>
<td></td>
<td></td>
<td></td>
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</tr>
</thead>
<tbody>
<tr>
<td>GAS TURBINE, NO. SCGT-2, SIMPLE-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS-100 PB, 882 MMBTU/HR AT 59 DEG F, WITH INTERCOOLER AND DRY LOW-NOX COMBUSTOR WITH A/N:</td>
<td>D191</td>
<td>C193</td>
<td>NOX: MAJOR SOURCE**</td>
<td>CO: 4 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; CO2: 120 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart TTTT, 10-23-2015]; NOX: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2005, 12-4-2015]; NOX: 11.21 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOX: 15 PPMV NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006]; NOX: 25.24 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; PM10: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 6.23 LBS/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475,</td>
<td></td>
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<td></td>
<td>8-7-1978]; SO2: (9) [40CFR 72 - Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006]; VOC: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]</td>
<td></td>
</tr>
<tr>
<td>CO OXIDATION CATALYST, NO. SCGT-2, BASF, MODEL CAMET, 165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 2 FT; LENGTH: 2 FT 1.5 IN</td>
<td>C193</td>
<td>D191 C194</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>STACK, TURBINE NO. SCGT-2, HEIGHT: 80 FT ; DIAMETER: 13 FT 6 IN</td>
<td>S196</td>
<td>C194</td>
<td></td>
<td></td>
<td></td>
</tr>
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(3) Denotes RECLAIM concentration limit
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(5) (5A) (5B) Denotes command and control emission limit
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<td>GAS TURBINE, NO. SCGT-3, SIMPLE-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS-100 PB, 882 MMBTU/HR AT 59 DEG F, WITH INTERCOOLER AND DRY LOW-NOX COMBUSTOR WITH A/N:</td>
<td>D197</td>
<td>C199</td>
<td>NOX: MAJOR SOURCE**</td>
<td>CO: 4 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; CO2: 120 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart TTTT, 10-23-2015]; NOX: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2005, 12-4-2015]; NOX: 11.21 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOX: 15 PPMV NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006]; NOX: 25.24 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; PM10: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 6.23 LBS/HR NATURAL GAS (5) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1981]; PM10: 6.23 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1981]; PM10: 6.23 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1981]</td>
<td>A63.3, A99.3, A99.4, A195.10, A195.11, A195.12, A327.1, B61.1, C1.5, C1.6, D29.2, D29.3, D82.1, D82.2, E193.4, E193.5, E193.6, E193.7, E193.9, E193.13, E193.15, E448.1, I297.5, K40.4</td>
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<td></td>
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<tr>
<td>CO OXIDATION CATALYST, NO. SCGT-3, BASF, MODEL CAMET, 165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 2 FT; LENGTH: 2 FT 1.5 IN</td>
<td>C199</td>
<td>D197 C200</td>
<td></td>
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<tr>
<td>SELECTIVE CATALYTIC REDUCTION, NO. SCGT-3, CORMETECH, MODEL CMHT, TITANIUM/VANADIUM/TUNGSTEN, 621.96 CU.FT.; WIDTH: 4 FT 11 IN; HEIGHT: 11 FT; LENGTH: 11 FT 6 IN</td>
<td>C200</td>
<td>C199 S202</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AMMONIA INJECTION, AQUEOUS AMMONIA STACK, TURBINE NO. SCGT-3, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN</td>
<td>S202</td>
<td>C200</td>
<td></td>
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(4) (4A) (4B) Denotes BACT emission limit
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(6) (6A) (6B) Denotes air toxic control rule limit
(7) (7A) (7B) Denotes NSR applicability limit
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<td></td>
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<tr>
<td>CO OXIDATION CATALYST, NO. SCGT-4, BASF, MODEL CAMEET, 165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 2 FT; LENGTH: 2 FT 1.5 IN A/N:</td>
<td></td>
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<td>C205</td>
<td>D203 C206</td>
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<td>8-7-1978]; SO2: (9) [40CFR 72 - Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006]; VOC: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1) -BACT, 12-6-2002]</td>
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<td>SELECTIVE CATALYTIC REDUCTION, NO. SCGT-4, CORMETECH, MODEL CMHT, TITANIUM/VANADIUM/ TUNGSTEN, 621.96 CU.FT.; WIDTH: 4 FT 11 IN; HEIGHT: 11 FT; LENGTH: 11 FT 6 IN WITH A/N:</td>
<td></td>
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<tr>
<td>C206</td>
<td>C205 S208</td>
<td></td>
<td>NH3: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]</td>
<td></td>
<td></td>
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<tr>
<td>AMMONIA INJECTION, AQUEOUS AMMONIA</td>
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</tr>
<tr>
<td>STACK, TURBINE NO. SCGT-4, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN A/N:</td>
<td></td>
<td></td>
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<tr>
<td>S208</td>
<td>C206</td>
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Process 13: OIL/WATER SEPARATION

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<tr>
<td><strong>Process 13: OIL/WATER SEPARATION</strong></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>STORAGE TANK, NO. OWS-1 (COMBINED-CYCLE TURBINES), WASTE WATER, ABOVE GROUND, 5000 GALS; DIAMETER: 5 FT 6 IN; LENGTH: 30 FT</td>
<td>D209</td>
<td></td>
<td></td>
<td>E193.4, E193.16</td>
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</tr>
<tr>
<td>STORAGE TANK, NO. OWS-2 (SIMPLE-CYCLE TURBINES), WASTE WATER, ABOVE GROUND, 5000 GALS; DIAMETER: 5 FT 6 IN; LENGTH: 30 FT</td>
<td>D210</td>
<td></td>
<td></td>
<td>E193.4, E193.16</td>
<td></td>
</tr>
</tbody>
</table>

* (1) (1A) (1B) Denotes RECLAIM emission factor

(3) Denotes RECLAIM concentration limit

(5) (5A) (5B) Denotes command and control emission limit

(7) Denotes NSR applicability limit

(9) See App B for Emission Limits

** Refer to section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.
The following sub-section provides an index to the devices that make up the facility description sorted by device ID.
## FACILITY PERMIT TO OPERATE
AES ALAMITOS, LLC

## SECTION H: DEVICE ID INDEX

<table>
<thead>
<tr>
<th>Device ID</th>
<th>Section H Page No.</th>
<th>Process</th>
<th>System</th>
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</thead>
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<td>C188</td>
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<td>C193</td>
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<td>S196</td>
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FACILITY PERMIT TO OPERATE
AES ALAMITOS, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

FACILITY CONDITIONS

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

<table>
<thead>
<tr>
<th>CONTAMINANT</th>
<th>EMISSIONS LIMIT</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM2.5</td>
<td>Less than 100 TONS IN ANY ONE YEAR</td>
</tr>
</tbody>
</table>
The operator shall comply with the terms and conditions set forth below:

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

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

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

\[
FF1 = \text{Boiler No. 1 monthly fuel usage in mmscf; } EF1 = 1.19 \text{ lb/mmscf}
\]

\[
FF2 = \text{Boiler No. 2 monthly fuel usage in mmscf; } EF2 = 1.19 \text{ lb/mmscf}
\]

\[
FF3 = \text{Boiler No. 3 monthly fuel usage in mmscf; } EF3 = 1.19 \text{ lb/mmscf}
\]

\[
FF4 = \text{Boiler No. 4 monthly fuel usage in mmscf; } EF4 = 1.19 \text{ lb/mmscf}
\]

\[
FF5 = \text{Boiler No. 5 monthly fuel usage in mmscf; } EF5 = 1.19 \text{ lb/mmscf}
\]

\[
FF6 = \text{Boiler No. 6 monthly fuel usage in mmscf; } EF6 = 1.19 \text{ lb/mmscf}
\]

\[
FF7 = \text{Combined-Cycle Turbine No. CCGT-1 monthly fuel usage in mmscf; } EF7 = 3.92 \text{ lb/mmscf}
\]

\[
FF8 = \text{Combined-Cycle Turbine No. CCGT-2 monthly fuel usage in mmscf; } EF8 = 3.92 \text{ lb/mmscf}
\]

\[
FF9 = \text{Auxiliary Boiler monthly fuel usage in mmscf; } EF9 = 7.42 \text{ lb/mmscf}
\]
The operator shall comply with the terms and conditions set forth below:

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

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

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

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

**[RULE 1325, 12-5-2014]**

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

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

(b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition.
SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

[FACILITY PERMIT TO OPERATE
AES ALAMITOS, LLC

Section H: Permit to Construct and Temporary Permit to Operate

The operator shall comply with the terms and conditions set forth below:

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

F18.1 Acid Rain SO2 Allowance Allocation for affected units are as follows:

<table>
<thead>
<tr>
<th>Device ID</th>
<th>Boiler ID</th>
<th>Contaminant</th>
<th>Tons in any year</th>
</tr>
</thead>
<tbody>
<tr>
<td>39</td>
<td>Unit 1</td>
<td>SO2</td>
<td>2703</td>
</tr>
<tr>
<td>42</td>
<td>Unit 2</td>
<td>SO2</td>
<td>17</td>
</tr>
<tr>
<td>45</td>
<td>Unit 3</td>
<td>SO2</td>
<td>81</td>
</tr>
<tr>
<td>48</td>
<td>Unit 4</td>
<td>SO2</td>
<td>541</td>
</tr>
<tr>
<td>51</td>
<td>Unit 5</td>
<td>SO2</td>
<td>3866</td>
</tr>
<tr>
<td>3</td>
<td>Unit 6</td>
<td>SO2</td>
<td>936</td>
</tr>
</tbody>
</table>

a). The allowance allocation(s) shall apply to calendar years 2010 and beyond.

b). The number of allowances allocated to Phase II affected units by U.S. EPA may change in a 1998 revision to 40CFR73 Tables 2, 3, and 4. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitate a revision to the unit SO2 allowance allocations identified in this permit (see 40 CFR 72.84)

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

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

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

b). The operator shall submit any additional relevant information requested by the Executive Officer or designated agency.
The operator shall comply with the terms and conditions set forth below:

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

F52.1 This facility is subject to the applicable requirements of the following rules or regulation(s):
The operator shall comply with the terms and conditions set forth below:

The facility shall submit a detailed retirement plan for the permanent shutdown of Boilers Nos. 1, 2, 5 and 3 (Devices D39, D42, D51, and D45, respectively), describing in detail the steps and schedule that will be taken to render Boilers Nos. 1, 2, 5, and 3 permanently inoperable. The retirement plan shall be submitted to SCAQMD within 60 days after Permits to Construct for Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 (Devices D165 and D173, respectively), common Steam Turbine Generator, and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Devices D185, D191, D197, and D203 respectively) are issued. AES shall not commence any construction of the Alamitos Energy Project including Gas Turbines Nos. CCGT-1, CCGT-2, SCGT-1, SCGT-2, SCGT-3, and SCGT-4, unless the retirement plan is approved in writing by SCAQMD. If SCAQMD notifies AES that the plan is not approvable, AES shall submit a revised plan addressing SCAQMD's concerns within 30 days. Within 30 calendar days of actual shutdown but no later than December 29, 2019, AES shall provide SCAQMD with a notarized statement that Boilers Nos. 1, 2, and 5 are permanently shut down and that any re-start or operation of the boilers shall require new Permits to Construct and be subject to all requirements of Nonattainment New Source Review and the Prevention Of Significant Deterioration Program. AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boilers Nos. 1, 2, and 5, or advise SCAQMD as soon as practicable should AES undertake permanent shutdown prior to December 29, 2019. AES shall cease operation of Boilers Nos. 1, 2, and 5 within 90 calendar days of the first fire of Gas Turbines No. CCGT-1 or CCGT-2, whichever is earlier. Within 30 calendar days of actual shutdown but no later than December 31, 2020, AES shall provide SCAQMD with a notarized statement that Boiler No. 3 is permanently shut down and that any re-start or operation of the boiler shall require a new Permit to Construct and be subject to all requirements of
FACILITY PERMIT TO OPERATE
AES ALAMITOS, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

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

AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boiler No. 3, or advise SCAQMD as soon as practicable should AES undertake permanent shutdown prior to December 31, 2020.

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

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

F52.2 This facility is subject to the applicable requirements of the following rules or regulation(s):
The operator shall comply with the terms and conditions set forth below:

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

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

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

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1714, 12-10-2012]

DEVICE CONDITIONS

A. Emission Limits

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

<table>
<thead>
<tr>
<th>CONTAMINANT</th>
<th>EMISSIONS LIMIT</th>
</tr>
</thead>
</table>

The operator shall comply with the terms and conditions set forth below:

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>Less than or equal to 95023 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>VOC</td>
<td>Less than or equal to 13314 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>PM10</td>
<td>Less than or equal to 6324 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>SOX</td>
<td>Less than or equal to 3616 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>CO</td>
<td>Less than or equal to 190753 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>VOC</td>
<td>Less than or equal to 52668 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>PM10</td>
<td>Less than or equal to 39440 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>SOX</td>
<td>Less than or equal to 7435 LBS IN ANY ONE YEAR</td>
</tr>
</tbody>
</table>
The operator shall comply with the terms and conditions set forth below:

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

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

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

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

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

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

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

For normal operation, the emission factors shall be as follows: CO, 16.32 lb/mmcf; VOC, 4.70 lb/mmcf; PM10, 3.92 lb/mmcf; and SOx, 2.24 lb/mmcf.

For a month during which both commissioning and normal operation take place, the monthly emissions shall be the sum of the commissioning emissions and the normal operation emissions.

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

The emission factors for the monthly emission limits shall be the same as the
The operator shall comply with the terms and conditions set forth below:

emission factors used to demonstrate compliance with the annual emission limits, except the annual emission factor for SOx is 0.75 lb/mmcf.

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD. The records shall include, but not be limited to, natural gas usage in a calendar month and automated monthly and annual calculated emissions.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1304.1, 9-6-2013; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition : D165, D173]

The operator shall limit emissions from this equipment as follows:

<table>
<thead>
<tr>
<th>CONTAMINANT</th>
<th>EMISSIONS LIMIT</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>Less than or equal to 8594 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>VOC</td>
<td>Less than or equal to 1973 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>PM10</td>
<td>Less than or equal to 4638 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>SOX</td>
<td>Less than or equal to 1207 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>CO</td>
<td>Less than or equal to 37710 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>VOC</td>
<td>Less than or equal to 7510 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>PM10</td>
<td>Less than or equal to 14695 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>SOX</td>
<td>Less than or equal to 1275 LBS IN ANY ONE YEAR</td>
</tr>
</tbody>
</table>
The operator shall comply with the terms and conditions set forth below:

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

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

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

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

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

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

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

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

For a month during which both commissioning and normal operation take place, the monthly emissions shall be the sum of the commissioning emissions and the normal operation emissions.

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

The emission factors for the monthly emission limits shall be the same as the
The operator shall comply with the terms and conditions set forth below:

emission factors used to demonstrate compliance with the annual emission limits, except the annual emission factor for SOx is 0.65 lb/mmcf.

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD. The records shall include, but not be limited to, natural gas usage in a calendar month and automated monthly and annual calculated emissions.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1304.1, 9-6-2013; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

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

The operator shall limit emissions from this equipment as follows:

<table>
<thead>
<tr>
<th>CONTAMINANT</th>
<th>EMISSIONS LIMIT</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>Less than or equal to 605 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>VOC</td>
<td>Less than or equal to 102 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>PM10</td>
<td>Less than or equal to 113.5 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>SOX</td>
<td>Less than or equal to 32 LBS IN ANY CALENDAR MONTH</td>
</tr>
</tbody>
</table>
FACILITY PERMIT TO OPERATE
AES ALAMITOS, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

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

\[
\text{Monthly Emissions, lb/month} = (\text{Monthly fuel usage in mmcf/month}) \times (\text{Emission factors indicated below})
\]

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

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

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

[Devices subject to this condition : D181]

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

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

[RULE 2012, 5-6-2005]

[Devices subject to this condition : D165, D173]

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

The operator shall maintain records of natural gas usage for this period.
The operator shall comply with the terms and conditions set forth below:

[RULE 2012, 5-6-2005]

[Devices subject to this condition : D165, D173]

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

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

[RULE 2012, 5-6-2005]

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

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

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

[RULE 2012, 5-6-2005]

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

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

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

[RULE 2012, 5-6-2005]

[Devices subject to this condition : D181]
The operator shall comply with the terms and conditions set forth below:

A195.8 The 2.0 PPMV NOX emission limit(s) is averaged over over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

   [Devices subject to this condition : D165, D173]

A195.9 The 2.0 PPMV CO emission limit(s) is averaged over over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

   [Devices subject to this condition : D165, D173]

A195.10 The 2.0 PPMV VOC emission limit(s) is averaged over over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

   [Devices subject to this condition : D165, D173, D185, D191, D197, D203]

A195.11 The 2.5 PPMV NOX emission limit(s) is averaged over over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

   [Devices subject to this condition : D185, D191, D197, D203]
SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

A195.12 The 4.0 PPMV CO emission limit(s) is averaged over over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

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

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

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

[Devices subject to this condition : D181]

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

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

[Devices subject to this condition : D181]

A195.15 The 5.0 PPMV NH3 emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen.
The operator shall comply with the terms and conditions set forth below:

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

\[
\text{NH}_3 \text{ (ppmvd)} = \frac{a - b \times (c \times 1.2)}{1,000,000} \times \frac{1,000,000}{b},
\]

where:

- \( a = \text{NH}_3 \text{ injection rate (lb/hr)/17(lb/lb-mol)} \)
- \( b = \text{dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol} \)
- \( c = \text{change in measured NOx across the SCR (ppmvd at 15% O}_2\) \)

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

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

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

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

[Devices subject to this condition : C170, C178, C188, C194, C200, C206]

A195.16 The 5.0 PPMV NH3 emission limit(s) is averaged over 1 hour, dry basis at 3 percent oxygen.
FACILITY PERMIT TO OPERATE
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The operator shall comply with the terms and conditions set forth below:

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

\[ \text{NH}_3 \ (\text{ppmvd}) = \left[ \frac{a - b \times (c \times 1.2)}{1,000,000} \right] \times 1,000,000 / b, \text{ where:} \]

- \( a \) = NH₃ injection rate (lb/hr) / 17(lb/lb-mol)
- \( b \) = dry exhaust gas flow rate (scf/hr) / 385.3 scf/lb-mol
- \( c \) = change in measured NOx across the SCR (ppmvd at 3% O₂)

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

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

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

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

[Devices subject to this condition : C183]

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

[RULE 475, 10-8-1976; RULE 475, 8-7-1978]

[Devices subject to this condition : D165, D173, D185, D191, D197, D203]

B. Material/Fuel Type Limits
The operator shall comply with the terms and conditions set forth below:

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

<table>
<thead>
<tr>
<th>Compound</th>
<th>Range</th>
<th>grain per 100 scf</th>
</tr>
</thead>
<tbody>
<tr>
<td>H2S</td>
<td>greater than</td>
<td>0.25</td>
</tr>
</tbody>
</table>

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

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

[Devices subject to this condition: D165, D173, D185, D191, D197, D203]

C. Throughput or Operating Parameter Limits

C1.3 The operator shall limit the number of start-ups to no more than 62 in any one calendar month.
The operator shall comply with the terms and conditions set forth below:

The number of cold startups shall not exceed 15 in any calendar month, the number of warm startups shall not exceed 12 in any calendar month, and the number of hot startups shall not exceed 35 in any calendar month, with no more than 2 startups in any one day.

The number of cold startups shall not exceed 80 in any calendar year, the number of warm startups shall not exceed 88 in any calendar year, and the number of hot startups shall not exceed 332 in any calendar year.

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

For the purposes of this condition, a warm startup is defined as a startup which occurs after the combustion turbine has been shut down 10 hours or more but less than 48 hours. A warm startup shall not exceed 30 minutes. The NOx emissions from a warm startup shall not exceed 17 lbs. The CO emissions from a warm startup shall not exceed 137 lbs. The VOC emissions from a warm startup shall not exceed 25 lbs.

For the purposes of this condition, a hot startup is defined as a startup which occurs after the steam turbine has been shut down for less than 10 hours. A hot startup shall not exceed 30 minutes. The NOx emissions from a hot startup shall not exceed 17 lbs. The CO emissions from a hot startup shall not exceed 137 lbs. The VOC emissions from a hot startup shall not exceed 25 lbs.

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.
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The operator shall comply with the terms and conditions set forth below:

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

[Devices subject to this condition : D165, D173]

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

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

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

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

[Devices subject to this condition : D165, D173]

C1.5 The operator shall limit the number of start-ups to no more than 62 in any one calendar month.
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The operator shall comply with the terms and conditions set forth below:

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

A startup shall not exceed 30 minutes. The NOx emissions from a startup shall not exceed 16.6 lbs. The CO emissions from a startup shall not exceed 15.4 lbs. The VOC emissions from a startup shall not exceed 2.80 lbs.

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

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

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

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

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

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.
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The operator shall comply with the terms and conditions set forth below:

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

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

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

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

The number of cold startups shall not exceed 24 in any calendar year, the number of warm startups shall not exceed 48 in any calendar year, and the number of hot startups shall not exceed 48 in any calendar year.

For the purposes of this condition, a cold startup is defined as a startup which occurs after the combustion turbine has been shut down for 48 hours or more. A cold startup shall not exceed 170 minutes. The NOx emissions from a cold startup shall not exceed 4.22 lbs.

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

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

The operator shall maintain records in a manner approved by the District, to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.
The operator shall comply with the terms and conditions set forth below:

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

[Devices subject to this condition : D181]

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

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

[Devices subject to this condition : D163, D164]

**D. Monitoring/Testing Requirements**

D12.9 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH3).

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

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

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

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

[Devices subject to this condition : C170, C178]

D12.10 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.
The operator shall comply with the terms and conditions set forth below:

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

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

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

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

[Devices subject to this condition : C170, C178]

D12.11 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

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

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

The pressure differential shall not exceed 1.6 inches water column.

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

[Devices subject to this condition : C170, C178]

D12.12 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH3).
The operator shall comply with the terms and conditions set forth below:

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

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

The operator shall maintain the ammonia injection rate between 110 and 180 pounds per hour, except during startups and shutdowns.

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

Devices subject to this condition: C188, C194, C200, C206

D12.13 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

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

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

The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between 500 degrees F and 870 degrees F, except during startups and shutdowns.

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

Devices subject to this condition: C188, C194, C200, C206

D12.14 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.
The operator shall comply with the terms and conditions set forth below:

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

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

The pressure differential shall not exceed 3.0 inches water column.

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

[Devices subject to this condition : C188, C194, C200, C206]

D12.15 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH3).

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

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

The operator shall maintain the ammonia injection rate between 0.3 and 1.1 pounds per hour.

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

[Devices subject to this condition : C183]

D12.16 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.
The operator shall comply with the terms and conditions set forth below:

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

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

The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between 415 degrees F and 628 degrees F, except during startups and shutdowns.

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

[Devices subject to this condition : C183]

D12.17 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

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

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

The pressure differential shall not exceed 2.0 inches water column.

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

[Devices subject to this condition : C183]

D29.2 The operator shall conduct source test(s) for the pollutant(s) identified below.
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The operator shall comply with the terms and conditions set forth below:

<table>
<thead>
<tr>
<th>Pollutant(s) to be tested</th>
<th>Required Test Method(s)</th>
<th>Averaging Time</th>
<th>Test Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOX emissions</td>
<td>District method 100.1</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>CO emissions</td>
<td>District method 100.1</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>SOX emissions</td>
<td>AQMD Laboratory Method 307-91</td>
<td>Not Applicable</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>VOC emissions</td>
<td>District Method 25.3</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>PM10 emissions</td>
<td>EPA Method 201A/District Method 5.1</td>
<td>District-approved averaging time</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>PM2.5</td>
<td>EPA Method 201A and 202</td>
<td>District-approved averaging time</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>NH3 emissions</td>
<td>District method 207.1 or EPA method 17</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>
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The operator shall comply with the terms and conditions set forth below:

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

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

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

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

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

The tests shall be conducted when the combined-cycle turbine is operating at loads of 45, 75, and 100 percent of maximum load, and the simple-cycle turbine is operating at loads of 50, 75, and 100 percent of maximum load.

For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and SCAQMD may be the following:

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

b) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and
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The operator shall comply with the terms and conditions set forth below:

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

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

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

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

[Devices subject to this condition : D165, D173, D185, D191, D197, D203]

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

<table>
<thead>
<tr>
<th>Pollutant(s) to be tested</th>
<th>Required Test Method(s)</th>
<th>Averaging Time</th>
<th>Test Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>SOX emissions</td>
<td>AQMD Laboratory Method 307-91</td>
<td>Not Applicable</td>
<td>Fuel Sample</td>
</tr>
<tr>
<td>VOC emissions</td>
<td>District Method 25.3</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>PM10 emissions</td>
<td>EPA Method 201A/District Method 5.1</td>
<td>District-approved averaging time</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>
The operator shall comply with the terms and conditions set forth below:

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

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

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

For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and SCAQMD may be the following:

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

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

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

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

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

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emissions limit.
The operator shall comply with the terms and conditions set forth below:

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

[Devices subject to this condition : D165, D173, D185, D191, D197, D203]

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

<table>
<thead>
<tr>
<th>Pollutant(s) to be tested</th>
<th>Required Test Method(s)</th>
<th>Averaging Time</th>
<th>Test Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>NH3 emissions</td>
<td>District method 207.1 and 5.3 or EPA method 17</td>
<td>1 hour</td>
<td>Inlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>

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

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

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

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

[Devices subject to this condition : C170, C178, C183, C188, C194, C200, C206]

D29.5 The operator shall conduct source test(s) for the pollutant(s) identified below.
The operator shall comply with the terms and conditions set forth below:

<table>
<thead>
<tr>
<th>Pollutant(s) to be tested</th>
<th>Required Test Method(s)</th>
<th>Averaging Time</th>
<th>Test Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOX emissions</td>
<td>District method 100.1</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>CO emissions</td>
<td>District method 100.1</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>SOX emissions</td>
<td>AQMD Laboratory Method 307-91</td>
<td>Not Applicable</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>VOC emissions</td>
<td>District Method 25.3</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>PM10 emissions</td>
<td>EPA Method 201A/District Method 5.1</td>
<td>District-approved averaging time</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>PM2.5</td>
<td>EPA Method 201A and 202</td>
<td>District-approved averaging time</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>NH3 emissions</td>
<td>District method 207.1 or EPA method 17</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>
The operator shall comply with the terms and conditions set forth below:

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

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

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

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

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

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

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

[RULE 1146, 11-1-2013; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2005, 12-4-2015]

[Devices subject to this condition : D181]
The operator shall comply with the terms and conditions set forth below:

D29.6 The operator shall conduct source test(s) for the pollutant(s) identified below.

<table>
<thead>
<tr>
<th>Pollutant(s) to be tested</th>
<th>Required Test Method(s)</th>
<th>Averaging Time</th>
<th>Test Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO emissions</td>
<td>District method 100.1</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>

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

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

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

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

[RULE 1146, 11-1-2013; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition : D181]

D82.1 The operator shall install and maintain a CEMS to measure the following parameters:
SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

CO concentration in ppmv.

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

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

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

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

\[
\text{CO Emission Rate, lbs/hr} = K \times C_{\text{co}} \times F_d \times \frac{20.9}{(20.9\% - \%O_2 \text{ d})} \times \frac{Q_g \times \text{HHV}}{10^6},
\]

where:

1. \( K = 7.267 \times 10^{-08} \text{ (lb/scf)/ppm} \)
2. \( C_{\text{co}} = \text{Average of four consecutive 15 min. average CO concentrations, ppm} \)
3. \( F_d = 8710 \text{ dscf/MMBTU natural gas} \)
4. \( \%O_2 \text{ d} = \text{Hourly average % by volume O2 dry, corresponding to Cco} \)
5. \( Q_g = \text{Fuel gas usage during the hour, scf/hr} \)
6. \( \text{HHV} = \text{Gross high heating value of fuel gas, BTU/scf} \)

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

[Devices subject to this condition : D165, D173, D185, D191, D197, D203]

D82.2 The operator shall install and maintain a CEMS to measure the following parameters:
The operator shall comply with the terms and conditions set forth below:

NOx concentration in ppmv.

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

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

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

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

[Devices subject to this condition : D165, D173, D185, D191, D197, D203]

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

NOx concentration in ppmv.

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

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

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the boiler commissioning period. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3).
FACILITY PERMIT TO OPERATE
AES ALAMITOS, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

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

[Devices subject to this condition : D181]

E. Equipment Operation/Construction Requirements

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

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

[Devices subject to this condition : D163, D164]

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

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.

[CA PRC CEQA, 11-23-1970]

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

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

The Permit to Construct shall expire one year from the date of issuance unless an extension of time has been approved in writing by the Executive Officer.

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

[RULE 205, 1-5-1990]

[Devices subject to this condition : D165, D173, D185, D191, D197, D203]
The operator shall comply with the terms and conditions set forth below:

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

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

[40 CFR 52.21 - PSD, 6-19-1978]

[Devices subject to this condition: D165, D173, D185, D191, D197, D203]

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

The Permit to Construct shall become invalid if construction is not commenced within 24 months after the issuance date, if construction is discontinued for a period of 24 months or more, or if construction is not completed within a reasonable time. The Executive Officer may extend the 24-month period upon a satisfactory showing that an extension is justified.

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

[Devices subject to this condition: D165, D173, D185, D191, D197, D203]

E193.8 The operator shall operate and maintain this equipment according to the following requirements:
The operator shall comply with the terms and conditions set forth below:

Total commissioning hours shall not exceed 996 hours of fired operation for each turbine from the date of initial turbine start-up. Of the 996 hours, commissioning hours without control shall not exceed 216 hours.

Two turbines may be commissioned at the same time.

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD. The records shall include, but not be limited to, the total number of commissioning hours, number of commissioning hours without control, and natural gas fuel usage.

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

[Devices subject to this condition : D165, D173]

E193.9 The operator shall operate and maintain this equipment according to the following requirements:
FACILITY PERMIT TO OPERATE
AES ALAMITOS, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

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

Four turbines may be commissioned at the same time.

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

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

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

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

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

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

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

The operator shall provide the SCAQMD with written notification of the initial startup date. The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request. The records shall include, but not be limited to, the number of commissioning hours and natural gas fuel usage.
FACILITY PERMIT TO OPERATE
AES ALAMITOS, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

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

[Devices subject to this condition : D181]

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

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

Compliance with the 1000 lbs per gross megawatt-hours CO2 emission limit (inclusive of degradation) shall be determined on a 12-operating-month rolling average basis.

This turbine shall be operated in compliance with all applicable requirements of 40 CFR 60 Subpart TTTT.

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

[Devices subject to this condition : D165, D173]

E193.12 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:

The 120 lbs/MMBtu CO2 emission limit shall only apply if this turbine supplies no more than 1,481,141 MWh-net electrical output to a utility power distribution system on either a 12-operating-month or a 3-year rolling average basis.

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

This turbine shall be operated in compliance with all applicable requirements of 40 CFR 60 Subpart TTTT.
The operator shall comply with the terms and conditions set forth below:

E193.13 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:

- The 120 lbs/MBtu CO2 emission limit for non-base load turbines shall apply.
- Compliance with the 120 lbs/MBtu CO2 emission limit shall be determined on a 12-operating-month rolling average basis.
- This turbine shall be operated in compliance with all applicable requirements of 40 CFR 60 Subpart TTTT, including applicable requirements for recordkeeping and reporting.

E193.14 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:
FACILITY PERMIT TO OPERATE
AES ALAMITOS, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

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

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

\[ \text{GHG} = 61.41 \times \text{FF} \]

Where GHG is the greenhouse gas emissions in tons of CO\(_2\) and FF is the monthly fuel usage in millions standard cubic feet.

The operator shall calculate and record the CO\(_2\) emissions in pounds per net megawatt-hour based on a 12-month rolling average. The CO\(_2\) emissions from this equipment shall not exceed 610,480 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO\(_2\) emissions shall not exceed 937.88 lbs per gross megawatt-hours (inclusive of equipment degradation).

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1714, 12-10-2012]

[Devices subject to this condition: D165, D173]

E193.15 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:
The operator shall comply with the terms and conditions set forth below:

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

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

\[
\text{GHG} = 61.41 \times \text{FF}
\]

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

The operator shall calculate and record the CO₂ emissions in pounds per net megawatt-hour based on a 12-month rolling average. The CO₂ emissions from this equipment shall not exceed 120,765 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO₂ emissions shall not exceed 1356.03 lbs per gross megawatt-hours (inclusive of equipment degradation).

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1714, 12-10-2012]

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

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

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

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

[Devices subject to this condition : D209, D210]
The operator shall comply with the terms and conditions set forth below:

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

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

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

The operator shall record and maintain written records of the maximum amount of electricity produced from this equipment and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

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

[Devices subject to this condition: D165, D173, D185, D191, D197, D203]

H. Applicable Rules

H23.7 This equipment is subject to the applicable requirements of the following rules or regulations:

<table>
<thead>
<tr>
<th>Contaminant</th>
<th>Rule</th>
<th>Rule/Subpart</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>District Rule</td>
<td>1146</td>
</tr>
</tbody>
</table>

These requirement shall include applicable portable analyzer testing and source testing requirements.
The operator shall comply with the terms and conditions set forth below:

[RULE 1146, 11-1-2013]

[Devices subject to this condition : D181]

I. Administrative

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

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

[Devices subject to this condition : D165]

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

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

[Devices subject to this condition : D173]
The operator shall comply with the terms and conditions set forth below:

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

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

[Devices subject to this condition : D185]

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

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

[Devices subject to this condition : D191]

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

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

[Devices subject to this condition : D197]
FACILITY PERMIT TO OPERATE
AES ALAMITOS, LLC

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

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

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

[Devices subject to this condition : D203]

I297.7 This equipment shall not be operated unless the facility holds 1351 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

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

[Devices subject to this condition : D181]

K. Record Keeping/Reporting

K40.4 The operator shall provide to the District a source test report in accordance with the following specifications:
SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

The operator shall comply with the terms and conditions set forth below:

Source test results shall be submitted to the District no later than 90 days after the source tests required by conditions D29.2, D29.3, and D29.4 are conducted.

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

All exhaust flow rates shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

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

[Devices subject to this condition : D165, D173, D185, D191, D197, D203]

The operator shall provide to the District a source test report in accordance with the following specifications:
The operator shall comply with the terms and conditions set forth below:

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

Emission data shall be expressed in terms of concentration (ppmv), corrected to 3 percent oxygen (dry basis), mass rate (lbs/hr), lbs/MM cubic feet, and lbs/MMBtu. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

All moisture concentration shall be expressed in terms of percent corrected to 3 percent oxygen.

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

[RULE 1146, 11-1-2013; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2005, 12-4-2015]

[Devices subject to this condition : D181]
AES ALAMITOS, LLC  
P.O. BOX 210307  
DALLAS, TX 75211

FACILITY ID: 115394

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

Contact: Stephen O’Kane, Manager

**PRELIMINARY DETERMINATION OF COMPLIANCE for**

**PERMITS TO CONSTRUCT FOR**

**ALAMITOS ENERGY CENTER (AEC)**

**EQUIPMENT DESCRIPTION**

**SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE**

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

<table>
<thead>
<tr>
<th>Equipment</th>
<th>ID No.</th>
<th>Connected To</th>
<th>Source Type/ Monitoring Unit</th>
<th>Emissions * And Requirements</th>
<th>Conditions</th>
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<tbody>
<tr>
<td>PROCESS 4: INORGANIC CHEMICAL STORAGE</td>
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<tr>
<td>STORAGE TANK, TANK-1 (COMBINED-CYCLE TURBINES), AQUEOUS AMMONIA 19 PERCENT, 40,000 GALS; DIAMETER: 13 FT; LENGTH: 45 FT</td>
<td>D163</td>
<td></td>
<td></td>
<td>C157.1, E144.1, E193.4</td>
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<td>A/N: 579167</td>
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<tr>
<td>STORAGE TANK, TANK-2 (SIMPLE-CYCLE TURBINES), AQUEOUS AMMONIA 19 PERCENT, 40,000 GALS; DIAMETER: 13 FT; LENGTH: 45 FT</td>
<td>D164</td>
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<td>C157.1, E144.1, E193.4</td>
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<td>A/N: 579168</td>
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<tr>
<td>PROCESS 12: INTERNAL COMBUSTION – POWER GENERATION</td>
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<tr>
<td>SYSTEM 1: COMBINED-CYCLE TURBINES (AEC CCGT POWER BLOCK)</td>
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<tr>
<td>GAS TURBINE, NO. CCGT-1, COMBINED-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL 7FA.05, 2275 MMBTU/HR HHV AT 28 F, WITH</td>
<td>D165</td>
<td>C169</td>
<td>NOX: MAJOR SOURCE**</td>
<td>CO: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996];</td>
<td>A63.2, A99.1, A99.2, A195.8, A195.9,</td>
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### Preliminary Determination of Compliance

#### Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

<table>
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<tr>
<th>Dry Low-Nox Combustor, GE DLN 2.6, With</th>
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<tr>
<td>A/N: 579142</td>
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<tr>
<td>Generator, No. CCGT-1, 236.645 MW Gross at 28 F</td>
</tr>
<tr>
<td>Heat Exchanger, Heat Recovery Steam Generator (HRSG), No. CCGT-1</td>
</tr>
<tr>
<td>Generator, Steam Turbine Generator (STG), 219.615 MW Gross at 28 F, Common with HRSG No. CCGT-2</td>
</tr>
</tbody>
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| Rule 1303(a)(1)-BACT, 12-6-2002; Rule 1703(a)(2)-PSD-BACT, 10-7-1988; CO: 2000 PPMV (5) [Rule 407, 4-2-1982]; CO2: 120 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 Subpart TTTT, 10-23-2015]; CO2: 1000 LBS/GROSS MWH NATURAL GAS (8A) [40 CFR 60 Subpart TTTT, 10-23-2015] |

| Rule 2012, 5-6-2005; NOx: 2 PPMV NATURAL GAS (4) [Rule 1703(a)(2)-PSD-BACT, 10-7-1988; Rule 2005, 6-3-2011; Rule 2005, 12-4-2015]; NOx: 8.35 LBS/MMSCF NATURAL GAS (1A) [Rule 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006]; NOx: 16.66 LBS/MMSCF NATURAL GAS (1) [Rule 2012, 5-6-2005]; PM10: 0.01 GRAINS/SCF (5A) [Rule 475, 10-8-1976; Rule 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [Rule 409, 8-7-1981]; PM10: 8.5 LB/HR NATURAL GAS (4) |

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<tr>
<th>Description</th>
<th>Model</th>
<th>Dimensions</th>
<th>Notes</th>
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<tr>
<td>CO Oxidation Catalyst, NO. CCGT-1</td>
<td>BASF, 265.8 CU. FT.</td>
<td>Width: 26 FT 2 IN; Height: 71 FT 9.6 IN; Length: 2.1 IN</td>
<td>A/N: 579160 C169 D165, C170</td>
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<tr>
<td>Selective Catalytic Reduction, NO. CCGT-1</td>
<td>CORMETECH, TITANIUM/VANADIUM/TUNGSTEN, 1289 CU. FT.</td>
<td>Width: 25 FT 8.5 IN; Height: 71 FT 7.2 IN; Length: 1 FT 6 IN With</td>
<td>A/N: 579160 C170 C169, S172</td>
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<tr>
<td>Ammonia Injection, Aqueous Ammonia</td>
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<td>[B171]</td>
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<tr>
<td>Stack, Turbine NO. CCGT-1</td>
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<td>Height: 140 FT; Diameter: 20 FT</td>
<td>A/N: 579142 S172 C170</td>
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<tr>
<td>Gas Turbine, No. CCGT-2, Combined-Cycle, Natural Gas, General Electric, Model 7FA.05</td>
<td></td>
<td>NOX: MAJOR SOURCE**</td>
<td>CO: 2 PPMV NATURAL GAS (4) A195.15, A12.9, A12.10, A12.11, D29.4, E193.4</td>
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Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

Preliminary Determination of Compliance
Alamitos Energy Center  
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170  

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<th>F, WITH DRY LOW-NOX COMBUSTOR, GE DLN 2.6, WITH A/N: 579143</th>
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<tr>
<td>Generator, No. CCGT-2, 236.645 MW gross at 28°F</td>
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<tr>
<td>Heat Exchanger, Heat Recovery Steam Generator (HRSG), No. CCGT-2</td>
</tr>
<tr>
<td>Generator, Steam Turbine Generator (STG), 219.615 MW gross at 28°F, common with HRSG No. CCGT-1</td>
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<thead>
<tr>
<th>BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; CO: 2000 PPMV (5) RULE 407, 4-2-1982;</th>
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<tr>
<td>CO2: 120 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 Subpart TTTT, 10-23-2015];</td>
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<tr>
<td>CO2: 1000 LBS/GROSS MWH NATURAL GAS (8A) [40 CFR 60 Subpart TTTT, 10-23-2015];</td>
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<tr>
<td>NOx: 2 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2005, 12-4-2015]; NOx: 8.35 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006]; NOx: 16.66 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005];</td>
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<tr>
<td>PM10: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 8.5 LB/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996];</td>
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Preliminary Determination of Compliance
Preliminary Determination of Compliance

CO OXIDATION CATALYST, NO. CCGT-2, BASF, 265.8 CU. FT.; WIDTH: 26 FT 2 IN; HEIGHT: 71 FT 9.6 IN; LENGTH: 2.1 IN
A/N: 579161
C177
D173, C178

SELECTIVE CATALYTIC REDUCTION, NO. CCGT-2, CORMETECH, TITANIUM/ VANADIUM/TUNGSTEN, 1289 CU. FT.; WIDTH: 25 FT 8.5 IN; HEIGHT: 71 FT 7.2 IN; LENGTH: 1 FT 6 IN WITH
A/N: 579161
C178
C177, S180

AMMONIA INJECTION, AQUEOUS AMMONIA
[B179]

STACK, TURBINE NO. CCGT-2, HEIGHT: 140 FT; DIAMETER: 20 FT
A/N: 579143
S180 C178

BOILER, AUXILIARY, WATER-TUBE, NATURAL GAS, BABCOCK & WILCOX, MODEL FM 103-88, WITH LOW NOX BURNER, FLUE GAS RECIRCULATION, 70.8 MMBTU/HR WITH
A/N: 579158
D181 C183

SO2: (9) [40 CFR 72 – Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006];

VOC: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]
### Preliminary Determination of Compliance

**Alamitos Energy Center**  
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

**BURNER, NATURAL GAS, JZHC/COEN, MODEL RMB, WITH LOW NOX BURNER, 70.8 MMBTU/HR**  
**[B182]**  

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<td>400 PPMV NATURAL GAS</td>
<td>RULE 1146, 11-1-2013</td>
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<td>NOx</td>
<td>5 PPMV NATURAL GAS</td>
<td>RULE 1703(a)(2) PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2005, 12-4-2015</td>
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<td>PM10</td>
<td>0.1 GRAINS/SCF</td>
<td>RULE 409, 8-7-1981</td>
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<tr>
<td>VOC</td>
<td>0.0052 LB/MMBTU NATURAL GAS</td>
<td>RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002</td>
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**SELECTIVE CATALYTIC REDUCTION, AUXILIARY BOILER, BABCOCK & WILCOX, VANADIUM, 46 CU. FT.; WIDTH: 5 FT 5 IN; HEIGHT: 3 FT 8 IN; LENGTH: 7 FT 3 IN WITH**  
A/N: 579166  
**[B184]**  

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<td>RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002</td>
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**AMMONIA INJECTION, AQUEOUS AMMONIA**  
**[B184]**  

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<td>A195.16, D12.15, D12.16, D12.17, D29.4, E193.4</td>
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**STACK, AUXILIARY BOILER, HEIGHT: 80 FT; DIAMETER: 3 FT**  
S211 C183
### Preliminary Determination of Compliance

*Alamitos Energy Center*

Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

| A/N: 579158 | PROCESS 12: INTERNAL COMBUSTION – POWER GENERATION
SYSTEM 2: SIMPLE-CYCLE TURBINES (AEC SCGT POWER BLOCK) |
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<tr>
<td>GAS TURBINE, NO. SCGT-1, SIMPLE-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS-100 PB, 882 MMBTU/HR AT 59 DEG F, WITH INTERCOOLER AND DRY LOW-NOX COMBUSTOR WITH</td>
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<tr>
<td>A/N: 579145</td>
<td>GENERATOR, 100.438 MW GROSS AT 59 F</td>
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<td>CO: 4.0 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982];</td>
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<td>NOx: MAJOR SOURCE**</td>
<td>CO2: 120 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 Subpart TTTT, 10-23-2015];</td>
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<td>A195.10, A195.11, A195.12, A327.1, B61.1, C1.5, C1.6, D29.2, D29.3, D82.1, D82.2, E193.4, E193.5, E193.6, E193.7, E193.9, E193.13, E193.15, E448.1, I297.3, K40.4</td>
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<td>NOx: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2005, 12-4-2015]; NOx: 11.21 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006]; NOx: 25.24 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005];</td>
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<td>PM10: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 6.23 LB/HR NATURAL</td>
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Preliminary Determination of Compliance

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

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<th>Item</th>
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<tr>
<td>CO Oxidation Catalyst</td>
<td>NO. SCGT-1, BASF, MODEL CAMET, 165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 2 FT; LENGTH: 2 FT 1.5 IN</td>
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<td>Selective Catalytic Reduction</td>
<td>NO. SCGT-1, CORMETECH, MODEL CMHT, TITANIUM/VANADIUM/ TUNGSTEN, 621.96 CU. FT.; WIDTH: 4 FT 11 IN; HEIGHT: 11 FT; LENGTH: 11 FT 6 IN WITH</td>
<td>C188</td>
<td>C187</td>
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<td>A/N: 579162</td>
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<td>S190</td>
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<td>Ammonia Injection</td>
<td>AQUEOUS AMMONIA</td>
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<tr>
<td>Stack, Turbine NO. SCGT-1</td>
<td>HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN</td>
<td>S190</td>
<td>C188</td>
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<td>A/N: 579145</td>
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<tr>
<td>Gas Turbine</td>
<td>NO. SCGT-2, SIMPLE-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS-100 PB, 882 MMBTU/HR AT 59 DEG F, WITH INTERCOOLER AND DRY LOW-NOX COMBUSTOR WITH</td>
<td>D191</td>
<td>C193</td>
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<td>CO: 4.0 PPMV NATURAL GAS (4)</td>
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<td>[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]</td>
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<td>A63.3, A99.3, A99.4, A195.10, A195.11, A195.12, A327.1,</td>
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**Major Source**
Preliminary Determination of Compliance

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

| A/N: 579147 | RULE 1703(a)(2)-PSD-BACT, 10-7-1988; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; CO2: 120 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 Subpart TTTT, 10-23-2015]; NOx: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2005, 12-4-2015]; NOx: 11.21 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006]; NOx: 25.24 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; PM10: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 6.23 LB/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; |

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<td>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</td>
<td>289</td>
<td>9</td>
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<tr>
<td>APPLICATION PROCESSING AND CALCULATIONS</td>
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A/N: 579147
GENERATOR, 100.438 MW GROSS AT 59 F

[B192]
## Preliminary Determination of Compliance

**Alamitos Energy Center**  
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

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### Application Processing and Calculations

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<td><strong>SO(_2):</strong> 0.06 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006]; VOC: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]</td>
<td>[40 CFR 72 – Acid Rain Provisions, 11-24-1997];</td>
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</tr>
<tr>
<td><strong>CO</strong>: 4.0 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; CO(_2): 120 LBS/MMBTU NATURAL GAS (8)</td>
<td>[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002];</td>
<td></td>
</tr>
</tbody>
</table>

---

**CO OXIDATION CATALYST, NO. SCGT-2, BASF, MODEL CAMET, 165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 2 FT; LENGTH: 2 FT 1.5 IN**

A/N: 579163

<table>
<thead>
<tr>
<th>C193</th>
<th>D191</th>
<th>C194</th>
</tr>
</thead>
</table>

**SELECTIVE CATALYTIC REDUCTION, NO. SCGT-2, CORMETECH, MODEL CMHT, TITANIUM/VANADIUM/ TUNGSTEN, 621.96 CU. FT.; WIDTH: 4 FT 11 IN; HEIGHT: 11 FT; LENGTH: 11 FT 6 IN**

WITH A/N: 579163

AMMONIA INJECTION, AQUEOUS AMMONIA

<table>
<thead>
<tr>
<th>C194</th>
<th>C193, S196</th>
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</thead>
</table>

**STACK, TURBINE NO. SCGT-2, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN**

A/N: 579147

<table>
<thead>
<tr>
<th>S196</th>
<th>C194</th>
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</table>

**GAS TURBINE, NO. SCGT-3, SIMPLE-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LMS-100 PB, 882 MMBTU/HR AT 59 DEG F, WITH INTERCOOLER AND DRY LOW-NOX COMBUSTOR WITH**

A/N: 579150

GENERATOR, 100.438 MW GROSS AT 59 F

<table>
<thead>
<tr>
<th>D197</th>
<th>C199</th>
<th>[B198]</th>
</tr>
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</table>

**NOX: MAJOR SOURCE**

| A63.3, A99.3, A99.4, A195.10, A195.11, A195.12, A327.1, B61.1, C1.5, C1.6, D29.2, D29.3, D82.1, D82.2, E193.4, E193.6, E193.7, E193.9, E193.13, |
Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

Preliminary Determination of Compliance

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

NOx: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2005, 12-4-2015]; NOx: 11.21 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOx: 15 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006]; NOx: 25.24 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005];

PM10: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 6.23 LB/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978];

SO2: (9) [40 CFR 72 - Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006];

E193.15, E448.1, I297.5, K40.4
<table>
<thead>
<tr>
<th>Equipment Type</th>
<th>NOx Source</th>
<th>NOx</th>
<th>CO</th>
<th>CO2</th>
<th>VOC</th>
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<tr>
<td>CO Oxidation Catalyst, No. SCGT-3, BASF, Model CAMET, 165.57 CU. FT.; WIDTH: 2.5 IN; HEIGHT: 2 FT; LENGTH: 2 FT 1.5 IN</td>
<td>[B201]</td>
<td></td>
<td></td>
<td></td>
<td>2 PPMV</td>
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<tr>
<td>Selective Catalytic Reduction, No. SCGT-3, CORMETECH, MODEL CMHT, TITANIUM/VANADIUM/ TUNGSTEN, 621.96 CU. FT.; WIDTH: 4 FT 11 IN; HEIGHT: 11 FT; LENGTH: 11 FT 6 IN WITH</td>
<td></td>
<td>5 PPMV</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ammonia Injection, Aqueous Ammonia</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stack, Turbine No. SCGT-3, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas Turbine, No. SCGT-4, Simple-Cycle, Natural Gas, General Electric, Model LMS-100 PB, 882 MMHBTU/HR AT 59 DEG F, WITH INTERCOOLER AND DRY LOW-NOX COMBUSTOR WITH</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generator, 100.438 MW GROSS AT 59 F</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Preliminary Determination of Compliance**

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170
<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Concentration</th>
<th>Description</th>
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<tbody>
<tr>
<td>NOx</td>
<td>11.21 LBS/MMSCF</td>
<td>NATURAL GAS (1A) RULE 2012, 5-6-2005; NOx: 15 PPMV NATURAL GAS (8) RULE 60, 7-6-2006; NOx: 25.24 LBS/MMSCF NATURAL GAS (1) RULE 2012, 5-6-2005;</td>
</tr>
<tr>
<td>PM10</td>
<td>0.01 GRAINS/SCF</td>
<td>RULE 475, 10-8-1976; RULE 475, 8-7-1978; PM10: 0.1 GRAINS/SCF RULE 409, 8-7-1981; PM10: 6.23 LB/HR NATURAL GAS (4) RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; PM10: 11 LBS/HR (5B) RULE 475, 10-8-1976; RULE 475, 8-7-1978;</td>
</tr>
<tr>
<td>SO2</td>
<td>0.06 LBS/MMBTU</td>
<td>NATURAL GAS (8) RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002</td>
</tr>
<tr>
<td>CO Oxidation Catalyst, No. SCGT-4, BASF, Model CAMET</td>
<td>C205 D203 C206</td>
<td>Preliminary Determination of Compliance</td>
</tr>
</tbody>
</table>

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170
### FACILITY CONDITIONS

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

**SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT**

**ENGINEERING AND COMPLIANCE**

**APPLICATION PROCESSING AND CALCULATIONS**

<table>
<thead>
<tr>
<th>Facility Condition</th>
<th>Emission Factor</th>
<th>Emission Rate</th>
<th>Concentration Limit</th>
<th>Emissions Limit</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>SELECTIVE CATALYTIC REDUCTION, NO. SCGT-4, CORMETECH, MODEL CMHT, TITANIUM/VANADIUM/ TUNGSTEN, 621.96 CU. FT.; WIDTH: 4 FT 11 IN; HEIGHT: 11 FT; LENGTH: 11 FT 6 IN WITH AMMONIA INJECTION, AQUEOUS AMMONIA</td>
<td>C206, C205, S208</td>
<td>NH3: 5 PPMV (4)</td>
<td>A195.15, D12.12, D12.13, D12.14, D29.4, E193.4</td>
<td></td>
<td></td>
</tr>
<tr>
<td>STACK, TURBINE NO. SCGT-4, HEIGHT: 80 FT; DIAMETER: 13 FT 6 IN WITH AGGREGATE SYSTEM, 0.6 CU. FT. LAYdown</td>
<td>S208</td>
<td></td>
<td>E193.4, E193.16</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OIL WATER SEPARATOR, NO. OWS-1 (COMBINED-CYCLE TURBINES), WASTE WATER, ABOVE GROUND, 5000 GALS; DIAMETER: 5 FT 6 IN; LENGTH: 30 FT</td>
<td>D209</td>
<td></td>
<td>E193.4, E193.16</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OIL WATER SEPARATOR, NO. OWS-2 (SIMPLE-CYCLE TURBINES), WASTE WATER, ABOVE GROUND, 5000 GALS; DIAMETER: 5 FT 6 IN; LENGTH: 30 FT</td>
<td>D210</td>
<td></td>
<td>E193.4, E193.16</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
- (1) Denotes RECLAIM emission factor
- (2) Denotes RECLAIM emission rate
- (3) Denotes RECLAIM concentration limit
- (4) Denotes BACT emissions limit
- (5A)(5B) Denotes command & control emission limit
- (6) Denotes air toxic control rule limit
- (7) Denotes NSR applicability limit
- (8)(8A)(8B) Denotes CFR limit (e.g. NSPS, NESHAPS, etc.)
- (9) See App B for Emission Limits
- (10) See Section J for NESHAP/MACT requirements

---

**FACILITY CONDITIONS**

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

**FACILITY CONDITIONS**

Note: All facility conditions appear in both Section D (Permits to Operate) and Section H (Permits to Construct). Conditions F9.1, F18.1, and F24.1 are existing facility conditions from Section D. The other conditions are new conditions for the AEC.
F2.1 The operator shall limit emissions from this facility as follows:

<table>
<thead>
<tr>
<th>Contaminant</th>
<th>Emissions Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM2.5</td>
<td>Less than 100 tons in any one year</td>
</tr>
</tbody>
</table>

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

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

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

- FF1 = Boiler No. 1 monthly fuel usage in mmscf; EF1 = 1.19 lb/mmscf
- FF2 = Boiler No. 2 monthly fuel usage in mmscf; EF2 = 1.19 lb/mmscf
- FF3 = Boiler No. 3 monthly fuel usage in mmscf; EF3 = 1.19 lb/mmscf
- FF4 = Boiler No. 4 monthly fuel usage in mmscf; EF4 = 1.19 lb/mmscf
- FF5 = Boiler No. 5 monthly fuel usage in mmscf; EF5 = 1.19 lb/mmscf
- FF6 = Boiler No. 6 monthly fuel usage in mmscf; EF6 = 1.19 lb/mmscf
- FF7 = Combined-Cycle Turbine No. CCGT-1 monthly fuel usage in mmscf; EF7 = 3.92 lb/mmscf
- FF8 = Combined-Cycle Turbine No. CCGT-2 monthly fuel usage in mmscf; EF8 = 3.92 lb/mmscf
- FF9 = Auxiliary Boiler monthly fuel usage in mmscf; EF9 = 7.42 lb/mmscf
- FF10 = Simple-Cycle Turbine No. SCGT-1 monthly fuel usage in mmscf; EF10 = 7.44 lb/mmscf
- FF11 = Simple-Cycle Turbine No. SCGT-2 monthly fuel usage in mmscf; EF11 = 7.44 lb/mmscf
- FF12 = Simple-Cycle Turbine No. SCGT-3 monthly fuel usage in mmscf; EF12 = 7.44 lb/mmscf
- FF13 = Simple-Cycle Turbine No. SCGT-4 monthly fuel usage in mmscf; EF13 = 7.44 lb/mmscf

Any changes to these emission factors must be approved in advance by the SCAQMD in writing and be based on unit specific source tests performed using SCAQMD-approved testing protocol.
AES Alamitos, LLC shall submit written reports of the monthly PM2.5 compliance demonstration required by this condition. The report submittal shall be included with the semi-annual Title V report as required under Rule 3004(a)(4)(f). Records of the monthly PM2.5 compliance demonstration shall be maintained on site for at least five years and made available upon SCAQMD request.

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

[Rule 1325, 12-5-2014]

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

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

(b) Of such opacity as to obscure an observer’s view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition.

[RULE 401, 3-2-1984; RULE 401, 9-11-1998 11-9-2001]

F18.1 This condition sets forth the Acid Rain SO\(_2\) Allowance Allocation for affected units, Boilers No. 1 - 6, applicable to calendar years 2010 and beyond.

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

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

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

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

[RULE 40 CFR 68 – Accidental Release Prevention, 5-24-1996]
Note: Facility condition F24.1 is applicable to the four existing ammonia tanks (Devices D19, D151, D152, and D153) in Section D, because they are permitted to contain 29% aqueous ammonia. This condition is not applicable to the two new ammonia tanks (Devices D163, D164) installed for the AEC project because they are permitted to contain 19% ammonia. Condition F24.1 will be removed from the facility permit after the four existing tanks are removed from the facility.

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

The facility shall submit a detailed retirement plan for the permanent shutdown of Boilers Nos. 1, 2, 5 and 3 (Devices D39, D42, D51, and D45, respectively), describing in detail the steps and schedule that will be taken to render Boilers Nos. 1, 2, 5, and 3 permanently inoperable.

The retirement plan shall be submitted to SCAQMD within 60 days after Permits to Construct for Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 (Devices D165 and D173, respectively), common Steam Turbine Generator, and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Devices D185, D191, D197, and D203 respectively) are issued.

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

Within 30 calendar days of actual shutdown but no later than December 29, 2019, AES shall provide SCAQMD with a notarized statement that Boilers Nos. 1, 2, and 5 are permanently shut down and that any re-start or operation of the boilers shall require new Permits to Construct and be subject to all requirements of Nonattainment New Source Review and the Prevention Of Significant Deterioration Program.

AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boilers Nos. 1, 2, and 5, or advise SCAQMD as soon as practicable should AES undertake permanent shutdown prior to December 29, 2019.

AES shall cease operation of Boilers Nos. 1, 2, and 5 within 90 calendar days of the first fire of Gas Turbines No. CCGT-1 or CCGT-2, whichever is earlier.

Within 30 calendar days of actual shutdown but no later than December 31, 2020, AES shall provide SCAQMD with a notarized statement that Boiler No. 3 is permanently shut
down and that any re-start or operation of the boiler shall require a new Permit to Construct and be subject to all requirements of Nonattainment New Source Review and the Prevention Of Significant Deterioration Program.

AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boiler No. 3, or advise SCAQMD as soon as practicable should AES undertake permanent shutdown prior to December 31, 2020.

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

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

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

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

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

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

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1714, 12-10-2012]
DEVICE CONDITIONS

COMBINED-CYCLE TURBINES

The operator shall limit emissions from this equipment as follows:

<table>
<thead>
<tr>
<th>CONTAMINANT</th>
<th>EMISSIONS LIMIT</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>Less than or equal to 95,023 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>VOC</td>
<td>Less than or equal to 13,314 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>PM10</td>
<td>Less than or equal to 6324 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>SOx</td>
<td>Less than or equal to 3616 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>CO</td>
<td>Less than or equal to 190,753 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>VOC</td>
<td>Less than or equal to 52,668 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>PM10</td>
<td>Less than or equal to 39,440 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>SOx</td>
<td>Less than or equal to 7435 LBS IN ANY ONE YEAR</td>
</tr>
</tbody>
</table>

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

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

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

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

Monthly Emissions, lb/month = (Monthly fuel usage in mmscf/month) * (Emission factors indicated below)
The following emission factors shall be used to demonstrate compliance with the monthly emission limits.

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

For normal operation, the emission factors shall be as follows: CO, 16.32 lb/mmcf; VOC, 4.70 lb/mmcf; PM10, 3.92 lb/mmcf; and SOx, 2.24 lb/mmcf.

For a month during which both commissioning and normal operation take place, the monthly emissions shall be the sum of the commissioning emissions and the normal operation emissions.

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

The emission factors for the monthly emission limits shall be the same as the emission factors used to demonstrate compliance with the annual emission limits, except the annual emission factor for SOx is 0.75 lb/mmcf.

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD. The records shall include, but not be limited to, natural gas usage in a calendar month and automated monthly and annual calculated emissions.

[Rule 1303(a)(1)-BACT, 5-10-1996; Rule 1303(a)(1)-BACT, 12-6-2002; Rule 1304.1, 9-6-2013; Rule 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition: D165, D173]

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

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

[Rule 2012, 5-6-2005]

[Devices subject to this condition: D165, D173]
A99.2 The 8.35 lbs/mscf NOx emission limit(s) shall only apply during the interim period after commissioning but prior to CEMS certification to report RECLAIM emissions, not to exceed one year after start of unit operations.

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

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D165, D173]

A195.8 The 2.0 PPMV NOx emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

[Devices subject to this condition: D165, D173]

A195.9 The 2.0 PPMV CO emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

[Devices subject to this condition: D165, D173]

A195.10 The 2.0 PPMV VOC emission limit is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

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

A327.1 For the purpose of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.
Preliminary Determination of Compliance
Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

[RULE 475, 10-8-1976; RULE 475, 8-7-1978]

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

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

<table>
<thead>
<tr>
<th>Compound</th>
<th>Range</th>
<th>Grain per 100 scf</th>
</tr>
</thead>
<tbody>
<tr>
<td>H2S</td>
<td>Greater than</td>
<td>0.25</td>
</tr>
</tbody>
</table>

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

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

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

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

The number of cold startups shall not exceed 15 in any calendar month, the number of warm startups shall not exceed 12 in any calendar month, and the number of hot startups shall not exceed 35 in any calendar month, with no more than 2 startups in any one day.

The number of cold startups shall not exceed 80 in any calendar year, the number of warm startups shall not exceed 88 in any calendar year, and the number of hot startups shall not exceed 332 in any calendar year.

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

For the purposes of this condition, a warm startup is defined as a startup which occurs after the combustion turbine has been shut down 10 hours or more but less than 48 hours. A warm startup shall not exceed 30 minutes. The NOx emissions from a warm startup shall not exceed 17 lbs. The CO emissions from a warm startup shall not exceed 137 lbs. The VOC emissions from a warm startup shall not exceed 25 lbs.
For the purposes of this condition, a hot startup is defined as a startup which occurs after the steam turbine has been shut down for less than 10 hours. A hot startup shall not exceed 30 minutes. The NOx emissions from a hot startup shall not exceed 17 lbs. The CO emissions from a hot startup shall not exceed 137 lbs. The VOC emissions from a hot startup shall not exceed 25 lbs.

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

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

[Devices subject to this condition: D165, D173]

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

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

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

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

[Devices subject to this condition: D165, D173]
D29.2 The operator shall conduct source test(s) for the pollutant(s) identified below.

<table>
<thead>
<tr>
<th>Pollutant(s) to be tested</th>
<th>Required Test Method(s)</th>
<th>Averaging Time</th>
<th>Test Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx emissions</td>
<td>District Method 100.1</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>CO emissions</td>
<td>District Method 100.1</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>SOx emissions</td>
<td>AQMD Laboratory Method 307-91</td>
<td>Not Applicable</td>
<td>Fuel Sample</td>
</tr>
<tr>
<td>VOC emissions</td>
<td>District Method 25.3</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>PM10 emissions</td>
<td>EPA Method 201A/ District Method 5.1</td>
<td>District-Approved</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>PM2.5</td>
<td>EPA Method 201A and 202</td>
<td>District-Approved</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>NH3 emissions</td>
<td>District Method 207.1 and 5.3 or EPA method 17</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>

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

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

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

The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.
The sampling time for PM and PM2.5 tests shall be 4 hours or longer as necessary to obtain a measurable amount of sample.

The tests shall be conducted when the combined-cycle turbine is operating at loads of 45, 75, and 100 percent of maximum load, and the simple-cycle turbine is operating at loads of 50, 75, and 100 percent of maximum load.

For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and SCAQMD may be the following:

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

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

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

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

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

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

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]
D29.3 The operator shall conduct source test(s) for the pollutant(s) identified below.

<table>
<thead>
<tr>
<th>Pollutant(s) to be tested</th>
<th>Required Test Method(s)</th>
<th>Averaging Time</th>
<th>Test Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>SOx emissions</td>
<td>AQMD Laboratory Method 307-91</td>
<td>Not Applicable</td>
<td>Fuel Sample</td>
</tr>
<tr>
<td>VOC emissions</td>
<td>District method 25.3</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>PM10 emissions</td>
<td>EPA Method 201A/ District Method 5.1</td>
<td>District-Approved Averaging Time</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>

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

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

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

For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and SCAQMD may be the following:

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

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

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

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

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

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

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

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

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

- CO concentration in ppmv.

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

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

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

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

CO Emission Rate, lbs/hr = K*Cco*Fd*[20.9/(20.9% - %O\textsubscript{2} d)]*(Qg * HHV)/10E+06, where:

1. \(K = 7.267 \times 10\text{-}08\) (lb/scf)/ppm
2. \(Cco = \text{Average of four consecutive 15 min. average CO concentrations, ppm}\)
3. \(Fd = 8710\) dscf/MMBTU natural gas
4. \(%O_2\,d = \text{Hourly average \% by volume O}_2\,\text{dry, corresponding to Cco}\)
5. \(Qg = \text{Fuel gas usage during the hour, scf/hr}\)
6. \( HHV = \text{Gross high heating value of fuel gas, BTU/scf} \)

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

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

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

- NOx concentration in ppmv.
  
  Concentrations shall be corrected to 15 percent oxygen on a dry basis.

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

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

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

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

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

  In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.

  [CA PRC CEQA, 11-23-1970]

  [Devices subject to this condition: D163, D164, D165, C170, D173, C178, D181, C183, D185, C188, D191, C194, D197, C200, D203, C206, D209, D210]
E193.5 The operator shall construct this equipment according to the following requirements:

The Permit to Construct shall expire one year from the date of issuance unless an extension of time has been approved in writing by the Executive Officer.

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

[RULE 205, 1-5-1990]

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

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

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

[40 CFR 52.21 – PSD, 6-19-1978]

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

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

The Permit to Construct shall become invalid if construction is not commenced within 24 months after the issuance date, if construction is discontinued for a period of 24 months or more, or if construction is not completed within a reasonable time. The Executive Officer may extend the 24-month period upon a satisfactory showing that an extension is justified.

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

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

E193.8 The operator shall operate and maintain this equipment according to the following requirements:
Total commissioning hours shall not exceed 996 hours of fired operation for each turbine from the date of initial turbine start-up. Of the 996 hours, commissioning hours without control shall not exceed 216 hours.

Two turbines may be commissioned at the same time.

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD. The records shall include, but not be limited to, the total number of commissioning hours, number of commissioning hours without control, and natural gas fuel usage.

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

[Devices subject to this condition: D165, D173]

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

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

Compliance with the 1000 lbs per gross megawatt-hours CO2 emission limit (inclusive of degradation) shall be determined on a 12-operating-month rolling average basis.

This turbine shall be operated in compliance with all applicable requirements of 40 CFR 60 Subpart TTTT.

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

[Devices subject to this condition: D165, D173]

E193.12 The operator shall upon completion of the construction, operate and maintain this equipment according to the following requirements:
The 120 lbs/MMBtu CO2 emission limit shall only apply if this turbine supplies no more than 1,481,141 MWh-net electrical output to a utility power distribution system on either a 12-operating-month or a 3-year rolling average basis.

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

This turbine shall be operated in compliance with all applicable requirements of 40 CFR 60 Subpart TTTT.

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

[Devices subject to this condition: D165, D173]

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

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

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

GHG = 61.41 * FF

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

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1714, 12-10-2012]

[Devices subject to this condition: D165, D173]

E448.1 The operator shall comply with the following requirements:
The total electrical output on a gross basis from Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 (Devices D165 and D173, respectively), common Steam Turbine Generator, and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Device D185, D191, D197, and D203, respectively) shall not exceed 1094.7 MW-gross at 59 deg F.

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

The operator shall record and maintain written records of the maximum amount of electricity produced from this equipment and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

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

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

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

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

[Devices subject to this condition: D165]

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

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

[Devices subject to this condition: D165]
respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

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

[Devices subject to this condition: D173]

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

Source test results shall be submitted to the District no later than 90 days after the source tests required by conditions D29.2, D29.3, and D29.4 are conducted.

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

All exhaust flow rates shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

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

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

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

<table>
<thead>
<tr>
<th>CONTAMINANT</th>
<th>EMISSIONS LIMIT</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>Less than or equal to 8594 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>VOC</td>
<td>Less than or equal to 1973 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>PM10</td>
<td>Less than or equal to 4638 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>SOx</td>
<td>Less than or equal to 1207 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>CO</td>
<td>Less than or equal to 37,710 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>VOC</td>
<td>Less than or equal to 7510 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>PM10</td>
<td>Less than or equal to 14,695 LBS IN ANY ONE YEAR</td>
</tr>
<tr>
<td>SOx</td>
<td>Less than or equal to 1275 LBS IN ANY ONE YEAR</td>
</tr>
</tbody>
</table>

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

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

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

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

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

The following emission factors shall be used to demonstrate compliance with the monthly emission limits.
For commissioning, the emission factors shall be as follows: CO, 112.03 lb/mmcf; VOC, 3.69 lb/mmcf; PM10, 2.00 lb/mmcf; and SOx, 7.69 lb/mmcf.

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

For a month during which both commissioning and normal operation take place, the monthly emissions shall be the sum of the commissioning emissions and the normal operation emissions.

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

The emission factors for the monthly emission limits shall be the same as the emission factors used to demonstrate compliance with the annual emission limits, except the annual emission factor for SOx is 0.65 lb/mmcf.

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD. The records shall include, but not be limited to, natural gas usage in a calendar month and automated monthly and annual calculated emissions.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1304.1, 9-6-2013; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

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

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

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

[RULE 2012, 5-6-2005]

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

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

[RULE 2012, 5-6-2005]

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

**A195.11** The 2.5 PPMV NOx emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

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

**A195.12** The 4.0 PPMV CO emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

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

**A195.10** The 2.0 PPMV VOC emission limit is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

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

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

[RULE 475, 10-8-1976; RULE 475, 8-7-1978]
B61.1 The operator shall not use natural gas containing the following specified compounds:

<table>
<thead>
<tr>
<th>Compound</th>
<th>Range</th>
<th>Grain per 100 scf</th>
</tr>
</thead>
<tbody>
<tr>
<td>H2S</td>
<td>Greater than</td>
<td>0.25</td>
</tr>
</tbody>
</table>

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

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

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

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

A startup shall not exceed 30 minutes. The NOx emissions from a startup shall not exceed 16.6 lbs. The CO emissions from a startup shall not exceed 15.4 lbs. The VOC emissions from a startup shall not exceed 2.80 lbs.

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

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

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

C1.6 The operator shall limit the number of shutdowns to no more than 62 in any one calendar month.
The number of shutdowns shall not exceed 500 in any calendar year.

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

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

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

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

D29.2 The operator shall conduct source test(s) for the pollutant(s) identified below.

<table>
<thead>
<tr>
<th>Pollutant(s) to be tested</th>
<th>Required Test Method(s)</th>
<th>Averaging Time</th>
<th>Test Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx emissions</td>
<td>District Method 100.1</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>CO emissions</td>
<td>District Method 100.1</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>SOx emissions</td>
<td>AQMD Laboratory Method 307-91</td>
<td>Not Applicable</td>
<td>Fuel Sample</td>
</tr>
<tr>
<td>VOC emissions</td>
<td>District method 25.3</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>PM10 emissions</td>
<td>EPA Method 201A/ District Method 5.1</td>
<td>District-approved averaging time</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>PM 2.5</td>
<td>EPA Method 201A and 202</td>
<td>District-approved averaging time</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>NH3 emissions</td>
<td>District Method 207.1</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>
The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test.

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

The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 90 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

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

The tests shall be conducted when the combined-cycle turbine is operating at loads of 45, 75, and 100 percent of maximum load, and the simple-cycle turbine is operating at loads of 50, 75, and 100 percent of maximum load.

For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and SCAQMD may be the following:

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

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

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

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

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

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

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

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

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<td>District method 25.3</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
<tr>
<td>PM10 emissions</td>
<td>EPA Method 201A/ District Method 5.1</td>
<td>District-Approved</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>

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

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

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

For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and SCAQMD may be the following:

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

b) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and
c) Analysis of Summa canisters per unmodified EPA Method TO-12 (with pre-concentration) or the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F.

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

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

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

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

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

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

CO concentration in ppmv

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

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

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

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

CO Emission Rate, lbs/hr = K*Cco*Fd[20.9/(20.9% - %O_2 d)][(Qg * HHV)/10E+06],

where:
1. K = 7.267 *10E-08 (lb/scf)/ppm

2. Cco = Average of four consecutive 15 min. average CO concentrations, ppm

3. Fd = 8710 dsf/MMBTU natural gas

4. $\%O_2 d$ = Hourly average % by volume O$_2$ dry, corresponding to Cco

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

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

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

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

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

NOx concentration in ppmv

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

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

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

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

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]
E193.4 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.

[CA PRC CEQA, 11-23-1970]

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

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

The Permit to Construct shall expire one year from the date of issuance unless an extension of time has been approved in writing by the Executive Officer.

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

[RULE 205, 1-5-1990]

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

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

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

[40 CFR 52.21 – PSD, 6-19-1978]

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

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

The Permit to Construct shall become invalid if construction is not commenced within 24 months after the issuance date, if construction is discontinued for a period of 24 months or more, or if construction is not completed within a reasonable time. The Executive Officer may extend the 24-month period upon a satisfactory showing that an extension is justified.
[RULE 1713(c), 10-7-1988]

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

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

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

Four turbines may be commissioned at the same time.

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

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

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

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

E193.13 The operator shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

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

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

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

[40 CFR 60 Subpart TTTT, 10-23-2015]
E193.15 The operator shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

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

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

\[ \text{GHG} = 61.41 \times \text{FF} \]

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

The operator shall calculate and record the CO2 emissions in pounds per net megawatt-hour based on a 12-month rolling average. The CO2 emissions from this equipment shall not exceed 120,765 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO2 emissions shall not exceed 1356.03 lbs per gross megawatt-hours (inclusive of equipment degradation).

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1714, 12-10-2012]

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

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

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

The operator shall record and maintain written records of the maximum amount of electricity produced from this equipment and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

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

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

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

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

[Devices subject to this condition: 185]

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

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

[Devices subject to this condition: 191]

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

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

[Devices subject to this condition: 197]

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

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

[Devices subject to this condition: 203]

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

Source test results shall be submitted to the District no later than 90 days after the source tests required by conditions D29.2, D29.3, and D29.4 are conducted.

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

All exhaust flow rates shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.
AUXILIARY BOILER

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

<table>
<thead>
<tr>
<th>CONTAMINANT</th>
<th>EMISSIONS LIMIT</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>Less than or equal to 605 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>VOC</td>
<td>Less than or equal to 102 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>PM10</td>
<td>Less than or equal to 113.5 LBS IN ANY CALENDAR MONTH</td>
</tr>
<tr>
<td>SOx</td>
<td>Less than or equal to 32 LBS IN ANY CALENDAR MONTH</td>
</tr>
</tbody>
</table>

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

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

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

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

[Rule 1303(a)(1)-BACT, 5-10-1996; Rule 1303(a)(1)-BACT, 12-6-2002; Rule 1303(b)(2)-Offset, 5-10-1996; Rule 1303(b)(2)-Offset, 12-6-2002; Rule 1703(a)(2) - PSD-BACT, 10-7-1988]
The 38.46 lbs/mmscf NOx emission limit(s) shall only apply during the interim period prior to CEMS certification to report RECLAIM emissions, not to exceed one year after start of unit operation.

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

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D181]

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

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

[Devices subject to this condition: D181]

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

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

[Devices subject to this condition: D181]

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

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

The number of cold startups shall not exceed 24 in any calendar year, the number of warm startups shall not exceed 48 in any calendar year, and the number of hot startups shall not exceed 48 in any calendar year.

For the purposes of this condition, a cold startup is defined as a startup which occurs after the combustion turbine has been shut down for 48 hours or more. A cold startup shall not exceed 170 minutes. The NOx emissions from a cold startup shall not exceed 4.22 lbs.
For the purposes of this condition, a warm startup is defined as a startup which occurs after
the combustion turbine has been shut down 10 hours or more but less than 48 hours. A
warm startup shall not exceed 85 minutes. The NOx emissions from a warm startup shall
not exceed 2.11 lbs.

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

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

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

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

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<td>AQMD Laboratory Method 307-91</td>
<td>Not Applicable</td>
<td>Fuel Sample</td>
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<td>VOC emissions</td>
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<td>1 hour</td>
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<tr>
<td>PM10 emissions</td>
<td>EPA Method 201A/</td>
<td>District-approved</td>
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</tr>
<tr>
<td></td>
<td>District Method 5.1</td>
<td>averaging time</td>
<td></td>
</tr>
<tr>
<td>PM 2.5</td>
<td>EPA Method 201A and 202</td>
<td>District-approved</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
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<td></td>
<td></td>
<td>averaging time</td>
<td></td>
</tr>
<tr>
<td>NH3 emissions</td>
<td>District Method 207.1 and 5.3 or EPA method 17</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>
The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test.

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

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

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

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

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

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


[Devices subject to this condition: D181]

D29.6 The operator shall conduct source test(s) for the pollutant(s) identified below.

<table>
<thead>
<tr>
<th>Pollutant(s) to be tested</th>
<th>Required Test Method(s)</th>
<th>Averaging Time</th>
<th>Test Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO emissions</td>
<td>District Method 100.1</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>
The test(s) shall be conducted in accordance with the testing frequency requirements specified in Rule 1146.

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

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

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

[Rule 1146, 11-1-2013; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988]

[Devices subject to this condition: D181]

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

NOx concentration in ppmv

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

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

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

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

[Devices subject to this condition: D181]

E193.4 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:
In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.

[CA PRC CEQA, 11-23-1970]

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

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

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

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

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

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

[Devices subject to this condition: D181]

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

<table>
<thead>
<tr>
<th>Contaminant</th>
<th>Rule</th>
<th>Rule/Subpart</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>District Rule</td>
<td>1146</td>
</tr>
</tbody>
</table>

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

[RULE 1146, 11-1-2013]

[Devices subject to this condition: D181]
I297.7  This equipment shall not be operated unless the facility holds 1351 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

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

[Devices subject to this condition: D181]

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

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

Emission data shall be expressed in terms of concentration (ppmv), corrected to 3 percent oxygen (dry basis), mass rate (lbs/hr), lbs/MM cubic feet, and lbs/MMBtu. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

All moisture concentration shall be expressed in terms of percent corrected to 3 percent oxygen.

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

[RULE 1146, 11-1-2013; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2005, 12-4-2015]

[Devices subject to this condition: D181]

**SCR/CO CATALYSTS FOR COMBINED-CYCLE TURBINES**

A195.15  The 5.0 PPMV NH3 emission limit is averaged over 1 hour, dry basis at 15 percent oxygen.
The operator shall calculate and continuously record the NH3 slip concentration using the following equation:

$$\text{NH}_3 \text{ (ppmvd)} = \left[\frac{a - b \times (c \times 1.2)}{1,000,000}\right] \times 1,000,000/b,$$

where:

- $a = \text{NH}_3 \text{ injection rate (lb/hr)/17(lb/lb-mol)}$
- $b = \text{dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol}$
- $c = \text{change in measured NOx across the SCR (ppmvd at 15% O2)}$

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

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

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

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

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

D12.9 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH3).

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

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

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011; RULE 2005, 12-4-2015]
D12.10  The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

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

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

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

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

[Devices subject to this condition: C170, C178]

D12.11  The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

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

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

The pressure differential shall not exceed 1.6 inches water column.

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

[Devices subject to this condition: C170, C178]

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

Preliminary Determination of Compliance

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170
Preliminary Determination of Compliance

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

### Pollutant(s) to be tested

<table>
<thead>
<tr>
<th>Pollutant(s) to be tested</th>
<th>Required Test Method(s)</th>
<th>Averaging Time</th>
<th>Test Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>NH3 emissions</td>
<td>District Method 207.1 and 5.3 or EPA Method 17</td>
<td>1 hour</td>
<td>Outlet of the SCR serving this equipment</td>
</tr>
</tbody>
</table>

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

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

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

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

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

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

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.

[CA PRC CEQA, 11-23-1970]

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

**SCR/CO CATALYSTS FOR SIMPLE-CYCLE TURBINES**

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

The operator shall calculate and continuously record the NH3 slip concentration using the following equation:
NH₃ (ppmvd) = \[a-b*(c*1.2)/1,000,000]*1,000,000/b, where:

\[a = \text{NH₃ injection rate (lb/hr)}/17(\text{lb/lb-mol})\]
\[b = \text{dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol}\]
\[c = \text{change in measured NOx across the SCR (ppmvd at 15% O2)}\]

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

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

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

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

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

D12.12 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH₃).

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

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

The operator shall maintain the ammonia injection rate between 110 and 180 pounds per hour, except during startups and shutdowns.

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

[Devices subject to this condition: C188, C194, C200, C206]
D12.13 The operator shall install and maintain an temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

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

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

The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between 500 degrees F and 870 degrees F, except during startups and shutdowns.

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

[Devices subject to this condition: C188, C194, C200, C206]

D12.14 The operator shall install and maintain a pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

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

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

The pressure differential shall not exceed 3.0 inches water column.

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

[Devices subject to this condition: C188, C194, C200, C206]

D29.4 The operator shall conduct source test(s) for the pollutant(s) identified below.
The test shall be conducted and the results submitted to the District within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

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

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

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

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

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

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.

[CA PRC CEQA, 11-23-1970]

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

**SCR FOR AUXILIARY BOILER**

A195.16 The 5.0 PPMV NH3 emission limit is averaged over 1 hour, dry basis at 3 percent oxygen.

The operator shall calculate and continuously record the NH3 slip concentration using the following equation:
NH$_3$ (ppmvd) = [(a-b*(c*1.2)/1,000,000)]*1,000,000/b, where:

- $a = \text{NH}_3$ injection rate (lb/hr)/17(lb/lb-mol)
- $b = \text{dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)}$
- $c = \text{change in measured NOx across the SCR (ppmvd at 3% O2)}$

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

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

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

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

[Devices subject to this condition: C183]

D12.15 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH$_3$).

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

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

The operator shall maintain the ammonia injection rate between 0.3 and 1.1 pounds per hour.

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

[Devices subject to this condition: C183]
D12.16  The operator shall install and maintain a(n) temperature gauge to accurately indicate the 
temperature in the exhaust at the inlet to the SCR reactor.

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

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

The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between 
415 degrees F and 628 degrees F, except during startups and shutdowns.

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

[Devices subject to this condition: C183]

D12.17  The operator shall install and maintain a(n) pressure gauge to accurately indicate the 
differential pressure across the SCR catalyst bed in inches water column.

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

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

The pressure differential shall not exceed 2.0 inches water column.

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

[Devices subject to this condition: C183]

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

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

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

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

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

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

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

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

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

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.

[CA PRC CEQA, 11-23-1970]

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

**AMMONIA TANKS**

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

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

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

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

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

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.

OIL/WATER SEPARATORS

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

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

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

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.
BACKGROUND AND FACILITY DESCRIPTION

Existing Facility

Southern California Edison (SCE) installed Utility Boiler No. 1 in 1956, No. 2 in 1957, No. 3 in 1961, No. 4 in 1962, No. 5 in 1969, and No. 6 in 1966. The AES Corporation purchased the power plant from SCE in 1998.

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

A summary of the utility boilers are summarized in the table below.

<table>
<thead>
<tr>
<th>Application No. (Device No.)</th>
<th>Equipment Description</th>
<th>Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>A/N 408704 (F97795)</td>
<td>Boiler, No. 1, Babcock and Wilcox, Natural Gas (D39)</td>
<td>1785 MMBtu/hr, 175 MW</td>
</tr>
<tr>
<td>A/N 408705 (F97796)</td>
<td>Boiler, No. 2, Babcock and Wilcox, Natural Gas (D42)</td>
<td>1785 MMBtu/hr, 175 MW</td>
</tr>
<tr>
<td>A/N 408706 (F97797)</td>
<td>Boiler, No. 3, Babcock and Wilcox, Natural Gas (D45)</td>
<td>3350 MMBtu/hr, 320 MW</td>
</tr>
<tr>
<td>A/N 408707 (F97798)</td>
<td>Boiler, No. 4, Babcock and Wilcox, Natural Gas (D48)</td>
<td>3350 MMBtu/hr, 320 MW</td>
</tr>
<tr>
<td>A/N 408728 (F97901)</td>
<td>Boiler, No. 5, Babcock and Wilcox, Natural Gas (D51)</td>
<td>4750 MMBtu/hr, 480 MW</td>
</tr>
<tr>
<td>A/N 408708 (F57292)</td>
<td>Boiler, No. 6, Babcock and Wilcox, Natural Gas (D3)</td>
<td>4752.2 MMBtu/hr, 480 MW</td>
</tr>
</tbody>
</table>

Total Generating Capacity 19,772.2 MMBtu/hr, 1950 MW

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

Proposed Facility

- Project Description
  On December 20, 2013, AES Southland, LLC (AES), a wholly owned subsidiary of The AES Corporation, submitted applications for Permits to Construct a combined-cycle gas turbine project, the Alamitos Energy Center (original AEC). This repowering project was proposed to replace the six utility boilers (Units 1 - 6) at the AGS. The original AEC project was to consist of four 3-on-1 combined-cycle gas turbine power blocks, with twelve natural-gas-fired combustion turbine...
generators, twelve heat recovery steam generators, twelve SCR and CO oxidation catalyst systems, and four steam turbine generators; two aqueous ammonia tanks; and three oil/water separators. The AEC was to have a net generating capacity of 1936 MW and a gross generating capacity of 1995 MW. In November 2014, AES received notice from Southern California Edison (SCE) that it was shortlisted for a power purchase agreement (PPA). The power plant configuration selected by SCE for a PPA was different from the project configuration proposed for the original AEC. Consequently, on December 17, 2014, AES requested SCAQMD to cancel the permit applications.

On October 23, 2015, AES Southland Energy, LLC (AES), a different wholly-owned subsidiary of The AES Corporation, submitted new applications for Permits to Construct an amended AEC (AEC) in the configuration selected by SCE. AES will construct, own, and operate the AEC, a natural-gas-fired, air-cooled, combined- and simple-cycle electrical generating facility with a gross generating capacity of 1094.702 megawatts (MW) and net generating capacity of 1072.67 MW.

The AEC will consist of two gas turbine power blocks.

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

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

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

Two selective catalytic reduction (SCR) systems and CO oxidation catalysts will be utilized for control of NOx and CO/VOC emissions, respectively. One 40,000-gallon ammonia (NH₃) storage tank will store 19% aqueous ammonia which is the reducing agent in the SCRs. An oil/water separator will be used to collect equipment wash water and rainfall. This power block is collectively the AEC CCGT and will be located on the southern-most portion of the AEC site.
Power Block 2 will consist of four simple-cycle CTGs with intercoolers. For the purposes of the equipment description, Rule 1304(a)(2) compliance demonstration, and Rule 1304.1 fee calculation, the applicable scenario from Table 31 - Simple-Cycle Turbine Operating Scenarios is Case 12, based on 100% load, 59 ºF. At those conditions, each combustion turbine generator is rated 100.438 MW-gross and 99.087 MW-net, at 59 ºF. Four SCR/CO oxidation catalyst systems, a second 40,000-gallon ammonia tank, and a second oil/water separator are included. This power block is collectively the AEC SCGT and will be located on the northern portion of the AEC site.

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

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

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

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

The demolition of the existing and operating Utility Boilers 1 – 6 is not necessary for the construction of AEC. These units will continue to provide essential electrical service concurrent with the construction of the AEC CCGT power block. Units 1, 2, and 5 will be retired once the AEC CCGT reaches the commissioning stage and become operational. Unit 3 will be retired once the AEC SCGT reaches the commissioning stage and become operational. Units 4 and 6 may operate through December 31, 2020, the current facility compliance date imposed by the OTC Policy. AES is no longer including the demolition as part of the proposed AEC project, but now plans to accomplish the demolition under a separate CEQA proceeding thought a Memorandum of Understanding with the City of Long Beach.

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

- **Modeling and Offset Exemption**

SCAQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler repower projects. The exemption applies to: “The source is replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The new equipment must have a maximum electrical power rating (in megawatts) that does not allow basinwide electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset.” Offsets are provided from the SCAQMD internal offset accounts.

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

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

AES proposes to replace existing Utility Boiler No. 1 (175 MW-gross), No. 2 (175 MW-gross), Unit 5 (480 MW-gross), and No. 3 (320 MW-gross) at AGS, with the two combined-cycle turbines
(692.951 MW-gross total) and four simple-cycle turbines (401.751 MW-gross total). At this time, AES has not identified plans for the surplus 55 MWs from the retirements of these four utility boilers. In addition, AES has not identified plans for the MWs from the retirement of Utility Boiler No. 4 (320 MW) and Utility Boiler No. 6 (480 MW).

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

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

<table>
<thead>
<tr>
<th>Project</th>
<th>Phase</th>
<th>First Fire or Shutdown Date</th>
<th>MW-gross</th>
</tr>
</thead>
<tbody>
<tr>
<td>Huntington Beach Energy Project (HBE)</td>
<td>Combined-Cycle Block&lt;sup&gt;a&lt;/sup&gt;</td>
<td>10/1/2019</td>
<td>693.822</td>
</tr>
<tr>
<td></td>
<td>HBGS Unit 1 Retired</td>
<td>11/1/2019</td>
<td>215</td>
</tr>
<tr>
<td></td>
<td>RBGS Unit 7 Retired</td>
<td>10/1/2019</td>
<td>480</td>
</tr>
<tr>
<td></td>
<td>Simple-Cycle Block&lt;sup&gt;b&lt;/sup&gt;</td>
<td>11/1/2023</td>
<td>201.62</td>
</tr>
<tr>
<td></td>
<td>HBGS Unit 2 Retired</td>
<td>12/31/2020</td>
<td>215</td>
</tr>
<tr>
<td></td>
<td>MW Installed</td>
<td></td>
<td>895.45</td>
</tr>
<tr>
<td></td>
<td>MW Retired</td>
<td></td>
<td>910</td>
</tr>
<tr>
<td></td>
<td>Surplus MW</td>
<td></td>
<td>14.55</td>
</tr>
<tr>
<td>Redondo Beach Energy Project (RBEP)</td>
<td>Combined-Cycle Block&lt;sup&gt;c&lt;/sup&gt;</td>
<td>11/1/2019</td>
<td>546.4</td>
</tr>
<tr>
<td></td>
<td>RBGS Unit 5 Retired</td>
<td>12/31/2019</td>
<td>175</td>
</tr>
<tr>
<td></td>
<td>RBGS Unit 8 Retired</td>
<td>12/31/2019</td>
<td>480</td>
</tr>
<tr>
<td></td>
<td>MW Installed</td>
<td></td>
<td>546.4</td>
</tr>
<tr>
<td></td>
<td>MW Retired</td>
<td></td>
<td>655</td>
</tr>
<tr>
<td></td>
<td>Surplus MW (HBE &amp; RBEP)</td>
<td></td>
<td>123.15</td>
</tr>
<tr>
<td>Alamitos Energy Center (AEC)</td>
<td>Combined-Cycle Block&lt;sup&gt;c&lt;/sup&gt;</td>
<td>10/1/2019</td>
<td>692.951</td>
</tr>
</tbody>
</table>
### Preliminary Determination of Compliance

**Alamitos Energy Center**

Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

**Proposed Schedule**

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

Major project milestones are listed in the following table.

**Table 3 - AEC Schedule Major Milestones**

<table>
<thead>
<tr>
<th>Activity</th>
<th>Dates¹</th>
<th>Commercial Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demolition of Unit 7</td>
<td>January 2017 – May 2017</td>
<td>Not Applicable</td>
</tr>
<tr>
<td>Auxiliary Boiler Commissioning</td>
<td>January 2020</td>
<td>Not Applicable</td>
</tr>
<tr>
<td>Construction of AEC CCGT.</td>
<td>June 2017 – March 2020</td>
<td>Second Quarter 2020 (April 1, 2020)</td>
</tr>
<tr>
<td>Construction of AEC SCGT.</td>
<td>May 2020 – August 2021</td>
<td>Third Quarter 2021</td>
</tr>
</tbody>
</table>

¹ From Response to Data Request 118 of Data Response Set 6, submitted by AES to CEC, dated 12/14/15.
**California Energy Commission**

The California Energy Commission (CEC) is the lead agency for licensing thermal power plants 50 megawatts and larger under the California Environmental Quality Act (CEQA) and has a certified regulatory program under CEQA. Under its certified program, the CEC is exempt from having to prepare an environmental impact report. Its certified program, however, does require environmental analysis of the project, including an analysis of alternatives and mitigation measures to minimize any significant adverse effect the project may have on the environment.

The CEC’s certification process subsumes all requirements of local, regional, state, and federal agencies required for the construction of a new plant. The CEC coordinates its review of the proposed facility with the agencies that will be issuing permits to ensure that its certification incorporates the conditions that are required by these various agencies. As the AEC will be rated at greater than 50 megawatts, it is subject to the CEC’s certification process.

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

**Original SCAQMD Applications Submitted**

AES submitted the following applications to the SCAQMD for Permits to Construct for the amended AEC project (original Application). The environmental consultant is CH₂M Hill.

<table>
<thead>
<tr>
<th>Application No.</th>
<th>Submittal Date</th>
<th>Deemed Complete Date</th>
<th>Equipment Description</th>
<th>Fees</th>
</tr>
</thead>
<tbody>
<tr>
<td>579140</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>RECLAIM/Title V Revision</td>
<td>$1,994.55</td>
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<tr>
<td>579142</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>Combined-Cycle Turbine</td>
<td>$27,075.57</td>
</tr>
<tr>
<td>579143</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>Combined-Cycle Turbine</td>
<td>$13,537.79 (50%--identical)</td>
</tr>
<tr>
<td>579145</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>Simple-Cycle Turbine</td>
<td>$27,075.57</td>
</tr>
<tr>
<td>579147</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>Simple-Cycle Turbine</td>
<td>$13,537.79 (50%--identical)</td>
</tr>
<tr>
<td>579150</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>Simple-Cycle Turbine</td>
<td>$13,537.79 (50%--identical)</td>
</tr>
<tr>
<td>579152</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>Simple-Cycle Turbine</td>
<td>$13,537.79 (50%--identical)</td>
</tr>
<tr>
<td>579158</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>Auxiliary Boiler</td>
<td>$9,128.07</td>
</tr>
<tr>
<td>579160</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>SCR/CO Catalyst for Combined-Cycle Turbine</td>
<td>$5,752.59</td>
</tr>
<tr>
<td>579161</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>SCR/CO Catalyst for Combined-Cycle Turbine</td>
<td>$2,876.30 (50%--identical)</td>
</tr>
<tr>
<td>579162</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>SCR/CO Catalyst for Simple-Cycle Turbine</td>
<td>$5,752.59</td>
</tr>
<tr>
<td>579163</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>SCR/CO Catalyst for Simple-Cycle Turbine</td>
<td>$2,876.30</td>
</tr>
</tbody>
</table>
Preliminary Determination of Compliance

Application Processng and Calculations

<table>
<thead>
<tr>
<th>Application No.</th>
<th>Submittal Date</th>
<th>Deemed Complete Date</th>
<th>Equipment Description</th>
<th>Fees</th>
</tr>
</thead>
<tbody>
<tr>
<td>579164</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>SCR/CO Catalyst for Simple-Cycle Turbine</td>
<td>$2,876.30 (50%--identical)</td>
</tr>
<tr>
<td>579165</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>SCR for Auxiliary Boiler</td>
<td>$5,752.59 (50%--identical)</td>
</tr>
<tr>
<td>579166</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>Ammonia Tank for Combined-Cycle Turbines</td>
<td>$2,281.98</td>
</tr>
<tr>
<td>579167</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>Ammonia Tank for Simple-Cycle Turbines</td>
<td>$1,140.99 (50%--identical)</td>
</tr>
<tr>
<td>579168</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>Oil/Water Separator Combined-Cycle Turbines (&gt; = 10,000 GPD)</td>
<td>$5,752.59</td>
</tr>
<tr>
<td>579169</td>
<td>10/23/15</td>
<td>1/14/16</td>
<td>Oil/Water Separator Simple-Cycle Turbines (&lt; 10,000 GPD)</td>
<td>$3,636.95</td>
</tr>
</tbody>
</table>

Total Fee Required: $161,000.40
Total Fee Submitted: $161,380.74
Refund: $380.34

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

Note: A/N 579142 is the master file.

Original Applications Deem Completion Chronology

Revised Application
In February 2016, AES became aware that permit conditions will be included to limit annual emissions and cold start-ups on an annual and monthly basis. On 3/30/16, AES submitted revisions (revised Application), primarily to increase the number of cold startups for the combined-cycle turbines on a monthly and annual basis. The revised Application includes revised emissions calculations and modeling, and incorporates revisions resulting from recent discussions with the SCAQMD over the course of permitting for the Huntington Beach Energy Project (HBEP) and AEC. The new revisions will be discussed below under the relevant sections.
APPLICATION DESCRIPTION

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

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


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

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

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

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

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

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

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

<table>
<thead>
<tr>
<th>Turbine Parameters</th>
<th>Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manufacturer</td>
<td>General Electric</td>
</tr>
<tr>
<td>Model</td>
<td>7FA.05</td>
</tr>
<tr>
<td>Fuel Type</td>
<td>Pipeline natural gas</td>
</tr>
<tr>
<td>Maximum Turbine Power Output</td>
<td>236,645 MW-gross at 28 °F (Case 1)</td>
</tr>
<tr>
<td>Steam Turbine Generator Output</td>
<td>219,615 MW-gross at 28 °F (Case 1)</td>
</tr>
<tr>
<td>Maximum Turbine Heat Input</td>
<td>2275 MMBtu/hr (HHV) at 28 °F (Case 1)</td>
</tr>
<tr>
<td>Turbine Heat Input at Average Ambient Temperature</td>
<td>2250 MMBtu/hr (HHV) at 65.3 °F (Case 4)</td>
</tr>
<tr>
<td>Gross 2x1 Combined-Cycle</td>
<td>692,905 kW at 28 °F (Case 1)</td>
</tr>
<tr>
<td>Net 2x1 Combined-Cycle</td>
<td>680,779 kW at 28 °F (Case 1)</td>
</tr>
<tr>
<td>NOx Combustion Control</td>
<td>Dry Low NOx Combustors, 9 ppmvd at 15% O₂</td>
</tr>
</tbody>
</table>

Each HRSG will be equipped with an oxidation catalyst and a selective catalytic reduction system located in the HRSG evaporator region.
CO Oxidation Catalyst
The CO oxidation catalyst, located between the HRSG and the SCR, will be used to control CO and VOC emissions. The catalyst will reduce CO emissions from 7 - 8 ppm to 2 ppmv, all 1-hr averages, dry basis at 15% O₂. The catalyst will reduce the VOC from approximately 2.2 ppm to 2 ppmv, all 1-hour averages, dry basis at 15% O₂.

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

<table>
<thead>
<tr>
<th>Catalyst Parameters</th>
<th>Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manufacturer</td>
<td>BASF Corp.</td>
</tr>
<tr>
<td>Model</td>
<td>TBD</td>
</tr>
<tr>
<td>Catalyst Type</td>
<td>Platinum Group Metals, Corrugated SS Foil w/</td>
</tr>
<tr>
<td></td>
<td>Catalytic Washcoat</td>
</tr>
<tr>
<td>Catalyst Guaranteed Life</td>
<td>NE Nooter/Erickson—Earlier of 36 months from first</td>
</tr>
<tr>
<td></td>
<td>gas in or 39 months from contracted delivery.</td>
</tr>
<tr>
<td>Space Velocity</td>
<td>467,260.55/hr</td>
</tr>
<tr>
<td>Catalyst Volume</td>
<td>265.8 ft³</td>
</tr>
<tr>
<td>CO removal efficiency</td>
<td>70% or greater</td>
</tr>
<tr>
<td>CO at stack outlet</td>
<td>2.0 ppmvd at 15% O₂</td>
</tr>
<tr>
<td>VOC at stack outlet</td>
<td>2.0 ppmvd at 15% O₂</td>
</tr>
<tr>
<td>Operating Temperature</td>
<td>570 - 692 °F</td>
</tr>
</tbody>
</table>

Selective Catalytic Reduction
The SCR catalyst will use ammonia injection in the presence of the catalyst to further reduce the NOx concentration in the exhaust gases. Diluted 19% aqueous ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst. The resulting reaction will reduce NOx to elemental nitrogen and water, resulting in NOx concentrations in the exhaust gas decreasing from 9 ppm to 2.0 ppmv, all 1-hour averages, dry basis at 15% O₂. The ammonia slip will be limited to 5 ppmvd at 15% O₂. Each SCR will be vented through a dedicated stack, which is 20 feet diameter and 140 feet high.

The exhaust temperature is required to be between 570 and 692 °F, as specified in condition no. D12.10. The minimum temperature is required to protect the catalyst face from ammonia salt formation and deposition on a cold catalyst. The maximum temperature is required to maintain catalyst effectiveness. The pressure drop across the catalyst shall be no greater than 1.6 inches water column, as required by condition no. D12.11. The ammonia flow rate shall be between 44 and 242 pounds per hour, as required by condition no. D12.9.
The following table lists the technical specifications for the SCR.

### Table 6 – Combined-Cycle Turbine Selective Catalytic Reduction Specifications

<table>
<thead>
<tr>
<th>Catalyst Parameters</th>
<th>Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manufacturer</td>
<td>Cormetech</td>
</tr>
<tr>
<td>Catalyst Description</td>
<td>Titanium/Vanadium/Tungsten, Corrugated Fiberglass/Ceramic</td>
</tr>
<tr>
<td>Catalyst Model No.</td>
<td>TBD</td>
</tr>
<tr>
<td>Catalyst Volume</td>
<td>1289 ft³</td>
</tr>
<tr>
<td>Reactor Dimensions</td>
<td>1.5 ft long x 25.7 ft wide x 71.6 ft high</td>
</tr>
<tr>
<td>Catalyst Guaranteed Life</td>
<td>NE Nooter/Erickson—Earlier of 36 months from first gas in or 39 months from contracted delivery.</td>
</tr>
<tr>
<td>Space Velocity</td>
<td>96,352.10 per hr</td>
</tr>
<tr>
<td>Area Velocity</td>
<td>67462.17 ft/hr</td>
</tr>
<tr>
<td>Ammonia Injection Rate</td>
<td>44 - 242 lb/hr</td>
</tr>
<tr>
<td>Ammonia Slip</td>
<td>5 ppm at 15% O₂</td>
</tr>
<tr>
<td>NOx removal efficiency</td>
<td>77% or greater</td>
</tr>
<tr>
<td>NOx at stack outlet</td>
<td>2.0 ppmv at 15% O₂</td>
</tr>
<tr>
<td>Operating Temperature</td>
<td>570 - 692 °F</td>
</tr>
<tr>
<td>Pressure Drop</td>
<td>1.6 inches water column</td>
</tr>
</tbody>
</table>

- **Performance and Catalyst Life Warranties**
  - **Performance Warranty**
    In a letter dated 6/5/15, Julie Lux, Nooter/Erikson, provided emissions guarantees for NOx, CO, VOC, PM₁₀, PM₂.₅, and NH₃. The warranted emissions levels are summarized in the table below.

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Warranted Emission Levels</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>2.0 ppmvd at 15% O₂</td>
</tr>
<tr>
<td>CO</td>
<td>2.0 ppmvd at 15% O₂</td>
</tr>
<tr>
<td>VOC</td>
<td>1.0 ppmvd at 15% O₂ (based on source test method not accepted by SCAQMD).</td>
</tr>
<tr>
<td>PM₁₀/PM₂.₅</td>
<td>6.7 lb/hr (not including ammonium sulfate particulates formed in the CO catalyst and SCR)</td>
</tr>
<tr>
<td>NH₃</td>
<td>5 ppmvd at 15% O₂</td>
</tr>
</tbody>
</table>

For a detailed discussion of the BACT/LAER versus warranty levels, see the BACT/LAER analysis under Regulation XIII—New Source Review (NSR) below.
A/N 579158—Auxiliary Boiler (Combined-Cycle Turbines)
In a letter dated 12/11/15, the applicant provided a process description and an updated boiler selection. The auxiliary boiler, Babcock & Wilcox (B & W), Model FM 103-88, watertube type, rated at 70.8 MMBtu/hr, assists with the fast start of the combined-cycle turbines. The auxiliary boiler provides enhanced startup times by maintaining the steam cycle in a ready state through the provision of steam for heat recovery steam generator (HRSG) sparging, turbine steam seals, steam pipe warming, condenser deaerating steam, and steam to the fuel gas heater. Prior to a CCGT startup, the auxiliary boiler will increase load from the minimum turndown rate to the maximum load and the produced steam will be directed to the system for HRSG sparging, turbine seals, pipe warming, condenser deaerating and to the fuel gas heater. Once the CCGT completes a startup and the steam turbine reaches maximum output, the auxiliary boiler will reduce load to the minimum turndown firing rate. If extended periods of CCGT outage are expected, the auxiliary boiler could be shut down until a start of the CCGT is expected.

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

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

<table>
<thead>
<tr>
<th>Boiler Parameters</th>
<th>Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boiler Manufacturer/Model</td>
<td>Babcock &amp; Wilcox/Model FM 103-88</td>
</tr>
<tr>
<td>Boiler Type</td>
<td>Watertube</td>
</tr>
<tr>
<td>Burner Manufacturer/Model</td>
<td>JZHC/Coen RMB</td>
</tr>
<tr>
<td>Maximum Heat Input</td>
<td>70.8 MMBtu/hr</td>
</tr>
<tr>
<td>Boiler NOx Control</td>
<td>Flue gas recirculation &amp; low NOx burner</td>
</tr>
<tr>
<td>NOx at Boiler Outlet</td>
<td>10 ppmv at 3% O₂, 1-hr average</td>
</tr>
<tr>
<td>NOx at SCR Outlet</td>
<td>5 ppmv at 3% O₂, 1-hr average</td>
</tr>
<tr>
<td>CO at Boiler Outlet</td>
<td>50 ppmv at 3% O₂, 1-hr average</td>
</tr>
</tbody>
</table>
4. **A/N 579166—Selective Catalytic Reduction for Auxiliary Boiler**

The auxiliary boiler will be equipped with a selective catalytic reduction system.

- **Selective Catalytic Reduction**
  
  The SCR catalyst will use ammonia injection in the presence of the catalyst to further reduce the NOx concentration in the exhaust gases. Diluted 19% aqueous ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst. The resulting reaction will reduce NOx to elemental nitrogen and water, resulting in NOx concentrations in the exhaust gas decreasing from 10 ppmv to 5.0 ppmv, all 1-hour averages, dry basis at 3% O\textsubscript{2}. The ammonia slip will be limited to 5 ppmvd at 3% O\textsubscript{2}. Each SCR will be vented through a dedicated stack, which is 3 feet diameter and 80 feet high.

  The exhaust temperature is required to be between 415 and 628 ºF, as specified in condition no. D12.16. The minimum temperature is required to protect the catalyst face from ammonia salt formation and deposition on a cold catalyst. The maximum temperature is required to maintain catalyst effectiveness. The pressure drop across the catalyst shall be no greater than 2 inches water column, as required by condition no. D12.17. The ammonia flow rate shall be between 0.3 and 1.1 pounds per hour, as required by condition no. D12.15.

  The following table lists the technical specifications for the SCR.

<table>
<thead>
<tr>
<th>Catalyst Properties</th>
<th>Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manufacturer</td>
<td>Babcock &amp; Wilcox (B &amp; W)</td>
</tr>
<tr>
<td>Catalyst Description</td>
<td>Vanadium, Homogeneous Honeycomb</td>
</tr>
<tr>
<td>Catalyst Model No.</td>
<td>FM Series</td>
</tr>
<tr>
<td>Catalyst Volume</td>
<td>46 ft\textsuperscript{3}</td>
</tr>
<tr>
<td>Reactor Dimensions</td>
<td>7.25 ft long x 5.4 ft wide x 3.7 ft high</td>
</tr>
<tr>
<td>Catalyst Guaranteed Life</td>
<td>Cormetech, Inc.--24,000 hours or three years</td>
</tr>
<tr>
<td>Space Velocity</td>
<td>485/hr</td>
</tr>
<tr>
<td>Area Velocity</td>
<td>47,800 ft/hr</td>
</tr>
<tr>
<td>Ammonia Injection Rate</td>
<td>0.3 – 1.1 lb/hr</td>
</tr>
<tr>
<td>Ammonia Slip</td>
<td>5 ppm at 3% O\textsubscript{2}</td>
</tr>
<tr>
<td>NOx removal efficiency</td>
<td>50% or greater</td>
</tr>
<tr>
<td>NOx at stack outlet</td>
<td>5.0 ppmv at 3% O\textsubscript{2}</td>
</tr>
<tr>
<td>Operating Temperature</td>
<td>415 – 628 ºF</td>
</tr>
<tr>
<td>Pressure Drop</td>
<td>2.0 inches water column</td>
</tr>
</tbody>
</table>
- **Performance and Catalyst Life Warranties**
- **Performance Warranty**
  
  In a letter dated 6/10/15, David Obrecht, Cleaver Brooks, provided guaranteed stack emissions for NOx (post-SCR), CO, VOC, PM$_{10}$, and NH$_3$.

  The warranted emissions levels are summarized in the table below.

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Warranted Emission Levels</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>5 ppmvd at 3% O$_2$</td>
</tr>
<tr>
<td>CO</td>
<td>50 ppmvd at 3% O$_2$</td>
</tr>
<tr>
<td>VOC</td>
<td>0.003 lbs/MMBtu</td>
</tr>
<tr>
<td>PM$_{10}$</td>
<td>0.0043 lbs/MMBtu</td>
</tr>
<tr>
<td>NH$_3$</td>
<td>5 ppmvd at 3% O$_2$</td>
</tr>
</tbody>
</table>

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

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

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

The simple-cycle power block will consist of the following equipment:

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

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

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

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

- One 230-kV interconnection to the existing onsite SCE 230-kV switchyard.
Combustion air will flow through the inlet air filters, evaporative inlet air coolers, and associated air inlet ductwork before being compressed and cooled in the intercooler and CTG compressor section and then entering the CTG combustion sections. Natural gas will be mixed with the cool compressed air prior to being introduced to the combustion sections and ignited. The hot combustion gases will expand through the power turbine section of the CTG, causing the section to rotate and drive the electric generator and CTG compressor. The hot combustion gases will exit the turbine section and enter the control equipment consisting of the oxidation catalyst and selective catalytic reduction system.

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

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

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

<table>
<thead>
<tr>
<th>Turbine Parameters</th>
<th>Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manufacturer</td>
<td>General Electric</td>
</tr>
<tr>
<td>Model</td>
<td>LMS-100 PB</td>
</tr>
<tr>
<td>Fuel Type</td>
<td>Pipeline natural gas</td>
</tr>
<tr>
<td>Maximum Turbine Power Output</td>
<td>100.438 MW-gross at 59 °F (Case 12)</td>
</tr>
<tr>
<td>Maximum Turbine Heat Input</td>
<td>882 MMBtu/hr (HHV) at 59 °F (Case 12)</td>
</tr>
<tr>
<td>Turbine Heat Input at Average Ambient Temperature</td>
<td>876 MMBtu/hr (HHV) at 65.3 °F (Case 4)</td>
</tr>
<tr>
<td>Gross 4 LMS-100 PB</td>
<td>401.751 kW at 59 °F (Case 12)</td>
</tr>
<tr>
<td>Net 4 LMS-100 PB</td>
<td>386.712 kW at 59 °F (Case 12)</td>
</tr>
<tr>
<td>NOx Combustion Control</td>
<td>Dry Low NOx Combustors, 25 ppmvd at 15% O₂</td>
</tr>
</tbody>
</table>
6. A/N 579162, 579163, 579164, 579165—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. SCGT-1, SCGT-2, SCGT-3, SCGT-4 (Simple-Cycle Turbines)
Each simple-cycle turbine will be equipped with an oxidation catalyst and a selective catalytic reduction system.

- **CO Oxidation Catalyst**
The CO oxidation catalyst, located between the HRSG and the SCR, will be used to control CO and VOC emissions. The catalyst will reduce CO emissions from 100 ppm to 4 ppmv, all 1-hr averages, dry basis at 15% O\(_2\). The catalyst will reduce the VOC from 4 ppm to 2 ppmv, all 1-hour averages, dry basis at 15% O\(_2\).

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

**Table 10 – Simple-Cycle Turbine CO Oxidation Catalyst Specifications**

<table>
<thead>
<tr>
<th>Catalyst Parameters</th>
<th>Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manufacturer</td>
<td>BASF Corp.</td>
</tr>
<tr>
<td>Model</td>
<td>Camet</td>
</tr>
<tr>
<td>Catalyst Type</td>
<td>Platinum Group Metals, Corrugated SS Foil w/ Catalytic Washcoat</td>
</tr>
<tr>
<td>Catalyst Guaranteed Life</td>
<td>BASF Corp 7-12 years</td>
</tr>
<tr>
<td>Space Velocity</td>
<td>139,539/hr</td>
</tr>
<tr>
<td>Catalyst Volume</td>
<td>165.57 ft(^3)</td>
</tr>
<tr>
<td>CO removal efficiency</td>
<td>99% or greater</td>
</tr>
<tr>
<td>CO at stack outlet</td>
<td>4.0 ppmvd at 15% O(_2)</td>
</tr>
<tr>
<td>VOC at stack outlet</td>
<td>2.0 ppmvd at 15% O(_2)</td>
</tr>
<tr>
<td>Operating Temperature</td>
<td>500-1250 (^{\circ}) F</td>
</tr>
</tbody>
</table>

- **Selective Catalytic Reduction**
The SCR catalyst will use ammonia injection in the presence of the catalyst to further reduce the NO\(_x\) concentration in the exhaust gases. Diluted 19% aqueous ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst. The resulting reaction will reduce NO\(_x\) to elemental nitrogen and water, resulting in NO\(_x\) concentrations in the exhaust gas decreasing from 25 ppm to 2.5 ppmv, all 1-hour averages, dry basis at 15% O\(_2\). The ammonia slip will be limited to 5 ppmvd at 15% O\(_2\). Each SCR will be vented through a dedicated stack, which is 13.5 feet diameter and 80 feet high.

The exhaust temperature is required to be between 500 and 870 \(^{\circ}\)F, as specified in condition no. D12.13. The minimum temperature is required to protect the catalyst face from...
ammonia salt formation and deposition on a cold catalyst. The maximum temperature is required to maintain catalyst effectiveness. The pressure drop across the catalyst shall be no greater than 3 inches water column, as required by condition no. D12.14. The ammonia flow rate shall be between 110 and 180 pounds per hour, as required by condition no. D12.12.

The following table lists the technical specifications for the SCR.

**Table 11 – Simple-Cycle Turbine Selective Catalytic Reduction Specifications**

<table>
<thead>
<tr>
<th>Catalyst Parameters</th>
<th>Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manufacturer</td>
<td>Cormetech</td>
</tr>
<tr>
<td>Catalyst Description</td>
<td>Titanium/Vanadium/Tungsten, Ceramic Honeycomb</td>
</tr>
<tr>
<td>Catalyst Model No.</td>
<td>CMHT</td>
</tr>
<tr>
<td>Catalyst Volume</td>
<td>621.96 ft$^3$</td>
</tr>
<tr>
<td>Reactor Dimensions</td>
<td>11.5 ft long x 4.9 ft wide x 11 ft high</td>
</tr>
<tr>
<td>Catalyst Guaranteed Life</td>
<td>Cormetech, Inc.—three years or 24,000 hours</td>
</tr>
<tr>
<td>Space Velocity</td>
<td>37,147/hr</td>
</tr>
<tr>
<td>Area Velocity</td>
<td>182,639 ft/hr</td>
</tr>
<tr>
<td>Ammonia Injection Rate</td>
<td>110 - 180 lb/hr</td>
</tr>
<tr>
<td>Ammonia Slip</td>
<td>5 ppm at 15% O$_2$</td>
</tr>
<tr>
<td>NOx removal efficiency</td>
<td>90% or greater</td>
</tr>
<tr>
<td>NOx at stack outlet</td>
<td>2.5 ppmv at 15% O$_2$</td>
</tr>
<tr>
<td>Operating Temperature</td>
<td>500 – 870 ºF</td>
</tr>
<tr>
<td>Pressure Drop</td>
<td>3.0 inches water column</td>
</tr>
</tbody>
</table>

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

In a document dated 6/16/15, Christopher Vu, General Electric, provided guarantees for NOx, CO, VOC, PM$_{10}$, and NH$_3$, based on a GE supplied SCR/CO Catalyst,. The warranted emissions levels are summarized in the table below.

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Warranted Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>2.5 ppmvd at 15% O$_2$</td>
</tr>
<tr>
<td>CO</td>
<td>4.0 ppmvd at 15% O$_2$</td>
</tr>
<tr>
<td>VOC</td>
<td>2 ppmvd at 15% O$_2$</td>
</tr>
<tr>
<td>PM$_{10}$</td>
<td>5 lb/hr</td>
</tr>
<tr>
<td>NH$_3$</td>
<td>5 ppmvd at 15% O$_2$</td>
</tr>
</tbody>
</table>
For a detailed discussion of the BACT/LAER versus warranty levels, see the BACT/LAER analysis under Regulation XIII—New Source Review (NSR) below.

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

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

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

To control the filling losses, the tanker truck will connect a filling line and a vapor return line to the AEC aqueous ammonia unloading system. The vapor return line allows vapors accumulated in the headspace of the aqueous ammonia tank to be returned to the ammonia tanker truck during filling operations.

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

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

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

9. **A/N 579169—Oil/Water Separator, No. OWS-1 (Combined-Cycle Turbines)**  
The oil/water separator for the combined-cycle turbine power block will treat stormwater from process areas that could potentially include oil or other lubricants for removal of accumulated oil that may result from equipment leakage or small spills and large particulate matter that may result from equipment leakage or small spills and large particulate matter that may

Alamitos Energy Center  
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170  

Preliminary Determination of Compliance
be present from equipment washdowns. The secondary containment area for the oil/grease-containing equipment is pumped out to the oil/water separator after each rain event to ensure sufficient capacity is available for additional stormwater. The oil/water separator throughput is 400 gallons/minute.

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

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

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

EMISSIONS CALCULATIONS

Alamitos Generating Station—Existing Equipment

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

  1. Boiler No. 1, 1785 MMBtu/hr
  2. Boiler No. 2, 1785 MMBtu/hr

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

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

  \[
  CO = \left(1,785,000,000 \text{ Btu/hr}\right) \left(8710 \text{ dscf/10}^6 \text{ Btu}\right) \left(500 \text{ ppm CO/10}^6\right) \\
  \left(20.9/(20.9-3.0)\right) \left(28 \text{ lbs CO/379 scf}\right) \left(8760 \text{ hr/yr}\right)/(\text{ton}/2000 \text{ lb}) \\
  = 2937.06 \text{ tpy}
  \]
NOx = (1,785,000,000 Btu/hr) (8710 dscf/10^6 Btu) (7 ppm/10^6)(20.9/(20.9-3.0))
(46 lbs NOx/385 scf for NOx RECLAIM) (8760 hr/yr)(ton/2000 lb) = 66.5 tpy

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

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

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

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

Combustion of natural gas in the turbines will result in greenhouse gas emissions of CO₂, CH₄, and N₂O. Emission factors for CO₂, CH₄, and N₂O are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised April 4, 2014.

CO₂: 53.06 kg CO₂/MMBtu
CH₄: 1 g CH₄/MMBtu
N₂O: 0.10 g N₂O/MMBtu

CO₂ = (1785 MMBtu/hr)(8760 hr/yr)(53.06 kg/MMBtu)(2.2046 lb/kg)(ton/2000 lb)
= 914,554.06 tpy

CH₄ = (1785 MMBtu/yr)(8760 hr/yr)(1 g/MMBtu)(2.205 x 10⁻³ lb/g) (ton/2000 lb)
= 17.24 tpy

N₂O = (1785 MMBtu/hr)(8760 hr/yr)(0.1 g/MMBtu)(2.205 x 10⁻³ lb/g)(ton/2000 lb)
= 1.7 tpy

CO₂ₑ emissions are equal to the sum of the mass emission of each individual GHG adjusted for its global warming potential. Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as amended by 79 FR 73779, 12/11/14:
(1) CH₄ is equivalent to 25 times the global warming potential of CO₂, and
(2) N₂O is equivalent to 298 times of CO₂.

CO₂ₑ = (914,554.06 tpy CO₂)(1 lb CO₂ₑ/lb CO₂) + (17.24 tpy CH₄)
3. Boiler No. 3, 3350 MMBtu/hr
4. Boiler No. 4, 3350 MMBtu/hr
Operating schedule: 52 wk/yr, 7 days/wk, 24 hr/day = 8760 hr/yr

\[
\begin{align*}
\text{CO: } & \quad 300 \text{ ppm CO per Rule 1303(b)(2) (permit limit)} \\
\text{NOx: } & \quad 7 \text{ ppmv NOx per Rule 2009 (permit limit)} \\
\text{ROG: } & \quad 5.5 \text{ lb/mmscf per AER default emission factors for natural gas fired boiler} \\
\text{SOx: } & \quad 0.6 \text{ lb/mmscf per AER default emission factors for natural gas fired boiler} \\
\text{PM/PM}_{10}: & \quad 7.6 \text{ lb PM/mmscf per AER default emission factor for natural gas fired boiler} \\
\text{PM}_{2.5}: & \quad 0.00113 \text{ lb/MMBTU—Emission factor approved by the SCAQMD Source Testing Dept., 9/2/15} \\
\end{align*}
\]

\[
\begin{align*}
\text{CO} & = \frac{(3,350,000,000 \text{ Btu/hr}) (8710 \text{ dscf}/10^6 \text{ Btu})(300 \text{ ppm CO/}10^6)}{(20.9/(20.9-3.0)) (28 \text{ lbs CO/379 scf})(8760 \text{ hr/yr})(\text{ton/2000 lb})} \\
& = 3307.28 \text{ tpy} \\
\text{NOx} & = \frac{(3,350,000,000 \text{ Btu/hr}) (8710 \text{ dscf}/10^6 \text{ Btu}) (7 \text{ ppm/}10^6)(20.9/(20.9-3.0))}{(46 \text{ lbs NOx/385 scf for NOx RECLAIM})(8760 \text{ hr/yr})(\text{ton/2000 lb})} = 124.80 \text{ tpy} \\
\text{For combustion emissions, the standard assumption is PM}_{10} = \text{PM.} \\
\text{PM}_{10} & = \frac{(3,350,000,000 \text{ Btu/hr}) (\text{cf}/1050 \text{ Btu}) (7.6 \text{ lb PM}_{10}/10^6 \text{ cf}) (8760 \text{ hr/yr})}{(\text{ton/2000 lb})} = 106.20 \text{ tpy} \\
\text{PM}_{2.5} & = \frac{(3,350.0 \text{ MMBtu/hr}) (0.00113 \text{ lb PM}_{2.5}/\text{MMBTU}) (8760 \text{ hr/yr})}{(\text{ton/2000 lb})} = 16.58 \text{ tpy} \\
\text{ROG} & = \frac{(3,350,000,000 \text{ Btu/hr}) (\text{cf}/1050 \text{ Btu}) (5.5 \text{ lb ROG AER/}10^6 \text{ cf})}{(8760 \text{ hr/yr})(\text{ton/2000 lb})} = 76.86 \text{ tpy} \\
\text{SOx} & = \frac{(3,350,000,000 \text{ Btu/hr}) (\text{cf}/1050 \text{ Btu}) (0.6 \text{ lb SOx AER/}10^6 \text{ cf})}{(8760 \text{ hr/yr}) (\text{ton/2000 lb})} = 8.38 \text{ tpy} \\
\text{CO}_2 & = \frac{(3,350 \text{ MMBtu/hr})(8760 \text{ hr/yr})(53.06 \text{ kg/MMBTu})(2.2046 \text{ lb/kg})}{(\text{ton/2000 lb})} = 1,716,389.96 \text{ tpy} \\
\text{CH}_4 & = \frac{(3,350 \text{ MMBtu/yr})(8760 \text{ hr/yr})(1 \text{ g/MMBTu})(2.205 \times 10^{-3} \text{ lb/g})}{(\text{ton/2000 lb})} = 32.35 \text{ tpy} \\
\text{N}_2\text{O} & = \frac{(3,350 \text{ MMBtu/hr})(8760 \text{ hr/yr})(0.1 \text{ g/MMBTu})(2.205 \times 10^{-3} \text{ lb/g})}{(\text{ton/2000 lb})} = 3.24 \text{ tpy} \\
\end{align*}
\]

Preliminary Determination of Compliance
CO_{2e} = (1,716,389.96 tpy CO_{2})(1 lb CO_{2e}/lb CO_{2}) + (32.35 tpy CH_{4})
(25 lb CO_{2e}/lb CH_{4}) + (3.24 tpy N_{2}O)(298 lb CO_{2e}/lb N_{2}O)
= 1,718,164.23 tpy

5. Boiler No. 5, 4750 MMBtu/hr
6. Boiler No. 6, 4752.2 MMBtu/hr
   Operating schedule: 52 wk/yr, 7 days/wk, 24 hr/day = 8760 hr/yr

   \[
   \begin{align*}
   CO: & \quad 300 \text{ ppm CO per Rule 1303(b)(2) (permit limit)} \\
   NOx: & \quad 5 \text{ ppmv NOx per Rule 2009 (permit limit)} \\
   ROG: & \quad 5.5 \text{ lb/mmscf per AER default emission factors for natural gas fired boiler} \\
   SOx: & \quad 0.6 \text{ lb/mmscf per AER default emission factors for natural gas fired boiler} \\
   PM/PM_{10}: & \quad 7.6 \text{ lb PM/mmscf per AER default emission factor for natural gas fired boiler} \\
   PM_{2.5}: & \quad 0.00113 \text{ lb/MBTU— Emission factor approved by the SCAQMD Source Testing Dept., 9/2/15} \\
   \end{align*}
   \]

\[
\begin{align*}
CO = (4,752,200,000 \text{ Btu/hr}) (8710 \text{ dscf/10}^6 \text{ Btu})(300 \text{ ppm CO/10}^6) \\
(20.9/(20.9-3.0)) (28 \text{ lbs CO/379 scf})(8760 \text{ hr/yr})(\text{ton/2000 lb})
= 4691.59 \text{ tpy}
\end{align*}
\]

\[
\begin{align*}
NOx = (4,752,200,000 \text{ Btu/hr}) (8710 \text{ dscf/10}^6 \text{ Btu}) (5 \text{ ppm/10}^6)(20.9/(20.9-3.0)) \\
(46 \text{ lbs NOx/385 scf for NOx RECLAIM})(8760 \text{ hr/yr})(\text{ton/2000 lb}) = 126.5 \\
\text{tpy}
\end{align*}
\]

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

\[
\begin{align*}
PM_{10} = (4,752,200,000 \text{ Btu/hr}) (\text{cf/1050 Btu}) (7.6 \text{ lb PM}_{10}/10^6 \text{ cf}) (8760 \text{ hr/yr}) \\
(\text{ton/2000 lb}) = 150.7 \text{ tpy}
\end{align*}
\]

\[
\begin{align*}
PM_{2.5} = (4,752.2 \text{ MMBtu/hr}) (0.00113 \text{ lb PM}_{2.5}/\text{MMBtu}) (8760 \text{ hr/yr}) (\text{ton/2000 lb})
= 23.52 \text{ tpy}
\end{align*}
\]

\[
\begin{align*}
ROG = (4,752,200,000 \text{ Btu/hr}) (\text{cf/1050 Btu}) (5.5 \text{ lb ROG AER/10}^6 \text{ cf}) \\
(8760 \text{ hr/yr})(\text{ton/2000 lb}) = 109.0 \text{ tpy}
\end{align*}
\]

\[
\begin{align*}
SOx = (4,752,200,000 \text{ Btu/hr}) (\text{cf/1050 Btu}) (0.6 \text{ lb SOx AER/10}^6 \text{ cf}) \\
(8760 \text{ hr/yr}) (\text{ton/2000 lb}) = 11.9 \text{ tpy}
\end{align*}
\]

\[
\begin{align*}
CO_2 = (4,752.2 \text{ MMBtu/hr})(8760 \text{ hr/yr})(53.06 \text{ kg/MBTU})(2.2046 \text{ lb/kg}) \\
(\text{ton/2000 lb}) = 2,434,814.44 \text{ tpy}
\end{align*}
\]

\[
\begin{align*}
CH_4 = (4,752.2 \text{ MMBtu/yr})(8760 \text{ hr/yr})(1 \text{ g/MBTU})(2.205 \times 10^{-3} \text{ lb/g}) \\
(\text{ton/2000 lb}) = 45.9 \text{ tpy}
\end{align*}
\]
Preliminary Determination of Compliance

APPLICATION PROCESSING AND CALCULATIONS

N2O = (4,752.2 MMBtu/hr)(8760 hr/yr)(0.1 g/MMBtu)(2.205 x 10^-3 lb/g)
(ton/2000 lb) = 4.59 tpy

CO2e = (2,434,814.44 tpy CO2)(1 lb CO2e/lb CO2) + (45.9 tpy CH4)
(25 lb CO2e/lb CH4) + (4.59 tpy N2O)(298 lb CO2e/lb N2O)

= 2,437,329.76 tpy

Table 13 - Alamitos Generating Station Potential to Emit Emissions

<table>
<thead>
<tr>
<th></th>
<th>Boiler No. 1</th>
<th>Boiler No. 2</th>
<th>Boiler No. 3</th>
<th>Boiler No. 4</th>
<th>Boiler No. 5</th>
<th>Boiler No. 6</th>
<th>AGS Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO (tpy)</td>
<td>2937.06</td>
<td>2937.06</td>
<td>3307.28</td>
<td>3307.28</td>
<td>4691.59</td>
<td>4691.59</td>
<td>21,871.86</td>
</tr>
<tr>
<td>NOx (tpy)</td>
<td>66.5</td>
<td>66.5</td>
<td>124.80</td>
<td>124.80</td>
<td>126.5</td>
<td>126.5</td>
<td>635.60</td>
</tr>
<tr>
<td>PM10 (tpy)</td>
<td>56.6</td>
<td>56.6</td>
<td>106.20</td>
<td>106.20</td>
<td>150.7</td>
<td>150.7</td>
<td>627.0</td>
</tr>
<tr>
<td>PM2.5 (tpy)</td>
<td>8.83</td>
<td>8.83</td>
<td>16.58</td>
<td>16.58</td>
<td>23.52</td>
<td>23.52</td>
<td>97.86</td>
</tr>
<tr>
<td>ROG (tpy)</td>
<td>41</td>
<td>41</td>
<td>76.86</td>
<td>76.86</td>
<td>109</td>
<td>109</td>
<td>453.72</td>
</tr>
<tr>
<td>SO2 (tpy)</td>
<td>4.5</td>
<td>4.5</td>
<td>8.38</td>
<td>8.38</td>
<td>11.9</td>
<td>11.9</td>
<td>49.56</td>
</tr>
<tr>
<td>CO2 (tpy)</td>
<td>914,554.06</td>
<td>914,554.06</td>
<td>1,716,389.96</td>
<td>1,716,389.96</td>
<td>2,434,814.44</td>
<td>2,434,814.44</td>
<td>10,131,516.92</td>
</tr>
<tr>
<td>CH4 (tpy)</td>
<td>17.24</td>
<td>17.24</td>
<td>32.35</td>
<td>32.35</td>
<td>45.9</td>
<td>45.9</td>
<td>190.98</td>
</tr>
<tr>
<td>N2O (tpy)</td>
<td>1.7</td>
<td>1.7</td>
<td>3.24</td>
<td>3.24</td>
<td>4.59</td>
<td>4.59</td>
<td>19.06</td>
</tr>
<tr>
<td>CO2e (tpy)</td>
<td>915,491.66</td>
<td>915,491.66</td>
<td>1,718,164.23</td>
<td>1,718,164.23</td>
<td>2,437,329.76</td>
<td>2,437,329.76</td>
<td>10,141,971.30</td>
</tr>
</tbody>
</table>

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

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

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

<table>
<thead>
<tr>
<th>Year</th>
<th>NOx</th>
<th>CO</th>
<th>ROG</th>
<th>PM10/PM2.5</th>
<th>SOx</th>
<th>CO2e</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>lb/year (tpy)</td>
<td>tpy</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>2,647</td>
<td>23,163</td>
<td>441</td>
<td>227</td>
<td>132</td>
<td>13,145</td>
</tr>
<tr>
<td>2</td>
<td>4,433</td>
<td>64,091</td>
<td>457</td>
<td>830</td>
<td>249</td>
<td>24,677</td>
</tr>
<tr>
<td>3</td>
<td>29,338</td>
<td>108,183</td>
<td>7,289</td>
<td>6,905</td>
<td>2,302</td>
<td>219,554</td>
</tr>
<tr>
<td>4</td>
<td>18,576</td>
<td>14,976</td>
<td>3,298</td>
<td>4,656</td>
<td>2,328</td>
<td>219,662</td>
</tr>
<tr>
<td>5</td>
<td>22,645</td>
<td>430,872</td>
<td>4,005</td>
<td>6,084</td>
<td>3,042</td>
<td>310,231</td>
</tr>
<tr>
<td>6</td>
<td>17,642</td>
<td>72,405</td>
<td>1,786</td>
<td>2,848</td>
<td>1,553</td>
<td>154,020</td>
</tr>
<tr>
<td>2014</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>2,296</td>
<td>43,095</td>
<td>621</td>
<td>320</td>
<td>186</td>
<td>18,702</td>
</tr>
<tr>
<td>2</td>
<td>9,794</td>
<td>252,396</td>
<td>1,350</td>
<td>2,454</td>
<td>736</td>
<td>73,661</td>
</tr>
</tbody>
</table>
EMISSIONS CALCULATIONS

Alamitos Energy Center--New Equipment


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

A. Criteria Pollutants

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

- Worst Case Operating Scenario

To determine the worst case operating scenario that yields the highest controlled emissions, the applicant provided fourteen operating scenarios corresponding to a full range of possible turbine loads and ambient temperatures, which bound the expected normal operating range of each proposed CTG. The operating scenarios are for three load conditions (100%, 75%, and approximately 45%) at four ambient temperatures (28 ºF, 59.0 ºF, 63.3 ºF, and 107 ºF), and with or without evaporative cooling of the inlet air to the turbines. The operating scenarios are presented in Table 5.1B.3R—Combined-Cycle: GE 7FA.05 Performance Data in Attachment 6 of AES Response Letter, 12/11/15. This table includes the scenarios for 59 ºF missing from the original Application, and revised VOC hourly emission rates based on the BACT limit of 2 ppmvd at 15% O₂, a correction from the emission rates based on 1 ppmvd at 15% O₂ (based on source test method not accepted by SCAQMD) provided in the original Application.

The operating scenarios data are summarized in the following table.
Table 15 – Combined-Cycle Turbine Operating Scenarios

<table>
<thead>
<tr>
<th>Case No.</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
<th>9</th>
<th>10</th>
<th>11</th>
<th>12</th>
<th>13</th>
<th>14</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTG Load Level (%)</td>
<td>100</td>
<td>75</td>
<td>45</td>
<td>100</td>
<td>75</td>
<td>100</td>
<td>44</td>
<td>100</td>
<td>100</td>
<td>75</td>
<td>48</td>
<td>100</td>
<td>75</td>
<td>44</td>
</tr>
<tr>
<td>CTG Inlet Air Cooling</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>On</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>On</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
</tr>
<tr>
<td>Ambient Temperature (°F)</td>
<td>28.0</td>
<td>28.0</td>
<td>28.0</td>
<td>65.3</td>
<td>65.3</td>
<td>65.3</td>
<td>65.3</td>
<td>107</td>
<td>107</td>
<td>107</td>
<td>107</td>
<td>90.0</td>
<td>90.0</td>
<td>90.0</td>
</tr>
<tr>
<td>Ambient Relative Humidity (%)</td>
<td>76%</td>
<td>76%</td>
<td>76%</td>
<td>87%</td>
<td>87%</td>
<td>87%</td>
<td>87%</td>
<td>11%</td>
<td>11%</td>
<td>11%</td>
<td>11%</td>
<td>60%</td>
<td>60%</td>
<td>60%</td>
</tr>
<tr>
<td><strong>Combustion Turbine Performance</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gross GTG Output, kW (one CTG)</td>
<td>236,645</td>
<td>177,484</td>
<td>106,017</td>
<td>229,659</td>
<td>227,708</td>
<td>170,781</td>
<td>101,102</td>
<td>217,778</td>
<td>194,136</td>
<td>145,602</td>
<td>92,797</td>
<td>231,197</td>
<td>173,398</td>
<td>101,727</td>
</tr>
<tr>
<td>Net CTG Output, kW (one CTG)</td>
<td>235,907</td>
<td>176,746</td>
<td>105,279</td>
<td>228,921</td>
<td>226,970</td>
<td>170,043</td>
<td>100,364</td>
<td>217,040</td>
<td>193,398</td>
<td>144,864</td>
<td>92,059</td>
<td>230,459</td>
<td>172,660</td>
<td>100,989</td>
</tr>
<tr>
<td>CTG Heat Input, MMBtu/hr (LHV) (one CTG)</td>
<td>2,052</td>
<td>1,619</td>
<td>1,245</td>
<td>2,029</td>
<td>2,019</td>
<td>1,568</td>
<td>1,179</td>
<td>1,942</td>
<td>1,754</td>
<td>1,403</td>
<td>1,126</td>
<td>2,032</td>
<td>1,582</td>
<td>1,182</td>
</tr>
<tr>
<td>CTG Heat Input, MMBtu/hr (HHV) (one CTG)</td>
<td>2,275</td>
<td>1,795</td>
<td>1,380</td>
<td>2,250</td>
<td>2,239</td>
<td>1,739</td>
<td>1,307</td>
<td>2,153</td>
<td>1,945</td>
<td>1,556</td>
<td>1,249</td>
<td>2,253</td>
<td>1,755</td>
<td>1,310</td>
</tr>
<tr>
<td>CTG Exhaust Temperature, ºF (one CTG)</td>
<td>1,104</td>
<td>1,112</td>
<td>1,215</td>
<td>1,142</td>
<td>1,142</td>
<td>1,153</td>
<td>1,215</td>
<td>1,119</td>
<td>1,162</td>
<td>1,204</td>
<td>1,215</td>
<td>1,139</td>
<td>1,144</td>
<td>1,125</td>
</tr>
<tr>
<td>Gross 2x1 Combined-Cycle, kW</td>
<td>692,905</td>
<td>529,868</td>
<td>355,002</td>
<td>688,980</td>
<td>684,653</td>
<td>519,700</td>
<td>342,082</td>
<td>628,950</td>
<td>569,016</td>
<td>435,703</td>
<td>307,722</td>
<td>692,951</td>
<td>524,659</td>
<td>342,458</td>
</tr>
<tr>
<td>Net 2x1 Combined-Cycle, kW</td>
<td>680,779</td>
<td>516,621</td>
<td>344,352</td>
<td>672,444</td>
<td>668,221</td>
<td>505,408</td>
<td>331,812</td>
<td>612,912</td>
<td>554,506</td>
<td>423,721</td>
<td>297,721</td>
<td>676,320</td>
<td>510,231</td>
<td>332,184</td>
</tr>
<tr>
<td>Gross STG Output, kW</td>
<td>219,615</td>
<td>174,900</td>
<td>142,968</td>
<td>229,662</td>
<td>229,237</td>
<td>178,138</td>
<td>139,878</td>
<td>193,394</td>
<td>180,744</td>
<td>144,499</td>
<td>122,128</td>
<td>230,557</td>
<td>177,863</td>
<td>139,004</td>
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<td><strong>Stack Parameters</strong></td>
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<td></td>
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<tr>
<td>Stack Exit Temperature, ºF</td>
<td>216</td>
<td>178</td>
<td>170</td>
<td>213</td>
<td>215</td>
<td>175</td>
<td>170</td>
<td>221</td>
<td>223</td>
<td>198</td>
<td>184</td>
<td>209</td>
<td>174</td>
<td>170</td>
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<tr>
<td>Stack Diameter, ft</td>
<td>20</td>
<td>20</td>
<td>20</td>
<td>20</td>
<td>20</td>
<td>20</td>
<td>20</td>
<td>20</td>
<td>20</td>
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<td>20</td>
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<tr>
<td>Stack Exit Velocity, ft/sec</td>
<td>67.0</td>
<td>51.2</td>
<td>40.0</td>
<td>66.0</td>
<td>66.2</td>
<td>48.9</td>
<td>38.8</td>
<td>66.3</td>
<td>59.9</td>
<td>46.0</td>
<td>39.9</td>
<td>65.6</td>
<td>49.3</td>
<td>38.7</td>
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<td><strong>CTG Outlet/Catalyst Inlet concentrations</strong></td>
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<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx, ppmvd (dry, 15% O2)</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
<td>9.00</td>
</tr>
<tr>
<td>CO, ppmvd (dry, 15% O2)</td>
<td>7.08</td>
<td>7.27</td>
<td>7.52</td>
<td>6.97</td>
<td>7.01</td>
<td>7.10</td>
<td>7.59</td>
<td>7.24</td>
<td>7.31</td>
<td>7.28</td>
<td>8.12</td>
<td>7.02</td>
<td>7.17</td>
<td>7.62</td>
</tr>
<tr>
<td>VOC, ppmvd (dry, 15% O2)</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
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<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
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<tr>
<td><strong>Catalyst Outlet/Stack Emissions Rates</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx, 2.0 ppmvd (dry, 15% O2)</td>
<td>16.5</td>
<td>13.0</td>
<td>10.0</td>
<td>16.3</td>
<td>16.2</td>
<td>12.6</td>
<td>9.47</td>
<td>15.6</td>
<td>14.1</td>
<td>11.3</td>
<td>9.05</td>
<td>16.3</td>
<td>12.7</td>
<td>9.49</td>
</tr>
</tbody>
</table>
**APPLICATION PROCESSING AND CALCULATIONS**

<table>
<thead>
<tr>
<th>CO, 2.0 ppmvd (dry, 15% O₂) BACT, lb/hr</th>
<th>10.0</th>
<th>7.92</th>
<th>6.09</th>
<th>9.93</th>
<th>9.88</th>
<th>7.67</th>
<th>5.77</th>
<th>9.50</th>
<th>8.58</th>
<th>6.87</th>
<th>5.51</th>
<th>9.94</th>
<th>7.74</th>
<th>5.78</th>
</tr>
</thead>
<tbody>
<tr>
<td>VOC, 2.0 ppmvd (dry, 15% O₂) BACT, lb/hr</td>
<td>5.75</td>
<td>4.54</td>
<td>3.49</td>
<td>5.68</td>
<td>5.66</td>
<td>4.39</td>
<td>3.30</td>
<td>5.44</td>
<td>4.92</td>
<td>3.93</td>
<td>3.16</td>
<td>5.69</td>
<td>4.43</td>
<td>3.31</td>
</tr>
<tr>
<td>PM₁₀/PM₂.₅, lb/hr (including ammonium sulfate, assuming 100% conversion from SO₃)²</td>
<td>8.50</td>
<td>8.50</td>
<td>8.50</td>
<td>8.50</td>
<td>8.50</td>
<td>8.50</td>
<td>8.50</td>
<td>8.50</td>
<td>8.50</td>
<td>8.50</td>
<td>8.50</td>
<td>8.50</td>
<td>8.50</td>
<td></td>
</tr>
<tr>
<td>SO₂ short-term rate (0.75 grains/100 scf), lb/hr¹</td>
<td>4.86</td>
<td>3.84</td>
<td>2.95</td>
<td>4.81</td>
<td>4.78</td>
<td>3.72</td>
<td>2.79</td>
<td>4.60</td>
<td>4.16</td>
<td>3.33</td>
<td>2.67</td>
<td>4.82</td>
<td>3.75</td>
<td>2.80</td>
</tr>
<tr>
<td>SO₂ long-term rate (0.25 grains/100 scf), lb/hr</td>
<td>1.62</td>
<td>1.28</td>
<td>0.98</td>
<td>1.60</td>
<td>1.59</td>
<td>1.24</td>
<td>0.93</td>
<td>1.53</td>
<td>1.39</td>
<td>1.11</td>
<td>0.89</td>
<td>1.61</td>
<td>1.25</td>
<td>0.93</td>
</tr>
<tr>
<td>SCR NH₃ slip, 5.0 ppmvd (dry, 15% O₂) BACT, lb/hr</td>
<td>15.3</td>
<td>12.0</td>
<td>9.26</td>
<td>15.1</td>
<td>15.0</td>
<td>11.7</td>
<td>8.77</td>
<td>14.4</td>
<td>13.0</td>
<td>10.4</td>
<td>8.38</td>
<td>15.1</td>
<td>11.8</td>
<td>8.79</td>
</tr>
</tbody>
</table>

¹ A percentage of the SO₂ in the turbine exhaust is assumed to oxidize to SO₃ in the CO catalyst and SCR. The SO₃ reacts with ammonia in the SCR to form ammonium sulfate particulates. Total PM₁₀ is comprised of the ammonium sulfate particulates and the PM₂.₅ in the turbine exhaust.

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

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Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

Preliminary Determination of Compliance
Case 1, based on 100% load, 28 °F ambient temperature, and without inlet cooling, is the worst case operating scenario that yields the highest controlled emissions. The emissions rates for NOx, CO, VOC, PM\textsubscript{10}/PM\textsubscript{2.5}, and the short-term SO\textsubscript{2} rate (0.75 grains/100 scf) will be used to calculate the normal operation emissions component for the maximum daily emissions and maximum monthly emissions. In an e-mailed dated 2/2/16, AES clarified that 0.75 grains/100 scf will be used for daily and monthly emissions, instead of the 0.25 grains/100 scf proposed in the original Application. Since Case 1 is the scenario that yields the highest Btu/hr consumption for each turbine, it is also the basis for the equipment description on the facility permit.

Case 4, based on 100% load, 65.3 °F ambient temperature, and with inlet cooling, is the worst case operating scenario that yields the highest emission rates for the average annual temperature. The emissions rates for NOx, CO, VOC, PM\textsubscript{10}/PM\textsubscript{2.5}, and the long-term SO\textsubscript{2} rate (0.25 grains/100 scf) will be used to calculate the normal operation emissions component for maximum annual emissions. Condition B61.1 requires testing to confirm the long-term SO\textsubscript{2} rate of 0.25 grains/100 scf, which is expected to be the average content.

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

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

- **Four Operational Modes**

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

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

*Commissioning*

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

The NOx, CO, and VOC emission rates are expected to be higher during the commissioning period than during normal operations, because the turbines are operated without, or with
partial, emission control systems in operation. The total emissions, however, will depend on the load levels, which are less than 100% for some of the commissioning activities. The PM$_{10}$/PM$_{2.5}$ and SO$_2$ emission rates are the same as during normal operation, because these pollutants are not controlled by the SCR/CO catalysts.

The original Application provided the duration and corresponding pollutant emission rates for each commissioning activity for a single CTG in Table 5.1B.1—Summary of Commissioning Emission Estimates: Combined-Cycle Turbines in Appendix 5.1B—Commissioning and Operational Emission Estimates. The PM$_{10}$/PM$_{2.5}$ and SOx emission rates are based on the maximum hourly emission rates, including the short-term rate for SO$_2$, from Table 15 (case 1).

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

The following table provides a summary of the commissioning activity parameters and emissions.
Table 16 - Combined-Cycle Turbine Commissioning Activity Parameters and Emissions

<table>
<thead>
<tr>
<th>Activity</th>
<th>Duration (hr)</th>
<th>CTG Load (%)</th>
<th>Fuel Use (MMSCF/hr)</th>
<th>Fuel Use (MMSCF/Activity)</th>
<th>NOx (SCR)</th>
<th>CO (OxCat)</th>
<th>VOC (OxCat)</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>SOx</th>
<th>PM10/PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTG Testing (Full Speed No Load, FSNL)</td>
<td>48</td>
<td>10</td>
<td>0.6866</td>
<td>32.9581</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>6,240</td>
<td>91,200</td>
<td>12,960</td>
<td>233</td>
<td>408</td>
</tr>
<tr>
<td>Steam Blows</td>
<td>120</td>
<td>40</td>
<td>1.2694</td>
<td>152.3331</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>8,190</td>
<td>3,888</td>
<td>360</td>
<td>583</td>
<td>1,020</td>
</tr>
<tr>
<td>Set Unit HRSG &amp; Steam Safety Valves</td>
<td>12</td>
<td>40</td>
<td>1.2694</td>
<td>15.2333</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>819</td>
<td>389</td>
<td>36.0</td>
<td>58.3</td>
<td>102</td>
</tr>
<tr>
<td>Steam Blows – Restoration</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>DLN Emissions Tuning</td>
<td>12</td>
<td>50</td>
<td>1.3541</td>
<td>16.2487</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>567</td>
<td>285</td>
<td>24.0</td>
<td>58.3</td>
<td>102</td>
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<tr>
<td>Emissions Tuning</td>
<td>12</td>
<td>60</td>
<td>1.4913</td>
<td>17.8956</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>630</td>
<td>298</td>
<td>24.0</td>
<td>58.3</td>
<td>102</td>
</tr>
<tr>
<td>Emissions Tuning</td>
<td>12</td>
<td>80</td>
<td>1.8323</td>
<td>21.9881</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>756</td>
<td>350</td>
<td>30.0</td>
<td>58.3</td>
<td>102</td>
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<tr>
<td>Restart CTGs and run HRSG in Bypass Mode: STG Bypass Valve Tuning. HRSG Blow Down and Drum Tuning</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Verify STG on Turning Gear, Establish Vacuum in ACC Ext Bypass Blowdown to ACC (Combined Blows). Commence Tuning On ACC Controls. Finalize Bypass Valve Tuning. ACC Cleaning.</td>
<td>168</td>
<td>80</td>
<td>1.8323</td>
<td>307.8339</td>
<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>2,328</td>
<td>1,078</td>
<td>273</td>
<td>816</td>
<td>1,428</td>
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<tr>
<td>Load Test STG / Combined-Cycle (2 x 1) Tuning</td>
<td>24</td>
<td>100</td>
<td>2.1734</td>
<td>52.1613</td>
<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>388</td>
<td>182</td>
<td>46.8</td>
<td>117</td>
<td>204</td>
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<tr>
<td>STG Load Test/ Combined-Cycle Tuning</td>
<td>96</td>
<td>80</td>
<td>1.8323</td>
<td>175.9051</td>
<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>1,331</td>
<td>616</td>
<td>156</td>
<td>467</td>
<td>816</td>
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<tr>
<td>RATA/ Pre-Performance Testing/Source Testing</td>
<td>84</td>
<td>80</td>
<td>1.8323</td>
<td>153.9170</td>
<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>1,164</td>
<td>539</td>
<td>137</td>
<td>408</td>
<td>714</td>
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<tr>
<td>Source Testing &amp; Drift Test Day 1</td>
<td>24</td>
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<td>1.3541</td>
<td>32.4973</td>
<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
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<td>50</td>
<td>1.3541</td>
<td>32.4973</td>
<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 3</td>
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<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 4</td>
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<td>50</td>
<td>1.3541</td>
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<td>78%</td>
<td>35%</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 5</td>
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<td>1.3541</td>
<td>32.4973</td>
<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 6</td>
<td>24</td>
<td>50</td>
<td>1.3541</td>
<td>32.4973</td>
<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 7</td>
<td>24</td>
<td>50</td>
<td>1.3541</td>
<td>32.4973</td>
<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Performance Testing</td>
<td>132</td>
<td>100</td>
<td>2.1734</td>
<td>286.8873</td>
<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>2,134</td>
<td>1,004</td>
<td>257</td>
<td>642</td>
<td>1,122</td>
</tr>
<tr>
<td>CALISO Certification &amp; Testing/PPA Testing</td>
<td>60</td>
<td>75</td>
<td>2.1734</td>
<td>130.4033</td>
<td>78%</td>
<td>78%</td>
<td>35%</td>
<td>804</td>
<td>371</td>
<td>97.5</td>
<td>292</td>
<td>510</td>
</tr>
</tbody>
</table>

Total for One CTG 996 1656.24 27,597 101,328 14,682 4,841 8,466
The applicant requested 996 hours of fired operation for the commissioning of each combined-cycle turbine, as indicated in the table above. The commissioning for each turbine is expected to extend over a period of six months.

The dispersion modeling analysis, discussed below, shows that the maximum impact would occur if both turbines, with both the SCR and CO oxidation catalyst at 0% control, were simultaneously undergoing commissioning activities with the highest unabated emissions (i.e., CTG Testing (Full Speed No Load)). The modeling results demonstrated that both turbines may undergo simultaneous commissioning without causing the NO\textsubscript{2} or CO ambient standards to be exceeded.

Startup of Combined-Cycle Turbines
A startup event occurs each time a CTG is started up. A startup begins with the initiation of combustion, and concludes when BACT emissions levels are achieved or the startup is aborted by a trip. During start-up operations, the turbine operates at elevated average concentration rates for NO\textsubscript{x}, CO, and VOC due to the phased-in effectiveness of the SCR and CO oxidation catalysts.

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

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

2) A warm start event would typically be 10 hours or more but less than 48 hours from a shutdown event. The time from fuel initiation until reaching the baseload operating rate is expected to take up to 30 minutes.

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

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

For monthly emissions, the applicant requested a maximum of 2 cold starts, 15 warm starts, 45 hot starts per turbine in the original Application. In the revised Application, the applicant requested a maximum of 15 cold starts, 12 warm starts, 35 hot starts per turbine.
For annual emissions, the applicant requested a maximum of 24 cold starts, 100 warm starts, and 376 hot starts per turbine in the original Application. In the revised Application, the applicant requested a maximum of 80 cold starts, 88 warm starts, 332 hot starts per turbine.

**Shutdown of Combined-Cycle Turbines**

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

The duration of a shutdown event is expected to take up to 30 minutes.

For daily emissions (for modeling), the applicant has requested a maximum of two shutdowns per turbine. For monthly emissions, the applicant has requested a maximum of 62 shutdowns per turbine. For annual emissions, the applicant has requested a maximum of 500 shutdowns per turbine.

- **Startup/Shutdown Emissions**
  The applicant provided maximum startup and shutdown emissions per event for NOx, CO, and VOC, and startup and shutdown hourly emission rates for NOx, CO, VOC, SO₂ (short-term) and PM₁₀/₂.₅ in Table 5.1-14R—GE 7FA.05 Startup/Shutdown Emission Rates in AES Response Letter, dated 12/11/15. This table includes revised hourly startup and shutdown emission for VOC based on the BACT limit of 2 ppmv at 15% O₂, a correction from the emission rates based on 1 ppmv at 15% O₂ (based on source test method not accepted by the SCAQMD) provided in the original Application.

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

<table>
<thead>
<tr>
<th>Table 17 – Combined-Cycle Turbine Start-up/Shutdown Emission Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Duration Minutes (hr)</strong></td>
</tr>
<tr>
<td>Cold Start</td>
</tr>
<tr>
<td>Warm Start</td>
</tr>
<tr>
<td>Hot Start</td>
</tr>
<tr>
<td>Shutdown</td>
</tr>
</tbody>
</table>
**Startup/Shutdown Conditions**

The startup/shutdown conditions limit and minimize emissions during startups and shutdowns when steady state BACT is not achievable. Condition no. C1.3 provides limits for startups, and condition no. C1.4 provides limits for shutdowns. The limits are necessary because condition nos. A195.8, A195.9, and A195.10 state that BACT for NO\textsubscript{x}, CO, and VOC, respectively, shall not apply during startups and shutdowns. The startup limits include: (1) number of cold starts per calendar month and year; (2) number of warm starts per calendar month and year; (3) number of hot starts per calendar month and year; (4) number of startups per day; and (5) duration of cold start, warm start, and hot start; and (6) NO\textsubscript{x}, CO, and VOC emissions per cold start, warm start, and hot start. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdown; and (3) NO\textsubscript{x}, CO, and VOC emissions per shutdown.

**Normal Operation**

Normal operation occurs after the CTGs, HRSGs, SCR/CO catalysts, and STG are working optimally. The emissions during normal operations are assumed to be fully controlled to BACT levels, and exclude emissions due to commissioning, startup and shutdown periods, which are not subject to BACT levels. NO\textsubscript{x} is controlled to 2.0 ppmvd, CO to 2.0 ppmvd, and VOC to 2.0 ppmvd, all 1-hr averages, at 15% O\textsubscript{2}.

**Maximum Daily, Monthly, Annual, NSR Emissions Calculations**

The following sections will discuss maximum daily emissions, maximum monthly emissions, maximum annual emissions, and associated emission factors and permit condition limits. Finally, offset requirements and the calculation of NSR entries will be discussed.

**Maximum Daily Emissions per Turbine**

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

**Commissioning Month**

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

**Normal Operating Month**

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

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

**Table 18 - Combined-Cycle Turbine Maximum Daily Emissions**

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>No. of Normal Operating Hr</th>
<th>Normal Operation Emission Rate, lb/hr</th>
<th>No. of Cold Startups</th>
<th>Lb/cold Startup</th>
<th>No. of Warm Startups</th>
<th>Lb/Warm Startup</th>
<th>No. of Shutdowns</th>
<th>Lb/Shutdown</th>
<th>Maximum Daily Emissions lb/day</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>21</td>
<td>16.5</td>
<td>2</td>
<td>61</td>
<td>0</td>
<td>17</td>
<td>2</td>
<td>10</td>
<td>488.50</td>
</tr>
<tr>
<td>CO</td>
<td>21</td>
<td>10.0</td>
<td>2</td>
<td>325</td>
<td>0</td>
<td>137</td>
<td>2</td>
<td>133</td>
<td>1126.00</td>
</tr>
<tr>
<td>VOC</td>
<td>21</td>
<td>5.75</td>
<td>2</td>
<td>36</td>
<td>0</td>
<td>25</td>
<td>2</td>
<td>32</td>
<td>256.75</td>
</tr>
<tr>
<td>PM₁₀/PM₂.₅</td>
<td>21</td>
<td>8.50</td>
<td>2</td>
<td>8.50</td>
<td>0</td>
<td>4.25</td>
<td>2</td>
<td>4.25</td>
<td>204.00</td>
</tr>
<tr>
<td>SOx</td>
<td>21</td>
<td>4.86</td>
<td>2</td>
<td>4.86</td>
<td>0</td>
<td>2.43</td>
<td>2</td>
<td>2.43</td>
<td>116.64</td>
</tr>
</tbody>
</table>

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

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

- **Maximum Monthly Emissions and Emission Factors per Turbine**
  Condition A63.2 specifies the monthly emissions limits for CO, VOC, PM₁₀, and SOx. Monthly limits are required to establish a basis for calculating offset requirements and ensure compliance with BACT requirements. RECLAIM rules do not allow a monthly limit for NOx. The monthly emissions for NOx, however, are indirectly limited by the monthly emissions limits for CO, VOC, PM₁₀, and SOx. The number of RECLAIM RTCs required are determined on an annual basis, which are calculated below and reflected in conditions I297.1 and I297.2.

The maximum monthly emissions and 30-day averages for each pollutant are based on the highest emissions of any month, including commissioning month(s), combination commissioning/normal operating month, and normal operating month. As explained below, AES has indicated there will be no combination commissioning/normal operating month. Therefore commissioning month(s) emissions and normal operating month emissions will be evaluated below. In addition, the commissioning emission factors and normal operating emission factors will be included in condition A63.2 for CO, VOC, PM₁₀, and SOx. The commissioning emission factor and the post-commissioning/pre-CEMS certification emission factor will be including in conditions A99.1 and A99.2, respectively, for NOx.
- Commissioning Months
- **Maximum Monthly Emissions, Commissioning**
  
  In the AES Response Letter dated 12/11/15, the applicant indicated that the commissioning period will extend over a period of 6 full months, and will not overlap with steady-state operation of the CTGs. The number of commissioning hours per month per turbine is 166 hours.

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

  **Month 1: CTG Testing and a portion of Steam Blows**

<table>
<thead>
<tr>
<th>Activity</th>
<th>Duration (hr)</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>SOx</th>
<th>PM10/PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTG Testing (Full Speed No Load, FSNL)</td>
<td>48</td>
<td>6,240</td>
<td>91,200</td>
<td>12,960</td>
<td>233</td>
<td>408</td>
</tr>
<tr>
<td>Steam Blows</td>
<td>118 of 120</td>
<td>8053.5</td>
<td>3823.2</td>
<td>354</td>
<td>573.3</td>
<td>1003</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>166</strong></td>
<td><strong>14293.5</strong></td>
<td><strong>95,023.2</strong></td>
<td><strong>13,314</strong></td>
<td><strong>806.3</strong></td>
<td><strong>1411</strong></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Activity</th>
<th>Duration (hr)</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>SOx</th>
<th>PM10/PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam Blows</td>
<td>2 of 120</td>
<td>136.5</td>
<td>64.8</td>
<td>6.0</td>
<td>9.7</td>
<td>17.0</td>
</tr>
<tr>
<td>Set Unit HRSG &amp; Steam Safety Valves</td>
<td>12</td>
<td>819</td>
<td>389</td>
<td>36.0</td>
<td>58.3</td>
<td>102</td>
</tr>
<tr>
<td>Steam Blows – Restoration</td>
<td>12</td>
<td>567</td>
<td>285</td>
<td>24.0</td>
<td>58.3</td>
<td>102</td>
</tr>
<tr>
<td>Emissions Tuning</td>
<td>12</td>
<td>630</td>
<td>298</td>
<td>24.0</td>
<td>58.3</td>
<td>102</td>
</tr>
<tr>
<td>Emissions Tuning</td>
<td>12</td>
<td>756</td>
<td>350</td>
<td>30.0</td>
<td>58.3</td>
<td>102</td>
</tr>
<tr>
<td>Restart CTGs and run HRSG in Bypass Mode. STG Bypass Valve Tuning. HRSG Blow Down and Drum Tuning</td>
<td>52 of 168</td>
<td>1607.4</td>
<td>744.3</td>
<td>188.5</td>
<td>563.4</td>
<td>986.0</td>
</tr>
<tr>
<td>Verify STG on Turning Gear, Establish Vacuum in ACC Ext Bypass Blowdown to ACC (Combined Blows). Commence Tuning On ACC Controls. Finalize Bypass Valve Tuning. ACC Cleaning</td>
<td>48</td>
<td>388</td>
<td>182</td>
<td>46.8</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>166</strong></td>
<td><strong>4515.9</strong></td>
<td><strong>2131.1</strong></td>
<td><strong>308.5</strong></td>
<td><strong>806.3</strong></td>
<td><strong>1411</strong></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Activity</th>
<th>Duration (hr)</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>SOx</th>
<th>PM10/PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Verify STG on Turning Gear, Establish Vacuum in ACC Ext Bypass Blowdown to ACC (Combined Blows). Commence Tuning On ACC Controls. Finalize Bypass Valve Tuning. ACC Cleaning</td>
<td>52 of 168</td>
<td>720.6</td>
<td>333.7</td>
<td>84.5</td>
<td>252.6</td>
<td>442</td>
</tr>
<tr>
<td>CT Base Load Testing/Tuning</td>
<td>24</td>
<td>388</td>
<td>182</td>
<td>46.8</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Load Test STG / Combined-Cycle (2 x 1) Tuning</td>
<td>48</td>
<td>499</td>
<td>251</td>
<td>62.4</td>
<td>233</td>
<td>408</td>
</tr>
<tr>
<td>STG Load Test/ Combined-Cycle Tuning</td>
<td>42 of 96</td>
<td>582.3</td>
<td>269.5</td>
<td>68.3</td>
<td>204.3</td>
<td>357</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>166</strong></td>
<td><strong>2189.9</strong></td>
<td><strong>1036.2</strong></td>
<td><strong>262</strong></td>
<td><strong>806.9</strong></td>
<td><strong>1411.0</strong></td>
</tr>
</tbody>
</table>
Month 4: Remainder of STG Load Test/Combined-Cycle Tuning, RATA/Pre-Performance Testing/Source Testing, Source Testing & Drift Test Day 1, and a portion of Source Testing & Drift Test Day 2

<table>
<thead>
<tr>
<th>Activity</th>
<th>Duration (hr)</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>SOx</th>
<th>PM10/PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>STG Load Test/Combined-Cycle Tuning</td>
<td>54 of 96</td>
<td>748.7</td>
<td>346.5</td>
<td>87.8</td>
<td>262.7</td>
<td>459</td>
</tr>
<tr>
<td>RATA/Pre-Performance Testing/Source Testing</td>
<td>84</td>
<td>1,164</td>
<td>539</td>
<td>137</td>
<td>408</td>
<td>714</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 1</td>
<td>24</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 2</td>
<td>4 of 24</td>
<td>41.5</td>
<td>20.8</td>
<td>5.2</td>
<td>19.5</td>
<td>34.0</td>
</tr>
<tr>
<td>Total</td>
<td>166</td>
<td>2203.2</td>
<td>1031.3</td>
<td>261.2</td>
<td>807.2</td>
<td>1411.0</td>
</tr>
</tbody>
</table>


<table>
<thead>
<tr>
<th>Activity</th>
<th>Duration (hr)</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>SOx</th>
<th>PM10/PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Source Testing &amp; Drift Test Day 2</td>
<td>20 of 24</td>
<td>207.5</td>
<td>104.2</td>
<td>26.0</td>
<td>97.5</td>
<td>170</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 3</td>
<td>24</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 4</td>
<td>24</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 5</td>
<td>24</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 6</td>
<td>24</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Source Testing &amp; Drift Test Day 7</td>
<td>24</td>
<td>249</td>
<td>125</td>
<td>31.2</td>
<td>117</td>
<td>204</td>
</tr>
<tr>
<td>Performance Testing</td>
<td>26 of 132</td>
<td>420.3</td>
<td>197.8</td>
<td>50.6</td>
<td>126.5</td>
<td>221.0</td>
</tr>
<tr>
<td>Total</td>
<td>166</td>
<td>1872.8</td>
<td>927</td>
<td>232.6</td>
<td>809.0</td>
<td>1411.0</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Activity</th>
<th>Duration (hr)</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>SOx</th>
<th>PM10/PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Performance Testing</td>
<td>106 of 132</td>
<td>1713.7</td>
<td>806.2</td>
<td>206.4</td>
<td>515.5</td>
<td>901.0</td>
</tr>
<tr>
<td>CALISO Certification &amp; Testing/PPA Testing</td>
<td>60</td>
<td>804</td>
<td>371</td>
<td>97.5</td>
<td>292</td>
<td>510</td>
</tr>
<tr>
<td>Total</td>
<td>166</td>
<td>2517.7</td>
<td>1177.2</td>
<td>303.9</td>
<td>807.5</td>
<td>1411.0</td>
</tr>
</tbody>
</table>

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

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Month</th>
<th>Commissioning Emissions, lb/month</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>One</td>
<td>14,293.5</td>
</tr>
<tr>
<td>CO</td>
<td>One</td>
<td>95,023.2</td>
</tr>
<tr>
<td>VOC</td>
<td>One</td>
<td>13,314.0</td>
</tr>
<tr>
<td>PM10/PM2.5</td>
<td>All months</td>
<td>1411</td>
</tr>
<tr>
<td>SOx</td>
<td>Five</td>
<td>809</td>
</tr>
</tbody>
</table>

- **Commissioning Emission Factors**

  The commissioning period emission factors are derived for inclusion in condition no. A63.2 for CO, VOC, PM10, and SOx, and in condition no. A99.1 for NOx. As explained in the Rule 2012 analysis below, condition no. A99.1 specifies the interim emission factor for NOx for the commissioning period (no certified CEMS), during which the...
CTGs are assumed to be operating at uncontrolled and partially controlled levels. For each pollutant, the emission factor is calculated as the total emissions for the commissioning period divided by the total fuel usage for the commissioning period, both from Table 16, above.

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

The table below shows the calculation of the emissions factors.

**Table 20 - Combined-Cycle Turbine Commissioning Emission Factors**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Total Commissioning Emissions, lb</th>
<th>Total Commissioning Fuel Usage, mmcf</th>
<th>Emission Factor, lb/mmcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>27,597</td>
<td>1656.24</td>
<td>16.66</td>
</tr>
<tr>
<td>CO</td>
<td>101,328</td>
<td>1656.24</td>
<td>61.18</td>
</tr>
<tr>
<td>VOC</td>
<td>14,682</td>
<td>1656.24</td>
<td>8.86</td>
</tr>
<tr>
<td>PM10/PM2.5</td>
<td>8,466</td>
<td>1656.24</td>
<td>5.11</td>
</tr>
<tr>
<td>SOx</td>
<td>4,841</td>
<td>1656.24</td>
<td>2.92</td>
</tr>
</tbody>
</table>

- **Normal Operating Month**
- **Maximum Normal Operating Month Emissions**

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

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

Alamitos Energy Center
ApplicationNos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>No. of Normal Operating Hours</th>
<th>Normal Operation Emission Rate, lb/hr</th>
<th>No. of Cold Startups</th>
<th>lb/cold startup</th>
<th>No. of Warm Startups</th>
<th>lb/warm startup</th>
<th>No. of Hot Startups</th>
<th>lb/hot startup</th>
<th>No. of Shutdowns</th>
<th>lb/shutdown</th>
<th>Maximum Monthly Emissions, lb/month (tons/month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>674.5</td>
<td>16.5</td>
<td>15</td>
<td>61</td>
<td>12</td>
<td>17</td>
<td>35</td>
<td>17</td>
<td>62</td>
<td>10</td>
<td>13,463.25 (6.73)</td>
</tr>
<tr>
<td>CO</td>
<td>674.5</td>
<td>10.0</td>
<td>15</td>
<td>325</td>
<td>12</td>
<td>137</td>
<td>35</td>
<td>137</td>
<td>62</td>
<td>133</td>
<td>26,305.00 (13.15)</td>
</tr>
<tr>
<td>VOC</td>
<td>674.5</td>
<td>5.75</td>
<td>15</td>
<td>36</td>
<td>12</td>
<td>25</td>
<td>35</td>
<td>25</td>
<td>62</td>
<td>32</td>
<td>7577.38 (3.79)</td>
</tr>
<tr>
<td>PM$<em>{10}$/PM$</em>{2.5}$</td>
<td>674.5</td>
<td>4.86</td>
<td>15</td>
<td>4.86</td>
<td>12</td>
<td>2.43</td>
<td>35</td>
<td>2.43</td>
<td>62</td>
<td>2.43</td>
<td>3615.84 (1.81)</td>
</tr>
<tr>
<td>SOx</td>
<td>674.5</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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

- Normal Operating Emission Factors
  The normal operating emission factors are derived for inclusion in condition no. A63.2 for CO, VOC, PM$_{10}$, and SOx, and in condition no. A99.2 for NOx. As explained in the Rule 2012 analysis below, condition no. A99.2 specifies the interim emission factor for the normal operating period after commissioning has been completed but before the CEMS is certified, during which the CTGs are assumed to be operating at BACT levels.

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

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Maximum Monthly Emissions, lb/month</th>
<th>Emission Factors, lb/mmcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>13,463.25</td>
<td>8.35</td>
</tr>
<tr>
<td>CO</td>
<td>26,305.00</td>
<td>16.32</td>
</tr>
<tr>
<td>VOC</td>
<td>7577.38</td>
<td>4.70</td>
</tr>
<tr>
<td>PM$_{10}$</td>
<td>6324.0</td>
<td>3.92</td>
</tr>
<tr>
<td>SOx</td>
<td>3615.84</td>
<td>2.24</td>
</tr>
</tbody>
</table>

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

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

- Permit Conditions—Monthly Emissions Limits
  Condition no. A63.2 specifies the maximum monthly emissions limits per turbine for CO, VOC, PM$_{10}$, and SOx. The maximum monthly emissions and 30-day averages for each pollutant are based on the highest emissions from any commissioning month (Table 19) or normal operating month (Table 21). The table below compares the maximum commissioning month emissions with the maximum normal operating month emissions.
Preliminary Determination of Compliance

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

(higher values in bold font) to determine the maximum monthly emissions limits and associated 30-day averages. AES has indicated commissioning and normal operations will not occur in the same month.

(Although condition no. A63.2 will not include a monthly limit for NOx, it is included in the table below because the determination of 30-day averages for all pollutants is required for the internal NSR Data Summary Sheet.)

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Maximum Commissioning Month Emissions, lb/month (lb/day)</th>
<th>Maximum Normal Operating Month Emissions, lb/month (lb/day)</th>
<th>Maximum Monthly Emissions, lb/month</th>
<th>30-Day Averages, lb/day</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>14,293.5 lb/month (476.45 lb/day)</td>
<td>13,463.25 lb/month (448.78 lb/day)</td>
<td>14,294</td>
<td>476.45</td>
</tr>
<tr>
<td>CO</td>
<td>95,023.2 lb/month (3167.44 lb/day)</td>
<td>26,305 lb/month (876.83 lb/day)</td>
<td>95,023</td>
<td>3167.44</td>
</tr>
<tr>
<td>VOC</td>
<td>13,314.0 lb/month (443.8 lb/day)</td>
<td>7577.38 lb/month (252.58 lb/day)</td>
<td>13,314</td>
<td>443.8</td>
</tr>
<tr>
<td>PM_{10}</td>
<td>1411 lb/month (47.03 lb/day)</td>
<td>6324.0 lb/month (210.8 lb/day)</td>
<td>6324</td>
<td>210.8</td>
</tr>
<tr>
<td>SOx</td>
<td>809 lb/month (27.0 lb/day)</td>
<td>3615.84 lb/month (120.53 lb/day)</td>
<td>3616</td>
<td>120.53</td>
</tr>
</tbody>
</table>

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

- **Maximum Annual Emissions per Turbine**
The annual emissions for the commissioning year and a normal operating year are calculated below. The number of RECLAIM NOx RTCs required are determined on an annual basis which will be reflected in conditions I297.1 - I297.2, as discussed under the Rule 2005(c)(2) analysis below.

- **Commissioning Year**
  Condition no. I297.1 – I297.2 specify the pounds of NOx RTCs that are required to be held in the facility’s allocation account to offset the annual emissions increase for the first year of operation. The first year of operation is the commissioning year.
In the AES Response Letter dated 12/11/15, the applicant indicated that the commissioning period will extend over a period of 6 full months, and will not overlap with steady-state operation of the CTGs. In AES response e-mail dated 4/6/16, AES reaffirmed that AEC project engineers has determined the combined-cycle power block commissioning will require six months to complete.

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Commissioning Year Emissions, lb/yr (tpy)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>(27,597 lb/commissioning) + (13,463.25 lb/month)(6 normal operating months) = 108,377 lb/yr (54.19 tpy)</td>
</tr>
<tr>
<td>CO</td>
<td>(101,328 lb/commissioning) + (26,305.0 lb/month)(6 normal operating months) = 259,158.0 lb/yr (129.58 tpy)</td>
</tr>
<tr>
<td>VOC</td>
<td>(14,682 lb/commissioning) + (7577.38 lb/month)(6 normal operating months) = 60,146.28 lb/yr (30.07 tpy)</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>(8,466 lb/commissioning) + (6324.0 lb/month)(6 normal operating months) = 46,410.0 lb/yr (23.21 tpy)</td>
</tr>
<tr>
<td>SOx</td>
<td>(4,841 lb/commissioning) + (3615.84 lb/month)(6 normal operating months) = 26,536.04 lb/yr (13.27 tpy)</td>
</tr>
</tbody>
</table>

Conditions I297.1 and I297.2 will require each turbine to hold 108,377 pounds of RTCs the first year.

**Normal Operating Year**

Because the monthly emissions limits in condition A63.2 are applicable each and every month, the annual emissions limits are the monthly emissions multiplied by twelve months, unless limited by permit condition. For maximum annual emissions per turbine, the applicant requested: (1) 4100 hours of normal operation, (2) 24 cold starts, (3) 100 warm starts, (4) 376 hot starts, and (5) 500 shutdowns for a total of 4612 hours, in the original Application. The revised Application requested: (1) 4100 hours of normal operation, (2) 80 cold starts, (3) 88 warm starts, (4) 332 hot starts, and (5) 500 shutdowns, for a total of 4640 hours. The normal operation emission rates are from Table 15 (case 4), and the startup and shutdown emissions per event from Table 17. The SOx emission rates are based on the long-term rate (0.25 grains/100 scf).
Table 25 - Combined-Cycle Turbine Maximum Annual Emissions, Normal Operating Year

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

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

- **Permit Conditions—Annual Emissions Limits**
  
  From Table 25, the annual emission limits for a normal operating year are included in condition A63.2 for CO, VOC, PM_{10}, and SOx to ensure that the annual PM_{10}/PM_{2.5} and NO_{2} emissions will not exceed the PM_{10}/PM_{2.5} and NO_{2} modeled emission rates for the annual averaging period provided in Table 51. As with the monthly limits, an annual emissions limit may not be added for NOx because AEC will be a RECLAIM facility and such a limit is not allowed by RECLAIM rules. The annual emissions for NOx, however, are indirectly limited by the annual emissions limits for CO, VOC, PM_{10}, and SOx. Additionally, the toxic pollutants and greenhouse gases are indirectly limited by the annual emissions limits.

The emission factors for the monthly emission limits shall be used to demonstrate compliance with the annual emission limits, except for SOx. AES requested that the maximum monthly emissions be based on 0.75 grains/100 scf, but the annual emissions be based on 0.25 grains/100 scf. The annual SOx emission factor is calculated below.

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Maximum Annual Emissions, lb/year</th>
<th>Emission Factors, lb/mmcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>SOx</td>
<td>7434.8</td>
<td>0.75</td>
</tr>
</tbody>
</table>

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

Where max annual fuel usage = (4640 hours, incl. startups/shutdowns) (2250 MMBtu/hr, Case 4) (mmscf/1050 MMBtu) = 9942.86 mmscf/yr
- **New Source Review (NSR) Database Entries**
  This section develops the internal NSR Data Summary Sheet entries.

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

  The 30-day averages per turbine are from *Table 23*. The uncontrolled emissions (R1) and controlled emissions (R2) are back calculated from the 30-day averages for the purpose of input into the internal NSR Data Summary Sheet only.

  **NOx**
  \[
  R2 = (476.45 \text{ lb/day})(\text{day/24 hr}) = 19.85 \text{ lb/hr}
  \]
  \[
  R1 = (19.85 \text{ lb/hr})(9 \text{ ppm uncontrolled}/2 \text{ ppm controlled per case 1}) = 89.33 \text{ lb/hr}
  \]
  \[
  30-DA = 476.45 \text{ lb/day}
  \]

  **CO**
  \[
  R2 = (3167.44 \text{ lb/day})(\text{day/24 hr}) = 131.98 \text{ lb/hr}
  \]
  \[
  R1 = (131.98 \text{ lb/hr})(7.08 \text{ ppm uncontrolled}/2 \text{ ppm controlled per case 1}) = 467.21 \text{ lb/hr}
  \]
  \[
  30-DA = 3167.44 \text{ lb/day}
  \]

  **ROG**
  \[
  R2 = R1 \text{ (Appx. 0% control efficiency per case 1)}
  \]
  \[
  R2 = R1 = (443.8 \text{ lb/day})(\text{day/24 hr}) = 18.49 \text{ lb/hr}
  \]
  \[
  30-DA = 443.8 \text{ lb/day}
  \]

  **PM\text{10}**
  \[
  R2 = R1 = (210.8 \text{ lb/day})(\text{day/24 hr}) = 8.78 \text{ lb/hr}
  \]
  \[
  30-DA = 210.8 \text{ lb/day}
  \]

  **SOx**
  \[
  R2 = R1 = (120.53 \text{ lb/day})(\text{day/24 hr}) = 5.02 \text{ lb/hr}
  \]
  \[
  30-DA = 120.53 \text{ lb/day}
  \]
B. Toxic Pollutants

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

In the revised Application, Table 5.9-1 has been revised to reflect previously provided changes due to the correction to AP-42 emission factors and new changes due to a higher annual fuel usage resulting from the increase in cold starts. The new changes due to the higher fuel usage are added to the table below.

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

<table>
<thead>
<tr>
<th>Compound</th>
<th>CAS</th>
<th>TAC/HAP</th>
<th>Emission Factor 1 (Lb/MMBtu)</th>
<th>Lb/hr</th>
<th>Lb/yr</th>
<th>TPY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>766417</td>
<td>TAC</td>
<td>15.3</td>
<td>70,004</td>
<td>35.0</td>
<td></td>
</tr>
<tr>
<td>Acetaldehyde</td>
<td>75070</td>
<td>TAC &amp; HAP</td>
<td>1.76E-04</td>
<td>0.39</td>
<td>1789</td>
<td>0.89</td>
</tr>
<tr>
<td>Acrolein</td>
<td>107028</td>
<td>HAP &amp; TAC</td>
<td>3.62E-06</td>
<td>0.008</td>
<td>36.7</td>
<td>0.018</td>
</tr>
<tr>
<td>Benzene</td>
<td>71432</td>
<td>HAP &amp; TAC</td>
<td>3.26E-06</td>
<td>0.0072</td>
<td>33.1</td>
<td>0.017</td>
</tr>
<tr>
<td>1,3-Butadiene</td>
<td>106990</td>
<td>HAP &amp; TAC</td>
<td>4.3E-07</td>
<td>0.0010</td>
<td>4.36</td>
<td>0.0022</td>
</tr>
<tr>
<td>Ethylbenzene</td>
<td>100414</td>
<td>HAP &amp; TAC</td>
<td>3.2E-05</td>
<td>0.071</td>
<td>324</td>
<td>0.16</td>
</tr>
<tr>
<td>Formaldehyde</td>
<td>50000</td>
<td>HAP &amp; TAC</td>
<td>3.6E-04</td>
<td>0.80</td>
<td>3648</td>
<td>1.82</td>
</tr>
<tr>
<td>Hexane</td>
<td>110543</td>
<td>HAP &amp; TAC</td>
<td>Not available</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Naphthalene</td>
<td>91203</td>
<td>HAP &amp; TAC</td>
<td>1.3E-06</td>
<td>0.0029</td>
<td>13.2</td>
<td>0.0066</td>
</tr>
<tr>
<td>PAHS (excluding naphthalene)</td>
<td>1151</td>
<td>HAP &amp; TAC</td>
<td>(2.2E-06 – 1.3E-06) * 0.5 = 0.45E-06</td>
<td>0.0010</td>
<td>4.56</td>
<td>0.0023</td>
</tr>
<tr>
<td>Propylene (propene)</td>
<td>115071</td>
<td>TAC</td>
<td>Not available</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Propylene Oxide</td>
<td>75569</td>
<td>HAP &amp; TAC</td>
<td>2.9E-05</td>
<td>0.063</td>
<td>290</td>
<td>0.15</td>
</tr>
<tr>
<td>Toluene</td>
<td>108883</td>
<td>HAP &amp; TAC</td>
<td>1.3E-04</td>
<td>0.29</td>
<td>1322</td>
<td>0.66</td>
</tr>
<tr>
<td>Xylene</td>
<td>1330207</td>
<td>HAP &amp; TAC</td>
<td>6.4E-05</td>
<td>0.14</td>
<td>649</td>
<td>0.32</td>
</tr>
</tbody>
</table>

Total Annual HAPS Emissions per Turbine, TPY 4.05

Total Annual Toxic Air Contaminants Emissions per Turbine, TPY 39.05

1. Emission factors based on AP-42, Section 3.1, Final Section, Table 3.1-3--Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbine (Uncontrolled), April 2000, unless otherwise noted in footnote 2.

2. Acetaldehyde, acrolein, benzene, and formaldehyde emission factors are based on AP-42, Section 3.1, Background Information, Table 3.4-1--Summary of Emission Factors for Natural Gas-Fired Gas Turbines, April 2000. These emission factors include control by CO catalyst.

3. Carcinogenic PAHs only. Naphthalene was subtracted from the total PAHs and considered separately in the HRA.

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

5. Ammonia and propylene are toxic air contaminants for the purpose of Rule 1401, but not federal hazardous air pollutants.
The hourly and annual emissions are calculated as follows:

For compounds other than ammonia
Hourly emissions, \( \text{lb/hr} = (\text{Emission Factor}) \times \) (maximum hourly heat input rate of 2275 MMBtu/hr (Case 1))

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

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

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

Ammonia
Maximum hourly emissions, \( \text{lb/hr} = (2275 \text{ MMBtu/hr}) \times (8710 \text{ dscf}/10^6 \text{ Btu}) \) (5 ppm NH\(_3\)/10\(^6\) Btu) (20.9/(20.9-15.0)) (17 lbs NH\(_3\)/379 scf) = 15.7 lb/hr

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

Maximum annual emissions, \( \text{lb/yr} = (4640 \text{ hr/yr}) \times (15.1 \text{ lb/hr}) \) (case 4) = 70,004 lb/yr = 35.0 tpy

C. Greenhouse Gases (GHG)
- Combustion: CO\(_2\), CH\(_4\), N\(_2\)O
Combustion of natural gas in the turbines will result in emissions of CO\(_2\), CH\(_4\), and N\(_2\)O.

As shown above for the toxic pollutants emissions calculations, the average annual heat input rate is 10,437,686 MMBtu/yr.

Emission factors for CO\(_2\), CH\(_4\), and N\(_2\)O are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised April 4, 2014.

For each combined-cycle turbine:

\[
\begin{align*}
\text{CO}_2 : & \quad 53.06 \text{ kg CO}_2/\text{MMBtu} \\
\text{CH}_4 : & \quad 1 \text{ g CH}_4/\text{MMBtu} \\
\text{N}_2\text{O} : & \quad 0.10 \text{ g N}_2\text{O}/\text{MMBtu} \\
\text{CO}_2 = & \quad (10,437,686 \text{ MMBtu/yr})(53.06 \text{ kg/MMBtu})(2.2046 \text{ lb/kg})
\end{align*}
\]
Preliminary Determination of Compliance

ENGINEERING AND COMPLIANCE

APPLICATION PROCESSING AND CALCULATIONS

- 1,220,959,551 lb/yr = 610,479.78 tpy → 610,480 tpy

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

\[ N_2O = (10,437,686 \text{ MMBtu/yr})(0.1 \text{ g/MMBtu})(2.205 \times 10^{-3} \text{ lb/g}) \]
\[ = 2301.51 \text{ lb/yr} = 1.15 \text{ tpy} \]

Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as amended by 79 FR 73779, 12/11/14:
(1) CH\(_4\) is equivalent to 25 times the global warming potential of CO\(_2\), and
(2) N\(_2\)O is equivalent to 298 times of CO\(_2\).

\[ \text{CO}_2e, \text{ tpy} = (1,220,959,551 \text{ lb/yr CO}_2)(1 \text{ lb CO}_2e/\text{lb CO}_2) + (23,015.10 \text{ lb/yr CH}_4) \]
\[ (25 \text{ lb CO}_2e/\text{lb CH}_4) + 2301.51 \text{ lb/yr N}_2O(298 \text{ lb CO}_2e/\text{lb N}_2O) \]
\[ = 1,222,220,778 \text{ lb/yr} = 611,110.39 \text{ tpy} = 50,925.87 \text{ tons/month} \]

- **Circuit Breakers: SF\(_6\)**

Condition F52.2 will specify a CO\(_2e\) facility-wide annual limit for SF\(_6\) (74.55 tpy) to enforce the BACT requirements for the circuit breakers located at the CCGT (17.44 tpy) and SCGT 57.11 tpy) power blocks.

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

For the CCGT:

- CCGT-1, CCGT-2, and Steam Turbine: 3000A 230 kV: 230 lb SF\(_6\)
- CCGT-1: 10000A 18 kV: 25 lb SF\(_6\)
- CCGT-2: 10000A 18 kV: 25 lb SF\(_6\)
- Steam Turbine: 10000A 18 kV: 25 lb SF\(_6\)
- Steam Turbine: 10000A 18 kV: 305 lb SF\(_6\)

Annual leakage = (305 lb SF\(_6\)) (0.5/100 annual leak rate) = 1.53 lb/yr SF\(_6\) = 0.00076 tpy

Pursuant to the **Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear** (17 CCR 95350-95359), §95352 specifies the maximum annual SF\(_6\) emission rate shall not exceed 1.0% in 2020, and each calendar year thereafter. PSD BACT, however, imposes a more stringent limit of 0.5%.
Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as amended by 79 FR 73779, 12/11/14, SF\(_6\) is equivalent to 22,800 times the global warming potential of CO\(_2\).

\[
(1.53 \text{ lb/yr SF}_6) (22,800 \text{ lb CO}_2\text{e/lb SF}_6) = 34,884 \text{ lb/yr} = 17.44 \text{ tpy CO}_2\text{e}
\]

\[
= 1.45 \text{ tons/month CO}_2\text{e}
\]

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

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

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

  \[
  \text{CO}_2 = (1,220,959,551 \text{ lb/yr}) (\text{yr} / 8736 \text{ hr}) = 139,761.85 \text{ lb/hr}
  \]

  \[
  \text{CH}_4 = (23,015.10 \text{ lb/yr}) (\text{yr} / 8736 \text{ hr}) = 2.63 \text{ lb/hr}
  \]

  \[
  \text{N}_2\text{O} = (2301.51 \text{ lb/yr}) (\text{yr} / 8736 \text{ hr}) = 0.26 \text{ lb/hr}
  \]

  \[
  \text{SF}_6 = (34,884 \text{ lb/yr}) (\text{yr} / 8736 \text{ hr}) = 3.99 \text{ lb/hr}
  \]

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

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

   A. **Criteria Pollutants**  
      NO\(_x\) = CO = VOC = PM\(_{10}\) = SO\(_x\) = 0 lb/hr = 0 lb/day

   B. **Toxic Pollutants**  
      From Table 26 above, the 5 ppmvd BACT level for ammonia results in an annual emission rate of 70,004 lb/yr = 35 tons/yr = 2.92 tons/month (avg)

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

      \[
      \text{NH}_3, \text{ lb/day} = (70,004 \text{ lb/yr}) (\text{yr}/52 \text{ wk}) (\text{wk}/7 \text{ days}) = 192.32 \text{ lb/day}
      \]

      \[
      \text{lb/hr} = (192.32 \text{ lb/day}) (\text{day}/24 \text{ hr}) = 8.01 \text{ lb/hr}
      \]

      **Note:** Ammonia is not a federal HAP.
3. A/N 579158—Auxiliary Boiler (Combined-Cycle Turbines), 70.8 MMBtu/hr
   The auxiliary boiler will have a commissioning period and extended startup periods.

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

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

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

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

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

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

      Three startup scenarios have been developed for the auxiliary boiler.

      1) For a **cold start event**, the auxiliary boiler is at ambient temperature at the time of the
      startup, which would typically occur if 48 hours or more elapse between a shutdown event
and a system startup event. For the cold start event, the time from fuel initiation until reaching the baseload operating rate is expected to take up to 170 minutes.

2) A **warm start event** would typically be 10 hours or more but less than 48 hours from a shutdown event. The time from fuel initiation until reaching the baseload operating rate is expected to take up to 85 minutes.

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

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

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

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

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

The applicant provided maximum startup emissions per event for NOx, CO, and VOC, and startup/shutdown hourly emission rates for NOx, CO, VOC, SO\(_2\) (0.25 gr/100 scf) and PM\(_{10/2.5}\) in **Table 5.1-18—Auxiliary Boiler Startup Emission Rates** in the original Application. The revised Application provided maximum startup emissions per event for SO\(_2\) (corrected to be based on 0.75 gr/100 scf) and PM\(_{10}\). The event emission rates were provided by the manufacturer.

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

<table>
<thead>
<tr>
<th>Duration (Minutes)</th>
<th>NOx lb/event</th>
<th>CO lb/event</th>
<th>VOC lb/event</th>
<th>PM(_{10}) lb/hr (lb/event)</th>
<th>PM(_{2.5}) lb/hr (lb/event)</th>
<th>SO(_2) lb/hr (lb/event)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cold Start</td>
<td>170 (2.83)</td>
<td>4.22</td>
<td>4.34</td>
<td>&lt; 0.3 (0.84)</td>
<td>&lt; 0.3 (0.84)</td>
<td>&lt; 0.048 (0.24)</td>
</tr>
<tr>
<td>Warm Start</td>
<td>85 (1.42)</td>
<td>2.11</td>
<td>2.17</td>
<td>&lt; 0.3 (0.42)</td>
<td>&lt; 0.3 (0.42)</td>
<td>&lt; 0.048 (0.12)</td>
</tr>
<tr>
<td>Hot Start</td>
<td>25 (0.42)</td>
<td>0.62</td>
<td>0.64</td>
<td>&lt; 0.3 (0.12)</td>
<td>&lt; 0.3 (0.12)</td>
<td>&lt; 0.048 (0.035)</td>
</tr>
</tbody>
</table>

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

**Emissions Calculations**

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

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

CO: 50 ppm CO  
NOx: 5 ppmv NOx per Rule 1146(c)(1)(F)  
ROG: Original Application: Cleaver Brooks Guarantee, 6/10/15 = 0.003 lb/MBtu,  
AES requested 0.004 lb/MBtu including safety margin.  
Revised Application & AES Response e-mail, 4/6/16:  
5.5 lb/mmcf = 0.0052 lb/mmbtu (based on 1050 btu/cf)  
Default Annual Emissions Reporting (AER) emission factor for natural-gas fired boilers

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

SOx: Original Application: 0.00068 lb/MBtu (0.25 gr/100 scf) for monthly emissions.  
Revised Application: 0.0020 lb/MBtu (0.75 gr/100 scf) for monthly emissions.  
(In an e-mailed dated 2/2/16, AES clarified that 0.75 grains/100 scf will be used for daily and monthly emissions, instead of the 0.25 grains/100 scf initially proposed.)
Normal Operating Rate:

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

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

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

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

\[
\text{lbs/day} = \frac{(114.39 \text{ lb/month})}{(30 \text{ days})} = 3.81 \text{ lb/day} \\
30 \text{ DA} = 3.81 \text{ lb/day}
\]

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

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

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

\[
\text{lbs/day} = \frac{(604.70 \text{ lb/month})}{(30 \text{ days})} = 20.16 \text{ lb/day} \\
30 \text{ DA} = 20.16 \text{ lb/day}
\]

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

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

\[
\text{lbs/month} = (730.98 \text{ hr})(0.11 \text{ lb/hr}) + (2 \text{ cold starts})(4.69 \text{ lb/cold start}) + (4 \text{ warm starts})
\]
(2.34 lb/warm start) + (4 hot starts)(0.69 lb/hot start) = 101.91 lb/month  
0.051 tons/month [0.61 tpy]

\[
lbs/day = \frac{(101.91 \text{ lb/month})}{(30 \text{ days})} = 3.40 \text{ lb/day} \\
30 \text{ DA} = 3.40 \text{ lb/day}
\]

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

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

PM_{10}, lbs/hr = (21,230,000 Btu/hr) (0.0072 lb/MMBtu/10^{6}) = 0.15 lb/hr, normal operating rate  
(see below for NSR Database Entry hourly rate)

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

\[
lbs/day = \frac{(113.49 \text{ lb/month})}{(30 \text{ days})} = 3.78 \text{ lb/day} \\
30 \text{ DA} = 3.78 \text{ lb/day}
\]

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

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

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

\[
lbs/day = \frac{(31.80 \text{ lb/month})}{(30 \text{ days})} = 1.06 \text{ lb/day} \\
30 \text{ DA} = 1.06 \text{ lb/day}
\]

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

- **Monthly Emissions Limit**

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

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

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

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

= 16,057 MMBtu/month

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

The normal operating emission factors are derived below for inclusion in condition no. A63.4 for CO, VOC, PM₁₀, and SOx. As explained in the Rule 2002 analysis below, condition A99.5 specifies the interim emission factor for NOx prior to CEMS certification is 38.46 lb/mmscf.

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Maximum Monthly Emissions, lb/month</th>
<th>Emission Factors, lb/mmscf</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>604.70</td>
<td>39.55</td>
</tr>
<tr>
<td>VOC</td>
<td>101.91</td>
<td>6.67</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>113.49</td>
<td>7.42</td>
</tr>
<tr>
<td>SOx</td>
<td>31.80</td>
<td>2.08</td>
</tr>
</tbody>
</table>

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

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

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

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

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

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

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

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

Maximum annual fuel consumption (MMBtu/month) = [(no. normal operating hours) * (21.23 MMBtu/hr)] + [((no. startups, cold) (hr/startup, cold) + (no. startups, warm) (hr/startup, warm) + (no. startups, hot) (hr/startup, hot)) * (41.36 MMBtu/hr)] = [(8603.76 hr) * (21.23 MMBtu/hr)] + [((24 cold starts)(2.83 hr/cold start) + (48 warm starts)(1.42 hr/warm start) + (48 hot starts)(0.42 hr/hot start)) * (41.36 MMBtu/hr)] = 189,119.91 MMBtu/yr

B. Toxic Pollutants

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

In the revised Application, Table 5.9-2 has been revised to reflect previously provided changes due to the correction to VCAPCD emission factors, and new changes due to a lower annual fuel usage. The new changes due to the lower fuel usage are added to the table below.
Table 30 - Auxiliary Boiler Toxic Air Contaminants/Hazardous Air Pollutants

<table>
<thead>
<tr>
<th>Compound</th>
<th>CAS</th>
<th>TAC/HAP</th>
<th>Emission Factor (lb/MMcf)</th>
<th>Emission Factor (lb/MMBtu)</th>
<th>Lb/hr</th>
<th>Lb/yr</th>
<th>TPY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>766417</td>
<td>TAC</td>
<td>0.0031</td>
<td>2.95E-06</td>
<td>0.16</td>
<td>423</td>
<td>0.212</td>
</tr>
<tr>
<td>Acetaldehyde</td>
<td>75070</td>
<td>TAC &amp; HAP</td>
<td>0.0027</td>
<td>2.57E-06</td>
<td>0.848</td>
<td>0.486</td>
<td></td>
</tr>
<tr>
<td>Acrolein</td>
<td>107028</td>
<td>HAP &amp; TAC</td>
<td>0.0058</td>
<td>5.52E-06</td>
<td>1.04</td>
<td>5.22E-04</td>
<td></td>
</tr>
<tr>
<td>Benzene</td>
<td>71432</td>
<td>HAP &amp; TAC</td>
<td>0.0069</td>
<td>6.57E-06</td>
<td>1.24</td>
<td>6.22E-04</td>
<td></td>
</tr>
<tr>
<td>Ethylbenzene</td>
<td>100414</td>
<td>HAP &amp; TAC</td>
<td>0.0123</td>
<td>1.17E-05</td>
<td>2.22</td>
<td>1.11E-03</td>
<td></td>
</tr>
<tr>
<td>Formaldehyde</td>
<td>50000</td>
<td>HAP &amp; TAC</td>
<td>0.0046</td>
<td>4.38E-06</td>
<td>3.10E-04</td>
<td>0.829</td>
<td>4.14E-04</td>
</tr>
<tr>
<td>Hexane</td>
<td>110543</td>
<td>HAP &amp; TAC</td>
<td>0.0003</td>
<td>2.86E-07</td>
<td>2.02E-05</td>
<td>0.054</td>
<td>2.70E-05</td>
</tr>
<tr>
<td>Naphthalene</td>
<td>91203</td>
<td>HAP &amp; TAC</td>
<td>0.0001</td>
<td>9.5E-08</td>
<td>6.74E-06</td>
<td>0.018</td>
<td>9.01E-06</td>
</tr>
<tr>
<td>PAHS (excl.</td>
<td>1151</td>
<td>HAP &amp; TAC</td>
<td>0.5300</td>
<td>5.05E-04</td>
<td>3.57E-02</td>
<td>95.5</td>
<td>4.77E-02</td>
</tr>
<tr>
<td>Propylene</td>
<td>115071</td>
<td>TAC</td>
<td>0.0265</td>
<td>2.52E-05</td>
<td>1.79E-03</td>
<td>4.77</td>
<td>2.39E-03</td>
</tr>
<tr>
<td>Toluene</td>
<td>108883</td>
<td>HAP &amp; TAC</td>
<td>0.0197</td>
<td>1.88E-05</td>
<td>1.33E-03</td>
<td>3.55</td>
<td>1.77E-03</td>
</tr>
<tr>
<td>Xylene</td>
<td>1330207</td>
<td>HAP &amp; TAC</td>
<td>0.0123</td>
<td>1.17E-05</td>
<td>2.22</td>
<td>1.11E-03</td>
<td></td>
</tr>
</tbody>
</table>

Total Annual HAPS Emissions, TPY 0.0074
Total Annual Toxic Air Contaminants Emissions, TPY 0.27

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

2 Ammonia and propylene are toxic air contaminants for the purpose of Rule 1401, but not federal hazardous air pollutants.

The hourly and annual emissions are calculated as follows:

For compounds other than ammonia
Hourly emissions, lb/hr = (Emission Factor) (70.8 MMBtu/hr max rating of boiler)

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

Ammonia
Maximum hourly emissions, lb/hr = (70.8 MMBtu/hr) (8710 dscf/10⁶ Btu)
(5 ppm NH₃ /10⁶) (20.9/(20.9-3.0)) (17 lbs NH₃/379 scf) = 0.16 lb/hr

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

C. Greenhouse Gases (GHG)
Combustion of natural gas in the boiler will result in emissions of CO₂, CH₄, and N₂O.

As shown above for the toxic pollutants emissions calculations, the average annual heat input rate is 189,119.91 MMBtu/yr.
Preliminary Determination of Compliance

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

   A. Criteria Pollutants
      NOX = CO = VOC = PM10 = SOx = 0 lb/hr = 0 lb/day

   B. Toxic Pollutants
      From Table 30 above, the 5 ppmvd BACT level for ammonia results in an annual emission rate
      of 423 lb/yr = 0.21 ton/yr = 0.018 ton/month (avg)
To calculate R1 and R2 for annualized operating schedule (52 wk/yr, 7 days/wk, 24 hr/day, same as CTGs).

\[
\text{NH}_3, \text{ lb/day} = (423 \text{ lb/yr}) \left( \frac{\text{yr}}{52 \text{ wk}} \right) \left( \frac{\text{wk}}{7 \text{ days}} \right) = 1.16 \text{ lb/day}
\]
\[
\text{lb/hr} = (1.16 \text{ lb/day}) \left( \frac{\text{day}}{24 \text{ hr}} \right) = 0.05 \text{ lb/hr}
\]

*Note:* Ammonia is not a federal HAP.

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

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

A. **Criteria Pollutants**

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

- **Worst Case Operating Scenario**

To determine the worst case operating scenario that yields the highest controlled emissions, the applicant provided fourteen operating scenarios. The operating scenarios are for three load conditions (100%, 75%, and 50%) at four ambient temperatures (28 ºF, 59.0 ºF, 65.3 ºF, and 107 ºF), and with or without evaporative cooling of the inlet air to the turbines. The operating scenarios are presented in *Table 5.1B.7R—Simple-Cycle: GE LMS-100PB Performance Data* in Attachment 6 of AES Response Letter, 12/11/15.

The operating scenarios data are summarized in the following table.
### Table 31 – Simple-Cycle Turbine Operating Scenarios

<table>
<thead>
<tr>
<th>Case No.</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
<th>9</th>
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<th>11</th>
<th>12</th>
<th>13</th>
<th>14</th>
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<tbody>
<tr>
<td>CTG Load Level (%)</td>
<td>100</td>
<td>75</td>
<td>50</td>
<td>100</td>
<td>100</td>
<td>75</td>
<td>50</td>
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<td>75</td>
<td>50</td>
<td>100</td>
<td>75</td>
<td>50</td>
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<tr>
<td>CTG Inlet Air Cooling</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>On</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>On</td>
<td>Off</td>
<td>Off</td>
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<tr>
<td>Ambient Temperature (°F)</td>
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<td>28.0</td>
<td>28.0</td>
<td>65.3</td>
<td>65.3</td>
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<td>107</td>
<td>107</td>
<td>107</td>
<td>59.0</td>
<td>59.0</td>
<td>59.0</td>
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<tr>
<td>Ambient Relative Humidity (%)</td>
<td>76.3%</td>
<td>76.3%</td>
<td>76.3%</td>
<td>86.8%</td>
<td>86.8%</td>
<td>86.8%</td>
<td>86.8%</td>
<td>10.7%</td>
<td>10.7%</td>
<td>10.7%</td>
<td>10.7%</td>
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<td>Combustion Turbine Performance</td>
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<td></td>
</tr>
<tr>
<td>Gross GTG Output, kW (one CTG)</td>
<td>100,317</td>
<td>75,011</td>
<td>49,671</td>
<td>99,215</td>
<td>98,788</td>
<td>73,878</td>
<td>48,916</td>
<td>82,840</td>
<td>70,821</td>
<td>52,867</td>
<td>34,887</td>
<td>100,438</td>
<td>75,030</td>
<td>49,740</td>
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<tr>
<td>Net CTG Output, kW (one CTG)</td>
<td>98,966</td>
<td>73,661</td>
<td>48,321</td>
<td>97,864</td>
<td>97,437</td>
<td>72,527</td>
<td>47,565</td>
<td>81,489</td>
<td>69,470</td>
<td>51,516</td>
<td>33,536</td>
<td>99,087</td>
<td>73,679</td>
<td>48,389</td>
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<tr>
<td>CTG Heat Input, MMBtu/hr (LHV)</td>
<td>792</td>
<td>645</td>
<td>498</td>
<td>789</td>
<td>789</td>
<td>653</td>
<td>789</td>
<td>637</td>
<td>493</td>
<td>689</td>
<td>619</td>
<td>514</td>
<td>404</td>
<td>795</td>
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<tr>
<td>CTG Heat Input, MMBtu/hr (HHV)</td>
<td>879</td>
<td>715</td>
<td>553</td>
<td>876</td>
<td>876</td>
<td>707</td>
<td>876</td>
<td>707</td>
<td>547</td>
<td>764</td>
<td>688</td>
<td>570</td>
<td>449</td>
<td>882</td>
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<tr>
<td>CTG Exhaust Temperature, ºF</td>
<td>789</td>
<td>816</td>
<td>888</td>
<td>797</td>
<td>797</td>
<td>814</td>
<td>833</td>
<td>837</td>
<td>868</td>
<td>908</td>
<td>981</td>
<td>794</td>
<td>815</td>
<td>885</td>
</tr>
<tr>
<td>4 LMS-100 PB Gross, kW</td>
<td>401,268</td>
<td>300,045</td>
<td>198,686</td>
<td>396,860</td>
<td>395,152</td>
<td>295,511</td>
<td>195,663</td>
<td>331,360</td>
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<td>211,467</td>
<td>139,549</td>
<td>401,751</td>
<td>300,120</td>
<td>198,958</td>
</tr>
<tr>
<td>4 LMS-100 PB Net, kW</td>
<td>386,261</td>
<td>286,924</td>
<td>187,440</td>
<td>381,903</td>
<td>380,226</td>
<td>283,284</td>
<td>184,485</td>
<td>317,669</td>
<td>270,480</td>
<td>200,014</td>
<td>129,478</td>
<td>386,712</td>
<td>286,998</td>
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<td>Stack Parameters</td>
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</tr>
<tr>
<td>Stack Exit Temperature, ºF</td>
<td>789</td>
<td>816</td>
<td>888</td>
<td>797</td>
<td>798</td>
<td>814</td>
<td>883</td>
<td>837</td>
<td>868</td>
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<td>815</td>
<td>885</td>
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<td>Stack Diameter, ft</td>
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<td>13.5</td>
<td>13.5</td>
<td>13.5</td>
<td>13.5</td>
<td>13.5</td>
<td>13.5</td>
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<tr>
<td>Stack Exit Velocity, ft/sec</td>
<td>109</td>
<td>94.0</td>
<td>78.0</td>
<td>109</td>
<td>108</td>
<td>93.3</td>
<td>77.4</td>
<td>99.2</td>
<td>91.8</td>
<td>80.3</td>
<td>67.4</td>
<td>109.3</td>
<td>94.1</td>
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<tr>
<td>CTG Outlet/Catalyst Inlet concentrations</td>
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<td></td>
</tr>
<tr>
<td>NOx, ppmvd (dry, 15% O2)</td>
<td>25.0</td>
<td>25.0</td>
<td>25.0</td>
<td>25.0</td>
<td>25.0</td>
<td>25.0</td>
<td>25.0</td>
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<tr>
<td>CO, ppmvd (dry, 15% O2)</td>
<td>100</td>
<td>100</td>
<td>125</td>
<td>100</td>
<td>100</td>
<td>125</td>
<td>100</td>
<td>100</td>
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<td>100</td>
<td>100</td>
<td>125</td>
<td>100</td>
<td>125</td>
</tr>
<tr>
<td>VOC, ppmvd (dry, 15% O2)</td>
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<td>4.0</td>
<td>4.0</td>
<td>4.0</td>
<td>4.0</td>
<td>4.0</td>
<td>4.0</td>
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<td>4.0</td>
<td>4.0</td>
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<tr>
<td>Catalyst Outlet/Stack Emissions Rates</td>
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<td></td>
</tr>
<tr>
<td>NOx, 2.5 ppmvd (dry, 15% O2)</td>
<td>8.23</td>
<td>6.70</td>
<td>5.18</td>
<td>8.20</td>
<td>8.17</td>
<td>6.62</td>
<td>5.12</td>
<td>7.15</td>
<td>6.44</td>
<td>5.34</td>
<td>4.20</td>
<td>8.26</td>
<td>6.70</td>
<td>5.18</td>
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<tr>
<td>CO, 4.0 ppmvd (dry, 15% O2)</td>
<td>8.01</td>
<td>6.52</td>
<td>5.04</td>
<td>7.98</td>
<td>7.96</td>
<td>6.44</td>
<td>5.99</td>
<td>6.97</td>
<td>6.27</td>
<td>5.20</td>
<td>4.09</td>
<td>8.05</td>
<td>6.52</td>
<td>5.04</td>
</tr>
</tbody>
</table>

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

Preliminary Determination of Compliance
### Preliminary Determination of Compliance

**Alamitos Energy Center**

**Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170**

1. A percentage of the SO$_2$ in the turbine exhaust is assumed to oxidize to SO$_3$ in the CO catalyst and SCR. The SO$_3$ reacts with ammonia in the SCR to form ammonium sulfate particulates. Total PM$_{10}$ is comprised of the ammonium sulfate particulates and the PM$_{10}$ in the turbine exhaust.

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

|                | BACT, lb/hr |                |                |                |                |                |                |                |
|----------------|-------------|----------------|----------------|----------------|----------------|----------------|----------------|
| **VOC, 2.0 ppmvd** | 2.30        | 1.87           | 1.44           | 2.29           | 2.28           | 1.85           | 1.43           | 2.00           |
| **PM$_{10}$/PM$_{2.5}$**, lb/hr (including ammonium sulfate, assuming 100% conversion from SO$_3$)** | 6.23        | 6.23           | 6.23           | 6.23           | 6.23           | 6.23           | 6.23           | 6.23           |
| **SO$_2$ short-term rate** (0.75 grains/100 scf), lb/hr** | 1.62        | 1.32           | 1.02           | 1.62           | 1.61           | 1.31           | 1.01           | 1.41           |
| **SO$_2$ long-term rate** (0.25 grains/100 scf), lb/hr** | 0.54        | 0.44           | 0.34           | 0.54           | 0.54           | 0.44           | 0.34           | 0.47           |
| **SCR NH$_3$ slip, 5.0 ppmvd** (dry, 15% O$_2$) BACT, lb/hr** | 6.09        | 4.96           | 3.83           | 6.07           | 6.05           | 4.90           | 3.79           | 5.30           |

---

**APPLICATION PROCESSING AND CALCULATIONS**

**PROCESSED BY**

V. Lee

**CHECKED BY**

P. Lee

**APPL. NO.**

579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

**DATE**

6/30/16
Case 1, based on 100% load, 28 °F ambient temperature, and without inlet cooling, is the worst case operating scenario that yields the highest controlled emissions. The emissions rates for NOx, CO, VOC, PM$_{10}$/PM$_{2.5}$, and the short-term SO$_2$ rate (0.75 grains/100 scf) will be used to calculate the normal operation emissions component for the maximum daily emissions and maximum monthly emissions.

Case 4, based on 100% load, 65.3 °F ambient temperature, and with inlet cooling, is the worst case operating scenario that yields the highest emission rates for the average annual temperature. The emissions rates for NOx, CO, VOC, PM$_{10}$/PM$_{2.5}$, and the long-term SO$_2$ rate (0.25 grains/100 scf) will be used to calculate the normal operation emissions component for maximum annual emissions. Condition B61.1 requires testing to confirm the long-term SO$_2$ rate of 0.25 grains/100 scf, which is expected to be the average content.

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

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

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

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

**Commissioning**
Commissioning is a one-time event and the NOx, CO, and VOC emission rates are expected to be higher during the commissioning period than during normal operations.
The original Application provided the duration and corresponding pollutant emission rates for each commissioning activity for a single CTG in Table 5.1B.2—Summary of Commissioning Emission Estimates: Simple-Cycle Turbines in Appendix 5.1B. The PM$_{10}$/PM$_{2.5}$ and SOx emission rates are based on the maximum hourly emission rates, including the short-term rate for SO$_2$, from Table 31 (case 1). In AES Response E-Mail dated 1/28/16, the applicant provided the fuel usage for each commissioning activity.

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

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

<table>
<thead>
<tr>
<th>Activity</th>
<th>Duration (hr)</th>
<th>CTG Load (%)</th>
<th>Fuel Use (MMscf/hr)</th>
<th>Fuel Use (MMscf/Activity)</th>
<th>NOx (SCR)</th>
<th>CO (OxCat)</th>
<th>VOC (OxCat)</th>
<th>Total Controlled Emissions, lb</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit Testing (Full Speed No Load, FSNL)</td>
<td>4</td>
<td>5</td>
<td>0.1848</td>
<td>0.7390</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>160</td>
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<tr>
<td>Unit DLN Emissions Tuning</td>
<td>12</td>
<td>100</td>
<td>0.8381</td>
<td>10.0571</td>
<td>75%</td>
<td>75%</td>
<td>33%</td>
<td>246</td>
</tr>
<tr>
<td>Unit Emissions Tuning</td>
<td>12</td>
<td>75</td>
<td>0.6143</td>
<td>7.3714</td>
<td>75%</td>
<td>75%</td>
<td>33%</td>
<td>198</td>
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<tr>
<td>Unit Base Load Testing</td>
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<td>0.6143</td>
<td>7.3714</td>
<td>75%</td>
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<td></td>
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<td></td>
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<tr>
<td>Install Temporary Emissions Test Equipment</td>
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<td></td>
</tr>
<tr>
<td>Refire Unit</td>
<td>12</td>
<td>100</td>
<td>0.8381</td>
<td>10.0571</td>
<td>75%</td>
<td>75%</td>
<td>33%</td>
<td>246</td>
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<tr>
<td>Unit Source Testing &amp; Drift Test Day 1-5; RATA/Pre-performance Testing/Part 60/75 Certification and Source Testing</td>
<td>168</td>
<td>100</td>
<td>0.8381</td>
<td>140.800</td>
<td>75%</td>
<td>75%</td>
<td>33%</td>
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<td>Unit Water Wash &amp; Performance Preparation</td>
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<td>100</td>
<td>0.8381</td>
<td>20.1143</td>
<td>75%</td>
<td>75%</td>
<td>33%</td>
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<td>Unit CALISO Certification</td>
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<td>0.8381</td>
<td>10.0571</td>
<td>75%</td>
<td>75%</td>
<td>33%</td>
<td>246</td>
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<tr>
<td>Total for One CTG</td>
<td>280</td>
<td></td>
<td>226.68</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>5,722</td>
</tr>
</tbody>
</table>

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

The dispersion modeling analysis, discussed below, showed that the maximum impact would occur if the four turbines, with both the SCR and CO oxidation catalyst at 0% control, were simultaneously undergoing commissioning activities with the highest unabated emissions (i.e., Testing (Full Speed No Load)). The modeling results demonstrated that all four turbines may undergo simultaneous commissioning without causing the NO\textsubscript{2} or CO ambient standards to be exceeded.

**Startup of CTGs**
A startup event occurs each time a simple-cycle CTG is started up.

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

For daily emissions (for modeling), the applicant has requested a maximum of two starts per turbine.

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

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

**Shutdown of CTGs**
A shutdown event occurs each time a simple-cycle CTG is shut down.

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

For daily emissions (for modeling), the applicant has requested a maximum of two shutdowns per turbine.

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

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

- **Startup/Shutdown Emissions**
The applicant provided maximum startup and shutdown emissions per event for NO\textsubscript{x}, CO, and VOC, and startup and shutdown hourly emission rates for NO\textsubscript{x}, CO, VOC, SO\textsubscript{2} and PM\textsubscript{10/2.5} in *Table 5.1-16—GE LMS-100 Startup/Shutdown Emission Rates* in the original Application. The revised Application provided startup and shutdown emissions per event for PM\textsubscript{10} and SO\textsubscript{2} (short-term rate).
The following table summarizes the emissions for the startup event and shutdown events.

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

<table>
<thead>
<tr>
<th>Duration Minutes (hr)</th>
<th>NOx lb/event</th>
<th>CO lb/event</th>
<th>VOC lb/event</th>
<th>PM_{10} lb/hr (lb/event)</th>
<th>PM_{2.5} lb/hr (lb/event)</th>
<th>SO_{2} lb/hr (lb/event)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Startup</td>
<td>30 (0.5)</td>
<td>16.6</td>
<td>15.4</td>
<td>&lt; 6.23 (3.12)</td>
<td>&lt; 6.23 (3.12)</td>
<td>Short-term: &lt; 1.62 (0.82)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Long-term: &lt; 0.54 (0.27)</td>
</tr>
<tr>
<td>Shutdown</td>
<td>13 (0.22)</td>
<td>3.12</td>
<td>28.1</td>
<td>&lt; 6.23 (1.35)</td>
<td>&lt; 6.23 (1.35)</td>
<td>Short-term: &lt; 1.62 (0.35)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Long-term: &lt; 0.54 (0.12)</td>
</tr>
</tbody>
</table>

**Startup/Shutdown Conditions**

The startup/shutdown conditions limit and minimize emissions during startups and shutdowns when steady state BACT is not achievable. Condition no. C1.5 provides limits for startups, and condition no. C1.6 provides limits for shutdowns. The limits are necessary because condition nos. A195.11, A195.12, and A195.10 state that BACT for NO_{x}, CO, and VOC, respectively, shall not apply during startups and shutdowns. The startup limits include: (1) number of starts per calendar month and year; (2) number of startups per day; and (3) duration of start; and (4) NO_{x}, CO, and VOC emissions per start. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdown; and (3) NO_{x}, CO, and VOC emissions per shutdown.

**Normal Operation**

Normal operation occurs after the CTGs and SCR/CO catalysts are working optimally. The emissions during normal operations are assumed to be fully controlled to BACT levels, and exclude emissions due to commissioning, startup and shutdown periods, which are not subject to BACT levels. NO_{x} is controlled to 2.5 ppmvd, CO to 4.0 ppmvd, and VOC to 2.0 ppmvd, all 1-hr averages, at 15% O2.

**Maximum Daily, Monthly, Annual, NSR Emissions Calculations**

The following sections will discuss maximum daily emissions, maximum monthly emissions, maximum annual emissions, and associated emission factors and permit condition limits. Finally, offset requirements and the calculation of NSR entries will be discussed.

**Maximum Daily Emissions per Turbine Commissioning Month**

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

**Normal Operating Month**

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

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

### Table 34 - Simple-Cycle Turbine Maximum Daily Emissions

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>No. of Normal Operating Hours</th>
<th>Normal Operation Emission Rate, lb/hr</th>
<th>No. of Startups</th>
<th>Lb/Startup</th>
<th>No. of Shutdowns</th>
<th>Lbs/Shutdown</th>
<th>Maximum Daily Emissions lb/day</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>22.56</td>
<td>8.23</td>
<td>2</td>
<td>16.6</td>
<td>2</td>
<td>3.12</td>
<td>225.11</td>
</tr>
<tr>
<td>CO</td>
<td>22.56</td>
<td>8.01</td>
<td>2</td>
<td>15.4</td>
<td>2</td>
<td>28.1</td>
<td>267.71</td>
</tr>
<tr>
<td>VOC</td>
<td>22.56</td>
<td>2.30</td>
<td>2</td>
<td>2.80</td>
<td>2</td>
<td>3.06</td>
<td>63.61</td>
</tr>
<tr>
<td>PM_{10}/PM_{2.5}</td>
<td>22.56</td>
<td>6.23</td>
<td>2</td>
<td>3.12</td>
<td>2</td>
<td>1.35</td>
<td>149.49</td>
</tr>
<tr>
<td>SOx</td>
<td>22.56</td>
<td>1.62</td>
<td>2</td>
<td>0.82</td>
<td>2</td>
<td>0.35</td>
<td>38.89</td>
</tr>
</tbody>
</table>

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

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

- **Maximum Monthly Emissions and Emission Factors per Turbine**

Condition A63.3 specifies the monthly emissions limits for CO, VOC, PM_{10}, and SOx. Such limits are required to establish a basis for calculating offset requirements and ensure compliance with BACT requirements. RECLAIM rules do not allow a monthly limit for NOx. The monthly emissions for NOx, however, are indirectly limited by the monthly emissions limits for CO, VOC, PM_{10}, and SOx. The number of RECLAIM RTCs required are determined on an annual basis which will be reflected in conditions I297.3 - I297.6 for the turbines.

The maximum monthly emissions and 30-day averages for each pollutant are based on the highest emissions of any month, including commissioning month(s), combination commissioning/normal operating month, and normal operating month. As explained below, AES has indicated there will be no combination commissioning/normal operating month. Therefore, commissioning month(s) emissions and normal operating month emissions will be evaluated below. In addition, the commissioning emission factors and normal operating emission factors will be included in condition A63.3 for CO, VOC, PM_{10}, and SOx. The commissioning emission factor and the post-commissioning/pre-CEMS certification emission factor will be included in conditions A99.3 and A99.4, respectively, for NOx.
• Commissioning Months
• Maximum Monthly Emissions, Commissioning

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

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

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

<table>
<thead>
<tr>
<th>Activity</th>
<th>Duration (hr)</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>SOx</th>
<th>PM2.5</th>
<th>PM10/PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit Testing (Full Speed No Load, FSNL)</td>
<td>4</td>
<td>160</td>
<td>976</td>
<td>20.3</td>
<td>6.48</td>
<td>24.9</td>
<td></td>
</tr>
<tr>
<td>Unit DLN Emissions Tuning</td>
<td>12</td>
<td>246</td>
<td>1,080</td>
<td>36.7</td>
<td>19.4</td>
<td>74.8</td>
<td></td>
</tr>
<tr>
<td>Unit Emissions Tuning</td>
<td>12</td>
<td>198</td>
<td>869</td>
<td>32.2</td>
<td>19.4</td>
<td>74.8</td>
<td></td>
</tr>
<tr>
<td>Unit Base Load Testing</td>
<td>12</td>
<td>198</td>
<td>869</td>
<td>13.7</td>
<td>19.4</td>
<td>74.8</td>
<td></td>
</tr>
<tr>
<td>No Operation</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Install Temporary Emissions Test Equipment</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Refire Unit</td>
<td>12</td>
<td>246</td>
<td>1,080</td>
<td>36.7</td>
<td>19.4</td>
<td>74.8</td>
<td></td>
</tr>
<tr>
<td>Unit Source Testing &amp; Drift Test Day 1-5; RATA/Pre-performance Testing/Part 60/75 Certification and Source Testing</td>
<td>41.33 of 168</td>
<td>847.27</td>
<td>3719.70</td>
<td>126.2</td>
<td>66.92</td>
<td>257.57</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>93.33</td>
<td>1895.27</td>
<td>8593.7</td>
<td>265.8</td>
<td>151.0</td>
<td>581.67</td>
<td></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Activity</th>
<th>Duration (hr)</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>SOx</th>
<th>PM2.5</th>
<th>PM10/PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit Source Testing &amp; Drift Test Day 1-5; RATA/Pre-performance Testing/Part 60/75 Certification and Source Testing</td>
<td>93.33 of 168</td>
<td>1913</td>
<td>8399.7</td>
<td>285.0</td>
<td>151.11</td>
<td>581.65</td>
<td></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Activity</th>
<th>Duration (hr)</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>SOx</th>
<th>PM2.5</th>
<th>PM10/PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit Source Testing &amp; Drift Test Day 1-5; RATA/Pre-performance Testing/Part 60/75 Certification and Source Testing</td>
<td>33.33 of 168</td>
<td>683.27</td>
<td>2999.70</td>
<td>101.78</td>
<td>53.96</td>
<td>207.71</td>
<td></td>
</tr>
<tr>
<td>Unit Water Wash &amp; Performance Preparation</td>
<td>24</td>
<td>492</td>
<td>2,160</td>
<td>73.3</td>
<td>38.9</td>
<td>150</td>
<td></td>
</tr>
<tr>
<td>Unit Performance Testing</td>
<td>24</td>
<td>492</td>
<td>2,160</td>
<td>73.3</td>
<td>38.9</td>
<td>150</td>
<td></td>
</tr>
<tr>
<td>Install Temporary Emissions Test Equipment</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unit CALISO Certification</td>
<td>12</td>
<td>246</td>
<td>1,080</td>
<td>36.7</td>
<td>19.4</td>
<td>74.8</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>93.33</td>
<td>1913.27</td>
<td>8399.7</td>
<td>285.08</td>
<td>151.16</td>
<td>582.5</td>
<td></td>
</tr>
</tbody>
</table>

The maximum emissions from any one of the 3 months are summarized in the table below.
Table 35 – Simple-Cycle Turbine Maximum Monthly Emissions, Commissioning

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Month</th>
<th>Commissioning Emissions, lb/month</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>Three</td>
<td>1913.27</td>
</tr>
<tr>
<td>CO</td>
<td>One</td>
<td>8593.7</td>
</tr>
<tr>
<td>VOC</td>
<td>Three</td>
<td>285.08</td>
</tr>
<tr>
<td>PM_{10}/PM_{2.5}</td>
<td>Three</td>
<td>582.5</td>
</tr>
<tr>
<td>SOx</td>
<td>Three</td>
<td>151.16</td>
</tr>
</tbody>
</table>

- **Commissioning Emission Factors**
  The commissioning period emission factors are derived for inclusion in condition no. A63.3 for CO, VOC, PM_{10}, and SOx, and in condition no. A99.3 for NOx. As explained in the Rule 2012 analysis below, condition A99.3 specifies the interim emission factor for NOx for the commissioning period (no certified CEMS), during which the CTGs are assumed to be operating at uncontrolled and partially controlled levels. For each pollutant, the emission factor is calculated as the total emissions for the commissioning period divided by the total fuel usage for the commissioning period, both from Table 32, above. The table below shows the calculation of the emissions factors.

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

Table 36 - Simple-Cycle Turbine Commissioning Emission Factors

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Total Commissioning Emissions, lb</th>
<th>Total Commissioning Fuel Usage, mmcf</th>
<th>Emission Factor, lb/mmcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>5722</td>
<td>226.68</td>
<td>25.24</td>
</tr>
<tr>
<td>CO</td>
<td>25,395</td>
<td>226.68</td>
<td>112.03</td>
</tr>
<tr>
<td>VOC</td>
<td>836</td>
<td>226.68</td>
<td>3.69</td>
</tr>
<tr>
<td>PM_{10}/PM_{2.5}</td>
<td>454</td>
<td>226.68</td>
<td>2.00</td>
</tr>
<tr>
<td>SOx</td>
<td>1744</td>
<td>226.68</td>
<td>7.69</td>
</tr>
</tbody>
</table>

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

    For maximum monthly emissions per turbine, the applicant has requested: (1) 700 normal operating hours (Case 1), (2) 62 startups (31 hr), and (3) 62 shutdowns (13.4 hr),
for a total of 744 hours. The normal operation emission rates is from Table 32 (case 1), and the startup and shutdown emissions per event are from Table 33. The SO\textsubscript{x} emission rates are based on the short-term rate (0.75 grains/100 scf).

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>No. of Normal Operating Hours</th>
<th>Normal Operation Emission Rate, lb/hr</th>
<th>No. of Startups</th>
<th>lb/startup</th>
<th>No. of Shutdowns</th>
<th>lb/shutdown</th>
<th>Maximum Monthly Emissions, lb/month (tons/month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO\textsubscript{x}</td>
<td>700</td>
<td>8.23</td>
<td>62</td>
<td>16.6</td>
<td>62</td>
<td>3.12</td>
<td>6983.64 (3.49)</td>
</tr>
<tr>
<td>CO</td>
<td>700</td>
<td>8.01</td>
<td>62</td>
<td>15.4</td>
<td>62</td>
<td>28.1</td>
<td>8304.0 (4.15)</td>
</tr>
<tr>
<td>VOC</td>
<td>700</td>
<td>2.30</td>
<td>62</td>
<td>2.80</td>
<td>62</td>
<td>3.06</td>
<td>1973.32 (0.99)</td>
</tr>
<tr>
<td>PM\textsubscript{10}/PM\textsubscript{2.5}</td>
<td>700</td>
<td>6.23</td>
<td>62</td>
<td>3.12</td>
<td>62</td>
<td>1.35</td>
<td>4638.14 (2.32)</td>
</tr>
<tr>
<td>SO\textsubscript{x}</td>
<td>700</td>
<td>1.62</td>
<td>62</td>
<td>0.82</td>
<td>62</td>
<td>0.35</td>
<td>1206.54 (0.60)</td>
</tr>
</tbody>
</table>

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

- **Normal Operating Month Emission Factors**
  The normal operating emission factors are derived for inclusion in condition no. A63.3 for CO, VOC, PM\textsubscript{10}, and SO\textsubscript{x}, and in A99.4 for NO\textsubscript{x}. As explained in the Rule 2012 analysis below, condition A99.3 specifies the interim emission factor for the normal operating period after commissioning has been completed but before the CEMS is certified, during which the CTGs are assumed to be operating at BACT levels.

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

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Maximum Monthly Emissions, lb/month</th>
<th>Emission Factors, lb/mmcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO\textsubscript{x}</td>
<td>6983.64</td>
<td>11.21</td>
</tr>
<tr>
<td>CO</td>
<td>8304</td>
<td>13.33</td>
</tr>
<tr>
<td>VOC</td>
<td>1973.32</td>
<td>3.17</td>
</tr>
<tr>
<td>PM\textsubscript{10}</td>
<td>4638.14</td>
<td>7.44</td>
</tr>
<tr>
<td>SO\textsubscript{x}</td>
<td>1206.54</td>
<td>1.94</td>
</tr>
</tbody>
</table>

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

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

- **Permit Conditions—Monthly Emissions Limits**
  Condition A63.3 specifies the maximum monthly emissions limits per turbine for CO, VOC, PM\textsubscript{10}, and SO\textsubscript{x}. The maximum monthly emissions and 30-day averages for each

Preliminary Determination of Compliance
pollutant are based on the highest emissions from any commissioning month (Table 35) or normal operating month (Table 37). The table below compares the maximum commissioning month emissions with the maximum normal operating month emissions (higher values in bold font) to determine the maximum monthly emissions limits and associated 30-day averages. AES has indicated commissioning and normal operations will not occur in the same month.

(Although condition A63.3 will not include a monthly limit for NOx, it is included in the table below because the determination of 30-day averages for all pollutants is required for the internal NSR Data Summary Sheet.)

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Maximum Commissioning Month Emissions, lb/month (lb/day)</th>
<th>Maximum Normal Operating Month Emissions, lb/month (lb/day)</th>
<th>Maximum Monthly Emissions, lb/month</th>
<th>30-Day Averages, lb/day</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>1913.27 lb/month (63.78 lb/day)</td>
<td>6983.64 lb/month (232.79 lb/day)</td>
<td>6983.64</td>
<td>232.79</td>
</tr>
<tr>
<td>CO</td>
<td>8593.7 lb/month (286.46 lb/day)</td>
<td>8304 lb/month (276.80 lb/day)</td>
<td>8593.7</td>
<td>286.46</td>
</tr>
<tr>
<td>VOC</td>
<td>285.08 lb/month (9.50 lb/day)</td>
<td>1973.32 lb/month (65.78 lb/day)</td>
<td>1973.32</td>
<td>65.78</td>
</tr>
<tr>
<td>PM_{10}</td>
<td>582.5 lb/month (19.42 lb/day)</td>
<td>4638.14 lb/month (154.60 lb/day)</td>
<td>4638.14</td>
<td>154.60</td>
</tr>
<tr>
<td>SOx</td>
<td>151.16 lb/month (5.04 lb/day)</td>
<td>1206.54 lb/month (40.22 lb/day)</td>
<td>1206.54</td>
<td>40.22</td>
</tr>
</tbody>
</table>

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

- **Maximum Annual Emissions per Turbine**
  The annual emissions for the commissioning year and a normal operating year are calculated below. The number of RECLAIM NOx RTCs required are determined on an annual basis which will be reflected in conditions 1297.3 - 1297.6, as discussed under the Rule 2005(c)(2) analysis below.
• Commissioning Year
  Condition I297.3 – I297.6 specify the pounds of NOx RTCs that are required to be held in the facility’s allocation account to offset the annual emissions increase for the first year of operation. The first year of operation is the commissioning year.

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

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Commissioning Year Emissions, lb/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>(5722 lb/commissioning) + (6983.64 lb/month)(9 normal operating months) = 68,574.76 lb/yr (34.29 tpy)</td>
</tr>
<tr>
<td>CO</td>
<td>(25,395 lb/commissioning) + (8304.0 lb/month)(9 normal operating months) = 100,131 lb/yr (50.7 tpy)</td>
</tr>
<tr>
<td>VOC</td>
<td>(836 lb/commissioning) + (1973.32 lb/month)(9 normal operating months) = 18,595.88 lb/yr (9.30 tpy)</td>
</tr>
<tr>
<td>PM_{10}</td>
<td>(1,744 lb/commissioning) + (4638.14 lb/month)(9 normal operating months) = 43,487.26 lb/yr (21.74 tpy)</td>
</tr>
<tr>
<td>SOx</td>
<td>(454 lb/commissioning) + (1206.54 lb/month)(9 normal operating months) = 11,312.86 lb/yr (5.66 tpy)</td>
</tr>
</tbody>
</table>

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

• Normal Operating Year
  Because the monthly emissions limits in condition A63.3 are applicable each and every month, the annual emissions limits are the monthly emissions multiplied by twelve months, unless limited by permit condition. For maximum annual emissions per turbine, the applicant has requested: (1) 2000 hours of normal operation (Case 4), (2) 500 startups (250 hr), and (3) 500 shutdowns (108 hr), for a total of 2358 hours. The normal operation emission rates from Table 31 (case 4), and the startup and shutdown emissions per event are from Table 33. The SOx emission rates are based on the long-term rate (0.25 grains/100 scf).
Table 41 - Simple-Cycle Turbine Maximum Annual Emissions, Normal Operations

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>No. of Normal Operating Hours</th>
<th>Normal Operation Emission Rate, lb/hr</th>
<th>No. of Startups</th>
<th>No. of Shutdowns</th>
<th>Maximum Annual Emissions, lb/yr (tpy)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>2000</td>
<td>8.20</td>
<td>500</td>
<td>16.6</td>
<td>500</td>
</tr>
<tr>
<td>CO</td>
<td>2000</td>
<td>7.98</td>
<td>500</td>
<td>15.4</td>
<td>500</td>
</tr>
<tr>
<td>VOC</td>
<td>2000</td>
<td>2.29</td>
<td>500</td>
<td>2.80</td>
<td>500</td>
</tr>
<tr>
<td>PM10/PM2.5</td>
<td>2000</td>
<td>6.23</td>
<td>500</td>
<td>3.12</td>
<td>500</td>
</tr>
<tr>
<td>SOx</td>
<td>2000</td>
<td>0.54</td>
<td>500</td>
<td>0.27</td>
<td>500</td>
</tr>
</tbody>
</table>

- **Permit Conditions—Annual Emissions Limits**
  
  From Table 41, the annual emission limits for a normal operating year are included in condition A63.3 for CO, VOC, PM10, and SOx to ensure that the annual PM10/PM2.5 and NO2 emissions will not exceed the PM10/PM2.5 and NO2 modeled emission rate for the annual averaging period provided in Table 53. As with the monthly limits, an annual emissions limit may not be added for NOx because AEC will be a RECLAIM facility and such a limit is not allowed by RECLAIM rules. The annual emissions for NOx, however, are indirectly limited by the annual emissions limits for CO, VOC, PM10, and SOx. Additionally, the toxic pollutants and greenhouse gases are indirectly limited by the annual emissions limits.

The emission factors for the monthly emission limits shall be used to demonstrate compliance with the annual emission limits, except for SOx. AES requested that the maximum monthly emissions be based on 0.75 grains/100 scf, but the annual emissions be based on 0.25 grains/100 scf. The annual SOx emission factor is calculated below.

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

<table>
<thead>
<tr>
<th>Pollutants</th>
<th>Maximum Annual Emissions, lb/year</th>
<th>Emission Factors, lb/mmcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>SOx</td>
<td>1275</td>
<td>0.65</td>
</tr>
</tbody>
</table>

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

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

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

  Operating Schedule: 52 wks/yr, 7 days/wk, 24 hrs/day (annualized schedule)
The 30-day averages per turbine are from Table 39. The uncontrolled emissions (R1) and controlled emissions (R2) are back calculated from the 30-day averages for the purpose of input into the internal NSR Data Summary Sheet only.

**NOx**
\[
R2 = (232.79 \text{ lb/day})(\text{day}/24 \text{ hr}) = 9.70 \text{ lb/hr}
\]
\[
R1 = (9.70 \text{ lb/hr})(25 \text{ ppm uncontrolled}/2.5 \text{ ppm controlled per case 1}) = 97.0 \text{ lb/hr}
\]

30-DA = 232.79 lb/day

**CO**
\[
R2 = (286.46 \text{ lb/day})(\text{day}/24 \text{ hr}) = 11.94 \text{ lb/hr}
\]
\[
R1 = (11.94 \text{ lb/hr})(100 \text{ ppm uncontrolled}/4 \text{ ppm controlled per case 1}) = 298.50 \text{ lb/hr}
\]

30-DA = 286.46 lb/day

**ROG**
\[
R2 = (65.78 \text{ lb/day})(\text{day}/24 \text{ hr}) = 2.74 \text{ lb/hr}
\]
\[
R1 = (2.74 \text{ lb/hr})(4 \text{ ppm uncontrolled}/2 \text{ ppm controlled per case 1}) = 5.48 \text{ lb/hr}
\]

30-DA = 65.78 lb/day

**PM\text{\textsubscript{10}}**
\[
R2 = R1 = (154.60 \text{ lb/day})(\text{day}/24 \text{ hr}) = 6.44 \text{ lb/hr}
\]

30-DA = 154.65 lb/day

**SOx**
\[
R2 = R1 = (40.22 \text{ lb/day})(\text{day}/24 \text{ hr}) = 1.68 \text{ lb/hr}
\]

30-DA = 40.22 lb/day

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

<table>
<thead>
<tr>
<th>Compound</th>
<th>CAS</th>
<th>TAC/HAP</th>
<th>Emission Factor ¹</th>
<th>Lb/hr</th>
<th>Lb/yr</th>
<th>TPY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia²</td>
<td>766417</td>
<td>TAC</td>
<td>6.09</td>
<td>14,309</td>
<td>7.15</td>
<td></td>
</tr>
<tr>
<td>Acetaldehyde²</td>
<td>75070</td>
<td>TAC &amp; HAP</td>
<td>1.76E-04</td>
<td>0.15</td>
<td>354</td>
<td>0.18</td>
</tr>
<tr>
<td>Acrolein²</td>
<td>107028</td>
<td>HAP &amp; TAC</td>
<td>3.62E-06</td>
<td>0.0031</td>
<td>7.26</td>
<td>0.0036</td>
</tr>
<tr>
<td>Benzene²</td>
<td>71432</td>
<td>HAP &amp; TAC</td>
<td>3.26E-06</td>
<td>0.0028</td>
<td>6.55</td>
<td>0.0033</td>
</tr>
<tr>
<td>1,3-Butadiene</td>
<td>106990</td>
<td>HAP &amp; TAC</td>
<td>4.3E-07</td>
<td>0.00037</td>
<td>0.86</td>
<td>0.00043</td>
</tr>
<tr>
<td>Ethylbenzene</td>
<td>100414</td>
<td>HAP &amp; TAC</td>
<td>3.2E-05</td>
<td>0.027</td>
<td>64.1</td>
<td>0.032</td>
</tr>
<tr>
<td>Formaldehyde²</td>
<td>50000</td>
<td>HAP &amp; TAC</td>
<td>3.6E-04</td>
<td>0.31</td>
<td>722</td>
<td>0.36</td>
</tr>
<tr>
<td>Hexane</td>
<td>110543</td>
<td>HAP &amp; TAC</td>
<td>Not available</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Naphthalene</td>
<td>91203</td>
<td>HAP &amp; TAC</td>
<td>1.3E-06</td>
<td>0.0011</td>
<td>2.62</td>
<td>0.0013</td>
</tr>
<tr>
<td>PAHS (excluding naphthalene)³, ⁴</td>
<td>1151</td>
<td>HAP &amp; TAC</td>
<td>(2.2E-06 – 1.3E-06)*0.5 = 0.45E-06</td>
<td>0.00038</td>
<td>0.90</td>
<td>0.00045</td>
</tr>
<tr>
<td>Propylene (propene)⁵</td>
<td>115071</td>
<td>TAC</td>
<td>Not available</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Propylene Oxide</td>
<td>75569</td>
<td>HAP &amp; TAC</td>
<td>2.9E-05</td>
<td>0.025</td>
<td>58.2</td>
<td>0.029</td>
</tr>
<tr>
<td>Toluene</td>
<td>108883</td>
<td>HAP &amp; TAC</td>
<td>1.3E-04</td>
<td>0.11</td>
<td>262</td>
<td>0.13</td>
</tr>
<tr>
<td>Xylene</td>
<td>1330207</td>
<td>HAP &amp; TAC</td>
<td>6.4E-05</td>
<td>0.055</td>
<td>128</td>
<td>0.064</td>
</tr>
</tbody>
</table>

Total Annual HAPS Emissions per Turbine, TPY 0.80
Total Annual Toxic Air Contaminant Emissions per Turbine, TPY 7.95

¹ Emission factors based on AP-42, Section 3.1, Final Section, Table 3.1-3 Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbine (Uncontrolled), April 2000, unless otherwise noted in footnote 2.

² Acetaldehyde, acrolein, benzene, and formaldehyde emission factors are based on AP-42, Section 3.1, Background Information, Table 3.4-1-- Summary of Emission Factors for Natural Gas-Fired Gas Turbines, April 2000. These emission factors include control by CO catalyst.

³ Carcinogenic PAHs only. Naphthalene was subtracted from the total PAHs and considered separately in the HRA.

⁴ Per Section 3.1.4.3 of AP-42, PAH emissions were assumed to be controlled by 50 percent by the oxidation catalyst.

⁵ Ammonia and propylene are toxic air contaminants for the purpose of Rule 1401, but not federal hazardous air pollutants.

The hourly and annual emissions are calculated as follows:

For compounds other than ammonia

- Hourly emissions, lb/hr = (Emission Factor) (maximum hourly heat input rate of 879 MMBtu/hr (Case 1))
- Annual emissions, lb/yr = (Emission Factor) (average annual heat input rate of 2,065,608 MMBtu/yr)

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

Note: Case 4 in Table 31 shows 876 MMBtu/hr, but AES used the more precise value of 875.64673 MMBtu/hr.
Ammonia
Maximum hourly emissions, lb/hr = (879 MMBtu/hr (case 1)) (8710 dscf/10^6 Btu) (5 ppm NH_3 /10^6) (20.9/(20.9-15.0)) (17 lbs NH_3/379 scf) = 6.09 lb /hr

This is the same as the 6.09 lb/hr from Table 31 (case 1)

Maximum annual emissions, lb/yr = (2358 hr/yr)(6.07 lb/hr (case 4)) = 14,313 lb/yr = 7.16 tpy

C. Greenhouse Gases (GHG)

• Combustion: CO_2, CH_4, N_2O
Combustion of natural gas in the turbines will result in emissions of CO_2, CH_4, and N_2O.

As shown above for the toxic pollutants emissions calculations, the average annual heat input rate is 2,064,775 MMBtu/yr.

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

For each simple-cycle turbine:

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

CO_2 = (2,064,775 MMBtu/yr)(53.06 kg/MBtu)(2.2046 lb/kg) = 241,529,277.3 lb/yr = 120,764.64 tpy \rightarrow 120,765 tpy

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

N_2O = (2,064,775 MMBtu/yr)(0.1 g/MBtu)(2.205 x 10^{-3} lb/g) = 455.28 lb/yr = 0.23 tpy

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

CO_{2e} = (241,529,277.3 lb/yr CO_2)(1 lb CO_2e/lb CO_2) + (4552.83 lb/yr CH_4) (25 lb CO_2e/lb CH_4) + (455.28 lb/yr N_2O)(298 lb CO_2e/lb N_2O) = 241,778,771.5 lb/yr = 120,889.39 tpy per turbine = 10,074.12 tons/month
**Circuit Breakers: SF6**

Condition F52.2 will specify a CO$_2$e facility-wide annual limit for SF$_6$ (74.55 tpy) to enforce the BACT requirements for the circuit breakers located at the CCGT (17.44 tpy) and SCGT (57.11 tpy) power blocks.

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

For the SCGT:

- **SCGT-1**: 1200A 230 kV 230 lb SF$_6$
- **SCGT-2**: 1200A 230 kV 230 lb SF$_6$
- **SCGT-3**: 1200A 230 kV 230 lb SF$_6$
- **SCGT-4**: 2000A 230 kV 216 lb SF$_6$
- **SCGT-1**: GCB 18 kV 24 lb SF$_6$
- **SCGT-2**: GCB 18 kV 24 lb SF$_6$
- **SCGT-3**: GCB 18 kV 24 lb SF$_6$
- **SCGT-4**: GCB 18 kV 24 lb SF$_6$ 1002 lb SF$_6$

Annual leakage = (1002 lb SF$_6$) (0.5/100 annual leak rate) = 5.01 lb/yr SF$_6$ = 0.0025 tpy

Pursuant to the Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear (17 CCR 95350-95359), §95352 specifies the maximum annual SF$_6$ emission rate for each gas-insulated switchgear (GIS) owner’s active GIS equipment shall not exceed 1.0% in 2020, and each calendar year thereafter. PSD BACT, however, imposes a more stringent limit of 0.5%.

Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as amended by 79 FR 73779, 12/11/14, SF$_6$ is equivalent to 22,800 times the global warming potential of CO$_2$.

\[(5.01 \text{ lb/yr SF}_6) (22,800 \text{ lb CO}_2\text{e/lb SF}_6) = 114,228.0 \text{ lb/yr} = 57.11 \text{ tpy CO}_2\text{e} = 4.76 \text{ ton/month}\]

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

This section develops the NSR database entries.

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

\[\Rightarrow 8736 \text{ hr/yr}\]
The hourly emissions are back calculated from the annual emissions and used for the purpose of input for the internal NSR Data Summary Sheet only.

\[
\begin{align*}
\text{CO}_2 &= (241,529,277.3 \text{ lb/yr}) \div (8736 \text{ hr}) = 27,647.58 \text{ lb/hr} \\
\text{CH}_4 &= (4552.83 \text{ lb/yr}) \div (8736 \text{ hr}) = 0.52 \text{ lb/hr} \\
\text{N}_2\text{O} &= (455.28 \text{ lb/yr}) \div (8736 \text{ hr}) = 0.05 \text{ lb/hr} \\
\text{SF}_6 &= (114,228 \text{ lb/yr}) \div (8736 \text{ hr}) = 13.08 \text{ lb/hr}
\end{align*}
\]

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

A. Criteria Pollutants
\[
\begin{align*}
\text{NO}_x &= \text{CO} = \text{VOC} = \text{PM}_{10} = \text{SO}_x = 0 \text{ lb/hr} = 0 \text{ lb/day}
\end{align*}
\]

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

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

\[
\begin{align*}
\text{NH}_3, \text{ lb/day} &= (14,309 \text{ lb/yr}) \div (52 \text{ wk}) \div (7 \text{ days}) = 39.31 \text{ lb/day} \\
\text{lb/hr} &= (39.31 \text{ lb/day}) \div (24 \text{ hr/day}) = 1.64 \text{ lb/hr}
\end{align*}
\]

*Note:* Ammonia is not a federal HAP.

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

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

\[
\begin{align*}
\text{NH}_3 &= 0 \text{ lb/hr} = 0 \text{ lb/day}
\end{align*}
\]

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

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

Long Beach Yearly Average Precipitation, 30 year average = 12.26 inches (1.02 ft)

For worst case, assume maximum monthly volume is the same as average annual volume.

Max monthly volume = (106,000 ft containment area)(1.02 ft average precipitation)(7.48 gal/ft$^3$ )

Pursuant to AP-42, Section 5.1, Final Section, Table 5.1-3—Fugitive Emission Factors for Petroleum Refineries, April 2015:

Controlled emission factor, refinery = 0.2 lb VOC/1000 gal waste water for covered separators.

The above emission factor is based on oil/water separators for petroleum refining operations, where the water is contaminated with petroleum products. At the AEC, the water is contaminated with lubricating oils and grease from the equipment. Since lubricating oil has a significantly lower vapor pressure than lubricating oils and grease, the above emission factor will be adjusted based on the relative vapor pressure of the materials expected to be in the storm water.

Vapor pressure of turbine lubricant:
http://qclubricants.com/msds/CHEVRON%20_turbine_2190_TEP_msds.pdf -- Chevron Safety Data Sheet for Chevron Turbine Oil Symbol 2190 TEP shows the vapor pressure is < 0.01 mm Hg at 37 ºC (100 ºF).

Vapor pressure of crude oil:
http://oilspill.fsu.edu/images/pdfs/msds-crude-oil.pdf -- BP West Coast Products, LLC, Material Safety Data Sheet for Crude Oil shows the vapor pressure is AP 1 to 2 at 100 ºF (REID-PSIA). The conversion from Reid vapor pressure units to millimeters of mercury (mm Hg) requires the use of the nomograph shown in EPA AP-42, Chapter 7.1, Figure 7.1-13a. The nomograph shows 2 psi Reid vapor pressure is equal to 2.2 psi stock true vapor pressure, both at 100 ºF. To convert 2 psia Reid vp to mm Hg--

$$(2 \text{ psia Reid vp})(2.2 \text{ psia true vp}/2 \text{ psi Reid vp})(51.7149 \text{ mm Hg/psia}) = 113.77 \text{ mm Hg}$$

The adjusted controlled emission factor for AEC is calculated as follows:

Controlled emission factor, AEC = (0.2 lb VOC/1000 gal waste water, refinery)
(vp of lubricating oil, 0.01 mm Hg)/(vp of crude oil, 113.77 mm Hg at 100 °F) 
= 0.000018 lb VOC/1000 gal wastewater

To calculate maximum monthly emissions:

\[
\text{VOC, lb/month} = (808,737.6 \text{ gal/month}) \times (0.000018 \text{ lb VOC/1000 gal}) \\
= 0.015 \text{ lb/month} = 0.0000075 \text{ tons/month} = 0.00009 \text{ tpy}
\]

\[
\text{lb/hr} = (0.015 \text{ lb/month}) \times (\text{month}/30 \text{ days}) \times (\text{day}/24 \text{ hr}) = 0.000021 \text{ lb/hr}
\]

(For NSR Data Summary Sheet)

30-day average = 0.015 lb / 30 days = 0.0005 lb/day

10. A/N 579170—Oil/Water Separator, No. OWS-2 (Simple-Cycle Turbines), 5000 gallons
Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

Total Containment Area = 16,177 ft\(^2\)

(including lube oil skids, GSU transformers, aux transformers, fin fan cooler pump skid, gas conditioning, GT fuel gas skid, LMS-100 PB miscellaneous skids, ammonia containment and unloading)

Max monthly volume = (16,177 ft containment area)(1.02 ft average precipitation)(7.48 gal/ft\(^3\))

= 123,424.04 gal/month

To calculate maximum monthly emissions:

\[
\text{VOC, lb/month} = (123,424.04 \text{ gal/month}) \times (0.000018 \text{ lb VOC/1000 gal}) \\
= 0.0022 \text{ lb/month} = 0.0000011 \text{ tons/month} = 0.000013 \text{ tpy}
\]

\[
\text{lb/hr} = (0.0022 \text{ lb/month}) \times (\text{month}/30 \text{ days}) \times (\text{day}/24 \text{ hr}) = 0.0000031 \text{ lb/hr}
\]

(For NSR Data Summary Sheet)

30-day average = 0.0022 lb / 30 days = 0.000073 lb/day

11. Facility Maximum Monthly and Annual Emissions, Normal Operation

a. Maximum Monthly Emissions, Normal Operations

The facility maximum monthly emissions are calculated for the public notice.
Table 43 - Facility Maximum Monthly Emissions, Normal Operations

<table>
<thead>
<tr>
<th>Equipment</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>PM10/PM2.5</th>
<th>SOx</th>
<th>NH3</th>
<th>CO2e</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined-Cycle Turbine</td>
<td>6.73</td>
<td>13.15</td>
<td>3.79</td>
<td>3.16</td>
<td>1.81</td>
<td></td>
<td>50,925.87</td>
</tr>
<tr>
<td>Combined-Cycle Turbine</td>
<td>6.73</td>
<td>13.15</td>
<td>3.79</td>
<td>3.16</td>
<td>1.81</td>
<td></td>
<td>50,925.87</td>
</tr>
<tr>
<td>Circuit Breakers for Combined-Cycle Turbine Power Block</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1.45</td>
<td></td>
</tr>
<tr>
<td>Simple-Cycle Turbine</td>
<td>3.49</td>
<td>4.15</td>
<td>0.99</td>
<td>2.32</td>
<td>0.60</td>
<td></td>
<td>10,074.12</td>
</tr>
<tr>
<td>Simple-Cycle Turbine</td>
<td>3.49</td>
<td>4.15</td>
<td>0.99</td>
<td>2.32</td>
<td>0.60</td>
<td></td>
<td>10,074.12</td>
</tr>
<tr>
<td>Simple-Cycle Turbine</td>
<td>3.49</td>
<td>4.15</td>
<td>0.99</td>
<td>2.32</td>
<td>0.60</td>
<td></td>
<td>10,074.12</td>
</tr>
<tr>
<td>Simple-Cycle Turbine</td>
<td>3.49</td>
<td>4.15</td>
<td>0.99</td>
<td>2.32</td>
<td>0.60</td>
<td></td>
<td>10,074.12</td>
</tr>
<tr>
<td>Circuit Breakers for Simple-Cycle Turbine Power Block</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>4.76</td>
<td></td>
</tr>
<tr>
<td>Auxiliary Boiler</td>
<td>0.057</td>
<td>0.30</td>
<td>0.051</td>
<td>0.057</td>
<td>0.016</td>
<td></td>
<td>922.72</td>
</tr>
<tr>
<td>SCR/CO Catalyst for Combined-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td>2.92</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCR/CO Catalyst for Combined-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td>2.92</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCR/CO Catalyst for Simple-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td>0.60</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCR/CO Catalyst for Simple-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td>0.60</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCR/CO Catalyst for Simple-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td>0.60</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCR for Auxiliary Boiler</td>
<td></td>
<td></td>
<td></td>
<td>0.018</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ammonia Tank for Combined-Cycle Turbines</td>
<td></td>
<td></td>
<td></td>
<td>0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ammonia Tank for Simple-Cycle Turbines</td>
<td></td>
<td></td>
<td></td>
<td>0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil/Water Separator for Combined-Cycle Turbines</td>
<td>0.0000075</td>
<td>0.0000011</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility Total</td>
<td>27.48</td>
<td>43.20</td>
<td>11.59</td>
<td>15.66</td>
<td>6.04</td>
<td>8.26</td>
<td>143,077.15</td>
</tr>
</tbody>
</table>

b. **Maximum Daily Emissions, Normal Operations**

The facility maximum daily emissions are calculated for the public notice. For this purpose only, the daily emissions are the monthly emissions from the table above, divided by 30 days.

**Table 44 - Facility Maximum Daily Emissions, Normal Operations**

<table>
<thead>
<tr>
<th>Tons/Day</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>PM10/PM2.5</th>
<th>SOx</th>
<th>NH3</th>
<th>CO2e</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facility Total</td>
<td>0.92</td>
<td>1.44</td>
<td>0.39</td>
<td>0.52</td>
<td>0.20</td>
<td>0.28</td>
<td>4769.24</td>
</tr>
</tbody>
</table>

c. **Maximum Annual Emissions, Normal Operations**

The facility maximum annual emissions are calculated for the public notice and for the purpose of rule applicability, as discussed under the rule analysis section below.
### Table 45 - Facility Maximum Annual Emissions, Normal Operations

<table>
<thead>
<tr>
<th>Equipment</th>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>PM10/PM2.5</th>
<th>SOx</th>
<th>NH3</th>
<th>CO2e</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined-Cycle Turbine</td>
<td>41.93</td>
<td>95.38</td>
<td>26.33</td>
<td>19.72</td>
<td>3.72</td>
<td></td>
<td>611,110.39</td>
</tr>
<tr>
<td>Combined-Cycle Turbine</td>
<td>41.93</td>
<td>95.38</td>
<td>26.33</td>
<td>19.72</td>
<td>3.72</td>
<td></td>
<td>611,110.39</td>
</tr>
<tr>
<td>Circuit Breakers for Combined-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>17.44</td>
</tr>
<tr>
<td>Simple-Cycle Turbine</td>
<td>13.13</td>
<td>18.86</td>
<td>3.76</td>
<td>7.35</td>
<td>0.64</td>
<td></td>
<td>120,889.39</td>
</tr>
<tr>
<td>Simple-Cycle Turbine</td>
<td>13.13</td>
<td>18.86</td>
<td>3.76</td>
<td>7.35</td>
<td>0.64</td>
<td></td>
<td>120,889.39</td>
</tr>
<tr>
<td>Simple-Cycle Turbine</td>
<td>13.13</td>
<td>18.86</td>
<td>3.76</td>
<td>7.35</td>
<td>0.64</td>
<td></td>
<td>120,889.39</td>
</tr>
<tr>
<td>Simple-Cycle Turbine</td>
<td>13.13</td>
<td>18.86</td>
<td>3.76</td>
<td>7.35</td>
<td>0.64</td>
<td></td>
<td>120,889.39</td>
</tr>
<tr>
<td>Circuit Breakers for Simple-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>57.11</td>
</tr>
<tr>
<td>Auxiliary Boiler</td>
<td>0.68</td>
<td>3.60</td>
<td>0.61</td>
<td>0.68</td>
<td>0.19</td>
<td></td>
<td>11,072.68</td>
</tr>
<tr>
<td>SCR/CO Catalyst for Combined-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>35.0</td>
</tr>
<tr>
<td>SCR/CO Catalyst for Combined-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>35.0</td>
</tr>
<tr>
<td>SCR/CO Catalyst for Simple-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>7.16</td>
</tr>
<tr>
<td>SCR/CO Catalyst for Simple-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>7.16</td>
</tr>
<tr>
<td>SCR/CO Catalyst for Simple-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>7.16</td>
</tr>
<tr>
<td>SCR/CO Catalyst for Simple-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>7.16</td>
</tr>
<tr>
<td>SCR for Auxiliary Boiler</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.21</td>
</tr>
<tr>
<td>Ammonia Tank for Combined-Cycle Turbines</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>Ammonia Tank for Simple-Cycle Turbines</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>Oil/Water Separator for Combined-Cycle Turbines</td>
<td>0.00009</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil/Water Separator for Simple-Cycle Turbines</td>
<td>0.000013</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Facility Total**

|       | 137.06 | 269.80 | 68.31 | 69.52 | 10.19 | 98.85 | 1,716,925.57 |

### RULE EVALUATION

The AEC project is expected to comply with all applicable SCAQMD rules and regulations, and federal and state regulations, as follows:

**DISTRICT RULES AND REGULATIONS**

#### Rule 205—Expiration of Permit to Construct

Section 70.6 of 40 CFR Part 70 and SCAQMD Rule 3004(a) and (b) require each Title V permit to include emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements, at the time of permit issuance.

Rule 205, 40 Part 52.21(r)(2), and Rule 1713(c) provide expiration requirements for permits to construct.

Rule 205—This rule provides that a permit to construct shall expire one year from the date of issuance unless an extension of time has been approved in writing by the Executive Officer. This requirement is set forth in condition 1.b in Section E: Administrative Conditions of the facility permit. Section E is comprised of a standard list of operating conditions that apply to all permitted equipment at the facility.
unless superseded by condition(s) listed elsewhere in the permit. Condition E193.5 implements Rule 205.

40 Part 52.21—Rule 1714(c) incorporates by reference the provisions of 40 Part 52.21—Prevention of Significant Deterioration of Air Quality. Part 52.21(r)(2) states: “Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.” Condition E193.6 implements 40 CFR 52.21 – PSD.

Rule 1713, adopted 10/7/88—Rule 1713(c) states: “A permit to construct shall become invalid if construction is not commenced within 24 months after receipt of such approval, if construction is discontinued for a period of 24 months or more, or if construction is not completed within a reasonable time. The Executive Officer may extend the 24-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 24 months of the projected and approve commencement date.” Condition E193.7 implements Rule 1713(c).

All three conditions, E193.5, E193.6, and E193.7, are applicable to the facility.

Rule 212—Standards for Approving Permits
Rule 2005(h) –Public Notice for RECLAIM (requires compliance with Rule 212)
Public notice is required for this project, as discussed below.

- Rule 212(c)(1)
  Public notice is required for any new or modified equipment under Regulation XXX (Title V) that may emit air contaminants located within 1000 feet from the outer boundary of a school, unless the modification will result in a reduction of emissions of air contaminants from the facility and no increase in health risk at any receptor location.

This subsection will require public notice because the proposed equipment will be located within 1000 feet of the outer boundary of a school. The nearest K-12 school—Rosie the Riveter Charter High School, 690 N. Studebaker Road, Long Beach, CA 90803— is located 971 feet away from the closest combined-cycle turbine. The school is located outside the entrance to the facility. All students participate in both high school and vocational training. The current enrollment is 64 students in grades 9th – 12th.
Subdivision (d) provides that in the case of notifications performed under paragraph (c)(1) of this rule, distribution of the public notice shall be to the parents or legal guardians of children in any school within 1/4 mile (1320 feet) of the facility and the applicant shall provide distribution of the public notice to each address within a radius of 1000 feet from the outer property line of the proposed new or modified facility. As the initial step, the Greatschools website (www.greatschools.org) was consulted to identify nearby schools and their approximate distances from the facility. Planning, Rule Development & Area Sources (PRDAS) staff was then requested to provide accurate distances from the boundary of the AGS facility to any schools that may be within ¼ mile, using Google Earth and a map of the AGS facility.

The next closest schools and their distances to the boundary of the AGS facility are as follows: (1) Kettering Elementary School, 550 Silvera Avenue, Long Beach, CA 90803, with a distance of 310 meters (0.19 miles), and (2) Hill Classical Middle School, 1100 Iroquois Avenue, Long Beach, CA 90805, with a distance of 880 meters (0.55 miles). Since Kettering Elementary School is located within ¼ mile of the facility, the public notice is also required to be distributed to the parents or legal guardians of the students at that school.

- **Rule 212(c)(2)**

Public notice is required for any new or modified facility which has on-site emission increases exceeding any of the daily maximums specified in subdivision (g) of this rule.

This subsection will require public notice because the on-site emission increases from the AEC will exceed the daily maximum thresholds set forth in subdivision (g) for VOC, NOx, PM<sub>10</sub>, SOx, and CO, as shown below.

<table>
<thead>
<tr>
<th></th>
<th>VOC</th>
<th>NOx</th>
<th>PM&lt;sub&gt;10&lt;/sub&gt;</th>
<th>SOx</th>
<th>CO</th>
<th>Lead</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEC 30-day averages, lb/day</td>
<td>1154.12</td>
<td>1887.87</td>
<td>1043.78</td>
<td>403.0</td>
<td>7500.88</td>
<td>0</td>
</tr>
<tr>
<td>Rule 212(c)(2) Daily Maximum, lbs/day</td>
<td>30</td>
<td>40</td>
<td>30</td>
<td>60</td>
<td>220</td>
<td>3</td>
</tr>
<tr>
<td>Increase Exceed Daily Maximum?</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
</tr>
</tbody>
</table>

VOC (30-day), lb/day = [[(443.8 lb/day-CC)(2 CC)] + [(65.78 lb/day-SC)(4 SC)] + (3.40 lb/day-boiler)] = 1154.12 lb/day
NOx (30-day), lb/day = [(476.45 lb/day-CC)(2 CC)] + [(232.79 lb/day-SC)(4 SC)] + (3.81 lb/day-boiler) = 1887.87 lb/day
PM<sub>10</sub> (30-day), lb/day = [(210.8 lb/day-CC)(2 CC)] + [(154.60 lb/day-SC)(4 SC)] + (3.78 lb/day-boiler) = 1043.78 lb/day
SOx (30-day), lb/day = [(120.53 lb/day-CC)(2 CC)] + [(40.22 lb/day-SC)(4 SC)] + (1.06 lb/day-boiler) = 403.0 lb/day
CO (30-day), lb/day = [(3167.44 lb/day-CC)(2 CC)] + [(286.46 lb/day-SC)(4 SC)] + (20.16 lb/day-boiler) = 7500.88 lb/day

The public notice requirements for subdivision (c)(2) are found in subdivisions (d) and (g). The District will prepare the public notice which will contain sufficient information to fully describe the project. In accordance with subdivision (d), the applicant will be required to distribute the public notice to each address within ¼ mile radius of the project.
Subdivision (g) requires that the public notification and comment process include all applicable provisions of 40 CFR Part 51, Section 51.161(b) and 40 CFR Part 124, Section 124.10. The minimum requirements specified in the above provisions are included in (g)(1), (g)(2), and (g)(3).

Pursuant to (g)(1), the District will make the following information available for public inspection at Bay Shore Neighborhood Library, located at 195 Bay Shore Avenue, Long Beach, CA 90803, during the 30-day comment period: (1) public notice, (2) project information submitted by the applicant, and (3) District's permit to construct evaluation.

Pursuant to (g)(2), the public notice will be published in a newspaper which serves the area that will be impacted by the project (Press Telegram).

Pursuant to (g)(3), the public notice will be mailed to the following persons: the applicant, Region IX EPA administrator, CARB, chief executives of the city and county where the project will be located, regional land use planning agency, and state and federal land managers whose lands may be affected by the emissions from the proposed project.

The Rule 212(c)(2) public notice will be combined with the Rule 3006 Title V public notice for a single public notice, with the public notice periods running concurrently for a single 30-day public comment period. (The Title V public notice requirements and completion are discussed below under Regulation XXX – Title V.)

- **Rule 212(c)(3)**
  Public notice is required for any new or modified equipment under Regulation XX or XXX with increases in emissions of toxic contaminants for which a person may be exposed to a maximum individual cancer risk greater than, or equal to one in a million during a lifetime (70 years) for facilities with more than one permitted unit, unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million using the risk assessment procedures and toxic air contaminants specified under Rule 1402.

  This subsection will **not** require public notice. The increases in toxic emissions from any combined-cycle turbine, any simple-cycle turbine, or the auxiliary boiler will not expose a person to a maximum individual cancer risk that is greater than or equal to one in a million. See the Rule 1401 rule analysis below.

**Rule 218 – Continuous Emission Monitoring**
The combined- and simple-cycle turbines are each equipped with an oxidation catalyst to control CO emissions. A CO CEMS is required to be installed on each turbine to demonstrate compliance with the CO emission limit. In accordance with paragraphs (c), (e), (f), the facility is required to submit an “Application for CEMS” for each CO CEMS and to adhere to retention of records requirements and reporting requirements once approval to operate the CO CEMS is granted. Compliance with this rule is expected.
Rule 401 – Visible Emissions
This rule prohibits the discharge of visible emissions for a period aggregating more than three minutes in any one hour which is as dark or darker in shade than Ringelmann No. 1. Visible emissions are not expected from the turbines and auxiliary boiler because they will be firing exclusively on pipeline quality natural gas.

Rule 402 – Nuisance
This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. Nuisance problems are not expected from the turbines, auxiliary boiler, and other equipment during normal operation.

Rule 403 – Fugitive Emissions
The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule includes the prohibition of fugitive dust emissions that remains visible in the atmosphere beyond the property line of the emission source.

Section (d) sets forth the requirements applicable to all persons. Section (d)(2) specifies no person shall conduct active operations without utilizing the applicable best available control measures included in Table 1 to minimize fugitive dust emissions from each fugitive dust source type within the active operation.

During the construction period, the project may also be subject to section (e)—Additional Requirements for Large Operations, which requires the implementation of applicable actions specified in Table 2 of the rule at all times and the implementation of applicable actions specified in Table 3 of the rule when the applicable performance standards cannot be met through use of Table 2 actions. The requirements include the submittal of: (1) a fully executed Large Operation Notification (Form 403N) to the SCAQMD Compliance Department by a representative that has completed the SCAQMD Fugitive Dust Control Class and has been issued a valid Certificate of Completion for the class; and (2) daily records to document the specific dust control actions taken. This rule does not require the submittal of a fugitive dust control plan.

The PDOC/FDOC is intended to provide an evaluation of operating emissions, including fugitive emissions emitted during the operation of a facility, and the control of these emissions to meet regulatory requirements. The PDOC/FDOC is not intended to evaluate fugitive emissions emitted during the construction phase or construction mitigation requirements to ensure compliance with Rule 403.
During normal operations, fugitive emissions are not expected from the operation of the turbines, auxiliary boiler, SCR/oxidation catalysts, ammonia tanks, and oil/water separators. Compliance with Rule 403 is expected.

**Rule 407 – Liquid and Gaseous Air Contaminants**

This rule limits the gas turbines to 2000 ppmv CO. The CO emissions from the combined-cycle turbines will be controlled by an oxidation catalyst to the BACT/LAER limit of 2 ppmvd at 15% O$_2$. The CO emissions from the simple-cycle turbines will be controlled by an oxidation catalyst to the BACT/LAER limit of 4 ppmvd at 15% O$_2$. The auxiliary boiler is expected to comply with the BACT/LAER limit of 50 ppmv CO.

The SO$_2$ portion of the rule does not apply per subdivision (c)(2), because the natural gas fired in the CTGs will comply with the sulfur limit in Rule 431.1. Therefore, compliance with this rule is expected.

**Rule 409 – Combustion Contaminants**

This rule restricts the combustion generated PM emissions from combustion equipment to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12% CO$_2$, averaged over 15 minutes.

- **Combined-Cycle Turbines**
  
  Each gas turbine is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the grain loading is expected to be 0.007 gr/scf.

  \[
  \text{Grain Loading} = \left[\frac{A \times B}{(C \times D)}\right] \times 7000 \text{ gr/lb}
  \]

  where:

  - A = Maximum PM$_{10}$ emission rate during normal operation, 8.5 lb/hr (case 1)
  - B = Rule specified percent of CO$_2$ in the exhaust (12%)
  - C = Percent of CO$_2$ in the exhaust (approx. 4.29% for natural gas)
  - D = Stack exhaust flow rate, scf/hr

  \[
  D = \frac{F_d \times 20.9}{(20.9 - \% O_2)} \times TFD = 8710 \times \frac{20.9}{17.9} \times 2275 = 23.1E+06 \text{ scf/hr}
  \]

  where:

  - $F_d$ = Dry F factor for fuel type, 8710 dscf/MMBtu
  - O$_2$ = Rule specific dry oxygen content in the effluent stream, 3%
  - TFD = Total fired duty measured at HHV, 2275 MMBTU/hr (case 1)

  \[
  \text{Grain Loading} = \left[\frac{(8.5 \times 12)}{(4.29) (23.1E+06)}\right] \times 7000 = 0.007 \text{ gr/scf} < 0.1 \text{ gr/scf limit}
  \]
**Simple-Cycle Turbines**
Each gas turbine is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the grain loading is expected to be 0.01 gr/scf.

Grain Loading  = 
\[
\frac{(A \times B)}{(C \times D)} \times 7000 \text{ gr/lb}
\]

where:

- **A** = Maximum PM$_{10}$ emission rate during normal operation, 6.23 lb/hr (case 1)
- **B** = Rule specified percent of CO$_2$ in the exhaust (12%)
- **C** = Percent of CO$_2$ in the exhaust (approx. 4.29% for natural gas)
- **D** = Stack exhaust flow rate, scf/hr

\[
D = F_d \times \frac{20.9}{(20.9 - \% O_2)} \times TFD = 8710 \times \frac{20.9}{17.9} \times 879 = 8.94E+06 \text{ scf/hr}
\]

where:

- **F$_d$** = Dry F factor for fuel type, 8710 dscf/MMBtu
- **O$_2$** = Rule specific dry oxygen content in the effluent stream, 3%
- **TFD** = Total fired duty measured at HHV, 879 MMBTU/hr (case 1)

Grain Loading  = 
\[
\frac{(6.23 \times 12)}{(4.29 \times (8.94E+06))} \times 7000 = 0.01 \text{ gr/scf} < 0.1 \text{ gr/scf limit}
\]

**Auxiliary Boiler**
The maximum PM emission rate during normal operation is 0.15 lb/hr, which is significantly less than the PM emission rates from the turbines above. Compliance with the 0.1 gr/scf limit is expected.

**Rule 431.1 – Sulfur Content of Gaseous Fuels**
The natural gas supplied to the gas turbines and auxiliary boiler is expected to comply with the 16 ppmv sulfur limit (calculated as H$_2$S) specified in this rule, because commercial grade natural gas has an average sulfur content of 4 ppm.

**Rule 474—Fuel Burning Equipment-Oxides of Nitrogen**
This rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.
Rule 475 – Electric Power Generating Equipment
This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976, and establishes a limit for combustion contaminants (particulate matter) of 11 lbs/hr or 0.01 grains/scf. Compliance is achieved if either the mass limit or the concentration limit is met.

- **Combined-Cycle Turbines**
  Each CTG is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the concentration is expected to be 0.0026 gr/scf.

  
  
  \[
  \text{Combustion Particulate (gr/scf)} = \left( \frac{\text{PM}_{10}, \text{lb/hr}}{\text{Stack Exhaust Flow, scf}} \right) \times 7000 \text{ gr/lb}
  \]

  \[
  \text{PM}_{10} = 8.5 \text{ lb/hr (case 1)}
  \]

  Stack exhaust flow = 23.1E+06 scf/hr (see Rule 409 analysis, above)

  Combustion Particulate = \(\frac{8.5}{23.1E+06}\) \times 7000 = 0.0026 gr/scf < 0.01 gr/scf limit

- **Simple-Cycle Turbines**
  Each CTG is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the concentration is expected to be 0.005 gr/scf.

  
  
  \[
  \text{Combustion Particulate (gr/scf)} = \left( \frac{\text{PM}_{10}, \text{lb/hr}}{\text{Stack Exhaust Flow, scf}} \right) \times 7000 \text{ gr/lb}
  \]

  \[
  \text{PM}_{10} = 6.23 \text{ lb/hr (case 1)}
  \]

  Stack exhaust flow = 8.94E+06 scf/hr (see Rule 409 analysis, above)

  Combustion Particulate = \(\frac{6.23}{8.94E+06}\) \times 7000 = 0.005 gr/scf < 0.01 gr/scf limit

Rule 1134 – Emissions of NOx from Stationary Gas Turbines
This rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.

Rule 1135 – Emissions of NOx from Electric Power Generating Systems
This rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.

Rule 1146—Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, as amended 11/1/13
NOx emissions from the auxiliary boiler are not subject to this rule, because this rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM
Facilities for Requirements Pertaining to NOx Emissions. However, the CO emissions are subject to this rule.

*Paragraph (a)*—This rule is applicable to boilers of equal to or greater than 5 MMBtu/hr rated heat input capacity, including the auxiliary boiler.

*Paragraph (b)(8)*—“Group I Unit” means any unit burning natural gas with a rated heat input greater than or equal to 75 MMBtu/hr, excluding thermal fluid heaters. The auxiliary boiler is a Group I unit.

*Subparagraph (c)(1)*—Subparagraph (c)(1)(F) is applicable to Group I units.

The requirements listed in subparagraphs (c)(1)(F) are shown below:

<table>
<thead>
<tr>
<th>Rule Reference</th>
<th>Category</th>
<th>Limit</th>
<th>Unit Shall be in Full Compliance on or before</th>
</tr>
</thead>
<tbody>
<tr>
<td>(c)(1)(F)</td>
<td>Group I Units</td>
<td>5 ppm or 0.0062 lbs/10⁶ Btu</td>
<td>January 1, 2013</td>
</tr>
</tbody>
</table>

Since AEC will be a RECLAIM facility, the 5 ppm NOx is not applicable to the auxiliary boiler pursuant to Rule 1146. The 5 ppm NOx is applicable pursuant to the top-down PSD BACT analysis below. Condition A195.13 specifies the NOx limit is 5 ppm, and condition D29.5 requires an initial source test.

*Paragraph (c)(4)*—The CO limit is 400 ppmv, corrected to 3% O₂, for natural gas.

The top-down PSD BACT analysis below indicates BACT/LAER requires the more stringent limit of 50 ppm. The Cleaver Brooks warranty letter, dated 6/10/15, guarantees 50 ppm CO. Condition A195.14 specifies the limit is 50 ppm, and condition D29.5 requires an initial source test.

*Paragraph (c)(6)*—Any unit(s) with a rated heat input capacity greater than or equal to 40 million Btu per hour and an annual heat input greater than 200 x 10⁹ Btu per year shall have a continuous in-stack nitrogen oxides monitor or equivalent verification system in compliance with 40 CFR part 60 Appendix B Specification 2. Maintenance and emission records shall be maintained and made accessible for a period of two years to the Executive Officer.

This NOx requirement is not applicable to the auxiliary boiler, because the RECLAIM requirements supersede the Rule 1146 requirements. Pursuant to Rule 2012--RECLAIM Monitoring Recording and Recordkeeping Requirements, the auxiliary boiler is classified as a “major NOx source.” As such, the boiler will be required to be equipped with a certified CEMS to meet RECLAIM requirements.
Paragraph (d)(3)—All parts per million emission limits specified in subdivision (c) are referenced at 3 percent volume stack gas oxygen on a dry basis averaged over a period of 15 consecutive minutes. Subdivision (c) sets forth emission limits for NOx and CO.

The 5 ppm NOx and 50 ppm CO limits are imposed pursuant to BACT/LAER, not Rule 1146. BACT requires a 1-hour averaging time. Accordingly, condition D29.5 require 1-hour averaging times for NOx, CO, VOC, and NH\textsubscript{3}. The sampling times for PM\textsubscript{10} and PM\textsubscript{2.5} are 1 hour or longer as necessary to obtain a measurable sample.

Paragraph (d)(4)—Compliance with the NOx and CO emission requirements of paragraph (c)(1) shall be determined using a District approved contractor under the Laboratory Approval Program according to the following procedures:

(A) District Source Test Method 100.1—Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling (March 1989), or …..

Condition D29.5 requires the use of Method 100.1 and a LAP-approved contractor.

Paragraph (d)(6)—Compliance with the NOx emission requirements in paragraph (d)(4) shall be conducted once:

(A) every three years for units with a rated heat input greater than or equal to 10 million Btu per hour, except for units subject to paragraph (c)(6) (CEMS).

As a major NOx source, the boiler will be required to be equipped with a certified CEMS to meet RECLAIM requirements, which supersede the above requirement.

Paragraph (d)(8)—Any owner or operator of units subject to this rule shall perform diagnostic emission checks of NOx emissions with a portable NOx, CO and oxygen analyzer according to the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Units Subject to South Coast Air Quality Management District Rules 1146 and 1146.1 according to the following schedule:

(A) On or after July 1, 2009, the owner or operator of units subject to paragraphs (c)(1), (c)(2), (c)(3), and (c)(4) shall check NOx emissions at least monthly or every 750 unit operating hours, whichever occurs later. If a unit is in compliance for three consecutive diagnostic emission checks, without any adjustments to the oxygen sensor set points, then the unit may be checked quarterly or every 2,000 unit operating hours, whichever occurs later, until the resulting diagnostic emission check exceeds the applicable limit specified in paragraphs (c)(1), (c)(2), or (c)(3).

(B) On or after January 1, 2015 or during burner replacement, whichever occurs later, the owner or operator of units subject to paragraph (c)(5) shall check NOx emissions according to the tune-up schedule specified in subparagraph (c)(5)(B).
(C) Records of all monitoring data required under subparagraphs (d)(8)(A) and (d)(8)(B) shall be maintained for a rolling twelve month period of two years (5 years for Title V facilities) and shall be made available to District personnel upon request.

(D) The portable analyzer diagnostic emission checks required under subparagraph (d)(8)(A) and (d)(8)(B) shall only be conducted by a person who has completed an appropriate District-approved training program in the operation of portable analyzers and has received a certification issued by the District.

For NO\textsubscript{X}: RECLAIM supersedes the above requirements. As a major NO\textsubscript{x} source, the boiler will be required to be equipped with a certified CEMS to meet RECLAIM requirements.

For CO: Rule 1146(d)(9) specifies that an owner or operator shall comply with the above requirements as applied to CO.

Paragraph (d)(9)—An owner or operator shall as applied to CO emissions specified in paragraph (d)(8) and subparagraph:

(A) (d)(6)(A) for units greater than or equal to 10 mmbtu/hr.

Condition (d)(6)(A) requires source testing every three years. Condition D29.6 requires testing to be conducted in accordance with the testing frequency requirements specified in Rule 1146. In addition, condition H23.7 requires compliance with the applicable requirements of Rule 1146.

**REGULATION XIII—NEW SOURCE REVIEW (NSR)**
The SCAQMD new source review rules are based on both the National Ambient Air Quality Standards (NAAQS) and the California Ambient Air Quality Standards (CAAQS). The primary NAAQS are the levels of air quality necessary, with an adequate margin of safety, to protect the public health.

- **Rule 1303(a)(1)—BACT/LAER (PM\textsubscript{10}, SO\textsubscript{x}, VOC, CO)**
- **Rule 2005(c)(1)(A)—BACT/LAER (NO\textsubscript{x})**

Rule 1303(a)(1) requires Best Available Control Technology (BACT) for a new or modified source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia, with the SCAQMD interpreting the emission increase to be 1 lb/day or greater of uncontrolled emissions.

The SCAQMD is not in attainment for PM\textsubscript{10} (California 24-hr and annual standards) and ozone, but is in attainment for PM\textsubscript{10} (national 24-hr standard), CO, NO\textsubscript{x}, and SO\textsubscript{x}. Since NO\textsubscript{x}, SO\textsubscript{x}, and VOC (no attainment standards for VOC) are precursors to non-attainment pollutants, they are treated as non-attainment pollutants as well. Specifically, NO\textsubscript{x} and VOC are precursors to ozone, PM\textsubscript{10}, and PM\textsubscript{2.5}, and SO\textsubscript{x} is a precursor to PM\textsubscript{10} and PM\textsubscript{2.5}. Thus, this rule requires BACT for NO\textsubscript{x} (non-RECLAIM), PM\textsubscript{10}, SO\textsubscript{x}, VOC, and ammonia. Moreover, the SCAQMD has determined that BACT is required for CO. Rule 2005(c)(1)(B) requires BACT for NO\textsubscript{x} for RECLAIM facilities.
Rule 1303(a)(2) provides that BACT for sources located at major polluting facilities shall be at least as stringent as Lowest Achievable Emissions Rate (LAER) as defined in the federal Clean Air Act Section 171(3). A facility is a major polluting facility (same as major stationary source) if it emits, or has the potential to emit, a criteria air pollutant at a level that equals or exceeds the following emission thresholds: (1) VOC, 10 tpy; (2) NOx, 10 tpy; (3) SOx, 100 tpy; (4) CO, 50 tpy; and (5) PM$_{10}$, 70 tpy. If a threshold for any one criteria pollutant is equaled or exceeded, the facility is a major polluting facility, and will be subject to LAER for all pollutants subject to NSR. The AGS is a major polluting facility because Table 13 indicates the PTEs for VOC (453.72 tpy), NOx (635.60 tpy), CO (21,871.86 tpy), and PM$_{10}$ (627 tpy) exceed the applicable thresholds.

Rule 1302(h) defines BACT as “the most stringent emission limitation or control technique which:

1. has been achieved in practice [AIP] for such category or class of source; or
2. is contained in any state implementation plan (SIP) approved by the US EPA approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or
3. is any other emission limitation or control technique, found by the Executive officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board.”

The first two requirements in the BACT definition above are required by federal law as LAER for major sources. The third part of the definition is unique to SCAQMD and some other areas in California, and allows for more stringent controls than LAER. For major polluting facilities, LAER is determined on a permit-by-permit basis.

The following sets forth the New Source Review BACT/LAER analyses for VOC, SO$_2$, and NH$_3$ which are not PSD pollutants for the proposed facility. As required by PSD, top-down BACT analyses are performed under Rule 1703(a)(2) below for the two pollutants subject to PSD review, NOx and PM$_{10}$. Although not subject to PSD review, a top-down BACT analysis is also included for CO to provide a more complete review. This section also compares the BACT/LAER levels established pursuant to NSR and PSD analyses to the warranted levels.

   • BACT/LAER for VOC Emissions

Preliminary Determination of Compliance

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170
VOCs are formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. Effective combustor design and post-combustion control using an oxidation catalyst are two technologies for controlling VOC emissions from a combustion turbine.

Combustor design—The formation of VOCs is limited by designing the combustion system to completely oxidize the fuel carbon to CO$_2$. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures with an excess of combustion air. Good combustor design (such as dry low NOx combustors) and best operating practices will minimize the formation of VOC while reducing the combustion temperature and NOx emissions. (Dry low NOx combustors and NOx control are discussed below in greater detail under the top-down BACT analysis for NOx.)

Oxidation catalyst—As discussed in the top-down BACT analysis for CO, an oxidation catalyst is typically a precious metal catalyst bed located in the HRSG. In addition to controlling CO by enhancing the oxidation of CO to CO$_2$, the catalyst enhances the oxidation of VOC to CO$_2$ without the addition of any reactant. Oxidation catalysts have been successfully installed on numerous combined- and simple-cycle combustion turbines.

Based on combined-cycle facilities recently permitted by the SCAQMD, including (1) LA City, DWP Scattergood Generating Station (2013), (2) Pasadena City, Dept. of Water & Power (2013), and (3) El Segundo Power (2011), the BACT/LAER limit for VOC is 2 ppm at 15% O$_2$ (1-hr averaging), without or with duct burner. This limit is consistent with the most stringent level found among recent BACT determination for combined-cycle natural gas fired combustion turbines.

The proposed/guaranteed levels is 1 ppm in the original Application, based on a top-down BACT analysis that included non-SCAQMD and SCAQMD combined-cycle turbine projects. The 1 ppmvd at 15% O$_2$ BACT levels is based on non-SCAQMD projects for which the VOC test method is not recognized by the SCAQMD. The proposed CTGs will be unable to meet a 1 ppmvd limit using the SCAQMD-approved test method, entitled SCAQMD Method 25.3—Determination of Low Concentration Non-Methane Non-Ethane Organic Compound Emissions for Clean Fueled Combustion Sources. The BACT/LAER limit for VOC remains 2 ppm at 15% O$_2$ (1-hr averaging). AES has accepted the SCAQMD’s determination in the revised Application.

The applicant has proposed to install dry low NOx combustors and an oxidation catalyst to meet a VOC BACT of 2 ppm at 15% O$_2$ (1-hr averaging), on which the PDOC/FDOC will be based.
BACT/LAER for SO\textsubscript{2} Emissions
Emissions of SO\textsubscript{x} are dependent on the sulfur content in the fuel rather than any combustion variables. During the combustion process, almost all of the sulfur in the fuel is oxidized to SO\textsubscript{2}.

Natural-gas-fired turbines in California are typically required to combust only California Public Utilities Commission (CPUC) pipeline-quality natural gas with a sulfur content of less than 1 grain of sulfur per 100 scf. The AEC will be supplied with natural gas from the Southern California Gas pipeline, which is limited by Tariff Rule No. 30 to a maximum total fuel sulfur content of less than 0.75 grain of sulfur per 100 scf. Therefore, the use of pipeline-quality natural gas with low sulfur content is BACT for SO\textsubscript{2}.

BACT/LAER for Ammonia Emissions
A very small amount of ammonia used in the SCR systems to control NO\textsubscript{x} from the turbine exhaust stream is not consumed by the reaction in the SCR systems. The applicant is proposing a BACT limit of 5 ppm at 15% O\textsubscript{2} (1-hr averaging).

The CARB “Guidance for Power Plant Siting and Best Available Control Technology,” dated September 1999, recommends that BACT levels for ammonia for gas turbines be set at not more than 5 ppmvd at 15% O\textsubscript{2}. The SCAQMD BACT for non-major sources for gas turbines rated at 50 MW or higher is 5.0 ppmvd at 15% O\textsubscript{2} and the BACT/LAER for major sources is the same limit with the additional requirement of 1-hr averaging. Therefore, the proposed limit of 5 ppm at 15% O\textsubscript{2} (1-hr averaging) meets BACT/LAER.

BACT/LAER vs. Guaranteed Levels
Based on the above BACT/LAER analysis for VOC, SO\textsubscript{2}, and NH\textsubscript{3}, and the PSD top-down BACT analysis for NO\textsubscript{x}, PM\textsubscript{10}, and CO performed under Rule 1703(a)(2), the SCAQMD has determined that BACT/LAER emission limits for combined-cycle facilities are as set forth in the table below. The table below presents the SCAQMD BACT/LAER determinations, the limits proposed by AES, and the guarantees for NO\textsubscript{x}, CO, VOC, and ammonia provided by Julie Lux, Nooter/Eriksen, in a letter dated 6/5/15.

Table 48 - Combined-Cycle Gas Turbine BACT/LAER Requirements, Proposed and Guaranteed Emissions Levels

<table>
<thead>
<tr>
<th></th>
<th>NO\textsubscript{x}</th>
<th>CO</th>
<th>VOC</th>
<th>PM\textsubscript{10}/SO\textsubscript{x}</th>
<th>NH\textsubscript{3}</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCAQMD Combined-Cycle Gas Turbine BACT/LAER Limits</td>
<td>2.0 ppmvd at 15% O\textsubscript{2}, 1-hr average</td>
<td>2.0 ppmvd at 15% O\textsubscript{2}, 1-hr average</td>
<td>2.0 ppmvd at 15% O\textsubscript{2}, 1-hr average</td>
<td>PUC quality natural gas with sulfur content ≤ 1 grain/100 scf</td>
<td>5.0 ppmvd at 15% O\textsubscript{2}, 1-hr average</td>
</tr>
<tr>
<td>AES Proposed BACT/LAER</td>
<td>2.0 ppmvd at 15% O\textsubscript{2}, 1-hr average</td>
<td>2.0 ppmvd at 15% O\textsubscript{2}, 1-hr average</td>
<td>Original--1.0 ppmvd at 15% O\textsubscript{2}, 1-hr average</td>
<td>PUC quality natural gas with sulfur content ≤ 1 grain/100 scf</td>
<td>5 ppmvd at 15% O\textsubscript{2}</td>
</tr>
</tbody>
</table>
Preliminary Determination of Compliance

### Application Processing and Calculations

<table>
<thead>
<tr>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>PM10/Sox</th>
<th>NH3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revised--2.0 ppmvd at 15% O₂, 1-hr average based on SCAQMD Method 25.3</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nooter/Eriksen Guarantees</td>
<td>2 ppmvd at 15% O₂</td>
<td>2 ppmvd at 15% O₂</td>
<td>1 ppmvd at 15% O₂</td>
<td>5 ppmvd at 15% O₂</td>
</tr>
<tr>
<td>Compliance?</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
</tbody>
</table>

- **Commissioning, Startups and Shutdowns**

  Condition nos. A195.8, A195.9, and A195.10 provide that the BACT limits of 2.0 ppmvd NOₓ, 2.0 ppmvd CO, and 2.0 ppmvd ROG, respectively, shall not apply during commissioning, startup, and shutdown periods.

  During commissioning, it is not technically feasible for the CTGs to meet BACT limits during the entire period because the dry low-NOₓ combustors may not be optimally tuned and the emissions are only partially abated as the CO and SCR catalysts are installed and tested in stages. The turbines, however, are typically operated at less than 100% load during commissioning. To limit the duration of the commissioning period during which BACT is not achievable, condition no. E193.8 limits the commissioning period to 996 hours of fired operation per turbine, including a maximum of 216 hours without control.

  During startups, it is not technically feasible for the CTGs to meet BACT limits during the entire startup because the SCR and CO catalysts that are used to achieve the required emissions reductions are not fully effective when the surface of the catalysts are below the manufacturers’ recommended operating range. Condition C1.3 specifies limits for cold, warm, and hot startups. The startup limits include: (1) number of cold starts per calendar month and year; (2) number of warm starts per calendar month and year; (3) number of hot starts per calendar month and year; (4) number of starts per day; (5) duration of cold starts, warm starts, and hot starts; and (6) NOₓ, CO, and VOC emissions per cold start, warm start, and hot start.

  During shutdowns, it is not technically feasible for the turbines to meet BACT limits during the entire shutdown because ammonia injection into the SCR reactor has ceased operation. The SCR and CO catalysts, however, are still above ambient temperatures and continue to operate for a portion of the shutdown. Condition C1.4 specifies limits for shutdowns. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdowns; and (3) NOₓ, CO, and VOC emissions per shutdown.

3. **A/N 579145, 579147, 579150, 579152—Simple-Cycle Combustion Turbine Generators Nos.**
SCGT-1, SCGT-2, SCGT-3, SCGT-4

A/N 579162, 579163, 579164, 579165—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. SCGT-1, SCGT-2, SCGT-3, SCGT-4 (Simple-Cycle Turbines)

- **BACT/LAER for VOC Emissions**
  
  The discussion on VOC formation and technologies for VOC control are the same as for the combined-cycle turbines.

  Based on simple-cycle facilities recently permitted by the SCAQMD, including (1) Canyon Power Plant (2011) and (2) CPV Sentinel (2012 & 2013), the BACT/LAER limit for VOC is 2.0 ppm at 15% \( O_2 \) (1-hr averaging). This limit is consistent with the most stringent level found among recent BACT determination for simple-cycle natural gas fired combustion turbines.

  The applicant has proposed to install dry low NOx combustors and an oxidation catalyst to meet a VOC BACT of 2.0 ppm at 15% \( O_2 \) (1-hr averaging).

- **BACT/LAER for \( SO_2 \) Emissions**
  
  As with the combined-cycle turbines, the use of pipeline-quality natural gas with low sulfur content is BACT for \( SO_2 \).

- **BACT/LAER for Ammonia Emissions**
  
  As with the combined-cycle turbines, the proposed limit of 5 ppm at 15% \( O_2 \) (1-hr averaging) meets BACT/LAER.

- **BACT/LAER vs. Guaranteed Levels**
  
  Based on the above BACT/LAER analysis for VOC, \( SO_2 \), and \( NH_3 \), and the PSD top-down BACT analysis for NOx, \( PM_{10} \), and CO performed under Rule 1703(a)(2), the SCAQMD has determined that BACT/LAER emission limits for simple-cycle facilities are as set forth in the table below. The table below presents the SCAQMD BACT/LAER determinations, the limits proposed by AES, and the guarantees for NOx, CO, VOC, and ammonia provided by Christopher Vu, GE Power & Electric, in a guarantee document dated 6/16/15.

  **Table 49 - Simple-Cycle Gas Turbine BACT/LAER Requirements, Proposed and Guaranteed Emissions Levels**

<table>
<thead>
<tr>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>( PM_{10}/SO_2 )</th>
<th>NH_3</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCAQMD Simple-Cycle Gas Turbine BACT/LAER</td>
<td>2.5 ppmvd at 15% ( O_2 ), 1-hr average</td>
<td>4.0 ppmvd at 15% ( O_2 ), 1-hr average</td>
<td>2.0 ppmvd at 15% ( O_2 ), 1-hr average</td>
<td>PUC quality natural gas with sulfur content ≤ 1 grain/100 scf</td>
</tr>
<tr>
<td>AES Proposed BACT/LAER</td>
<td>2.5 ppmvd at 15% ( O_2 ), 1-hr average</td>
<td>4.0 ppmvd at 15% ( O_2 ), 1-hr average</td>
<td>2.0 ppmvd at 15% ( O_2 ), 1-hr average</td>
<td>PUC quality natural gas with sulfur content ≤ 1 grain/100 scf</td>
</tr>
</tbody>
</table>
**Preliminary Determination of Compliance**

**ENGINEERING AND COMPLIANCE**

**APPLICATION PROCESSING AND CALCULATIONS**

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<table>
<thead>
<tr>
<th>NOx</th>
<th>CO</th>
<th>VOC</th>
<th>PM10/SOx</th>
<th>NH3</th>
</tr>
</thead>
<tbody>
<tr>
<td>GE Power &amp; Water Guarantees</td>
<td>2.5 ppmvd at 15% O2</td>
<td>4 ppmvd at 15% O2</td>
<td>2.0 ppmvd at 15% O2</td>
<td>PUC quality natural gas with sulfur content ≤ 1 grain/100 scf</td>
</tr>
</tbody>
</table>

Compliance? Yes Yes Yes Yes Yes

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**Commissioning, Startups andShutdowns**

Condition nos. A195.11, A195.12, and A195.10 provide that the BACT limits of 2.5 ppmvd NOx, 4.0 ppmvd CO, and 2.0 ppmvd ROG, respectively, shall not apply during commissioning, startup, and shutdown periods.

During commissioning, it is not technically feasible for the CTGs to meet BACT limits during the entire period because the dry low-NOx combustors may not be optimally tuned and the emissions are only partially abated as the CO and SCR catalysts are installed and tested in stages. The turbines, however, are typically operated at less than 100% load during commissioning. To limit the duration of the commissioning period during which BACT is not achievable, condition no. E193.9 limits the commissioning period to 280 hours of fired operation per turbine, including a maximum of four hours without control.

During startups, it is not technically feasible for the CTGs to meet BACT limits during the entire startup because the SCR and CO catalysts that are used to achieve the required emissions reductions are not fully effective when the surface of the catalysts are below the manufacturers’ recommended operating range. Condition C1.5 specifies limits for startups. The startup limits include: (1) number of starts per calendar month and year; (2) number of starts per day; (3) duration of starts, and (4) NOx, CO, and VOC emissions per start.

During shutdowns, it is not technically feasible for the turbines to meet BACT limits during the entire shutdown because ammonia injection into the SCR reactor has ceased operation. The SCR and CO catalysts, however, are still above ambient temperatures and continue to operate for a portion of the shutdown. Condition C1.6 specifies limits for shutdowns. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) duration of shutdowns; and (3) NOx, CO, and VOC emissions per shutdown.

5. A/N 579158—Auxiliary Boiler (Combined-Cycle Turbines), 70.8 MMBtu/hr
6. A/N 579166—Selective Catalytic Reduction for Auxiliary Boiler

**BACT/LAER for VOC Emissions**

VOCs are formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The commercially available control measures that are identified in the most-stringent BACT determinations are use of low-sulfur, pipeline quality natural gas and good combustion practice to ensure complete combustion. This is BACT for the auxiliary boiler.
• **BACT/LAER for SO₂ Emissions**
  As with the combined- and simple-cycle turbines, the use of pipeline-quality natural gas with low sulfur content is BACT for SO₂.

• **BACT/LAER for Ammonia Emissions**
  As with the combined- and simple-cycle turbines, the proposed limit of 5 ppm at 15% O₂ (1-hr averaging) meets BACT/LAER.

• **BACT/LAER vs. Guaranteed Levels**
  Based on the above BACT/LAER analysis for VOC, SO₂, and NH₃, and the PSD top-down BACT analysis for NOₓ, PM₁₀, and CO performed under Rule 1703(a)(2), the SCAQMD has determined that BACT/LAER emission limits for auxiliary boilers are as set forth in the table below. The table below presents the SCAQMD BACT/LAER determinations, the limits proposed by AES, and the guarantees for NOₓ, CO, VOC, and ammonia provided by David Obrecht, Cleaver Brooks, in a letter dated 6/10/15.

<table>
<thead>
<tr>
<th></th>
<th>SCAQMD Boiler, ≥ 75 MMBtu/hr, BACT/LAER Limits</th>
<th>AES Proposed BACT/LAER</th>
<th>Cleaver Brooks Guarantees</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOₓ</td>
<td>5.0 ppmvd at 3% O₂, 1-hr average</td>
<td>5.0 ppmvd at 3% O₂, 1-hr average</td>
<td>5.0 ppmvd at 3% O₂, 1-hr average</td>
</tr>
<tr>
<td>CO</td>
<td>50 ppmvd at 3% O₂, 1-hr average</td>
<td>50 ppmvd at 3% O₂, 1-hr average</td>
<td>None</td>
</tr>
<tr>
<td>VOC</td>
<td>None</td>
<td>Natural gas</td>
<td>Natural gas</td>
</tr>
<tr>
<td>PM₁₀/SOₓ</td>
<td>Natural gas</td>
<td>Natural gas</td>
<td>Natural gas</td>
</tr>
<tr>
<td>NH₃</td>
<td>5.0 ppmvd at 3% O₂, 1-hr average</td>
<td>5.0 ppmvd at 3% O₂</td>
<td>5.0 ppmvd at 3% O₂</td>
</tr>
</tbody>
</table>

| Compliance?            | Yes                                           | Yes                    | Yes                      | Yes | Yes |

• **Commissioning, Startups and Shutdowns**
  Condition nos. A195.13 and A195.14 provide that the BACT limits of 5.0 ppmvd NOₓ and 50.0 ppmvd CO, respectively, shall not apply during commissioning and startup periods.

  During commissioning, it is not technically feasible for the auxiliary boiler to meet the BACT limits for NOₓ and CO during the entire period. The emissions are only partially abated as the operation of the low NOₓ burner, FGR and SCR catalyst are optimized. To limit the duration of the commissioning period during which BACT is not achievable, condition no. E193.10 limits the commissioning period to 30 hours of fired operation.

  During startups, it is not technically feasible for the auxiliary boiler to meet the BACT limits for NOₓ and CO during the entire startup. The SCR that is used to achieve the required emissions reduction for NOₓ is not fully effective when the surface of the catalyst is below...
the manufacturers’ recommended operating range. Further, the low NOx burner, FGR and other combustion components require the startup period to become fully functional. Condition C1.7 specifies limits for cold, warm, and hot startups. The startup limits include: (1) number of cold starts per calendar month and year; (2) number of warm starts per calendar month and year; (3) number of hot starts per calendar month and year; (4) number of starts per day; (5) duration of cold starts, warm starts, and hot starts; and (6) NOx emissions per cold start, warm start, and hot start.

7. A/N 579167—Ammonia Storage Tank, No. Tank-1 (Combined-Cycle Turbines), 40,000 gallons
8. A/N 579168—Ammonia Storage Tank, No. Tank-2 (Simple-Cycle Turbines), 40,000 gallons

For an ammonia storage tank, BACT for ammonia requires the use of a pressure vessel for storage and a vapor return line for transfer, which are required by conditions C157.1 and E144.1, respectively. The tanks will be pressure vessels with a pressure relief valve set at 50 psig to control breathing losses. The filling losses will be controlled by a vapor return line to the delivery vehicle.

9. A/N 579169—Oil/Water Separator, No. OWS-1 (Combined-Cycle Turbines), 5000 gallons
10. A/N 579170—Oil/Water Separator, No. OWS-2 (Simple-Cycle Turbines), 5000 gallons

The Bay Area Air Quality Management District BACT Guideline indicates that for Water Treating – Oil/Water Separator, the achieved-in-practice BACT for VOC is a vapor-tight fixed cover totally enclosing the separator tank liquid contents.

Since turbine lubricant has a significantly lower vapor pressure (0.01 mm Hg) than crude oil (113.77 mm Hg), condition E193.16 will require a fixed cover to minimize VOC emissions. A “vapor-tight” cover would imply that the inspector is required to check for fugitive emissions with a portable analyzer. Both tanks will be equipped with gasketed covers.

- **Rule 1303(b)(1)—Modeling**
  The Executive Officer or designee shall, except as Rule 1304 applies, deny the Permit to Construct for any new or modified source with results in a net emission increase of any nonattainment air contaminant at a facility, unless the applicant substantiates with air dispersion modeling that the new facility or modification will not cause a violation, or make significantly worse an existing violation according to Appendix A of the rule, or other analysis approved by the Executive Officer or designee, of any state or national ambient air quality standards at any receptor location in the District. As discussed for the BACT/LAER requirements above, the SCAQMD is not in attainment for PM\textsubscript{10} (California 24-hr and annual standards) and ozone, but is in attainment for PM\textsubscript{10} (national 24-hr standard), CO, NOx, and SOx. Since NOx, SOx, and VOC (no attainment standards for VOC) are precursors to non-attainment pollutants, they are treated as non-attainment pollutants as well.

Rule 1303 requires modeling for NO\textsubscript{2} (non-RECLAIM), CO, PM\textsubscript{10}, and SO\textsubscript{2}. Rule 2005(c)(1)(B) requires modeling for NO\textsubscript{2} for RECLAIM facilities. (The standards in Appendix A are outdated. The modeling analyses below are based on current ambient air quality standards.)
Compliance determination is different for attainment and nonattainment pollutants. For attainment pollutants, \( \text{NO}_2 \), CO, \( \text{SO}_2 \), \( \text{PM}_{10} \) (federal standard), the modeled peak impacts plus the worst-case background concentrations shall not exceed the most stringent air quality standard. For non-attainment pollutants where the background concentrations exceed the ambient air quality standards, the modeled peak impacts shall not cause an exceedance of the Rule 1303 significant change thresholds. The South Coast Air Basin is designated non-attainment for the state \( \text{PM}_{10} \) standard, and state and federal \( \text{PM}_{2.5} \) standards.

Rule 1304(a) provides an exemption from the modeling requirements of Rule 1303(b)(1) and the offset requirement of Rule 1303(b)(2) for:

(2) Electric Utility Steam Boiler Replacement
The source is replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The new equipment must have a maximum electrical power rating (in megawatts) that does not allow basin wide electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset.

Page 11 of the Final Staff Report for Proposed Rule 1304.1—Electrical Generating Facility Fee for Use of Offset Exemption, dated 9/6/13, clarifies: “Currently, pursuant to Rule 1304(a)(2), replacement of an electrical steam boiler at an EGF [Electric Generating Facility] that does not increase basin wide MW capacity at that utility (now interpreted as owner) is exempt from the modeling and offset requirements of Rule 1303(b)(2).” Rule 1304(a)(2) provides an exemption for new qualifying equipment, such as combined-cycle turbines and simple-cycle turbines with intercoolers, that have a maximum electrical rating (in megawatts) that is less than or equal to the maximum electrical rating (in megawatts) of the electric utility steam boiler(s) that the new equipment replaces. Both the new equipment and the existing electric utility boiler(s) must have the same owner and be located in the basin. For example, this exemption allows the transfer of 480 MW credit from the Redondo Beach Generating Station (retirement of Utility Boiler No. 7) to the Huntington Beach Energy Project (new combined- and simple-cycle turbines), as listed in Table 2 – AES Rule 1304(a)(2) Offset Plan above. Offsets are provided from the SCAQMD internal offset accounts, as discussed in the Rule 1304.1 analysis below.

AES proposes to replace existing Utility Boiler No. 1 (175 MW-gross), No. 2 (175 MW-gross), Unit 5 (480 MW-gross), and No. 3 (320 MW-gross) for a total of 1150 MW-gross. The replacement equipment are two combined-cycle turbines (692.951 MW-gross total at 59 °F) and four simple-cycle turbines (401.751 MW-gross total at 59 °F) for a total of 1094.7 MW-gross total. At this time, AES has not identified plans for the surplus 55 MWs from the permanent retirements. Condition E448.1 limits the total electrical output from AEC to 1094.7 MW-gross at 59 °F.
The combined- and simple-cycle turbines, but not the auxiliary boiler, are exempt from the modeling requirements of Rule 1303 (CO, PM\textsubscript{10}, SO\textsubscript{2}). However, the applicant has provided a modeling analysis of impacts for the entire project to evaluate the project’s air quality impacts for the CEC’s CEQA document. This modeling analysis includes the auxiliary boiler.

Rule 2005 (NO\textsubscript{2}), Rule 1401 (health risk assessment for toxics), and Rule 1703 PSD (NO\textsubscript{2}, PM\textsubscript{10}, CO) do not provide any exemptions for the project. The applicant has provided the modeling for the project required to demonstrate compliance with these rules.

Pursuant to SCAQMD procedure, Planning, Rule Development & Area Sources (PRDAS) staff was requested to review the dispersion modeling analysis, including the health risk assessment results, provided by the applicant for this project. PRDAS staff reviewed the applicant’s dispersion modeling analysis, by independently reproducing the modeling analysis, to verify compliance with SCAQMD rules and in support of the CEC’s CEQA document. Their modeling review memo, dated 5/20/16, from Planning & Rules Manager Ian MacMillan, to Sr. Engineering Manager Andrew Lee provided comments on the applicant’s modeling analyses and independent modeling results. (See Appendix of this document for copy of memo.) The maximum modeled concentrations and updated background levels provided by PRDAS staff are incorporated in the modeling results tables for Rules 1303, 1703, 1401, and 2005, below.

**AERMOD, METEOROLOGICAL DATA, BACKGROUND DATA**

The applicant utilized AERMOD (version 15181) for the air dispersion modeling which is the current EPA approved model and requires hourly meteorological data. The meteorological data from the SCAQMD’s North Long Beach meteorological station was used, which is appropriate for the project. The MET data is for the periods of January 1, 2006 through December 31, 2009, and January 1, 2011 through December 31, 2011. At the direction of the SCAQMD, 2010 meteorological data were not recommended for use because the data do not meet the 90 percent completeness requirements. Similarly, 2012 met data were not recommended for use because the collected wind speeds are suspicious. The final preprocessed AERMET data files for 2006 through 2009 and 2011 were provided via e-mail by the SCAQMD. This surface data has been coupled with the upper air data from the National Climatic Data Center twice-daily soundings from the San Diego Miramar National Weather Service station (Station #03190).

The original Application indicated that the three most recent years of background hourly NO\textsubscript{2} data from the Hudson Long Beach monitoring station (South Coastal Los Angeles County 3), the three most recent years of background CO, SO\textsubscript{2}, ozone, and annual NO\textsubscript{2} data from the North Long Beach monitoring station (South Coastal Los Angeles County 1), and the three most recent years of background PM\textsubscript{10} and PM\textsubscript{2.5} data from the South Long Beach monitoring station (South Coastal Los Angeles County 2) were used to determine the background concentrations. Further, the SCAQMD has stated that hourly NO\textsubscript{2} data collected at the Hudson Long Beach monitoring station (South Coastal Los Angeles County 3, EPA ID 06-037-4006) are considered representative of the AEC site.
This monitoring station is located approximately 7.2 miles to the northwest of the AEC site and is considered representative because it captures the large NOx-emitting sources in the Ports area that are upwind of the AEC. The South Long Beach monitoring station is the nearest to AEC but only measures PM\textsubscript{10} and PM\textsubscript{2.5}. The predicted modeling impacts were added to the background concentrations for comparison to the ambient air quality standards.

The maximum modeled 1-hour and annual NO\textsubscript{2} concentrations include NO\textsubscript{2} to NOx conversion ratios of 0.80 and 0.75, respectively, as approved by EPA.

The base modeling receptor grid for the AERMOD modeling consists of receptors that are placed at the ambient air boundary (i.e., the project’s property boundary) and Cartesian-grid receptors that are placed beyond the project’s site boundary at spacing that increases with distance from the origin. Property boundary receptors were placed at 30-meter intervals. Beyond the project’s property boundary, receptor spacing was as follows:

- 50-meter spacing from property boundary to 500 meters from the origin
- 100-meter spacing from beyond 500 meters to 3 km from the origin
- 500-meter spacing from beyond 3 km to 10 km from the origin
- 1,000-meter spacing from beyond 10 km to 25 km from the origin
- 5,000-meter spacing from beyond 25 km to 50 km from the origin

**PRDAS Staff’s Comments**

PRDAS staff’s modeling review memo indicated the AERMOD modeling generally conforms to the SCAQMD’s dispersion modeling methodology. The applicant utilized AERMOD (version 15181) for the air dispersion modeling, which is the current EPA approved model. The applicant used meteorological data from the SCAQMD’s Long Beach station, which is appropriate for the project. The EPA-approved NO\textsubscript{2} to NOx conversion ratios of 0.80 and 0.75 are assumed for evaluating 1-hour and annual NO\textsubscript{2} impacts from the project, respectively. The receptor grid area covered is adequate to determine the maximum impacts from the facility.

In an e-mail dated 5/3/16, PRDAS staff informed the applicant’s consultant that their proposed background concentrations reflected the 2009-2013 period and are required to be updated to include the background concentrations for 2014. In its review, PRDAS staff used the monitoring data for South Coastal Los Angeles County monitoring stations (SRA No. 4) for the last three years (2012-2014) to determine the background concentrations. Their modeling review memo incorporates these background concentrations which are added to their predicted modeling impacts for comparison to the ambient air quality standards.
FUMIGATION IMPACTS

Fumigation (both inversion break-up and shoreline fumigation) is a meteorological condition that can produce high concentrations of ground-level pollutants. Fumigation impacts can be greater than impacts predicted with the AERMOD model. To verify that fumigation impacts do not result in higher ambient air quality impacts, the application conducted fumigation modeling. The effects of fumigation on the maximum modeled impacts were evaluated using the EPA AERSCREEN (Version 15181), as requested by the CEC. The results of the fumigation modeling were based on the respective loads and operating scenarios which were identified in the normal operation dispersion modeling discussed in detail below, as the worst-case impact scenario for each combination of pollutant and averaging time. Regulatory default mixing heights were selected.

The original Application stated the combined- and simple-cycle turbines are located more than 3,000 meters away from the shoreline. However, for modeling purposes, all emission sources were conservatively assumed to be located at the auxiliary boiler distance of 2,960 meters from the shoreline. These model inputs into AERSCREEN resulted in no fumigation occurrences because the plume heights were below the thermal internal boundary layer (TIBL) heights for the distance to shoreline of 2,960 meters. The original Application concluded that as there are no fumigation occurrences, no fumigation impacts are expected from AEC operation.

In an e-mail dated 4/28/16, PRDAS staff informed AES’s consultant that the AERSCREEN runs provided for the shoreline fumigation and inversion break-up impacts did not have the inversion break-up option turned on in the model. The consultant was requested to re-run AERSCREEN to include inversion break-up. In addition, the shoreline fumigation runs provided did not include the simple-cycle turbines, but are required to be included for all runs. In an e-mail dated 5/2/16, AES provided the inversion break-up analysis.

PRDAS staff has reviewed the applicant’s revised fumigation analysis. The tall stacks that will be constructed along the shoreline may cause fumigation. During these short term events, the maximum impacts could be higher than predicted by AERMOD for normal operation. Only the shorter averaging periods, less than or equal to 8 hours should be considered, because these meteorological phenomena do not persist for long periods. AERSCREEN (version 15181), the model recommended by EPA, was utilized for the analysis. The modeling parameters for the worst-case operating scenarios were used for each of the modeled pollutants and averaging times. The federal NO\textsubscript{2} and SO\textsubscript{2} standards cannot be evaluated with AERSCREEN due to the form of those standards and are not considered in this analysis. Because AERSCREEN can only be run with one emission source, the total project impacts were determined by adding the impacts from the seven combustion equipment.

Shoreline Fumigation--For all of the sources, shoreline fumigation was not calculated by AERSCREEN because the plume height was below the thermal internal boundary layer heights for the distance to the shoreline. The analysis indicated the combustion sources are too far away from the shoreline to result in shoreline fumigation occurrences.
Inversion Break-up—The impacts, combined with background concentrations, are below the applicable ambient air quality standards, as shown in the table below. The table incorporates maximum modeled concentrations and updated background levels provided by PRDAS staff.

Table 50A –Inversion Break-up Impacts during Normal Operations – Total Project

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Maximum Modeled (µg/m³)</th>
<th>Background Concentration (µg/m³)</th>
<th>Total Predicted Concentration (µg/m³)</th>
<th>State Standard CAAQS (µg/m³)</th>
<th>Federal Standard, Primary NAAQS (µg/m³)</th>
<th>Compliance?</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂</td>
<td>1-hour</td>
<td>69.4</td>
<td>255.5</td>
<td>324.9</td>
<td>339</td>
<td>--</td>
<td>Yes</td>
</tr>
<tr>
<td>SO₂</td>
<td>1-hour</td>
<td>4.9</td>
<td>58.2</td>
<td>63.1</td>
<td>655</td>
<td>--</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>3-hour</td>
<td>4.9</td>
<td>58.2</td>
<td>63.1</td>
<td>--</td>
<td>1,300</td>
<td>Yes</td>
</tr>
<tr>
<td>CO</td>
<td>1-hour</td>
<td>414</td>
<td>4237</td>
<td>4651</td>
<td>23,000</td>
<td>40,000</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>8-hour</td>
<td>138</td>
<td>2977</td>
<td>3115</td>
<td>10,000</td>
<td>10,000</td>
<td>Yes</td>
</tr>
</tbody>
</table>

The maximum 1-hour NO₂ concentration includes an ambient NO₂ to NOx conversion ratio of 0.80.

NORMAL OPERATION IMPACTS
Turbine emissions and stack parameters, such as flow rate and exit temperature, exhibit some variation with ambient temperature and operating load. Therefore, to evaluate the worst-case impacts, a dispersion modeling analysis was performed at three different load scenarios at three temperature conditions for each turbine type (combined- and simple-cycle).

For combined-cycle turbines, the loads (45%, 75%, 100%) and temperatures (28 °F, 65.3 °F, and 107 °F) are reflected in Table 15 - Combined-Cycle Turbine Operating Scenarios, above. For simple-cycle turbines, the loads (50%, 75%, 100%) and temperatures (28 °F, 65.3 °F, and 107 °F) are reflected in Table 31 - Simple-Cycle Turbine Operating Scenarios, above. This load analysis included the operation of the auxiliary boiler. The load analysis results are presented in revised Table 5.1C.8a—Operational Results—Load Analysis in the revised Application, and were used to select the worst-case impacts for each criteria pollutant and corresponding averaging period.

1. Combined-Cycle Gas Turbines Modeled Rates and Stack Parameters
The combined-cycle emission rates and operating scenario resulting in the maximum predicted concentrations are presented in revised Table 5.1-31—AEC CCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts in the revised Application. The emission rates and operating scenarios have been reviewed.
Table 51 - Modeled Emission Rates - Normal Operation for AEC CCGT

<table>
<thead>
<tr>
<th>Averaging Time</th>
<th>Worst-case Emission Scenario</th>
<th>Pollutant</th>
<th>Emissions Per Turbine, lbs/hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-hour</td>
<td>NO$_2$: Both turbines in cold start-up mode, 28 °F ambient temperature.</td>
<td>NO$_2$</td>
<td>61</td>
</tr>
<tr>
<td></td>
<td>CO: Both turbines in cold start-up mode, 28 °F ambient temperature.</td>
<td>CO</td>
<td>325</td>
</tr>
<tr>
<td></td>
<td>SO$_2$: Both turbines in cold start-up mode, 28 °F ambient temperature.</td>
<td>SO$_2$</td>
<td>3.84</td>
</tr>
<tr>
<td>1-hour (federal)</td>
<td>NO$_2$: Both turbines in cold start-up mode, 28 °F ambient temperature.</td>
<td>NO$_2$</td>
<td>61</td>
</tr>
<tr>
<td></td>
<td>SO$_2$: Both turbines in cold start-up mode, 65.3 °F ambient temperature.</td>
<td>SO$_2$</td>
<td>3.72</td>
</tr>
<tr>
<td>3-hour</td>
<td>SO$_2$: Both turbines continuous average (75%) load operation, 65.3 °F ambient temperature.</td>
<td>SO$_2$</td>
<td>3.72</td>
</tr>
<tr>
<td>8-hour</td>
<td>CO: Both turbines complete two cold starts, 2 shutdowns, and balance of period at minimum (45%) load, 28 °F ambient temperature.</td>
<td>CO</td>
<td>118</td>
</tr>
<tr>
<td>24-hour</td>
<td>PM$<em>{10}$, PM$</em>{2.5}$: Both turbines continuous minimum (44%) load operation, 65.3 °F ambient temperature.</td>
<td>PM$<em>{10}$, PM$</em>{2.5}$</td>
<td>8.5</td>
</tr>
<tr>
<td></td>
<td>SO$_2$: Both turbines continuous average (75%) load operation, 65.3 °F ambient temperature.</td>
<td>SO$_2$</td>
<td>3.72</td>
</tr>
<tr>
<td>Annual</td>
<td>NO$<em>2$, PM$</em>{10}$, PM$<em>{2.5}$: Both turbines operate at minimum (44%) load for 4100 normal operating hours, 80 cold starts, 88 warm starts, 332 hot starts, and 500 shutdowns, for total of 4640 hours, 65.3 °F ambient temperature. Condition A63.2 limits annual CO, VOC, PM$</em>{10}$, and SOx emissions, which also indirectly limits annual NOx emissions.</td>
<td>NO$_2$</td>
<td>6.24</td>
</tr>
<tr>
<td></td>
<td>PM$<em>{10}$, PM$</em>{2.5}$: Both turbines operate at minimum (44%) load for 4100 normal operating hours, 80 cold starts, 88 warm starts, 332 hot starts, and 500 shutdowns, for total of 4640 hours, 65.3 °F ambient temperature. Condition A63.2 limits annual CO, VOC, PM$_{10}$, and SOx emissions, which also indirectly limits annual NOx emissions.</td>
<td>PM$<em>{10}$, PM$</em>{2.5}$</td>
<td>4.50</td>
</tr>
</tbody>
</table>

1 See Table 5.1-31—AEC CCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts on pages 5.1-31 and 5.1-32, and discussion on page 5.1-31 of the revised Application.

2 The maximum 1-hour NOx and CO emission rates are based on a 60-minute cold start-up event at 28 °F.
The 1-, 3-, and 24-hour SO$_2$ emission rates are based on the worst case fuel sulfur content of 0.75 grain per 100 dscf of natural gas.
Table 52 - Modeled Stack Parameters - Normal Operation for AEC CCGT

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Scenario</th>
<th>Stack Diameter (m)</th>
<th>Stack Height (m)</th>
<th>Exhaust Temp (°F (°K))</th>
<th>Exhaust velocity (ft/s (m/s))</th>
<th>Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂</td>
<td>1-hour</td>
<td>6.10</td>
<td>42.7</td>
<td>170 (350)</td>
<td>40 (12.2)</td>
<td>CC03</td>
</tr>
<tr>
<td></td>
<td>1-hour</td>
<td>6.10</td>
<td>42.7</td>
<td>170 (350)</td>
<td>40 (12.2)</td>
<td>CC03</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>6.10</td>
<td>42.7</td>
<td>170 (350)</td>
<td>38.8 (11.8)</td>
<td>CC07</td>
</tr>
<tr>
<td>CO</td>
<td>1-hour</td>
<td>6.10</td>
<td>42.7</td>
<td>170 (350)</td>
<td>40 (12.2)</td>
<td>CC03</td>
</tr>
<tr>
<td></td>
<td>8-hour</td>
<td>6.10</td>
<td>42.7</td>
<td>170 (350)</td>
<td>40 (12.2)</td>
<td>CC03</td>
</tr>
<tr>
<td>SO₂</td>
<td>1-hour</td>
<td>6.10</td>
<td>42.7</td>
<td>175 (353)</td>
<td>48.9 (14.9)</td>
<td>CC06</td>
</tr>
<tr>
<td></td>
<td>1-hour</td>
<td>6.10</td>
<td>42.7</td>
<td>175 (353)</td>
<td>48.9 (14.9)</td>
<td>CC06</td>
</tr>
<tr>
<td></td>
<td>3-hour</td>
<td>6.10</td>
<td>42.7</td>
<td>175 (353)</td>
<td>48.9 (14.9)</td>
<td>CC06</td>
</tr>
<tr>
<td></td>
<td>24-hour</td>
<td>6.10</td>
<td>42.7</td>
<td>175 (353)</td>
<td>48.9 (14.9)</td>
<td>CC06</td>
</tr>
<tr>
<td>PM₁₀, PM₂.₅</td>
<td>24-hour</td>
<td>6.10</td>
<td>42.7</td>
<td>170 (350)</td>
<td>38.8 (11.8)</td>
<td>CC07</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>6.10</td>
<td>42.7</td>
<td>170 (350)</td>
<td>38.8 (11.8)</td>
<td>CC07</td>
</tr>
</tbody>
</table>

1. See Table 5.1C.5—Operational Stack Parameters in Appendix 5.1C.1, and Table 5.1-31—AEC CCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts.

2. Simple Cycle Gas Turbines Modeled Rates and Stack Parameters

The simple-cycle turbine emission rates and operating scenario resulting in the maximum predicted concentrations are presented in Table 5.1-32—AEC SCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts, a source for the information presented in the two tables below. The emission rates and operating scenarios have been reviewed.

As clarified in AES Response Letter, dated 1/7/16, the maximum 1-hour NOx and CO emission rates are based on a startup event, a shutdown event, and the balance at steady-state operation (Case 3--50% load), not on 60 minutes of a start-up event as indicated in footnote a to Table 5.1-32 in the original Application.
### Table 53 - Modeled Emission Rates - Normal Operation for AEC SCGT

<table>
<thead>
<tr>
<th>Averaging Time</th>
<th>Worst-case Emission Scenario</th>
<th>Pollutant</th>
<th>Emissions Per Turbine, lbs/hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-hour</td>
<td>NO₂: Four turbines in startup, shutdown, and balance of period at minimum (50%) load, 28 °F ambient temperature.</td>
<td>NO₂</td>
<td>21.2</td>
</tr>
<tr>
<td></td>
<td>CO: Four turbines in startup, shutdown, and balance of period at minimum (50%) load, 28 °F ambient temperature.</td>
<td>CO</td>
<td>44.9</td>
</tr>
<tr>
<td></td>
<td>SO₂: Four turbines in startup, shutdown, and balance of period at minimum (50%) load, 28 °F ambient temperature.</td>
<td>SO₂</td>
<td>1.62</td>
</tr>
<tr>
<td>1-hour (federal)</td>
<td>NO₂: Four turbines in startup, shutdown, and balance of period at minimum (50%) load, 28 °F ambient temperature.</td>
<td>NO₂</td>
<td>21.2</td>
</tr>
<tr>
<td></td>
<td>SO₂: Four turbines in startup, shutdown, and balance of period at minimum (50%) load, 28 °F ambient temperature.</td>
<td>SO₂</td>
<td>1.61</td>
</tr>
<tr>
<td>3-hour</td>
<td>SO₂: Four turbines continuous maximum (100%) load operation, 65.3 °F ambient temperature.</td>
<td>SO₂</td>
<td>1.61</td>
</tr>
<tr>
<td>8-hour</td>
<td>CO: Four turbines complete 2 starts, 2 shutdowns, and balance of period at minimum (50%) load, 28 °F ambient temperature.</td>
<td>CO</td>
<td>15.0</td>
</tr>
<tr>
<td>24-hour</td>
<td>PM₁₀, PM₂.₅: Four turbines continuous minimum (50%) load operation, 65.3 °F ambient temperature.</td>
<td>PM₁₀, PM₂.₅</td>
<td>6.23</td>
</tr>
<tr>
<td></td>
<td>SO₂: Four turbines continuous maximum (100%) load operation, 65.3 °F ambient temperature.</td>
<td>SO₂</td>
<td>1.61</td>
</tr>
<tr>
<td>Annual</td>
<td>NO₂, PM₁₀, PM₂.₅: Four turbines operate at minimum (50%) load for 2000 normal operating hours, 500 starts, and 500 shutdowns, for total of 2358 hours, 65.3 °F ambient temperature. Condition A63.3 limits annual CO, VOC, PM₁₀, and SOx emissions, which also indirectly limits annual NOx emissions.</td>
<td>NO₂</td>
<td>2.29</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM₁₀, PM₂.₅</td>
<td>1.68</td>
</tr>
</tbody>
</table>

1. See Table 5.1-32—AEC SCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts on pages 5.1-32 and 5.1-33, and discussion on page 5.1-32 of the revised Application.
2 The maximum 1-hour NOx and CO emission rates are based on a startup event, a shutdown event, and the balance at steady-state operation (Case 3—50% load at 28 °F) per AES Response Letter, dated 1/7/16.

3 The 1-, 3-, and 24-hour SO\textsubscript{2} emission rates are based on the worst case fuel sulfur content of 0.75 grain per 100 dscf of natural gas.

### Table 54 - Modeled Stack Parameters - Normal Operation for AEC SCGT

<table>
<thead>
<tr>
<th></th>
<th>Stack Diameter (m)</th>
<th>Stack Height (m)</th>
<th>Exhaust Temp (°F (°K))</th>
<th>Exhaust velocity (ft/s (m/s))</th>
<th>Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO\textsubscript{2}</td>
<td>1-hour</td>
<td>4.11</td>
<td>24.4</td>
<td>888 (749)</td>
<td>78 (23.8)</td>
</tr>
<tr>
<td></td>
<td>1-hour (federal)</td>
<td>4.11</td>
<td>24.4</td>
<td>888 (749)</td>
<td>78 (23.8)</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>4.11</td>
<td>24.4</td>
<td>883 (746)</td>
<td>77.4 (23.6)</td>
</tr>
<tr>
<td>CO</td>
<td>1-hour</td>
<td>4.11</td>
<td>24.4</td>
<td>888 (749)</td>
<td>78 (23.8)</td>
</tr>
<tr>
<td></td>
<td>8-hour</td>
<td>4.11</td>
<td>24.4</td>
<td>888 (749)</td>
<td>78 (23.8)</td>
</tr>
<tr>
<td>SO\textsubscript{2}</td>
<td>1-hour</td>
<td>4.11</td>
<td>24.4</td>
<td>789 (693)</td>
<td>109 (33.3)</td>
</tr>
<tr>
<td></td>
<td>1-hour (federal)</td>
<td>4.11</td>
<td>24.4</td>
<td>798 (699)</td>
<td>108 (33.0)</td>
</tr>
<tr>
<td></td>
<td>3-hour</td>
<td>4.11</td>
<td>24.4</td>
<td>798 (699)</td>
<td>108 (33.0)</td>
</tr>
<tr>
<td></td>
<td>24-hour</td>
<td>4.11</td>
<td>24.4</td>
<td>798 (699)</td>
<td>108 (33.0)</td>
</tr>
<tr>
<td>PM\textsubscript{10}, PM\textsubscript{2.5}</td>
<td>24-hour</td>
<td>4.11</td>
<td>24.4</td>
<td>883 (746)</td>
<td>77.4 (23.6)</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>4.11</td>
<td>24.4</td>
<td>883 (746)</td>
<td>77.4 (23.6)</td>
</tr>
</tbody>
</table>

1 See Table 5.1C.5—Operational Stack Parameters in Appendix 5.1C.1—Dispersion Modeling and Climate Information, and Table 5.1-32—AEC SCGT Emission Rates and Operating Scenarios Corresponding to the Highest Predicted AERMOD Impacts.

### 3. Auxiliary Boiler Modeled Rates and Stack Parameters

The auxiliary boiler emission rates and stack parameters included in each combined- and simple-cycle modeled scenario are presented in revised Table 5.1-33-- Auxiliary Boiler Emission Rates and Stack Parameters in the revised Application. The emission rates and operating scenarios have been reviewed.

As explained in AES Response Letter, dated 12/11/15, the auxiliary boiler was not modeled in startup mode as part of the worst-case operational modeling scenarios for 1-hour NO\textsubscript{2} and 1-hour CO because startup of the auxiliary boiler does not occur concurrently with the worst-case emission scenario and only occurs prior to startup of one of the combined-cycle turbines. A process description for the auxiliary boiler was provided in the same letter.

As clarified in AES Response Letter, dated 1/7/16, the normal operating emission rates are based on 100% load for 1-hour and 3-hour averaging periods, but on 50% load for 24-hour and annual averaging periods. A review of the 8-hour averaging period indicates that the normal operating rate is correctly based on 100% load. The revised Application changed the load from 50% to 30% and corrected the SO\textsubscript{2} emission factor basis from 0.25 grains/100 scf to 0.75 grains/100 scf.
Table 55 - Modeled Emission Rates - Normal Operation for Auxiliary Boiler 1

<table>
<thead>
<tr>
<th>Averaging Time</th>
<th>Worst-case Emission Scenario</th>
<th>Pollutant</th>
<th>Emissions Per Turbine, lbs/hr 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-hour</td>
<td>NO₂: Boiler maximum firing rate operation (excluded startups and shutdowns).</td>
<td>NO₂</td>
<td>0.42</td>
</tr>
<tr>
<td></td>
<td>CO: Boiler maximum firing rate operation (excluded startups and shutdowns).</td>
<td>CO</td>
<td>2.83</td>
</tr>
<tr>
<td></td>
<td>SO₂: Boiler maximum firing rate operation (excluded startups and shutdowns).</td>
<td>SO₂</td>
<td>0.14</td>
</tr>
<tr>
<td>1-hour (federal)</td>
<td>NO₂: Boiler maximum firing rate operation (excluded startups and shutdowns).</td>
<td>NO₂</td>
<td>0.42</td>
</tr>
<tr>
<td></td>
<td>SO₂: Boiler maximum firing rate operation (excluded startups and shutdowns).</td>
<td>SO₂</td>
<td>0.14</td>
</tr>
<tr>
<td>3-hour</td>
<td>SO₂: Boiler maximum firing rate operation (excluded startups and shutdowns).</td>
<td>SO₂</td>
<td>0.14</td>
</tr>
<tr>
<td>8-hour</td>
<td>CO: Boiler complete 1 cold start and balance of period at maximum firing rate operation.</td>
<td>CO</td>
<td>2.37</td>
</tr>
<tr>
<td>24-hour</td>
<td>PM₁₀, PM₂.₅: Boiler operate at 30% of maximum firing rate for 31 days, including 2 cold starts, 4 warm starts, 4 hot starts, averaged over 30 days.</td>
<td>PM₁₀, PM₂.₅</td>
<td>0.16</td>
</tr>
<tr>
<td></td>
<td>SO₂: Boiler operate at 30% of maximum firing rate for 31 days, including 2 cold starts, 4 warm starts, 4 hot starts, averaged over 30 days.</td>
<td>SO₂</td>
<td>0.046</td>
</tr>
<tr>
<td>Annual</td>
<td>NO₂, PM₁₀, PM₂.₅: Boiler operate at 30% of maximum firing rate for 8760 hours total, including 24 cold starts, 48 warm starts, 48 hot starts. Condition A63.4 limits annual CO, VOC, PM₁₀, and SOₓ emissions, which also indirectly limits annual NOₓ emissions.</td>
<td>NO₂</td>
<td>0.15</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM₁₀, PM₂.₅</td>
<td>0.15</td>
</tr>
</tbody>
</table>

1 See Table 5.1-33—Auxiliary Boiler Emission Rates and Stack Parameters on page 5.1-34, and discussion on page 5.1-33 of the revised Application.

2 The maximum 1-hour NOₓ and CO and 1-hour and 3-hour SO₂ emission rates are based on normal operation at the maximum hourly firing rate.

3 The 1-, 3-, and 24-hour SO₂ emission rates are based on the short-term fuel sulfur content of 0.75 grain per 100 dscf of natural gas.
Table 56 - Modeled Stack Parameters - Normal Operation for Auxiliary Boiler

<table>
<thead>
<tr>
<th>Parameter</th>
<th>1-hour</th>
<th>1-hour (federal)</th>
<th>Annual</th>
<th>8-hour</th>
<th>1-hour (federal)</th>
<th>3-hour</th>
<th>24-hour</th>
<th>24-hour</th>
<th>Annual</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>0.91</td>
<td>24.4</td>
<td>318 (432)</td>
<td>69.5 (21.2)</td>
<td>AB</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>0.91</td>
<td>24.4</td>
<td>318 (432)</td>
<td>69.5 (21.2)</td>
<td>AB</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SO₂</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>0.91</td>
<td>24.4</td>
<td>318 (432)</td>
<td>69.5 (21.2)</td>
<td>AB</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PM₁₀, PM₂.₅</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>0.91</td>
<td>24.4</td>
<td>318 (432)</td>
<td>69.5 (21.2)</td>
<td>AB</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

See Table 5.1.C.5—Operational Stack Parameters in Appendix 5.1.C.1—Dispersion Modeling and Climate Information, and Table 5.1-33—Auxiliary Boiler Emission Rates and Stack Parameters.

4. Modeled Results – Normal Operation for AEC

The combined- and simple-cycle turbines, but not the auxiliary boiler, are exempt from the modeling requirements of Rule 1303(b)(1) pursuant to the Rule 1304(a)(2) exemption. Therefore the state and federal ambient air quality standards and Rule 1303 thresholds in the table below do not apply and are shown for informational purposes only. Because the South Coast Air Basin is designated non-attainment for the state PM₁₀ standard, and state and federal PM₂.₅ standards, project increments are compared to the significant change thresholds in Rule 1303.

The applicant has provided a modeling analysis of impacts for the entire project in support of the CEC’s CEQA document. The dispersion modeling analysis for maximum AEC operational impacts includes the operation of the two combined-cycle turbines, four simple-cycle turbines, and the auxiliary boiler. The applicant correctly included startups and shutdowns for the maximum hourly emissions for the turbines. Given the number of startups and shutdowns, the emissions from these events cannot be considered as intermittent, as described in the US EPA’s memo dated 3/1/2011.

The maximum AEC operational impacts are presented in revised Table 5.1-38-- AEC Operation Impacts Analysis—Maximum Modeled Impacts Compared to the Ambient Air Quality Standards in the revised Application. PRDAS staff has reviewed the applicant’s analysis and provided updated background concentrations, which are incorporated in the table below.
Table 57 - Modeled Results - Normal Operation for Total Project

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Maximum Predicted Impact (µg/m³)</th>
<th>Background Concentration (µg/m³)</th>
<th>Total Predicted Concentration (µg/m³)</th>
<th>State Standard CAAQS (µg/m³)</th>
<th>Federal Standard, Primary NAAQS (µg/m³)</th>
<th>Rule 1303 Thresholds (µg/m³)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂¹</td>
<td>1-hour</td>
<td>31.3</td>
<td>255.5</td>
<td>286.8</td>
<td>339</td>
<td>--</td>
<td>188</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>1-hour (98&lt;sup&gt;th&lt;/sup&gt; percentile)&lt;sup&gt;²&lt;/sup&gt;</td>
<td>22.6</td>
<td>146.3</td>
<td>168.9</td>
<td>--</td>
<td>188</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>0.2</td>
<td>47.6</td>
<td>47.8</td>
<td>57</td>
<td>100</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>SO₂</td>
<td>1-hour</td>
<td>2.1</td>
<td>58.2</td>
<td>60.3</td>
<td>655</td>
<td>--</td>
<td>196</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>1-hour (99&lt;sup&gt;th&lt;/sup&gt; percentile)&lt;sup&gt;³&lt;/sup&gt;</td>
<td>2.1</td>
<td>58.2</td>
<td>60.3</td>
<td>--</td>
<td>196</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td>3-hour</td>
<td>1.7</td>
<td>58.2</td>
<td>59.9</td>
<td>--</td>
<td>1,300</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td>24-hour</td>
<td>0.5</td>
<td>7.9</td>
<td>8.4</td>
<td>105</td>
<td>--</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>CO</td>
<td>1-hour</td>
<td>186</td>
<td>4,237</td>
<td>4,423</td>
<td>23,000</td>
<td>40,000</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td>8-hour</td>
<td>44</td>
<td>2,977</td>
<td>3021</td>
<td>10,000</td>
<td>10,000</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>PM&lt;sub&gt;10&lt;/sub&gt;</td>
<td>24-hour</td>
<td>1.7</td>
<td>59.0</td>
<td>60.7</td>
<td>150</td>
<td>No</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td>24-hour</td>
<td>1.7</td>
<td>59.0</td>
<td>60.7</td>
<td>150</td>
<td>2.5</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>20</td>
<td>12</td>
<td>1</td>
<td>1</td>
<td>No</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>PM&lt;sub&gt;2.5&lt;/sub&gt;</td>
<td>24-hour</td>
<td>1.3</td>
<td>12</td>
<td>35</td>
<td>2.5</td>
<td>No</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>12</td>
<td>12</td>
<td>1</td>
<td>1</td>
<td>No</td>
<td>No</td>
<td></td>
</tr>
</tbody>
</table>

¹ The maximum 1-hour and annual NO₂ concentrations include ambient NO₂ to NOx conversion ratios of 0.80 and 0.75, respectively.

² On 4/12/10, the U.S. EPA established a new 1-hour NO₂ standard of 100 ppb (188 µg/m³). The form of the federal 1-hour NO₂ standard involves a three year average of the 98<sup>th</sup> percentile of the annual distribution of daily maximum 1-hour concentrations.

³ On 6/2/10, the U.S. EPA established a new 1-hour SO₂ standard of 75 ppb (196 µg/m³). The form of the federal 1-hour SO₂ standard involves a three year average of the 99<sup>th</sup> percentile of the annual distribution of daily maximum 1-hour concentrations.

5. Modeled Results – Normal Operation for Auxiliary Boiler

The auxiliary boiler are subject to the modeling requirements of Rule 1303(b)(1). The maximum auxiliary boiler impacts were not provided in any table in the original or revised Applications. PRDAS staff has provided the maximum modeled concentrations and updated background concentrations for the following table.
## Table 57A - Modeled Results - Normal Operation for Auxiliary Boiler

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Maximum Predicted Impact (µg/m³)</th>
<th>Background Concentration (µg/m³)</th>
<th>Total Predicted Concentration (µg/m³)</th>
<th>State Standard CAAQS (µg/m³)</th>
<th>Federal Standard, Primary NAAQS (µg/m³)</th>
<th>Rule 1303 Thresholds (µg/m³)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂</td>
<td>1-hour</td>
<td>1.2</td>
<td>255.5</td>
<td>256.7</td>
<td>339</td>
<td>--</td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>1-hour (98th percentile)</td>
<td>1.1</td>
<td>146.3</td>
<td>147.4</td>
<td>--</td>
<td>188</td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>0.03</td>
<td>47.6</td>
<td>47.63</td>
<td>57</td>
<td>100</td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td>SO₂</td>
<td>1-hour</td>
<td>0.5</td>
<td>58.2</td>
<td>58.7</td>
<td>655</td>
<td>--</td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>1-hour (99th percentile)</td>
<td>0.5</td>
<td>30.1</td>
<td>30.6</td>
<td>--</td>
<td>196</td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>3-hour</td>
<td>0.5</td>
<td>58.2</td>
<td>58.7</td>
<td>--</td>
<td>1,300</td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>24-hour</td>
<td>0.1</td>
<td>7.9</td>
<td>8.0</td>
<td>105</td>
<td>--</td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td>CO</td>
<td>1-hour</td>
<td>10</td>
<td>4,237</td>
<td>4,247</td>
<td>23,000</td>
<td>40,000</td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>8-hour</td>
<td>6</td>
<td>2,977</td>
<td>2,983</td>
<td>10,000</td>
<td>10,000</td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>24-hour</td>
<td>0.3</td>
<td>59.0</td>
<td>59.3</td>
<td>150</td>
<td>--</td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>24-hour</td>
<td>0.5</td>
<td>50</td>
<td>50</td>
<td>150</td>
<td>2.5</td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>0.04</td>
<td>20</td>
<td></td>
<td>1</td>
<td></td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td>PM₂.⁵</td>
<td>24-hour</td>
<td>0.1</td>
<td></td>
<td>35</td>
<td>2.5</td>
<td></td>
<td>--</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>0.04</td>
<td></td>
<td>12</td>
<td>1</td>
<td></td>
<td>--</td>
<td>No</td>
</tr>
</tbody>
</table>

The maximum 1-hour and annual NO₂ concentrations include ambient NO₂ to NOx conversion ratios of 0.80 and 0.75, respectively.

### 6. Modeled Results - Rule 2005

See Rule 2005 analysis below.

**COMMISSIONING IMPACTS**

The combined- and simple-cycle turbines, but not the auxiliary boiler, are exempt from the modeling requirements of Rule 1303(b)(1) pursuant to the Rule 1304(a)(2) exemption. Therefore the state and federal ambient air quality standards and Rule 1303 thresholds in the table below do not apply and are shown for informational purposes only. Because the South Coast Air Basin is designated non-attainment for the state PM₁₀ standard, and state and federal PM₂.⁵ standards, project increments are compared to the significant change thresholds in Rule 1303.

As discussed above, the NOx, CO, and VOC emission rates are expected to be higher during the commissioning period than during normal operations, because the turbines are operated without, or with partial, emission control systems in operation. The PM₁₀/PM₂.⁵ and SO₂ emission rates are the same as during normal operation, because these pollutants are not controlled by the SCR/CO catalysts.
1. **Combined-Cycle Gas Turbines**

The total duration of the AEC CCGT commissioning period is expected to be up to 1,992 hours (996 hours per turbine). During the commissioning period, each GE 7FA.05 will be operated for up to 216 hours without emission control systems in operation. Although SCAQMD PRDAS staff has indicated that the annual averaging period is to be based on routine operation and not include a once-in-a-lifetime event, such as commissioning, the applicant provided modeling for annual impacts for the commissioning year, consisting of commissioning emissions and normal operating emissions the balance of the year.

A total of three scenarios were modeled. The three scenarios consist of two GE 7FA.05s modeled at 10% load, 40% load, and 80% load, with all scenarios including the operation of the auxiliary boiler. The conservative assumption is that both turbines would be commissioned simultaneously. The modeling for the short-term averaging periods include NOx and CO only.

Separate scenarios for commissioning impacts were not run for SO\(_2\) and PM\(_{10}\)/PM\(_{2.5}\) since emissions of these pollutants are higher during normal operation than during commissioning. The sum of the maximum operational impacts from the combined-cycle turbines and the auxiliary boiler were conservatively used to represent commissioning impacts.

The AERMOD dispersion analysis was conducted using the parameters and emission rates for commissioning of the AEC CCGT, as presented in revised Table 5.1-29—AEC CCGT Commissioning Dispersion Modeling Scenarios in the revised Application. The highest unabated emission rates per turbine occur during CTG testing at full speed with no load, with this event lasting up to 48 hours.

<table>
<thead>
<tr>
<th>Scenarios</th>
<th>No. of Turbines/Modeling Load</th>
<th>Stack Diameter (m)</th>
<th>Stack Height (m)</th>
<th>Exit Velocity (m/sec)</th>
<th>Exhaust Temperature (°K)</th>
<th>1-hr NOx (lb/hr)</th>
<th>1-hr CO (lb/hr)</th>
<th>8-hr CO (lb/hr)</th>
<th>Annual NOx (lb/hr)</th>
<th>Annual PM(<em>{10})/PM(</em>{2.5}) (gr/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTG Testing (Full Speed No Load)</td>
<td>Two/10%</td>
<td>6.10</td>
<td>42.7</td>
<td>9.33</td>
<td>361</td>
<td>130</td>
<td>1900</td>
<td>1900</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Steam Blows</td>
<td>Two/40%</td>
<td>6.10</td>
<td>42.7</td>
<td>11.9</td>
<td>359</td>
<td>68.3</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Emissions Tuning</td>
<td>Two/80%</td>
<td>6.10</td>
<td>42.7</td>
<td>16.1</td>
<td>366</td>
<td>63.0</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Commissioning Year(^2)</td>
<td>Two/Worst Case</td>
<td>6.10</td>
<td>42.7</td>
<td>11.8</td>
<td>350</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>9.39</td>
<td>5.47</td>
</tr>
</tbody>
</table>

\(^1\) See Table 5.1C.1—Commissioning Stack Parameters in Appendix 5.1C.1, and Table 5.1-29—AEC CCGT Commissioning Dispersion Modeling Scenarios on page 5.1-30 in the revised Application.

\(^2\) Emission rates, stack exit velocity, and stack temperature for the commissioning year, consisting of commissioning emissions and normal operating emissions the balance of the year, are based on the operational load resulting in the highest modeled impact of NOx, PM\(_{10}\), and PM\(_{2.5}\).
The modeling shows that the maximum impact occurs when the two turbines are simultaneously undergoing commissioning activities with the highest unabated emissions, and the auxiliary boiler is in operation. The results of the modeling analysis are presented in revised Table 5.1-36-AEC CCGT Commissioning Impacts Analysis—Maximum Modeled Impacts Compared to the Ambient Air Quality Standards in the revised Application.

PRDAS staff has reviewed the applicant’s analysis and provided updated background concentrations, which are incorporated in the table below.

Table 59 - Modeled Results – Commissioning for AEC CCGT
(Auxiliary Boiler in Normal Operation)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Maximum Predicted Impact (µg/m³)</th>
<th>Background Concentration (µg/m³)</th>
<th>Total Predicted Concentration (µg/m³)</th>
<th>State Standard CAAQS (µg/m³)</th>
<th>Federal Standard, Primary NAAQS (µg/m³)</th>
<th>Rule 1303 Thresholds (µg/m³)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂</td>
<td>1-hour</td>
<td>67.6</td>
<td>255.5</td>
<td>323.1</td>
<td>339</td>
<td>--</td>
<td>188</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>1-hour</td>
<td>Analysis excluded because turbine testing at full speed with no load will occur once in the lifetime of AEC and last less than 48 hours.</td>
<td></td>
<td>--</td>
<td></td>
<td>188</td>
<td></td>
<td>No</td>
</tr>
<tr>
<td>SO₂</td>
<td>1-hour</td>
<td>2.2</td>
<td>58.2</td>
<td>60.4</td>
<td>655</td>
<td>--</td>
<td>196</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Analysis excluded because turbine testing at full speed with no load will occur once in the lifetime of AEC and last 48 hours.</td>
<td></td>
<td>--</td>
<td>196</td>
<td></td>
<td></td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td>3-hour</td>
<td>1.9</td>
<td>58.2</td>
<td>60.1</td>
<td>1,300</td>
<td>No</td>
<td></td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>24-hour</td>
<td>0.6</td>
<td>7.9</td>
<td>8.5</td>
<td>105</td>
<td>365</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>CO</td>
<td>1-hour</td>
<td>1.231</td>
<td>4,237</td>
<td>5,468</td>
<td>23,000</td>
<td>40,000</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>8-hour</td>
<td>835</td>
<td>2,977</td>
<td>3,812</td>
<td>10,000</td>
<td>10,000</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>24-hour</td>
<td>1.6</td>
<td>59.0</td>
<td>60.6</td>
<td>-</td>
<td>150</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>24-hour</td>
<td>1.6</td>
<td></td>
<td>50</td>
<td>150</td>
<td>2.5</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>0.2</td>
<td></td>
<td>20</td>
<td>1</td>
<td>1</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>PM₂.₅</td>
<td>24-hour</td>
<td>1.1</td>
<td></td>
<td>-</td>
<td>35</td>
<td>2.5</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>0.2</td>
<td></td>
<td>12</td>
<td>12</td>
<td>1</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>

The maximum 1-hour and annual NO₂ concentrations include ambient NO₂ to NOx conversion ratios of 0.80 and 0.75, respectively.

2. **Simple-Cycle Gas Turbines**

The total duration of the AEC SCGT commissioning period is expected to be up to 1,120 hours (280 hours per turbine). During the commissioning period, each GE LMS-100 PB will be operated for up to 4 hours without emission control systems in operation. Although SCAQMD PRDAS staff has indicated that the annual averaging period is to be based on routine operation and not include a once-in-a-lifetime event, such as commissioning, the applicant provided modeling for annual impacts for the commissioning year, consisting of commissioning emissions and normal operating emissions the balance of the year.
A total of three scenarios were modeled. The three scenarios consist of four GE LMS-100 PB modeled at 5% load, 75% load, and 100% load, with all scenarios including the operation of two GE 7FA.05 turbines and the auxiliary boiler. The conservative assumption is that four turbines would be commissioned simultaneously. The modeling for the short-term averaging periods include NOx and CO only. For SOx and PM$_{10}$, the highest short-term emission rates (Case 1) and resulting maximum air quality impact result from normal operating conditions were used to represent commissioning impacts.

The AERMOD dispersion analysis was conducted using the parameters and emission rates for commissioning of the AEC SCGT, as presented in Table 5.1-30—AEC SCGT Commissioning Dispersion Modeling Scenarios, which is a source for the table below. The highest unabated emission rates per turbine occur during CTG testing at full speed with no load, with this event lasting up to 4 hours.

### Table 60 - Modeled Emission Rates and Stack Parameters – Commissioning for AEC SCGT (Four Turbines)

<table>
<thead>
<tr>
<th>Scenarios</th>
<th>No. of Turbines/Modeling Load</th>
<th>Stack Diameter (m)</th>
<th>Stack Height (m)</th>
<th>Exit Velocity (m/sec)</th>
<th>Exhaust Temperature (°K)</th>
<th>1-hr NOx</th>
<th>1-hr CO</th>
<th>8-hr CO</th>
<th>Annual NOx</th>
<th>Annual PM$<em>{10}$/PM$</em>{2.5}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Testing (Full Speed No Load)</td>
<td>Four/5%</td>
<td>4.11</td>
<td>24.4</td>
<td>10.0</td>
<td>728</td>
<td>40.1</td>
<td>244</td>
<td>244</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Commissioning and Normal Operating Year</td>
<td>Four/Worst Case</td>
<td>4.11</td>
<td>24.4</td>
<td>23.6</td>
<td>746</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>2.95</td>
<td>1.88</td>
</tr>
</tbody>
</table>

1. See Table 5.1C.1—Commissioning Stack Parameters in Appendix 5.1C.1—Dispersion Modeling and Climate Information, and Table 5.1-30—AEC SCGT Commissioning Dispersion Modeling Scenarios on page 5.1-30 in the revised Application.

2. Emission rates, stack exit velocity, and stack temperature for the combined annual commissioning and operation are based on the operational load resulting in the highest modeled impact of NOx, PM$_{10}$, and PM$_{2.5}$.

The simple-cycle turbines will be commissioned after the combined-cycle turbines are already in operation. The modeling shows the maximum impact occurs while the four simple-cycle turbines are simultaneously undergoing commissioning activities with the highest unabated emissions presented in the table above, the two combined-cycle turbines are simultaneously operating with the steady-state emissions presented in Table 51 - Modeled Emission Rates - Normal Operation for AEC CCGT above, and the auxiliary boiler is in operation. The results of the modeling analysis are presented in revised Table 5.1-37-- AEC SCGT Commissioning Impacts Analysis—Maximum Modeled Impacts Compared to the Ambient Air Quality Standards in the revised Application.
PRDAS staff has reviewed the applicant’s analysis and provided updated background concentrations, which are incorporated in the table below.

### Table 61 - Modeled Results – Commissioning for AEC SCGT
(CCCT & Auxiliary Boiler in Normal Operation)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Maximum Predicted Impact (µg/m³)</th>
<th>Background Concentration (µg/m³)</th>
<th>Total Predicted Concentration (µg/m³)</th>
<th>State Standard CAAQS (µg/m³)</th>
<th>Federal Standard, Primary NAAQS (µg/m³)</th>
<th>Rule 1303 Thresholds (µg/m³)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂</td>
<td>1-hour</td>
<td>61.9</td>
<td>255.5</td>
<td>317.4</td>
<td>339</td>
<td>--</td>
<td>188</td>
<td>No</td>
</tr>
<tr>
<td>Federal 1-hour Analysis excluded because turbine testing at full speed with no load will occur once in the lifetime of AEC and last 4 hours.</td>
<td>--</td>
<td>188</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual</td>
<td>0.20</td>
<td>47.6</td>
<td>47.8</td>
<td>57</td>
<td>100</td>
<td>N/A</td>
<td>N/A</td>
<td>No</td>
</tr>
<tr>
<td>SO₂</td>
<td>1-hour</td>
<td>2.1</td>
<td>58.2</td>
<td>60.3</td>
<td>655</td>
<td>--</td>
<td>196</td>
<td>No</td>
</tr>
<tr>
<td>Federal 1-hour Analysis excluded because turbine testing at full speed with no load will occur once in the lifetime of AEC and last 4 hours.</td>
<td>--</td>
<td>196</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3-hour</td>
<td>1.7</td>
<td>58.2</td>
<td>59.9</td>
<td>--</td>
<td>1,300</td>
<td>N/A</td>
<td>N/A</td>
<td>No</td>
</tr>
<tr>
<td>24-hour</td>
<td>0.5</td>
<td>7.9</td>
<td>8.4</td>
<td>105</td>
<td>365</td>
<td>N/A</td>
<td>N/A</td>
<td>No</td>
</tr>
<tr>
<td>CO</td>
<td>1-hour</td>
<td>470</td>
<td>4,237</td>
<td>4,707</td>
<td>23,000</td>
<td>40,000</td>
<td>365</td>
<td>No</td>
</tr>
<tr>
<td>8-hour</td>
<td>240</td>
<td>2,977</td>
<td>3,217</td>
<td>10,000</td>
<td>10,000</td>
<td>N/A</td>
<td>N/A</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>24-hour</td>
<td>1.7</td>
<td>59.0</td>
<td>60.7</td>
<td>-</td>
<td>150</td>
<td>N/A</td>
<td>No</td>
</tr>
<tr>
<td>24-hour</td>
<td>1.7</td>
<td>50</td>
<td>150</td>
<td>2.5</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>No</td>
</tr>
<tr>
<td>Annual</td>
<td>0.2</td>
<td>20</td>
<td>1</td>
<td>1</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>No</td>
</tr>
<tr>
<td>PM₂.₅</td>
<td>24-hour</td>
<td>1.3</td>
<td>-</td>
<td>35</td>
<td>2.5</td>
<td>N/A</td>
<td>N/A</td>
<td>No</td>
</tr>
<tr>
<td>Annual</td>
<td>0.2</td>
<td>12</td>
<td>12</td>
<td>1</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>No</td>
</tr>
</tbody>
</table>

The maximum 1-hour and annual NO₂ concentrations include ambient NO₂ to NOx conversion ratios of 0.80 and 0.75, respectively.

3. **Auxiliary Boiler**
   As explained in AES Response Letter, dated 12/11/15, the auxiliary boiler will be commissioned and ready for operation before the commissioning of the combined-cycle turbines. Because the commissioning will be completed in five days and the daily emissions are equivalent to two cold startups, the commissioning does not need to be modeled separately.

- **Rule 1303(b)(2)—Offsets**
  Rule 1303(b)(2) requires a net emission increase in emissions of any nonattainment air contaminant (PM₁₀, ROG, and SOx) from a new or modified source to be offset unless exempt from offset requirements pursuant to Rule 1304. Since CO is an attainment pollutant and not a precursor to any nonattainment pollutant, offset requirements are not applicable.

   “Source” is defined by Rule 1302(ao) to mean “any permitted individual unit, piece of equipment, article, machine, process, contrivance, or combination thereof, which may emit or control an air
contaminant. This includes any permit unit at any non-RECLAIM facility and any device at a RECLAIM facility.”

Unless exempt, the amount of offsets required for each pollutant is determined using the 30-day average. The 30-day average is based on the highest emissions for any month, including a month where commissioning takes place. The offset ratio for emission reduction credits (ERCs) is 1.2-to-1.

- **Combined-Cycle Turbines, A/N 579142, 579143**
- **Simple-Cycle Turbines, A/N 579145, 579147, 1549150, 579152**
  - VOC, SOx, and PM
    SCAQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler repower projects. The exemption applies to: “The source is replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-recovered gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The new equipment must have a maximum electrical power rating (in megawatts) that does not allow basinwide electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset.” This exemption applies to the combined-cycle turbines, and simple-cycle turbines equipped with intercoolers.

- **NOx**
  For NOx RTC requirements, see Rule 2005(c)(2) analysis below.

- **Auxiliary Boiler, A/N 579158**
- **Oil-Water Separator, Combined-Cycle Turbines, A/N 579169**
- **Oil-Water Separator, Simple-Cycle Turbines, A/N 579170**
  - VOC, SOx, and PM
    Rule 1304(d)(2)(B) specifies that any modified facility that has a post-modification potential equal to or more than 4 tpy VOC, 4 tpy SOx, and 4 tpy PM is required to provide offsets for the emissions increases. This requirement is applicable to the auxiliary boiler and two oil-water separators.

### Table 62 - Post-Modification Project 30-Day Averages

<table>
<thead>
<tr>
<th>A/N</th>
<th>Equipment</th>
<th>VOC 30-Day Average, lbs/day</th>
<th>SOx 30-Day Average, lbs/day</th>
<th>PM$_{10}$ 30-Day Average, lbs/day</th>
</tr>
</thead>
<tbody>
<tr>
<td>579158</td>
<td>Auxiliary Boiler</td>
<td>3.40</td>
<td>1.06</td>
<td>3.78</td>
</tr>
<tr>
<td>579169</td>
<td>Oil/Water Separator, Combined-Cycle Turbines</td>
<td>0.0005</td>
<td></td>
<td></td>
</tr>
<tr>
<td>579170</td>
<td>Oil/Water Separator, Simple-Cycle Turbines,</td>
<td>0.000073</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Project, lbs/day</td>
<td>3.40 lb/day</td>
<td>1.06 lb/day</td>
<td>3.78 lb/day</td>
</tr>
</tbody>
</table>

Preliminary Determination of Compliance

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170
VOC
ERCs required = 3.40 \times 1.2 \text{ offset factor} = 4.08 \text{ lb/day} \rightarrow 4 \text{ lb/day}

SO\textsubscript{X}
ERCs required = 1.06 \times 1.2 \text{ offset factor} = 1.27 \text{ lb/day} \rightarrow 1 \text{ lb/day}

PM\textsubscript{10}
ERCs required = 3.78 \times 1.2 \text{ offset factor} = 4.54 \text{ lb/day} \rightarrow 5 \text{ lb/day}

- NO\textsubscript{X}
  For NO\textsubscript{X} RTC requirements for the auxiliary boiler, see Rule 2005(c)(2) analysis below.

The following table summarizes the number of ERCs and RTCs required for each permit unit.

<table>
<thead>
<tr>
<th>A/N</th>
<th>Equipment</th>
<th>VOC ERCs, lbs/day</th>
<th>SO\textsubscript{X} ERCs, lbs/day</th>
<th>PM\textsubscript{10} ERCs, lbs/day</th>
<th>NO\textsubscript{X} RTCs, lb/yr (first year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>579142</td>
<td>Combined-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td>108,377</td>
</tr>
<tr>
<td>579143</td>
<td>Combined-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td>108,377</td>
</tr>
<tr>
<td>579145</td>
<td>Simple-Cycle Turbine</td>
<td></td>
<td></td>
<td></td>
<td>68,575</td>
</tr>
<tr>
<td>579147</td>
<td>Simple-Cycle Turbines</td>
<td></td>
<td></td>
<td></td>
<td>68,575</td>
</tr>
<tr>
<td>579150</td>
<td>Simple-Cycle Turbines</td>
<td></td>
<td></td>
<td></td>
<td>68,575</td>
</tr>
<tr>
<td>579152</td>
<td>Simple-Cycle Turbines</td>
<td></td>
<td></td>
<td></td>
<td>68,575</td>
</tr>
<tr>
<td>579158</td>
<td>Auxiliary Boiler</td>
<td>4</td>
<td>1</td>
<td>5</td>
<td>1351</td>
</tr>
<tr>
<td>579169</td>
<td>Oil-Water Separator, Combined-Cycle Turbines</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>579170</td>
<td>Oil-Water Separator, Simple-Cycle Turbines</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Project, lbs/day</strong></td>
<td><strong>4</strong></td>
<td><strong>1</strong></td>
<td><strong>5</strong></td>
<td></td>
<td>First year: 218,105 lb for combined-cycle turbines &amp; boiler. First year: 274,300 lb for simple-cycle turbines.</td>
</tr>
</tbody>
</table>

Regarding the NO\textsubscript{X} RTCs, the first-year operation for the combined-cycle turbines and auxiliary boiler will have ended prior to the first-year operation for the simple-cycle turbines.

A summary of the Certificates of Proof for Registered Emission Reduction Credit, with the ERC seller/originator history, for the VOC ERCs and the PM\textsubscript{10} ERCs provided for the AEC are shown in the table below. Since Rule 1309--Emission Reduction Credits and Short Term Credits is not SIP-approved, the Short-Term ERCs (STERCs) provided have been converted to ERCs for use as offsets.
ROG ERCs-- Based on the original application, AES provided 5 lbs/day of ROG in the form of a stream of Short Term ERCs. Since the revised application increased the ROG emission factor but reduced the normal operating rate from 50% to 30% load, 4 lbs/day of ROG ERCs are now required.

PM<sub>10</sub> ERCs—Based on the original application, AES provided 5 lbs/day of PM<sub>10</sub> ERCs. Although the revised application increased the PM<sub>10</sub> emission factor and reduced the normal operating rate from 50% to 30% load, 5 lbs/day of PM<sub>10</sub> ERCs are still required.

SOx ERCs—Based on the original application, AES did not provide any SOx ERCs. Since the methodology for determining the number of ERCs is to multiply the offset factor of 1.2 times the 30-day average, then round to a whole number, 1 lb/day of SOx ERC was required. Since the revised application corrected the normal operating rate from a basis of 0.25 grains/100 cf (original application) to 0.75 grains/100 cf, it became clearer that 1 lb/day of SOx ERC is required. AES has agreed to provide 1 lb/day of SOx ERC.
## Preliminary Determination of Compliance

**Alamitos Energy Center**  
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

### Table 63A - ERC Certificate Nos. and History

<table>
<thead>
<tr>
<th>Emittent</th>
<th>STERC Cert. No.</th>
<th>ERC Cert. No.</th>
<th>Title Change Appl. No.</th>
<th>Date of Issue</th>
<th>ERC Type</th>
<th>Amount (lb/day)</th>
<th>Name</th>
<th>Cert. No.</th>
<th>Address</th>
<th>Cert. No.</th>
<th>Zone</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM₁₀</td>
<td>AQ014168</td>
<td>578696</td>
<td>10/9/2015</td>
<td>ERC</td>
<td>4</td>
<td>CE2 Carbon Capital, LLC ID 178346</td>
<td>AQ014162</td>
<td>750 Eldridge St, Terminal Island, CA 90731</td>
<td>AQ006307</td>
<td>01-Coastal</td>
<td></td>
</tr>
<tr>
<td>PM₁₀</td>
<td>AQ014169</td>
<td>578697</td>
<td>10/9/2015</td>
<td>ERC</td>
<td>1</td>
<td>CE2 Carbon Capital, LLC ID 178346</td>
<td>AQ014160</td>
<td>1001 N Tustin, Santa Ana, CA 92705</td>
<td>AQ000491</td>
<td>01-Coastal</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>PM₁₀ Total</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>ROG</td>
<td>AQ014175</td>
</tr>
<tr>
<td>ROG</td>
<td>AQ014176</td>
</tr>
<tr>
<td>ROG</td>
<td>AQ014177</td>
</tr>
<tr>
<td>ROG</td>
<td>AQ014178</td>
</tr>
<tr>
<td>ROG</td>
<td>AQ014179</td>
</tr>
<tr>
<td>ROG</td>
<td>AQ014180</td>
</tr>
<tr>
<td>ROG</td>
<td>AQ014181</td>
</tr>
<tr>
<td>ROG Total</td>
<td>5</td>
</tr>
<tr>
<td>SOx</td>
<td></td>
</tr>
</tbody>
</table>

**AES has agreed to provide 1 lb/day SOx ERC.**

| SOx Total | 1 |

---

1 The Certificates of Proof include the address where the reduction was created, but not the company name.
• **Rule 1303(b)(3)—Sensitive Zone Requirements**

• **Rule 2005(e)—Trading Zone Restrictions**
  Both rules provide that credits shall be obtained from the appropriate trading zone. A facility located in zone 1, such as AES Alamitos, may obtain ERCs originated in zone 1 only, and RTCs originated in zone 1 only.

• **Rule 1303(b)(4)—Facility Compliance**
  AEC will comply with all applicable rules and regulations of the District, as required by this rule.

• **Rule 1303(b)(5)—Major Polluting Facilities**

• **Rule 2005(g)—Additional Federal Requirements for Major Stationary Sources**
  Any major modification at an existing major polluting facility shall comply with the following provisions. AGS is an existing major polluting facility as defined by Rule 1302(s), and its replacement by AEC is a major modification under Rule 1302(r).

  • **Rule 1303(b)(5)(A) – Alternative Analysis**
  • **Rule 2005(g)(2)—Alternative Analysis**
  • **Rule 1303(b)(5)(D) – Compliance through CEQA**
  • **Rule 2005(g)(3)—Compliance through CEQA**

  Rule 1303(b)(5)(A) requires an analysis of alternative sites, sizes, production processes and environmental control techniques, and a demonstration that the benefits of the proposed project outweigh the environmental and social costs associated with that project. Rule 2005(g)(2) requires an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source which demonstrates that the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of its location, construction, and modification.

  Rule 1303(b)(5)(D) specifies the requirements of subparagraph (b)(5)(A) may be met through compliance with CEQA. Rule 2005(g)(3) specifies the requirements of paragraph (g)(2) may be met through CEQA analysis.

The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger. The CEC's 12-month permitting process is a certified regulatory program under CEQA and includes various opportunities for public and inter-agency participation. Section 6 of the Supplemental AFC presents a review of alternatives, including the “no project” alternative, power plant site alternatives, alternative project design features (alternative natural gas supply pipeline routes, electrical transmission system alternatives, water supply alternatives), technology alternatives (generation technology alternatives, conventional boiler and steam turbine, nuclear, Kalina combined-cycle, internal combustion engines), fuel technology alternatives, NOx control alternatives, energy storage options, and waste discharge alternatives.
Rule 1303(b)(5)(B) – Statewide Compliance

Rule 2005(g)(1) – Statewide Compliance

Rule 1303(b)(5)(C) – Protection of Visibility

Rule 2005(g)(4) — Protection of Visibility

Rule 1304.1 — Electrical Generating Facility Fee for Use of Offset Exemption

The purpose of this rule is to require Electrical Generating Facilities (EGFs) which use the specific offset exemption described in Rule 1304(a)(2) [Electric Utility Steam Boiler Replacement] to pay fees for up to the full amount of offsets provided by the SCAQMD. Notwithstanding Rule 1301(c)(1), this rule applies to all permits issued to EGFs electing to use Rule 1304(a)(2) and receiving the applicable permit to construct on or after September 6, 2013.

Requirements

(a) The purpose of this rule is to require Electrical Generating Facilities (EGFs) which use the specific offset exemption described in Rule 1304(a)(2) [Electric Utility Steam Boiler Replacement] to pay fees for up to the full amount of offsets provided by the SCAQMD. Notwithstanding Rule 1301(c)(1), this rule applies to all permits issued to EGFs electing to use Rule 1304(a)(2) and receiving the applicable permit to construct on or after September 6, 2013.

(c) Requirements

(l) Any EGF operator electing to use the offset exemptions provided by Rule 1304(a)(2) shall pay a fee, the Offset Fee (F_i), calculated pursuant to paragraph (c)(2), for each pound per day of each pollutant (i), for which the SCAQMD provides offsets. This
fee may be paid on an annual basis or as a single payment or a combination of both at the election of the applicant.

(2) The Offset Fee ($F_i$), for a specific pollutant $(i)$, shall be calculated by multiplying the applicable pollutant specific Annual Offset Fee Rate $(R_i)$ or Single Payment Offset Fee Rate $(L_i)$ and Offset Factor in Table A1 or A2, as applicable, by the fraction of the potential to emit level(s) of the new replacement unit(s). This fraction is calculated as the product of the potential to emit of the new replacement unit $(PTE_{rep,i})$ multiplied by the new replacement to existing unit generation annual capacity ratio. This annual capacity ratio which is defined as the maximum permitted annual megawatt hour (MWh) generation of the new replacement unit(s) $(C_{rep})$ minus the most recent twenty-four (24) months average of the megawatt hour (MWh) generation (megawatt utilization) of the unit(s) to be replaced $(C_{2YR Avg Existing})$ divided by the maximum permitted annual megawatt hour (MWh) generation of the new replacement unit(s) $(C_{rep})$.

Note: Tables A1 and A2 indicate the annual offset fee rates $(R_i)$ and single payment offset fee rates $(L_i)$ for PM, NOx (non-RECLAIM sources only), SOx, and VOC are adjusted annually by the CPI.

Rule 1304.1 was adopted on 9/6/13. Therefore, the offset fee rates in the rule are effective for the fiscal year ending 6/30/14. For each successive fiscal year, the offset fee rates are required to be adjusted by the Governing Board-approved annual percent fee increase, effective each July 1.

(3) The owner/operator of an EGF electing to use the offset fee exemption of Rule 1304(a)(2) shall remit the offset fees as follows:

(A) For the annual payment option:

(i) The owner/operator must remit the first year annual offset fee payment prior to the issuance of the permit to construct and such fees shall be based on the total amount of the repowered MW capacity for which a permit to construct is being issued by SCAQMD for the facility. Subsequent payments shall be remitted annually based on the cumulative total of MW capacity that commenced operation, on or before the anniversary date of the original commencement of operation of such MW capacity at the fee rates in effect at the time the fee is due.

(ii) The owner/operator of an EGF that has elected the annual fee payment option may switch to the single payment option upon submittal of a written request to the Executive Officer for such a change in payment method. The amount of the single payment offset fee due shall be based
on offset fee rates applicable at the time the written request for the change in payment method is submitted to the Executive Officer. The sum of the annual offset fees remitted prior to the submittal of a request for change to a single payment option shall be credited towards the single payment offset fee due.

(B) For the single payment option, the owner/operator must remit the entire fee prior to issuance of the permit to construct.

Analysis:
In an e-mail, dated 2/25/16, AES selected the annual payment option for the first payment due prior to the issuance of the permits to construct, thereafter switching to the single payment option prior to the end of the first year of operation.

The SCAQMD has provided a Rule 1304.1 Excel calculator that is available on the SCAQMD website to calculate total annual fee and total single fee for a set of turbines. Estimates of the annual offset fees that are required to be remitted prior to the issuance of the permits to construct are shown below in Table 65 for the combined-cycle turbines and in Table 66 for the simple-cycle turbines. Estimates of the single offset fees are shown below in Table 65A for the combined-cycle turbines and in Table 66A for the simple-cycle turbines. The annual offset fees paid will be credited towards the single offset fees that AES has indicated it will switch to subsequent to the initial payment.

- Combined-Cycle Turbines
The inputs for the calculator are discussed below.

a-Gross Rating of New Replacement Units (MW): 692.951 MW

Basis:

\[(231.197 \text{ MW-gross/CTG}) \times (2 \text{ CTGs}) + 230.557 \text{ MW-gross/steam turbine}\]  
= 692.951 MW (Case 12)

b-Maximum Fraction of Time Allowed to Operate (%): 53%

Basis:

c-Max Allowable Operating Hours Annually (hr/yr) = 4612 hr/yr

Hours in a Year (hr/yr) = 8760 hr/yr

Fraction of Time Allowed to Operate = 4640 hr/yr ÷ 8760 hr/yr = 53%

Note: For the purpose of this rule, startup and shutdown hours are included.
e-Average Last 2 years of Existing Unit(s) Actual Generation (MWh/yr): 311,104 MW-net

*Basis:*
Rule 1304.1(c) defines $C_{2YRAvgExisting}$ to mean “the average annual megawatt-hour (MWh) generation of the existing unit(s) to be replaced using the last twenty-four (24) month period immediately prior to issuance of the permit to construct.” The AGS’s megawatt-hours are reported to the EPA through the EPA’s Acid Rain program and can be downloaded for the appropriate 24-month period.

Once the timing of the issuance of the permits to construct is determined, the “e-Average Last 2 years of Existing Unit(s) Actual Generation (MWh/yr)” for the appropriate 24-month period will be finalized and used to calculate the initial annual fee for PM$_{10}$, SOx, and VOC.

For a preliminary estimate, the applicant provided the 2013 and 2014 generation for Boilers Nos. 1, 2, 5, and 3.

### Table 64 - AGS 2-Year Average Electrical Production (2013 & 2014)

<table>
<thead>
<tr>
<th>Unit</th>
<th>Rating MW-gross</th>
<th>Shutdown Date</th>
<th>2013 MWh-gross</th>
<th>2013 MWh-net</th>
<th>2014 MWh-gross</th>
<th>2014 MWh-net</th>
<th>2-Year Average MWh-gross</th>
<th>2-Year Average MWh-net</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>175</td>
<td>12/29/2019</td>
<td>17,923</td>
<td>15,645</td>
<td>22,414</td>
<td>22,103</td>
<td>20,168</td>
<td>18,874</td>
</tr>
<tr>
<td>2</td>
<td>175</td>
<td>12/29/2019</td>
<td>30,766</td>
<td>26,094</td>
<td>85,834</td>
<td>82,964</td>
<td>58,300</td>
<td>54,529</td>
</tr>
<tr>
<td>5</td>
<td>480</td>
<td>12/29/2019</td>
<td>510,029</td>
<td>489,433</td>
<td>74,250</td>
<td>71,345</td>
<td>292,139</td>
<td>280,389</td>
</tr>
<tr>
<td>3</td>
<td>320</td>
<td>12/31/2020</td>
<td>369,385</td>
<td>350,913</td>
<td>499,518</td>
<td>473,800</td>
<td>434,452</td>
<td>412,357</td>
</tr>
</tbody>
</table>

Source: [http://energyalmanac.ca.gov/electricity/web_qfer/](http://energyalmanac.ca.gov/electricity/web_qfer/)

To offset the 692.951 MW for the installation of the combined-cycle turbines, assume 175 MW are provided by the retirement of Unit 1, 38 MW from the retirement of Unit 2, and 480 MW from the retirement of Unit 5. For Unit 2, the remaining 137 MW will be used to offset the simple-cycle turbines.

$$C_{2YRAvgExisting} = (18,874 \text{ MW-net, Unit 1}) + (54,529 \text{ MW-net, Unit 2})$$

$$+ (38 \text{ MW/175 MW}) + (280,389 \text{ MW-net, Unit 5}) = 311,104 \text{ MW-net}$$

**PTE$_{PM10}$**: 421.6 lb/day

*Basis:*
Rule 1304(c)(2) defines PTE$_{repi}$ as “the permitted potential to emit of new replacement unit(s) for pollutant I, in pounds per day. (Maximum permitted monthly emissions ÷ 30 days).” *Table 23* provides the 30-day averages per turbine.
210.8 lb/day-turbine * 2 turbines = 421.6 lb/day

$P_{TEr_{SOx}}$: 241.06 lb/day

*Basis:*
120.53 lb/day-turbine * 2 turbines = 241.06 lb/day

$P_{TEr_{VOC}}$: 887.60 lb/day

*Basis:*
443.8 lb/day-turbine * 2 turbines = 887.60 lb/day

$P_{TEr_{NOx}}$: Not applicable to RECLAIM facility.

**Total Annual Fee**

*Table 65* shows the preliminary estimate for the Total Annual Fee ($/yr) is $2,127,993 for the fiscal year ending on 6/30/14. This amount is required to be adjusted by the annual fee for each subsequent fiscal year.

The fee increases to date are: (1) 1.6% effective 7/1/14, (2) 1.4% effective 7/1/15, and (3) 2.4% effective 7/1/16. The fee for the fiscal year starting 7/1/16 is $2,244,924.89.

\[ \text{[$2,127,993 \times 1.016 \times 1.014 \times 1.024 = $2,244,924.89]} \]

**Total Single Fee**

*Table 65A* shows the preliminary estimate for the Total Single Fee ($/yr) is $53,204,741.00 for the fiscal year ending on 6/30/14.

The fee for the fiscal year starting 7/1/16 is $56,128,308.32. \[ \text{[$53,204,741.00 \times 1.016 \times 1.014 \times 1.024 = $56,128,308.32]} \]

**Annual Payment Prior to Issuance of Permits to Construct, Switching to Single Payment by End of First Year**

The preliminary estimated annual payment that will be required to be remitted prior to the issuance of the permits to construct for the combined-cycle turbines is $2,244,924.89 (7/1/16 fiscal year).

The preliminary estimated subsequent single payment is $53,883,383.43 (7/1/16 fiscal year). \[ \text{[$56,128,308.32 - $2,244,924.89 = $53,883,383.43]} \]
### Preliminary Determination of Compliance

#### Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

**Table 65 - Rule 1304.1 Emissions Offset Fee Calculator for Combined-Cycle Turbines—Annual Fee Payment**

<table>
<thead>
<tr>
<th>Input Cumulative Project Profile Values:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>a-Gross Rating of New Replacement Unit(s) (MW)</td>
<td>692.951</td>
</tr>
<tr>
<td>b-Maximum Fraction of Time Allowed to Operate (%)</td>
<td>53</td>
</tr>
<tr>
<td>Hours in a Year (hr/yr)</td>
<td>8,760</td>
</tr>
<tr>
<td>c-Max Allowable Operating Hours Annually (hr/yr)</td>
<td>4,640</td>
</tr>
<tr>
<td>d-Max Allowed Generation New Replacement Unit(s) Annually (MWhr/yr)</td>
<td>3,215,293 = ( C_{rep}^* )</td>
</tr>
<tr>
<td>e- Average Last 2 Years of Existing Unit(s) Actual Generation (MWhr/yr)</td>
<td>311,104 = ( C_{2YR\text{avgExisting}} )</td>
</tr>
</tbody>
</table>

**ANNUAL FEE PAYMENT** (> 100 MW Cumulatively):

<table>
<thead>
<tr>
<th>i</th>
<th>PTE_{PM10}</th>
<th>R_{PM10 A1}</th>
<th>R_{PM10 A2}</th>
<th>R_{PM10 blended}</th>
<th>OF_{PM10}</th>
<th>( C_{rep} )</th>
<th>( C_{2YR\text{avgExisting}} )</th>
<th>Ratio</th>
<th>( F_{PM10} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>(lbs/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>-</td>
<td>(MWhr/yr)</td>
<td>(MWhr/yr)</td>
<td>-</td>
<td>($)</td>
<td></td>
</tr>
<tr>
<td>PM10</td>
<td>421.60</td>
<td>997</td>
<td>3,986</td>
<td>3,555</td>
<td>1.00</td>
<td>3,215,293</td>
<td>311,104</td>
<td>0.903</td>
<td>1,353,638</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>PTE_{SOx}</th>
<th>R_{SOx A1}</th>
<th>R_{SOx A2}</th>
<th>R_{SOx blended}</th>
<th>OF_{SOx}</th>
<th>( C_{rep} )</th>
<th>( C_{2YR\text{avgExisting}} )</th>
<th>Ratio</th>
<th>( F_{SOx} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>(lbs/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>-</td>
<td>(MWhr/yr)</td>
<td>(MWhr/yr)</td>
<td>-</td>
<td>($)</td>
</tr>
<tr>
<td>SOx</td>
<td>241.06</td>
<td>793</td>
<td>3,170</td>
<td>2,827</td>
<td>1.00</td>
<td>3,215,293</td>
<td>311,104</td>
<td>0.903</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>PTE_{VOC}</th>
<th>R_{VOC A1}</th>
<th>R_{VOC A2}</th>
<th>R_{VOC blended}</th>
<th>OF_{VOC}</th>
<th>( C_{rep} )</th>
<th>( C_{2YR\text{avgExisting}} )</th>
<th>Ratio</th>
<th>( F_{VOC} )</th>
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</thead>
<tbody>
<tr>
<td>(lbs/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>-</td>
<td>(MWhr/yr)</td>
<td>(MWhr/yr)</td>
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<tr>
<td>VOC</td>
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<td>47</td>
<td>185</td>
<td>165</td>
<td>1.20</td>
<td>3,215,293</td>
<td>311,104</td>
<td>0.903</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>PTE_{NOx}</th>
<th>R_{NOx A1}</th>
<th>R_{NOx A2}</th>
<th>R_{NOx blended}</th>
<th>OF_{NOx}</th>
<th>( C_{rep} )</th>
<th>( C_{2YR\text{avgExisting}} )</th>
<th>Ratio</th>
<th>( F_{NOx} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>(lbs/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>-</td>
<td>(MWhr/yr)</td>
<td>(MWhr/yr)</td>
<td>-</td>
<td>($)</td>
</tr>
<tr>
<td>NOx**</td>
<td>Not Applicable</td>
<td>666</td>
<td>2,663</td>
<td>2,375</td>
<td>1.20</td>
<td>3,215,293</td>
<td>311,104</td>
<td>0.903</td>
</tr>
</tbody>
</table>

**TOTAL ANNUAL FEE ($/yr) 2,127,993**

**Only applicable if project source is not in RECLAIM**

* If \( C_{rep} \) is known it can be entered directly (in MWhr)
Table 65A - Rule 1304.1 Emissions Offset Fee Calculator for Combined-Cycle Turbines—Single Fee Payment

<table>
<thead>
<tr>
<th>Input Cumulative Project Profile Values:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>a-Gross Rating of New Replacement Unit(s) (MW)</td>
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</tr>
<tr>
<td>e- Average Last 2 Years of Existing Unit(s) Actual Generation (MWhr/yr)</td>
<td>311,104</td>
</tr>
</tbody>
</table>

SINGLE FEE PAYMENT (> 100 MW Cumulatively):

<table>
<thead>
<tr>
<th>i</th>
<th>PM10</th>
<th>SOx</th>
<th>VOC</th>
<th>NOx**</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PTE_{PM10}</td>
<td>L_{PM10 A1}</td>
<td>L_{PM10 A2}</td>
<td>L_{PM10 blended}</td>
</tr>
<tr>
<td>(lbs/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>-</td>
</tr>
<tr>
<td>PM10</td>
<td>421.60</td>
<td>24,911</td>
<td>99,643</td>
<td>88,858</td>
</tr>
<tr>
<td></td>
<td>PTE_{SOx}</td>
<td>L_{SOx A1}</td>
<td>L_{SOx A2}</td>
<td>L_{SOx blended}</td>
</tr>
<tr>
<td>(lbs/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>-</td>
</tr>
<tr>
<td>SOx</td>
<td>241.06</td>
<td>19,816</td>
<td>79,262</td>
<td>70,683</td>
</tr>
<tr>
<td></td>
<td>PTE_{VOC}</td>
<td>L_{VOC A1}</td>
<td>L_{VOC A2}</td>
<td>L_{VOC blended}</td>
</tr>
<tr>
<td>(lbs/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>-</td>
</tr>
<tr>
<td>VOC</td>
<td>887.60</td>
<td>1,159</td>
<td>4,635</td>
<td>4,133</td>
</tr>
<tr>
<td></td>
<td>PTE_{NOx}</td>
<td>L_{NOx A1}</td>
<td>L_{NOx A2}</td>
<td>R_{NOx blended}</td>
</tr>
<tr>
<td>(lbs/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>($ per lb/day)</td>
<td>-</td>
</tr>
<tr>
<td>NOx**</td>
<td>Not Applicable</td>
<td>16,643</td>
<td>66,571</td>
<td>59,366</td>
</tr>
</tbody>
</table>

** Only applicable if project source is not in RECLAIM
* If C_{rep} is known it can be entered directly (in MWh)

TOTAL SINGLE FEE ($/yr) 53,204,741
Simple-Cycle Turbines with Intercoolers
The inputs for the calculator are discussed below.

a-Gross Rating of New Replacement Units (MW): 401.75 MW

Basis:
(100.438 MW-gross/ CTG) * (4 CTGs) = 401.75 MW (Case 12)

b-Maximum Fraction of Time Allowed to Operate (%): 27%

Basis:
c-Max Allowable Operating Hours Annually (hr/yr) = 2358 hr/yr

Hours in a Year (hr/yr) = 8760 hr/yr

Fraction of Time Allowed to Operate = 2358 hr/yr ÷ 8760 hr/yr = 27%

Note: For the purpose of this rule, startup and shutdown hours are included.

e-Average Last 2 years of Existing Unit(s) Actual Generation (MWh/yr): 384,172 MW-net

Basis:
To offset the 401.75 MW for the installation of the simple-cycle turbines, assume 137 MW are provided by the retirement of Unit 2 and 265 MW from the retirement of Unit 3. At this time, AES has not finalized plans for the surplus 55 megawatts from the retirements.

\[
C_{2YRAvgExisting} = (54,529 MW-net, Unit 2) (137 MW/175 MW) + (412,357 MW-net, Unit 3)(265 MW/320 MW) = 384,172 MW-net
\]

PTE_{PM10}: 619 lb/day

Basis:
Table 39 provides the 30-day averages per turbine.

154.60 lb/day-turbine * 4 turbines = 618 lb/day

PTE_{SOX}: 161 lb/day

Basis:
40.22 lb/day-turbine * 4 turbines = 161 lb/day
PTE_{\text{VOC}}: 263 lb/day

Basis:
65.78 lb/day-turbine * 4 turbines = 263 lb/day

PTE_{\text{NOx}}: Rule 1304.1 is not applicable to NOx for a RECLAIM facility.

Total Annual Fee
Table 66 shows the preliminary estimate for the Total Annual Fee ($/yr) is $1,466,085 for the fiscal year ending on 6/30/14. This amount is required to be adjusted by the annual fee for each subsequent fiscal year.

The fee increases to date are: (1) 1.6% effective 7/1/14, (2) 1.4% effective 7/1/15, and (3) 2.4% effective 7/1/16. The fee for the fiscal year starting 7/1/16 is $1,546,645.46. [$1,466,085 * 1.016 * 1.014 * 1.024 = $1,546,645.46]

Total Single Fee
Table 66A shows the preliminary estimate for the Total Single Fee ($/yr) is $36,650,221.00 for the fiscal year ending on 6/30/14.

The fee for the fiscal year starting 7/1/16 is $38,664,127.77. [$36,650,221.00 * 1.016 * 1.014 * 1.024 = $38,664,127.77]

Annual Payment Prior to Issuance of Permits to Construct, Switching to Single Payment by End of First Year
The preliminary estimated annual payment that will be required to be remitted prior to the issuance of the permits to construct for the combined-cycle turbines is $1,546,645.46 (7/1/16 fiscal year).

The preliminary estimated subsequent single payment is $37,117,482.31 (7/1/16 fiscal year). [$38,664,127.77 - $1,546,645.46 = $37,117,482.31]
Table 66 - Rule 1304.1 Emissions Offset Fee Calculator for Simple-Cycle Turbines—Annual Fee Payment

<table>
<thead>
<tr>
<th>Input Cumulative Project Profile Values:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>a-Gross Rating of New Replacement Unit(s) (MW)</td>
<td>401.75</td>
</tr>
<tr>
<td>b-Maximum Fraction of Time Allowed to Operate (%)</td>
<td>27</td>
</tr>
<tr>
<td>Hours in a Year (hr/yr)</td>
<td>8,760</td>
</tr>
<tr>
<td>c-Max Allowable Operating Hours Annually (hr/yr)</td>
<td>2,358</td>
</tr>
<tr>
<td>d-Max Allowed Generation New Replacement Unit(s) Annually (MWhr/yr)</td>
<td>947,326.5</td>
</tr>
<tr>
<td>e-Average Last 2 Years of Existing Unit(s) Actual Generation (MWh/yr)</td>
<td>384,172</td>
</tr>
</tbody>
</table>

**ANNUAL FEE PAYMENT (> 100 MW Cumulatively):**

<table>
<thead>
<tr>
<th>i</th>
<th>PTE $PM_{10}$</th>
<th>$R_{PM_{10}A1}$</th>
<th>$R_{PM_{10}A2}$</th>
<th>$R_{PM_{10}blended}$</th>
<th>OF $PM_{10}$</th>
<th>$C_{rep}$</th>
<th>$C_{2YRAvgExisting}$</th>
<th>Ratio</th>
<th>F $PM_{10}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM$10$</td>
<td>618.00</td>
<td>997</td>
<td>3,986</td>
<td>3,242</td>
<td>1.00</td>
<td>947,326.5</td>
<td>384,172</td>
<td>0.594</td>
<td>1,191,050</td>
</tr>
<tr>
<td><strong>SOX</strong></td>
<td>161.00</td>
<td>793</td>
<td>3,170</td>
<td>2,578</td>
<td>1.00</td>
<td>947,326.5</td>
<td>384,172</td>
<td>0.594</td>
<td>246,771</td>
</tr>
<tr>
<td><strong>VOC</strong></td>
<td>263.00</td>
<td>47</td>
<td>185</td>
<td>151</td>
<td>1.20</td>
<td>947,326.5</td>
<td>384,172</td>
<td>0.594</td>
<td>28,264</td>
</tr>
<tr>
<td><strong>NOX</strong></td>
<td>Not Applicable</td>
<td>666</td>
<td>2,663</td>
<td>2,166</td>
<td>1.20</td>
<td>947,326.5</td>
<td>384,172</td>
<td>0.594</td>
<td>Not Applicable</td>
</tr>
</tbody>
</table>

**TOTAL ANNUAL FEE ($/yr):** 1,466,085

* Only applicable if project source is not in RECLAIM

* If $C_{rep}$ is known it can be entered directly (in MWh)
### Table 66 - Rule 1304.1 Emissions Offset Fee Calculator for Simple-Cycle Turbines—Single Fee Payment

<table>
<thead>
<tr>
<th>Input Cumulative Project Profile Values:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>a-Gross Rating of New Replacement Unit(s) (MW)</td>
<td>401.75</td>
</tr>
<tr>
<td>b-Maximum Fraction of Time Allowed to Operate (%)</td>
<td>27</td>
</tr>
<tr>
<td>c-Hours in a Year (hr/yr)</td>
<td>8,760</td>
</tr>
<tr>
<td>d-Max Allowable Operating Hours Annually (hr/yr)</td>
<td>2,358</td>
</tr>
<tr>
<td>e-Average Last 2 Years of Existing Unit(s) Actual Generation (MWh/yr)</td>
<td>384,172</td>
</tr>
</tbody>
</table>

**SINGLE FEE PAYMENT** (> 100 MW Cumulatively):

<table>
<thead>
<tr>
<th>i</th>
<th>PM10</th>
<th>SOx</th>
<th>VOC</th>
<th>NOx</th>
<th><strong>T</strong>OTAL SINGLE FEE ($/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>618.00</td>
<td>161.00</td>
<td>263.00</td>
<td>Not Applicable</td>
<td>36,650,221</td>
</tr>
</tbody>
</table>

- **PM10**
  - $PTE_{PM10}$ (lbs/day) | 618.00 |
  - $L_{PM10\text{A1}}$ (per lb/day) | 24,911 |
  - $L_{PM10\text{A2}}$ (per lb/day) | 99,643 |
  - $L_{PM10\text{blended}}$ (per lb/day) | 81,041 |
  - $OF_{PM10}$ (MWhr/yr) | 1.00 |
  - $C_{rep}$ (MWhr/yr) | 947,326.5 |
  - $C_{2YRAvgExisting}$ (MWhr/yr) | 384,172 |
  - Ratio | 0.594 |
  - $F_{PM10}$ ($/yr) | 29,773,040 |

- **SOx**
  - $PTE_{SOx}$ (lbs/day) | 161.00 |
  - $L_{SOx\text{A1}}$ (per lb/day) | 19,816 |
  - $L_{SOx\text{A2}}$ (per lb/day) | 79,262 |
  - $L_{SOx\text{blended}}$ (per lb/day) | 64,465 |
  - $OF_{SOx}$ (MWhr/yr) | 1.00 |
  - $C_{rep}$ (MWhr/yr) | 947,326.5 |
  - $C_{2YRAvgExisting}$ (MWhr/yr) | 384,172 |
  - Ratio | 0.594 |
  - $F_{SOx}$ ($/yr) | 6,169,917 |

- **VOC**
  - $PTE_{VOC}$ (lbs/day) | 263.00 |
  - $L_{VOC\text{A1}}$ (per lb/day) | 1,159 |
  - $L_{VOC\text{A2}}$ (per lb/day) | 4,635 |
  - $L_{VOC\text{blended}}$ (per lb/day) | 3,770 |
  - $OF_{VOC}$ (MWhr/yr) | 1.20 |
  - $C_{rep}$ (MWhr/yr) | 947,326.5 |
  - $C_{2YRAvgExisting}$ (MWhr/yr) | 384,172 |
  - Ratio | 0.594 |
  - $F_{VOC}$ ($/yr) | 707,264 |

- **NOx**
  - $PTE_{NOx}$ (lbs/day) | Not Applicable |
  - $L_{NOx\text{A1}}$ (per lb/day) | 16,643 |
  - $L_{NOx\text{A2}}$ (per lb/day) | 66,571 |
  - $L_{NOx\text{blended}}$ (per lb/day) | 54,143 |
  - $OF_{NOx}$ (MWhr/yr) | 1.20 |
  - $C_{rep}$ (MWhr/yr) | 947,326.5 |
  - $C_{2YRAvgExisting}$ (MWhr/yr) | 384,172 |
  - Ratio | 0.594 |
  - $F_{NOx}$ ($/yr) | Not Applicable |

**Only applicable if project source is not in RECLAIM**

**If $C_{rep}$ is known it can be entered directly (in MWh)**

**TOTAL SINGLE FEE ($/yr) 36,650,221**

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

Preliminary Determination of Compliance
• Combined-Cycle Turbines and Simple-Cycle Turbines with Intercoolers

Total Annual Fee
The preliminary estimate for the total annual fee for the combined- and simple-cycle turbines is $3,791,570.35 for the fiscal year starting 7/1/16.

\[\$2,244,924.89 \text{ (combined-cycle)} + \$1,546,645.46 \text{ (simple-cycle)} = \$3,791,570.35\]

Total Single Fee
The preliminary estimate for the total single fee for the combined- and simple-cycle turbines is $94,792,436.09 for the fiscal year starting 7/1/16.

\[\$56,128,308.32 \text{ (combined-cycle)} + \$38,664,127.77 \text{ (simple-cycle)} = \$94,792,436.09\]

• Annual Payment Prior to Issuance of Permits to Construct, Switching to Single Payment by End of First Year

The preliminary estimated annual payment that will be required to be remitted prior to the issuance of the permits to construct for the combined-cycle turbines is $3,791,570.35 (7/1/16 fiscal year).

The preliminary estimated subsequent single payment is $91,000,865.74 (7/1/16 fiscal year).

\[\$94,792,436.09 - \$3,791,570.35 = \$91,000,865.74\]

Prior to actual remittal, the fees will be finalized using the most recent twenty-four months average of the MWh generation of the Utility Boilers to be replaced (C2YRAvgExisting) and the offset fee rates applicable at that time.

**Rule 1313—Permits to Operate**
Section (d) is applicable to the retirement plan.

(d) For a new source or modification which will be a replacement, in whole or part, for an existing source on the same or contiguous property, a maximum of 90 days may be allowed as a startup period for simultaneous operation of the subject sources.

**Analysis:** From Table 2 above, the schedule for AGS Boilers Nos. 1, 2, and 5 shutdown is 12/29/2019. The combined-cycle block startup is scheduled for 11/1/2019. The schedule for AGS Boiler No. 3 shutdown is 12/31/2020. The simple-cycle block startup is scheduled for 6/1/2021.

Condition no. F52.1 limits simultaneous operation to 90 days, and sets forth a number of requirements for the retirement plan and the retirement of the AGS Boilers.

(g) Emission Limitation Permit Conditions
Every permit shall have the following conditions:
(1) Identified BACT conditions
(2) Monthly maximum emissions from the permitted source

**Analysis:**

**Combined-Cycle Turbines**

BACT--Condition nos. A195.8, A195.9, and A195.10 set forth the BACT limits for NOx, CO, and VOC, respectively.

Monthly Emissions--Condition no. A63.2 sets forth the monthly limits for CO, VOC, PM$_{10}$, and SOx. These limits indirectly limit NOx.

**Simple-Cycle Turbines**

BACT--Condition nos. A195.11, A195.12, and A195.10 set forth the BACT limits for NOx, CO, and VOC, respectively.

Monthly Emissions--Condition no. A63.3 sets forth the monthly limits for CO, VOC, PM$_{10}$, and SOx. These limits indirectly limit NOx.

**Auxiliary Boiler**

BACT--Condition nos. A195.13 and A195.14 set forth the BACT limits for NOx and CO, respectively.

Monthly Emissions--Condition no. A63.4 sets forth the monthly limits for CO, VOC, PM$_{10}$, and SOx. These limits indirectly limit NOx.

**Selective Catalytic Reduction**

BACT—Condition nos. A195.15 and A195.16 set forth the BACT limit for the combined- and simple-cycle turbine SCRs (NH$_3$ at 15% O$_2$) and auxiliary boiler SCR (NH$_3$ at 3% O$_2$), respectively.

Monthly Emissions—Monthly emission limits are applicable to basic equipment, not control equipment.

**Ammonia Tanks**

BACT—Condition 157.1 requires the tanks to be equipped with a pressure relief valve set at 50 psig. Condition E144.1 requires the tanks to be vented, during filling, to the vessel from which it is being filled.

Monthly Emissions—The pressure relief valves and vapor return lines result in no ammonia emissions emitted from the tanks under normal operations.
Oil/Water Separators
BACT—Condition E193.16 requires fixed covers for the tanks.

Monthly Emissions—Throughput limits are not necessary because the 30-day averages for both tanks are no more than 0.0005 lb/day.

**Rule 1325—Federal PM2.5 New Source Review Program**

Rule 1325 was amended on 12/5/14 to incorporate administrative changes to definitions, provisions and exclusions, based on comments received from the U.S. EPA regarding SIP approvability of Rule 1325. The amended rule was approved into the California State Implementation Plan on 5/1/15. The applicable requirements of 40 CFR Part 51, Appendix S, were necessary for permitting actions until Rule 1325 became SIP-approved.

The relevant sections are presented below, followed by the rule analysis.

(a) This rule applies to any new major polluting facility, major modifications to a major polluting facility, and any modification to an existing facility that would constitute a major polluting facility in and of itself; located in areas federally designated pursuant to Title 40 of the Code of Federal Regulations (40 CFR) 81.305 as non-attainment for PM$_{2.5}$. With respect to major modifications, this rule applies on a pollutant-specific basis to emissions of PM$_{2.5}$ and its precursors, for which (1) the source is major, (2) the modification results in a significant increase, and (3) the modification results in a significant net emissions increase.

(b) Definitions
For the purposes of this rule, the definitions in Title 40 CFR 51.165(a)(1), as it exists on June 3, 2011 shall apply, unless the same term is defined below, then the defined term below shall apply:

(1) BASELINE ACTUAL EMISSIONS means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with the following:
   (A) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Executive Officer shall allow the use of a different time period upon a determination that it is more representative of normal source operation….

(3) MAJOR MODIFICATION means:
   (A) Any physical change in or change in the method of operation of a major polluting facility that would result in: a significant emissions increase of a regulated NSR pollutant; and a significant net emissions increase of that pollutant from the major polluting facility.
MAJOR POLLUTING FACILITY means, on a pollutant specific basis, any emissions source located in areas federally designated pursuant to 40 CFR 81.305 as non-attainment for the South Coast Air Basin (SOCAB) which has actual emissions of, or the potential to emit, 100 tons or more per year of PM$_{2.5}$, or its precursors. A facility is considered to be a major polluting facility only for the specific pollutant(s) with a potential to emit of 100 tons or more per year.

SIGNIFICANT means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:
- Nitrogen oxides: 40 tons per year
- Sulfur dioxide: 40 tons per year
- PM$_{2.5}$: 10 tons per year

Requirements
(1) The Executive Officer shall deny the Permit for a new major polluting facility; or major modification to a major polluting facility; or any modification to an existing facility that would constitute a major polluting facility in and of itself, unless each of the following requirements is met:
(A) Lowest Achievable Emission Rate (LAER) is employed for the new or relocated source or for the actual modification to an existing source; and
(B) Emission increases shall be offset at an offset ratio of 1.1:1 for PM$_{2.5}$ and the ratio required in Regulation XIII or Rule 2005 for NOx and SO$_2$ as applicable; and
(C) Certification is provided by the owner/operator that all major sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act; and
(D) An analysis is conducted of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstration made that the benefits of the proposed project outweigh the environmental and social costs associated with that project.

Test Methods
For the purpose of this rule only, testing for point sources of PM$_{2.5}$ shall be in accordance with U.S. EPA Test Methods 201A and 202.

Analysis:
The applicability analysis is summarized in the table below.
Table 67 – Rule 1325 Applicability

<table>
<thead>
<tr>
<th></th>
<th>NOx</th>
<th>SO₂</th>
<th>PM&lt;sub&gt;2.5&lt;/sub&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alamitos Generating Station Potential to Emit, TPY <em>(Table 13)</em></td>
<td>635.60</td>
<td>49.56</td>
<td>97.86</td>
</tr>
<tr>
<td>Major Source for Particular Pollutant?</td>
<td>Yes, PTE is greater than 100 tpy.</td>
<td>No, PTE is less than 100 tpy.</td>
<td>No, PTE is less than 100 tpy.</td>
</tr>
<tr>
<td>Alamitos Generating Station (AGS) Actual Emissions (2013 &amp; 2014 Avg) TPY <em>(Table 14)</em></td>
<td>47.47</td>
<td>4.68</td>
<td>10.91</td>
</tr>
<tr>
<td>Alamitos Energy Center (AEC) Potential to Emit, TPY <em>(Table 45)</em></td>
<td>137.06</td>
<td>10.19</td>
<td>69.52</td>
</tr>
<tr>
<td>Net Emissions Increase (AEC PTE – AGS actual)</td>
<td>89.59</td>
<td>5.51</td>
<td>58.61</td>
</tr>
<tr>
<td>If AGS is a major facility for particular pollutant, does the AEC result in a net significant emissions increase?</td>
<td>Yes, net increase is greater than 40 tpy.</td>
<td>No, net increase is less than 100 tpy.</td>
<td>No, net increase is less than 100 tpy.</td>
</tr>
<tr>
<td>If AGS is not a major facility for particular pollutant, does the AEC constitute a modification that would constitute a major polluting facility in and of itself?</td>
<td>No, net increase is less than 100 tpy.</td>
<td>No, net increase is less than 100 tpy.</td>
<td>No, net increase is less than 100 tpy.</td>
</tr>
<tr>
<td>Rule 1325 Applicable?</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>

Rule 1325 is applicable to NOx. The AGS is a major polluting facility for NOx because the PTE is greater than 100 tpy, and the AEC constitutes a major modification because the net NOx increase is greater than 40 tpy. NOx meets the requirements of Rule 1325(c)(1)(A) – (D). For (c)(1)(A), the turbines meet LAER for NOx as discussed under the Rule 1703(a)(2)—Top-Down BACT analysis, below. For (c)(1)(B), the NOx emissions will be offset as discussed under the analysis for Rule 2005(c)(2)—Offsets, below. For (c)(1)(C), certification of statewide compliance is provided as discussed under Rule 2005(g)(1) for Statewide Compliance, below. For (c)(1)(D), the alternatives discussion was provided as discussed under the Rule 2005(g)(2) for Alternative Analysis, below.

Rule 1325 is not applicable to SO₂ and PM<sub>2.5</sub>. The AGS is not a major polluting facility for SO₂ and PM<sub>2.5</sub> because the PTEs for both are less than 100 tpy. The AEC does not constitute a modification to an existing facility that would constitute a major polluting facility in and of itself, because the net increase for SO₂ and PM<sub>2.5</sub> are less than 100 tpy as enforced by the annual emissions limits for SOx and PM<sub>10</sub> in conditions A63.2, A63.3, and A63.4.

Condition F2.1 will limit the PM<sub>2.5</sub> emissions for the facility to 100 tpy.
For Boiler Nos. 1 – 6, the PM\textsubscript{2.5} emission factor is 0.00113 lb/MMBtu, which was approved by SCAQMD Source Testing Dept., 9/2/15, as discussed for the emissions calculations above.  

\[(0.00113 \text{ lb/MMBtu}) \times (1050 \text{ MMBtu/MMcf}) = 1.19 \text{ lb/mmcf}\]

For the Combined-Cycle Turbines, the PM\textsubscript{2.5} emission factor is assumed to be equal to the PM\textsubscript{10} emission factor for normal operation from condition A63.2, 3.92 lb/mmcf.

For the Auxiliary Boiler, the PM\textsubscript{2.5} emission factor is assumed to be equal to the PM\textsubscript{10} emission factor from condition A63.4, 7.42 lb/mmcf.

For the Simple-Cycle Turbines, the PM\textsubscript{2.5} emission factor is assumed to be equal to the PM\textsubscript{10} emission factor for normal operation from condition A63.3, 7.44 lb/mmcf.

Source test conditions D29.2 and D29.5 require EPA Method 201A and 202 for PM\textsubscript{2.5} testing. These methods do not specify an averaging time. Consultation with the SCAQMD source testing department indicates the sampling time is required to be long enough to obtain a measureable amount of sample, with past tests requiring at least 4 hours of sampling for the turbines. The sampling time required for the auxiliary boiler is possibly more than 1 hour but additional experience is required to determine a minimum sampling time.

**Pending PM\textsubscript{2.5} Threshold Revision**

The applicable regulations for lowering the PM\textsubscript{2.5} threshold for major source from 100 tpy to 70 tpy follows.

40 CFR 52.245 New Source Review rules

(d)  By August 14, 2017, the New Source Review rules for PM\textsubscript{2.5} for the South Coast Air Quality Management District must be revised and submitted as a SIP revision. The rules must satisfy the requirements of sections 189(b)(3) and 189(e) and all other applicable requirements of the Clean Air Act for implementation of the 2006 PM\textsubscript{2.5} NAAQS.

The CAA Section 189 referenced above has been codified as 42 U.S.C. 7513a. Plan provisions and schedules for plan submissions, reproduced below.

§7513a. Plan provisions and schedules for plan submissions

(B) **Serious Areas**

(3) **Major Sources**

For any Serious Area, the terms "major source" and "major stationary source" include any stationary source or group of stationary sources located within a contiguous area and under common control that emits, or has the potential to emit, at least 70 tons per year of PM–10.

In reclassifying SCAQMD as serious nonattainment for PM\textsubscript{2.5}, the necessary New Source Review (NSR) rules are not due to EPA until August 14, 2017. Section 189(b)(3) is the

Preliminary Determination of Compliance
requirement for major sources to be considered those with a potential to emit of 70 tons per year. As such, this threshold will not apply until SCAQMD adopts/revises its PM$_{2.5}$ NSR requirements to meet section 189(b)(3) by August 14, 2017.

**Rule 1401—New Source Review of Toxic Air Contaminants**

**Rule 2005(j) – RECLAIM Rule 1401 Compliance**

Rule 1401 specifies limits for maximum individual cancer risk (MICR), and acute and chronic hazard index (HI) from new permit units, relocations, or modifications to existing permits that emit toxic air contaminants. Because the limits are for each permit unit, the limits are for each turbine and the auxiliary boiler. Rule 2005(j) requires compliance with Rule 1401 for RECLAIM facilities. The relevant requirements are presented below.

(d) Requirements

The Executive Officer shall deny the permit to construct a new, relocated or modified permit unit if emissions of any toxic air contaminant listed in Table I may occur, unless the applicant has substantiated to the satisfaction of the Executive Officer all of the following:

1. **MICR and Cancer Burden**
   - The cumulative increase in MICR which is the sum of the calculated MICR values for all toxic air contaminants emitted from the new, relocated or modified permit unit will not result in any of the following:
     1. an increased MICR greater than one in one million ($1.0 \times 10^{-6}$) at any receptor location, if the permit unit is constructed without T-BACT;
     2. an increased MICR greater than ten in one million ($1.0 \times 10^{-5}$) at any receptor location, if the permit unit is constructed with T-BACT;
     3. a cancer burden greater than 0.5.

2. **Chronic Hazard Index**
   - The cumulative increase in total chronic HI for any target organ system due to total emissions from the new, relocated or modified permit unit owned or operated by the applicant for which applications were deemed complete on or after the date when the risk value for the compound is finalized by the state Office of Environmental Health Hazard Assessment (OEHHA), unless paragraph (e)(3) applies, will not exceed 1.0 at any receptor location.

3. **Acute Hazard Index**
   - The cumulative increase in total acute HI for any target organ system due to total emissions from the new, relocated or modified permit unit owned or operated by the applicant for which applications were deemed complete on or after the date when the risk value for the compound is finalized by OEHHA, unless paragraph (e)(3) applies, will not exceed 1.0 at any receptor location.
On March 6, 2015, the California Office of Environmental Health Hazard Assessment (OEHHA) approved the Air Toxics Hot Spots Program Guidance Manual for Preparation of Risk Assessments (Revised OEHHA Guidelines). On June 5, 2015, the SCAQMD approved amendments to Rule 1401 to revise definitions and risk assessment procedures to be consistent with the Revised OEHHA Guidelines. These updated guidelines take into account recent scientific advances which have found greater risk to children when they are exposed to cancer causing compounds.

The applicant provided health risk assessment (HRA) modeling using the California Air Resources Board’s (ARB) Hotspots Analysis Reporting Program Version 2 (HARP 2, version 16088) Air Dispersion Modeling and Risk Assessment Tool (ADMRT), which incorporates methodology presented in the Revised OEHHA Guidelines. The SCAQMD HRA procedures require HARP to be used in Tier 4 risk assessments. The HARP On-Ramp tool was used to import the American Meteorological Society/EPA Regulatory Model (AERMOD) air dispersion modeling output plot files into HARP2. The AERMOD dispersion model (Version 15181) was used to predict ground-level concentrations of air toxic emissions associated with AEC. The AERMOD settings, source parameters, meteorological data, and source definition for the risk assessment were the same as the air quality impact analysis methodology performed for Rules 1303 and 1703.

- **Combined-Cycle Turbines**
  The toxic air contaminants emissions calculations for determination of the maximum hourly and annual emissions rates are shown in Table 26 - Combined-Cycle Turbine Toxic Air Contaminants/Hazardous Air Pollutants, above.

  The maximum hourly turbine impacts for the combined-cycle turbines were predicted using the exhaust parameters for the 65.3 °F, minimum load case, which represents the turbine exhaust parameters associated with the maximum predicted 1-hour ground-level impact in the dispersion modeling (Case 7 in Table 15). The annual turbine impacts were also predicted for the 65.3 °F, minimum load case, which represents the average annual temperature and load scenario resulting in the maximum predicted annual ground-level impact in the dispersion modeling (Case 7 in Table 15).

AES Response Letter, dated 12/11/15, provided a revised health risk assessment in Table 12-2—Health Risk Assessment Summary: Individual Units. The health risk assessment in Table 5.9-4—Health Risk Assessment Summary: Individual Units in the original Application was required to be revised to be based on US EPA AP-42 emission factors.

In the revised Application, the results of the risk assessment analysis are in revised Table 5.9-4. For the combined-cycle turbines, the table has been revised to reflect previously provided changes due to the change to AP-42 emission factors and new changes due to a higher annual fuel usage resulting from the increase in cold starts. The new changes due to the higher fuel usage are included the table below.
PRDAS staff has reviewed the applicant’s health risk assessment by independently performing the health risk assessment. The risk assessment results provided by PRDAS staff show minor differences from the applicant’s results and are used to demonstrate compliance with the Rule 1401 standards in the table below. The modeling review memo shows the maximum results for the boiler, CCGT and SCGT. In an e-mail dated 4/29/16, PRDAS staff provided results for each turbine.

The MICR limit is ten in one million for each combined- and simple-cycle turbine because Best Available Control Technology For Toxics (T-BACT) for combustion turbines is determined to be an oxidation catalyst (see discussion below).

### Table 68--Model Results for HRA for Combined-Cycle Turbine

<table>
<thead>
<tr>
<th>Health Risk Index</th>
<th>Residential/Sensitive Receptor Risk</th>
<th>Worker Receptor Risk</th>
<th>Rule 1401 Thresholds (T-BACT)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCGT-1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MICR</td>
<td>$0.48 \times 10^{-6}$</td>
<td>$0.025 \times 10^{-6}$</td>
<td>$10 \times 10^{-6}$</td>
<td>No</td>
</tr>
<tr>
<td>HIC</td>
<td>0.0017</td>
<td>0.0012</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>HIA</td>
<td>0.00657</td>
<td>0.00662</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>CCGT-2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MICR</td>
<td>$0.49 \times 10^{-6}$</td>
<td>$0.025 \times 10^{-6}$</td>
<td>$10 \times 10^{-6}$</td>
<td>No</td>
</tr>
<tr>
<td>HIC</td>
<td>0.00123</td>
<td>0.00171</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>HIA</td>
<td>0.00657</td>
<td>0.00672</td>
<td>1</td>
<td>No</td>
</tr>
</tbody>
</table>

- **Auxiliary Boiler**
  The toxic air contaminants emissions calculations for determination of the maximum hourly and annual emissions rates are shown in *Table 30 - Toxic Air Contaminants/Hazardous Air Pollutants for Auxiliary Boiler*, above.

  The maximum hourly and annual impacts for the auxiliary boiler were predicted, based on the auxiliary boiler operating at 100 percent load for the hourly impacts and 50% load for the annual impacts.

  AES Response Letter, dated 12/11/15, provided a revised health risk assessment in *Table 12-2—Health Risk Assessment Summary: Individual Units*. The health risk assessment in *Table 5.9-4—Health Risk Assessment Summary: Individual Units* in the original Application was required to be revised to be based on VCAPCD emission factors.

  In the revised Application, the results of the risk assessment analysis are in revised *Table 5.9-4*. For the auxiliary boiler, the table has been revised to reflect previously provided changes due to the
change to VCAPCD emission factors, and new changes due to a lower annual fuel usage. The new changes due to the lower fuel usage are added to the table below.

PRDAS staff has reviewed the applicant’s health risk assessment. The risk assessment results provided by PRDAS staff show minor differences from the applicant’s results and are used to demonstrate compliance with the Rule 1401 standards in the table below.

**Table 69--Model Results for HRA for Auxiliary Boiler**

<table>
<thead>
<tr>
<th>Health Risk Index</th>
<th>Residential/ Sensitive Receptor Risk</th>
<th>Worker Receptor Risk</th>
<th>Rule 1401 Thresholds</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>MICR</td>
<td>0.0091 x 10^-6</td>
<td>0.00091 x 10^-6</td>
<td>1 x 10^-6</td>
<td>No</td>
</tr>
<tr>
<td>HIC</td>
<td>0.0000284</td>
<td>0.0000967</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>HIA</td>
<td>0.000318</td>
<td>0.00049</td>
<td>1</td>
<td>No</td>
</tr>
</tbody>
</table>

- **Simple-Cycle Turbines**
  The toxic air contaminants emissions calculations for determination of the maximum hourly and annual emissions rates are shown in *Table 42 - Simple-Cycle Turbine Toxic Air Contaminants/Hazardous Air Pollutants*, above.

The maximum hourly turbine impacts for the simple-cycle turbines were predicted using the exhaust parameters for the 65.3 °F, minimum load case, which represents the turbine exhaust parameters associated with the maximum predicted 1-hour ground-level impact in the dispersion modeling (Case 7 in *Table 31*). The annual turbine impacts were also predicted for the 65.3 °F, minimum load case, which represents the average annual temperature and load scenario resulting in the maximum predicted annual ground-level impact in the dispersion modeling (Case 7 in *Table 31*). (AES clarified that, for hourly impacts, the maximum ground-level for normalized emission rates (i.e., emission rates that do not vary by load or ambient temperature) occur at an ambient temperature of 107 °F at minimum load. However, as this exhaust scenario cannot occur at the same time as the worst-case 1-hour combined-cycle exhaust scenario for the combined-cycle turbines, the scenario resulting in the maximum ground-level impact from the 65.3 °F ambient temperature scenarios was chosen.)

AES Response Letter, dated 12/11/15, provided the health risk assessment in *Table 12-2—Health Risk Assessment Summary: Individual units*. The health risk assessment in *Table 5.9-4—Health Risk Assessment Summary: Individual Units* in the original Application was required to be revised to be based on US EPA AP-42 emission factors.

The risk assessment results provided by PRDAS staff show minor differences from the applicant’s results and are used to demonstrate compliance with the Rule 1401 standards in the table below.
Table 70—Model Results for HRA for Simple-Cycle Turbine

<table>
<thead>
<tr>
<th>Health Risk Index</th>
<th>Residential/ Sensitive Receptor Risk</th>
<th>Worker Receptor Risk</th>
<th>Rule 1401 Thresholds (T-BACT)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCGT-1</td>
<td>MICR 0.049 x 10^{-6}</td>
<td>0.0019 x 10^{-6}</td>
<td>10 x 10^{-6}</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>HIC 0.000126</td>
<td>0.000136</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>HIA 0.00151</td>
<td>0.00237</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>SCGT-2</td>
<td>MICR 0.049 x 10^{-6}</td>
<td>0.0019 x 10^{-6}</td>
<td>10 x 10^{-6}</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>HIC 0.000124</td>
<td>0.000137</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>HIA 0.00153</td>
<td>0.00385</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>SCGT-3</td>
<td>MICR 0.048 x 10^{-6}</td>
<td>0.0019 x 10^{-6}</td>
<td>10 x 10^{-6}</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>HIC 0.000122</td>
<td>0.000137</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>HIA 0.00174</td>
<td>0.00242</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>SCGT-4</td>
<td>MICR 0.047 x 10^{-6}</td>
<td>0.0019 x 10^{-6}</td>
<td>10 x 10^{-6}</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>HIC 0.00012</td>
<td>0.0000466</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>HIA 0.00175</td>
<td>0.00239</td>
<td>1</td>
<td>No</td>
</tr>
</tbody>
</table>

- **Facility-wide**
  Because the Rule 1401 limits are for each permit unit, the limits are for each turbine and the auxiliary boiler. The following facility-wide health risk assessment is provided for CEQA and informational purposes only.

AES Response Letter, dated 12/11/15, provided the health risk assessment in *Table 12-3—Health Risk Assessment Summary: Facility*. The health risk assessment in *Table 5.9-5—Health Risk Assessment Summary: Facility* in the original Application was required to be revised to be based on corrected emission factors for the turbines and auxiliary boiler.

In the revised Application, the results of the risk assessment analysis are in revised *Table 5.9-5*. The table has been revised to reflect previously provided changes due to the corrected emission factors, and new changes due to the changes in annual fuel usages for the combined-cycle turbines and auxiliary boiler. The facility-wide results represent the combined predicted risk for all seven combustion units operating simultaneously. The maximum impacts reported represent the maximum predicted impacts at one receptor from all sources combined. The maximum impacts reported for the individual equipment shown in the tables above may occur at different receptors. Therefore, the results for the individual equipment are not directly additive to arrive at facility-wide results.
PRDAS staff has reviewed the applicant’s health risk assessment. The results provided by PRDAS staff show minor differences from the applicant’s results, except for the cancer burden. The applicant provided a cancer burden of $1.79 \times 10^{-9}$, but PRDAS staff provided a cancer burden of $0.0097$. The risk assessment results provided by PRDAS staff are used to demonstrate compliance with the Rule 1401 standards in the table below.

<table>
<thead>
<tr>
<th>Health Risk Index</th>
<th>Residential/Sensitive Receptor Risk</th>
<th>Worker Receptor Risk</th>
<th>Rule 1401 Thresholds (T-BACT)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>MICR</td>
<td>$1.1 \times 10^{-6}$</td>
<td>$0.052 \times 10^{-6}$</td>
<td>$10 \times 10^{-6}$</td>
<td>No</td>
</tr>
<tr>
<td>HIC</td>
<td>0.0028</td>
<td>0.00364</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>HIA</td>
<td>0.0176</td>
<td>0.0188</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>Cancer Burden</td>
<td>0.0097</td>
<td></td>
<td>0.5</td>
<td>No</td>
</tr>
</tbody>
</table>

PRDAS staff based the cancer burden of 0.0097 on a radius of 0.63 km and a population density of 7000 persons/km$^2$.

- **Best Available Control Technology For Toxics (T-BACT) for Combustion Turbines**
  
The MICR limit is ten in one million for each combined- and simple-cycle turbine because T-BACT for combustion turbines is determined to be an oxidation catalyst.

  Rule 1401(c)(2) defines T-BACT to mean the most stringent emissions limitation or control technique which: (A) has been achieved in practice for such permit unit category or class of source; or (B) is any other emissions limitation or control technique, including process and equipment changes of basic and control equipment, found by the Executive Officer to be technologically feasible for such class or category of sources, or for a specific source.

  The final maximum achievable control standard (MACT) for stationary combustion turbines was published on March 5, 2004 (69 FR 10512), and subsequently codified at 40 CFR Part 63, Subpart YYYY—National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Stationary Combustion Turbines. The determination that an oxidation catalyst is T-BACT for combustion turbines is supported by EPA’s assessment that it is not aware of any add-on control devices which can reduce organic HAP emissions to levels lower than those resulting from the application of oxidation catalyst systems (69 FR 10530).

Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions. This NESHAP implements section 112(d) of the Clean Air Act (CAA) by requiring all major sources to meet HAP emission standards reflecting the application of the...
maximum achievable control technology for combustion turbines. EPA identified stationary combustion turbines as major sources of hazardous air pollutants emissions, such as formaldehyde, toluene, benzene, and acetaldehyde.

Subpart YYYY requires an affected new or reconstructed stationary combustion turbine to comply with the emission limitation to reduce the concentration of formaldehyde in the exhaust to 91 parts per billion by volume (ppbvvd) or less, at 15 percent O\textsubscript{2}. The affected turbines are lean premix gas-fired, lean premix oil-fired, diffusion flame gas-fired, and diffusion flame oil-fired stationary combustion turbines. The oil-fired stationary combustion turbines must comply with the emissions limitations and operating limitations upon startup. The gas-fired stationary combustion turbines must comply with the Initial Notification requirements set forth in §63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance. Subpart YYYY was amended on August 18, 2004 (69 FR 51184) to stay the effectiveness of the standards in the lean premix gas-fired and diffusion flame subcategories, because, on April 7, 2004, EPA had proposed to delist four subcategories, including lean premix gas-fired turbines, from the Stationary Combustion Turbines source category (69 FR 18327). The delisting process remains pending.

EPA explained that, for new sources, the MACT floor is defined as the emission control that is achieved in practice by the best controlled similar source. (69 FR 10530) EPA considered using a surrogate for all organic HAP emissions in order to reduce the costs associated with monitoring while at the same time being relatively sure that the pollutants the surrogate is supposed to represent are also controlled. They investigated the use of formaldehyde concentration as a surrogate because formaldehyde is the HAP emitted in the highest concentrations from stationary combustion turbines. Formaldehyde, toluene, benzene, and acetaldehyde account for essentially all the mass of HAP emissions from the stationary combustion turbine exhaust, and emissions data show that these pollutants are equally controlled by an oxidation catalyst. EPA reviewed testing information conducted on a diffusion flame combustion turbine equipped with an oxidation catalyst control system, emissions tests conducted on reciprocating internal combustions engines equipped with oxidation catalysts, and catalyst performance information obtained from a catalyst vendor. EPA concluded that it is appropriate to use formaldehyde as a surrogate for all organic HAP emissions. (69 FR 10530)

For new lean premix gas-fired turbines such as the proposed turbines for AEC, EPA reviewed emissions data it had available at proposal, and additional test reports received during the comment period. The best performing turbine is equipped with an oxidation catalyst. Based on testing of the formaldehyde concentration from the best performing turbine, the MACT floor for organic HAP for new stationary lean premix gas-fired turbines is, therefore, an emission limit of 91 ppbvvd formaldehyde at 15 percent oxygen. (69 FR 10530) No beyond-the-floor regulatory alternatives were identified for new lean premix gas-fired turbines. EPA is not aware of any add-on control devices which can reduce organic HAP emissions to levels lower than those resulting from the application of oxidation catalyst systems. EPA, therefore, determined that MACT for organic
HAP emissions from new stationary lean premix gas-fired turbines is the same as the MACT floor, i.e., an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen. (69 FR 10530)

As discussed in the rule analysis for Subpart YYYY below, this subpart is not applicable to the proposed combined- and simple-cycle turbines because AEC will not be a major source for HAP emissions.

REGULATION XVII – PREVENTION OF SIGNIFICANT DETERIORATION
The federal Prevention of Significant Deterioration (PSD) has been established to protect deterioration of air quality in those areas that already meet the primary NAAQS. This regulation sets forth preconstruction review requirements for stationary sources to ensure that air quality in clean air areas do not significantly deteriorate while maintaining a margin for future industrial growth. Specifically, the PSD program establishes allowable concentration increases for attainment pollutants due to new or modified emission sources that are classified as major stationary sources.

Effective upon delegation by EPA, this regulation shall apply to preconstruction review of stationary sources that emit attainment air contaminants. On 3/3/03, EPA rescinded its delegation of authority to the SCAQMD. On 7/25/07, the EPA and SCAQMD signed a new “Partial PSD Delegation Agreement.” The agreement is intended to delegate the authority and responsibility to the District for issuance of initial PSD permits and for PSD permit modifications where the applicant does not seek to use the emissions calculation methodologies promulgated in 40 CFR 52.21 (NSR Reform) but not included in SCAQMD Regulation XVII. The Partial Delegation agreement did not delegate authority and responsibility to SCAQMD to issue new or modified PSD permits based on Plant-wide Applicability Limits (PALS) provisions of 40 CFR 52.21.

Since this is a partial delegation the facilities in the South Coast Air Basin (SCAB) may either apply directly to EPA for the PSD permit in accordance with the current requirements of 40 CFR Part 52 Subpart 21, or apply to the SCAQMD in accordance with the current requirements of Regulation XVII. AES has opted to apply to the SCAQMD.

The SCAB has been in attainment for NO\textsubscript{2}, SO\textsubscript{2}, and CO emissions. In addition, effective 7/26/13, the SCAB has been redesignated to attainment for the 24-hour PM\textsubscript{10} national ambient air quality standard. Therefore, this regulation applies to these emissions.

- **RULES 1701, 1702, 1706--PSD APPLICABILITY**
  The relevant PSD applicability rule sections are presented below, followed by the applicability analysis.

  - **Rule 1701(b)(2) provides:**
    All of the requirements of this regulation apply, except as exempted in Rule 1704, to the following stationary sources:
(A) A new source or modification at an existing source where the increase in potential to emit is at least 100 or 250 tons of attainment air contaminants per year, depending on the source category; or

(B) A significant emission increase at an existing major stationary source; or

(C) Any net emission increase at a major stationary source located within 10 km of a Class I area, if the emission increase would impact the Class I area by 1.0 µg/m³, (24-hours average).

- **Rule 1702** provides definitions.

  (m) “Major Stationary Source” means: “one of the following source categories: (1) Fossil fuel-fired steam electric plants of more than 250 million BTU/hr input…; which emits or has the potential to emit 100 tons per year or more of any contaminant regulated by the Act; or (2) an unlisted stationary source that emits or has the potential to emit 250 tons per year or more of any pollutant regulated by the Act; or (3) a physical change in a stationary source not otherwise qualifying under paragraph (1) or (2) if a modification would constitute a major stationary source by itself.

  (s) Significant Emission Increase means any attainment air contaminant for which the net cumulative emission increase of that air contaminant from a major stationary source is greater than the amount specified as follows:

<table>
<thead>
<tr>
<th>Contaminant</th>
<th>Emissions Rate (tpy)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon Monoxide</td>
<td>100</td>
</tr>
<tr>
<td>Sulfur Dioxide</td>
<td>40</td>
</tr>
<tr>
<td>Nitrogen Oxides</td>
<td>40</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>15</td>
</tr>
</tbody>
</table>

- **Rule 1706** shall be used as the basis for calculating applicability to Regulation XVII as delineated in Rule 1703(a). **Rule 1706(e)** provides the emissions calculation methodology for determining a net emission increase.

  (1)(A) The emissions for new permit units shall be calculated as the potentials to emit.

  (1)(B) The emissions for removal from service shall be calculated from:

  (i) the sum of actual emissions, as determined from company records, which have occurred during the two-year period immediately preceding date of permit application, or a different two year time period within the past
five (5) years upon a determination by the Executive Officer that it is more representative of normal source operation, except annual emission declarations pursuant to Rule 301 may be used if less than the actual emissions as determined above; and

(ii) the total emissions in those two years shall be calculated on an annual basis.

**PSD Applicability Analysis:**
The District is presently in attainment for the primary NAAQS for NOx, CO, SOx, and PM\textsubscript{10}. For proposed modifications at existing major sources, PSD applies to each regulated pollutant for which the proposed emissions increase resulting from the modification both is significant and results in a significant net emissions increase. The following table summarizes the Rule 1701(b)(2)(A) and (B) analysis to determine which pollutants are subject to PSD review. Rule 1701(b)(2)(C) is not applicable because the AEC is not located within 10 km of a Class I area. The nearest Class I area, San Gabriel Wilderness, is located 53 km away.

<table>
<thead>
<tr>
<th>Table 71 – Prevention of Significant Deterioration Applicability</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
</tr>
<tr>
<td>Alamitos Generating Station Potential to Emit, TPY (Table 13)</td>
</tr>
<tr>
<td>Major Source?</td>
</tr>
<tr>
<td>Alamitos Generating Station (AGS) Actual Emissions (2013 &amp; 2014 Avg), TPY (Table 14)</td>
</tr>
<tr>
<td>Alamitos Energy Center (AEC) Potential to Emit, TPY = Emissions Increase (Table 45)</td>
</tr>
<tr>
<td>Does the AEC result in a significant emissions increase?</td>
</tr>
<tr>
<td>Net Emissions Increase (AEC PTE – AGS actual)</td>
</tr>
<tr>
<td>Does the AEC result in a net significant emissions increase?</td>
</tr>
<tr>
<td>PSD Applicable?</td>
</tr>
</tbody>
</table>

Because the AGS is a fossil fuel-fired steam electric plant of more than 250 million BTU/hr input, the major source threshold for the facility is 100 tons per year. The AGS is an existing...
major stationary source as defined by Rule 1702(m)(1) because the potentials to emit for CO, NOx, and PM$_{10}$ emissions all are 100 tpy or more. If a source is a major source for any one regulated pollutant, it is considered to be a major source for all regulated pollutants. The AEC will result in significant emissions increases for CO, NOx, and PM$_{10}$, but not SO$_2$. The AEC will result in net significant increases for NOx and PM$_{10}$, but not CO and SO$_2$. Therefore, CO is not subject to PSD because the increase is significant but the net increase is a net decrease. SO$_2$ is not subject to PSD because both the increase and net increase are less than the significant emissions threshold. NOx and PM$_{10}$ are subject to PSD review because the emissions increases and net emissions increases for both constitute significant increases. For completeness, the following PSD review will include CO.

- **RULE 1703—PSD REQUIREMENTS**
  The relevant PSD requirement sections are presented below, followed by the requirements analysis for each section. As determined above, the pollutants subject to PSD review are NOx and PM$_{10}$. For completeness, CO will be included in the following PSD review.

  
  (a)(2) Each permit unit is constructed using BACT for each criteria air contaminant for which there is a net emission increase;

  (a)(3) For each significant emission increase of an attainment air contaminant at a major stationary source:

  (A) The applicant certifies in writing, prior to the issuance of the permit, that the subject stationary source shall meet all applicable limitations and standards under the Clean Air Act (42 U.S.C. 7401, et seq.) and all applicable emission limitations and standards which are part of the State Implementation Plan approved by the Environmental Protection Agency or is on a compliance schedule approved by appropriate federal, state, or District officials.

  (B) The new source or modification will be constructed using BACT.

  (C) The applicant has substantiated by modeling that the proposed source or modification, in conjunction with all other applicable emission increases or reductions (including secondary emissions) affecting the impact area, will not cause or contribute to a violation of:

  (i) Any National or State Ambient Air Quality Standard in any air quality control region; or

  (ii) Any applicable maximum allowable increase over the baseline concentration in any area.

  (D) The applicant conducts an analysis of the ambient air quality in the impact area the new or modified stationary source would affect…. The applicant
may rely on existing continuous monitoring data collected by the District if approved by the Executive Office…;

(E) The applicant provides an analysis of the impairment to visibility, soil, and vegetation that would occur as a result of the new or modified stationary source and the air quality impact projected for the baseline area as a result of general commercial, residential, industrial, and other growth associated with the source;

(F) The Executive Officer provides a copy of the complete application (within 10 days after being deemed complete by the District) to the EPA, the Federal Land Manager for any Class I area located within 100 km of the source, and to the federal official charged with direct responsibility for management of any lands within the Class I area….

**PSD REQUIREMENTS ANALYSES:**


   Each permit unit is required to be constructed using BACT for each criteria air contaminant for which there is a net emission increase.

   BACT is defined in 40 CFR 52.21(b)(12) as: "an emissions limitation...based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 [New Source Performance Standards (NSPS)] and 61 [NESHAPS]..."  

   EPA outlines the process used to perform the case-by-case analysis, called a Top-Down BACT analysis, in a June 13, 1989 memorandum. The top-down analysis method was further discussed in the EPA’s New Source Review Workshop Manual, October 1990.

   The top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked (“top”) option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not “achievable” in that case.
If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT. EPA has broken down this analytical process into the following five steps.

Step 1: Identify all available control technologies.
Step 2: Eliminate technically infeasible options.
Step 3: Rank remaining control technologies.
Step 4: Evaluate most effective controls and document results.
Step 5: Select the BACT.

As required by PSD, top-down BACT analyses are presented below for the two pollutants subject to PSD review, NOx and PM\textsubscript{10}. Although not subject to PSD review for AEC, a top-down BACT analysis is also presented below for CO for the purpose of completeness.

A. **Top-Down BACT Analysis for Combined-Cycle Gas Turbines and Simple-Cycle Gas Turbines for Nitrogen Oxide (NOx) Emissions**

Step 1: Identify all available control technologies.

NOx is a by-product of the combustion of natural gas-and-air mixture in the turbines, which are high temperature environments. Thermal NO\textsubscript{X} is created by the high temperature reaction in the combustion chamber between the nitrogen and oxygen in the combustion air. The heat from combustion causes the nitrogen (N\textsubscript{2}) molecules in the combustion air to dissociate into individual N\textsubscript{2} atoms, which then combine with oxygen (O\textsubscript{2}) molecules in the air to form nitric oxide (NO) and nitrogen dioxide (NO\textsubscript{2}). The principal form of nitrogen oxide produced during turbine combustion is NO, but NO reacts quickly to form NO\textsubscript{2}, creating a mixture of NO and NO\textsubscript{2} called NOx.

Combustion controls minimize the amount of NOx created during the combustion process. The control technologies include:

A. Water or Steam Injection
B. Dry-Low NOx (DLN) Combustors

Post- combustion controls remove NOx from the exhaust stream after the combustion has occurred. The control technologies include:

A. SCR
B. SCONOx (now EMx)
C. Selective Non-Catalytic Reduction (SNCR)
Combustion Control Technologies

A. Water or Steam Injection
The injection of water or steam into the combustor of a gas turbine quenches the flame and absorbs heat, reducing the combustion temperature. This temperature reduction reduces the formation of thermal NOx. Typically combined with a post-combustion control technology, water or steam injection alone can achieve a NOx emission of 25 part(s) per million dry volume (ppmvd) at 15 percent O₂, but with the added economic, energy, and environmental expenses of using water.

B. Dry-Low NOx (DLN) Combustors
In conventional combustors, the fuel and air are injected separately and mixed by diffusion before combustion occurs. This method of combustion results in combustion “hot spots,” which produce higher levels of NOx.

Lean premix and catalytic combustors are two types of DLN combustors that are available alternatives to the conventional combustors to reduce NOx combustion “hot spots.”

Lean premix combustors are the most popular DLN combustors available. These combustors reduce the formation of thermal NOx through the following processes: (1) using excess air to reduce the flame temperature (i.e., lean combustion); (2) reducing combustor residence time to limit exposure in a high-temperature environment; (3) mixing fuel and air in an initial “pre-combustion” stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or (4) achieving two-stage rich/lean combustion using a primary fuel-rich combustion stage to limit the amount of oxygen available to combine with the nitrogen in the combustion air, and then using a secondary lean burn-stage to complete combustion in a cooler environment. Lean premix combustors have only been developed for gas-fired turbines. The more advanced designs are capable of achieving a 70- to 90-percent NOx reduction with a vendor-guaranteed NOx concentration of 9 to 25 ppmvd.

Catalytic combustor technology is available under the trade name XONON™. The XONON™ combustion system improves the combustion process by lowering the peak combustion temperature through the use of a catalyst to reduce the formation of thermal NOx. The combustion process is comprised of a partial combustion of the fuel in the catalyst module followed by a completion of the combustion downstream of the catalyst. In the catalyst module, a portion of the fuel is combusted without a flame at relatively low temperature to produce a hot gas. A homogenous combustion
Post-Combustion Control Technologies

A. SCR
SCR is a post-combustion control technology designed to control NOx emissions from gas turbines, boilers, and other NOx-emitting equipment. The SCR system consists of a catalyst bed with an ammonia injection grid located upstream of the catalyst. The ammonia reacts with the NOx and oxygen in the presence of a catalyst to form nitrogen and water. The catalyst consists of a support system with a catalyst coating typically of titanium dioxide, vanadium pentoxide, or zeolite. A small amount of ammonia that is not consumed in the reaction is emitted in the exhaust stream and is referred to as “ammonia slip.”

B. EMx™ (formerly SCONOx)
The EMx™ system uses a single catalyst to remove NOx emissions in the turbine exhaust gas by oxidizing NO to NO2 and then absorbing NO2 onto the catalytic surface using a potassium carbonate absorber coating. The potassium carbonate coating reacts with NO2 to form potassium nitrates and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EMx catalyst is from 300 to 700 degrees Fahrenheit (°F). EMx™ does not use ammonia, so there are no ammonia emissions from this catalyst system. When all of the potassium carbonate absorber coating has been converted to N2 compounds, NOx can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O2. Hydrogen in the gas reacts with the nitrites and nitrates to form water and N2. Carbon dioxide (CO2) in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst.

C. Selective Non-Catalytic Reduction (SNCR)
SNCR involves injection of ammonia or urea into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,600 to 2,100 °F. This technology is not available for combustion turbines because gas turbine exhaust temperatures are below the required minimum temperature of 1,600 °F.

Step 2: Eliminate technically infeasible options.

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170
Combustion Control Technologies

A. Water or Steam Injection

The use of water or steam injection is considered a feasible technology for reducing NOx emissions to 25 ppmvd when firing natural gas. When combined with SCR, water or steam injection can achieve 2 ppmvd and 2.5 ppmvd NOx levels for combined- and simple-cycle turbines, respectively, but at a slightly lower thermal efficiency as compared to DLN combustors.

B. Dry-Low NOx (DLN) Combustors

The use of lean premix combustors is a feasible technology for reducing NOx emissions from the AEC. DLN combustors are capable of achieving 9 to 25 ppmvd NOx emission over a relatively large operating range (70 to 100 percent load), and when combined with SCR can achieve controlled NOx emissions of 2 ppmvd and 2.5 ppmvd NOx levels for combined- and simple-cycle turbines, respectively.

The XONON™ catalytic combustor has been demonstrated successfully in a 1.5-MW simple-cycle pilot facility and is commercially available for turbines rated up to 10 MW. The technology has not been demonstrated on commercial gas turbines greater than 10 MW, such as the proposed combined- and simple-cycle turbines. XONON™ is an innovative but not currently demonstrated technology that has received very limited trial operation. Therefore, the technology is not considered feasible for AEC.

Post-Combustion Control Technologies

A. SCR

The use of SCR, with an ammonia slip of less than 5 ppm, is considered a feasible technology for reducing NOx emissions to achieve 2 ppmvd and 2.5 ppmvd NOx levels for combined- and simple-cycle turbines, respectively.

B. EMx™ (formerly SCONOx)

The use of EMx™ system is considered a feasible technology for reducing NOx emissions from AEC.

In the Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Pio Pico Energy Center, PSD Permit No. SD 11-01, dated June 2012, the EPA noted that the EMx™ technology is a relatively newer technology that has yet to be demonstrated in practice on combustion turbines greater than 50 MW. The manufacturer has stated that it is a scalable technology and that NOx guarantees of <1.5 ppm are available.
In the Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Palmdale Hybrid Power Plant, PSD Permit No. SE 09-01, dated August 2011, the EPA noted that it is unclear what NO\textsubscript{X} emission levels can actually be achieved by the technology. The EPA found only one BACT analysis that determined that EMx\textsuperscript{TM}/SCONO\textsubscript{x} was BACT for a large combustion turbine. However, the accompanying permit for the facility, Elk Hills Power in California, allowed the use of SCR or SCONO\textsubscript{x} to meet a permit limit of 2.5 ppm, and the actual technology that was installed in that case was SCR. The EPA noted that the Redding Power Plant in California, a 43 MW gas-fired combustion turbine, was permitted with a 2.0 ppm demonstration limit using SCONO\textsubscript{x}. In a letter dated June 23, 2005 from the Shasta County Air Quality Management District (Shasta County AQMD) to the Redding Electric Utility, however, it was determined that the unit could not meet the demonstration limit and, as a result, the limit was revised to 2.5 ppm. Based on these two examples, it appears that EMx\textsuperscript{TM} has been demonstrated to achieve 2.5 ppm only.

The technology has not been demonstrated in practice on combustion turbines greater than 50 MW, such as the proposed combined- and simple-cycle turbines. EMx\textsuperscript{TM} is carried forward in this BACT analysis as a potential NO\textsubscript{x} control technology. However, substantial evidence demonstrates that EMx\textsuperscript{TM} is not yet demonstrated as technically feasible for the AEC project.

C. Selective Non-Catalytic Reduction (SNCR)
SNCR is not considered technically feasible for the proposed combined- and simple-cycle turbines. SNCR requires exhaust gas temperatures in the range of 1,600 to 2,100 °F, which is higher than the exhaust temperatures from natural-gas-fired combustion turbine installations. For the proposed combined-cycle turbines, the turbine exhaust temperature range is expected to be 170 to 223 °F. For the proposed simple-cycle turbines, the turbine exhaust temperature range is expected to be 789 to 981 °F.

**Step 3: Rank remaining control technologies.**

**Combined-Cycle Turbines**
A summary of recent BACT limits for similar combined-cycle, natural gas-fired combustion turbines is provided in the table below.

IDC Bellingham was included because it is the only known facility that was permitted with a BACT limit less than the 2.0 ppm, 1-hr average, proposed by AEC.
IDC Bellingham was permitted with a limit of 1.5 ppm during normal operations. However, this project was cancelled, so this limit has never been demonstrated as achievable. As shown in the table below, all recently issued permits indicate that a limit of 2.0 ppm based on a 1-hr average represents the highest level of NO\textsubscript{X} control.

**Table 72 - Summary of Recent NO\textsubscript{X} BACT Limits for Similar Combined-Cycle, Natural Gas-Fired Combustion Turbines**

<table>
<thead>
<tr>
<th>Facility</th>
<th>Permit Issuance</th>
<th>NO\textsubscript{X} Limit @ 15% O\textsubscript{2}</th>
</tr>
</thead>
<tbody>
<tr>
<td>LA City, DWP Scattergood Generating Station, California</td>
<td>2013</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Pasadena City, Dept. of Water &amp; Power, California</td>
<td>2013</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Langley Gulch Power Plant, Idaho</td>
<td>2013</td>
<td>2.0 ppm (3-hr rolling)</td>
</tr>
<tr>
<td>El Segundo Power, LLC, California</td>
<td>2011</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Lower Colorado River Authority, Texas</td>
<td>2011</td>
<td>2.0 ppm (24-hr)</td>
</tr>
<tr>
<td>Palmdale Hybrid Power Project, California</td>
<td>2011</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Avenal Energy Project, California</td>
<td>2011</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Warren County Power Station, Virginia</td>
<td>2010</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Live Oaks Power Plant, Georgia</td>
<td>2010</td>
<td>2.5 ppm (3-hr)</td>
</tr>
<tr>
<td>Colousa Generating Station, California</td>
<td>2010</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Victorville II Hybrid Power Project, California</td>
<td>2010</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Pondera Capital Management, King Power Station, Texas</td>
<td>2010</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Russell City Energy Center, California</td>
<td>2010</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Madison Bell Energy Center, Texas</td>
<td>2009</td>
<td>2.0 ppm (24-hr rolling)</td>
</tr>
<tr>
<td>Chouteau Power Plant, Oklahoma</td>
<td>2009</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Lamar Power Partners, Texas</td>
<td>2009</td>
<td>2.0 ppm (24-hr)</td>
</tr>
<tr>
<td>Patillo Branch Power Company, Texas</td>
<td>2009</td>
<td>2.0 ppm (24-hr)</td>
</tr>
<tr>
<td>FMPA Cane Island Power Park, Florida</td>
<td>2008</td>
<td>2.0 ppm (24-hr)</td>
</tr>
<tr>
<td>FPL West County Energy Center Unit 3, Florida</td>
<td>2008</td>
<td>2.0 ppm (24-hr)</td>
</tr>
<tr>
<td>Kleen Energy Systems, Connecticut</td>
<td>2008</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Blythe Energy LLC (Blythe II), California</td>
<td>2007</td>
<td>2.0 ppm (3-hr)</td>
</tr>
<tr>
<td>PSO Southwestern Power Plant, Oklahoma</td>
<td>2007</td>
<td>9.0 ppm (no averaging time)</td>
</tr>
<tr>
<td>Carlsbad Energy Center – NRG, California</td>
<td>2007</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Rocky Mountain Energy Center, Colorado</td>
<td>2006</td>
<td>3.0 ppm (1-hr)</td>
</tr>
<tr>
<td>San Joaquin Valley Energy Center, California</td>
<td>2006</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Elk Hills Power, California</td>
<td>2006</td>
<td>2.5 ppm (1-hr)</td>
</tr>
<tr>
<td>Inland Empire Energy Center, California</td>
<td>2005</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Bicent (California) Malburg (formerly Vernon City, Light and Power Dept.), California</td>
<td>2003</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Burbank City, Burbank Water &amp; Power, SCPPA (Magnolia Power Plant), California</td>
<td>2003</td>
<td>2 ppm (3-hr)</td>
</tr>
<tr>
<td>LA City, DWP Haynes Generating Station, California</td>
<td>2002</td>
<td>2 ppm (1-hr)</td>
</tr>
<tr>
<td>IDC Bellingham, Massachusetts</td>
<td>2000</td>
<td>1.5 ppm (1-hr) Project cancelled</td>
</tr>
</tbody>
</table>
For combined-cycle turbines, the available control technologies are ranked according to control effectiveness in the table below.

**Table 73 - NOx Control Technologies for Combined-Cycle Turbines**

<table>
<thead>
<tr>
<th>NOx Control Technology</th>
<th>Controlled Emission Rate (ppmvd @ 15% O\textsubscript{2}, 1-hr average)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water or Steam Injection</td>
<td>25</td>
</tr>
<tr>
<td>Dry Low-NOx Combustors (lean premix)</td>
<td>9 - 25</td>
</tr>
<tr>
<td>EM\textsuperscript{x} with Dry Low-NOx Combustors (lean premix)</td>
<td>2.5</td>
</tr>
<tr>
<td>SCR with Dry Low-NOx Combustors (lean premix)</td>
<td>2.0</td>
</tr>
</tbody>
</table>

**Simple-Cycle Turbines**

A summary of recent BACT limits for similar simple-cycle, natural gas-fired combustion turbines is provided in the table below.

**Table 74 - Summary of Recent NOx BACT Limits for Similar Simple-Cycle, Natural Gas-Fired Combustion Turbines**

<table>
<thead>
<tr>
<th>Facility</th>
<th>Permit Issuance</th>
<th>NOx Limit @ 15% O\textsubscript{2}</th>
</tr>
</thead>
<tbody>
<tr>
<td>LA City, DWP Scattergood Generating Station, California</td>
<td>2013</td>
<td>2.5 ppm (1-hr)</td>
</tr>
<tr>
<td>CPV Sentinel, California</td>
<td>2012 &amp; 2013</td>
<td>2.5 ppm (1-hr)</td>
</tr>
<tr>
<td>Pio Pico Energy Center, California</td>
<td>2012</td>
<td>2.5 ppm (1-hr)</td>
</tr>
<tr>
<td>Walnut Creek Energy Park, California</td>
<td>2011</td>
<td>2.5 ppm (1-hr)</td>
</tr>
<tr>
<td>TID Almond 2 Power Plant, California</td>
<td>2010</td>
<td>2.5 ppm (1-hr)</td>
</tr>
<tr>
<td>Canyon Power Plant, California</td>
<td>2010</td>
<td>2.5 ppm (1-hr)</td>
</tr>
<tr>
<td>Starwood Power – Midway, California</td>
<td>2008</td>
<td>2.5 ppm (1-hr)</td>
</tr>
<tr>
<td>Panoche Energy, California</td>
<td>2007</td>
<td>2.5 ppm (1-hr)</td>
</tr>
</tbody>
</table>

For simple-cycle turbines, the available control technologies are ranked according to control effectiveness in the table below. The controlled emission rates are from Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Pio Pico Energy Center.

**Table 75 - NOx Control Technologies for Simple-Cycle Turbines**

<table>
<thead>
<tr>
<th>NOx Control Technology</th>
<th>Controlled Emission Rate (ppmvd @ 15% O\textsubscript{2}, 1-hr average)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water or Steam Injection</td>
<td>&gt; 9</td>
</tr>
<tr>
<td>Dry Low-NOx Combustors and Inlet Air Coolers</td>
<td>9</td>
</tr>
<tr>
<td>SNCR</td>
<td>~ 4.5 (based on demonstrated control efficiency of 40 – 60%)</td>
</tr>
</tbody>
</table>
Step 4: Evaluate most effective controls.

Combined-Cycle Turbines
Based on the information presented in this BACT analysis, NOx emission rates of 2.0 ppm (1-hour) are the lowest NOx emission rates achieved in practice at similar sources.

Simple-Cycle Turbines
Based on the information presented in this BACT analysis, NOx emission rates of 2.5 ppm (1-hour) are the lowest NOx emission rates achieved in practice at similar sources. SCR has not been able to duplicate the emission rate of 2.0 ppm NOx achieved with combined-cycle turbines, because the exhaust gas temperatures are higher for simple-cycle turbines.

Step 5: Select the BACT.

Combined-Cycle Turbines
Based on a review of the available control technologies for NOx emissions from natural gas-fired combined-cycle turbines, the conclusion is that BACT is the use of dry low-NOx combustors with SCR to control NOx emissions to 2.0 ppmvd (1-hour average) during normal operation. This is the same as the BACT proposed by AES.

Simple-Cycle Turbines
Based on a review of the available control technologies for NOx emissions from natural gas-fired simple-cycle turbines, the conclusion is that BACT is the use of dry low-NOx combustors with SCR to control NOx emissions to 2.5 ppmvd (1-hour average) during normal operation. This is the same as the BACT proposed by AES.

B. Top-Down BACT Analysis for Combined-Cycle Gas Turbines and Simple-Cycle Gas Turbines for Particulate Matter (PM$_{10}$) Emissions

Step 1: Identify all available control technologies.

A. Combustion Control Technologies
The major sources of PM$_{10}$ emissions from a natural-gas-fired gas turbine equipped with SCR for post-combustion control of NOx are: (1) the conversion of fuel sulfur to sulfates and ammonium sulfates; (2) unburned hydrocarbons that can lead to the formation of particulate matter in the exhaust stack; and (3) particulate matter in the ambient air entering the gas
turbine through the inlet air filtration system, and the aqueous ammonia dilution air. Therefore, the use of clean-burning, low-sulfur fuels such as natural gas will result in minimal formation of PM$_{10}$ during combustion. Best combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, thereby minimizing emissions of unburned hydrocarbons that can lead to formation of particulate matter at the stack. In addition to good combustion, use of high-efficiency filtration on the inlet air and SCR dilution air system will minimize the entrainment of particulate matter into the exhaust stream.

B. Post-Combustion Control Technologies

Two post-combustion control technologies designed to reduce particulate matter emissions from industrial sources are electrostatic precipitators and baghouses.

**Step 2: Eliminate technically infeasible options.**

Electrostatic precipitators and baghouses are typically used on solid/liquid-fuel fired or other types of sources with high particulate matter emission concentrations. Neither of these control technologies is appropriate for use on natural-gas-fired turbines because of the very low levels and small aerodynamic diameter of particulate matter from natural gas combustion. Therefore, electrostatic precipitators and baghouses are not considered technically feasible control technologies. However, clean-burning fuels, best combustion practices, and inlet air filtration are considered technically feasible for control of PM$_{10}$ emissions from combined- and simple-cycle turbines.

**Step 3: Rank remaining control technologies.**

The use of clean-burning fuels, best combustion practices, and inlet air filtration are the technically feasible natural-gas-fired turbine control technologies. No add-on control devices are technically feasible to control PM$_{10}$ emissions from natural-gas-fired turbines.

**Step 4: Evaluate most effective controls.**

Based on the information presented in this BACT analysis, using good combustion practice, pipeline quality natural gas with low sulfur content, and inlet air filtration to control PM$_{10}$ emissions is consistent with BACT at similar sources.

**Step 5: Select the BACT.**
Based on the above review, the BACT for PM$_{10}$ emissions is using pipeline-quality natural gas with low sulfur content, good combustion practice, and inlet air filtration. This is the same as the BACT proposed by AES.

C. **Top-Down BACT Analysis for Combined-Cycle Gas Turbines and Simple-Cycle Turbines for Carbon Monoxide (CO) Emissions**

**Step 1: Identify all available control technologies.**

**Combustion Control Technologies**

CO is formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of CO is limited by designing the combustion system to completely oxidize the fuel carbon to CO$_2$. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures (in excess of 1,800 °F) with an excess of combustion air. Higher combustion temperatures tend to reduce the formation of CO but increase the formation of NOx. The application of water or steam injection or dry low-NOx combustors tends to lower combustion temperatures and to reduce NOx formation, but potentially increasing CO formation. However, using good combustor design and following best operating practices will minimize the formation of CO while reducing the combustion temperature and NOx emissions.

**Post-Combustion Control Technologies**

A. **Oxidation Catalyst**

An oxidation catalyst is typically a precious metal catalyst bed. The catalyst enhances oxidation of CO to CO$_2$ without the addition of any reactant. Oxidation catalyst is a well-demonstrated technology for large combustion turbines.

B. **EMx™ (formerly SCONOx)**

The EMx™ system can reduce both NOx and CO from gas turbines. CO emissions are reduced by the oxidation of CO to CO$_2$ in the catalyst.

**Step 2: Eliminate technically infeasible options.**

**Combustion Control Technologies**

Good combustor design and best operating practices are technically feasible options for controlling CO emissions from combined- and simple-cycle turbines.

**Post-Combustion Control Technologies**

A. **Oxidation Catalyst**
The use of oxidation catalyst is considered a feasible technology for reducing CO emissions to 2 ppmvd for combined-cycle turbines and to 4 ppmvd for simple-cycle turbines, when firing natural gas.

B. EMx™ (formerly SCONOx)

The use of EMx™ system is considered a feasible technology for reducing CO emissions from AEC. In the Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Palmdale Hybrid Power Plant, PSD Permit No. SE 09-01, dated August 2011, the EPA noted it is unclear what level of control would be achieved by the technology on a long-term basis with a short (1-hr) averaging period. The manufacturer claims that emission rates below 1 ppm are achievable, but there is a lack of information that demonstrates this on large combustion turbines. EMx™ is carried forward in this BACT analysis as a potential CO control technology. However, substantial evidence demonstrates that EMx™ is not yet demonstrated as technically feasible for the AEC project.

Step 3: Rank remaining control technologies.

Combined-Cycle Turbines

A summary of recent BACT limits for similar combined-cycle, natural gas-fired combustion turbines is provided in the table below.

Table 76 - Summary of Recent CO BACT Limits for Similar Combined-Cycle, Natural Gas-Fired Combustion Turbines

<table>
<thead>
<tr>
<th>Facility</th>
<th>Permit Issuance</th>
<th>CO Limit @ 15% O₂, without duct firing</th>
<th>CO Limit @ 15% O₂, with duct firing</th>
</tr>
</thead>
<tbody>
<tr>
<td>LA City, DWP Scattergood Generating Station, California</td>
<td>2013</td>
<td>2.0 ppm (1-hr)</td>
<td></td>
</tr>
<tr>
<td>Pasadena City, Dept. of Water &amp; Power, California</td>
<td>2013</td>
<td>2.0 ppm (1-hr)</td>
<td></td>
</tr>
<tr>
<td>Langley Gulch Power Plant, Idaho</td>
<td>2013</td>
<td>2.0 ppm (3-hr rolling)</td>
<td></td>
</tr>
<tr>
<td>El Segundo Power, LLC, California</td>
<td>2011</td>
<td>2.0 ppm (1-hr)</td>
<td>2.0 ppm (1-hr)</td>
</tr>
<tr>
<td>Lower Colorado River Authority, Texas</td>
<td>2011</td>
<td>4.0 ppm (3-hr)</td>
<td></td>
</tr>
<tr>
<td>Palmdale Hybrid Power Project, California</td>
<td>2011</td>
<td>2.0 ppm (1-hr)</td>
<td>2.0 ppm (1-hr) (3-yr demonstration &amp; post-demonstration)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.5 ppm (1-hr)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(Post-demonstration)</td>
<td></td>
</tr>
<tr>
<td>Avenal Energy Project, California</td>
<td>2011</td>
<td>2.0 ppm (1-hr)</td>
<td>2.0 ppm (1-hr) (3-yr demonstration &amp; post-demonstration)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.5 ppm (1-hr)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(Post-demonstration)</td>
<td></td>
</tr>
</tbody>
</table>
As the above table demonstrates, most projects have CO emission rates that are the same as or higher than the CO emission rate proposed for the combined-cycle turbines. Four projects, however, have CO emission rates that are lower, as discussed below.

- **Kleen Energy Systems, Connecticut**
  This facility currently has the lowest permit limits for CO. The permit includes CO limits of 0.9 ppm and 1.8 ppm, on a 1-hr averaging basis for operating without and with duct burner, respectively. The initial source tests were performed in June 2011. Based on a November 2011 letter from the Connecticut Department of Energy & Environmental Protection, the facility was able to successfully demonstrate compliance with the CO emission limits of 0.9 and 1.7 ppmvd for unfired and fired operation, respectively.
It should be emphasized that the Kleen Energy Systems permit provides an exemption from these limits during periods of “shifts between loads.” Further, the permit does not specify limits for those periods of shifts between loads, which realistically can comprise a substantial percentage of normal operations. In contrast, the SCAQMD does require BACT during periods of shifts between loads. The Kleen Energy System limits do not meet the definition of BACT as implemented by the SCAQMD.

- **Warren County Power Station, Virginia**
  The final PSD permit includes CO emission limits of 1.5 ppm and 2.4 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively. The 1.5 ppm without duct burner is lower than the SCAQMD BACT/LAER limit of 2.0 ppm, but the 2.4 ppm with duct burner is higher than the SCAQMD BACT/LAER limit of 2.0 ppm. Based on publicly available information, commercial operation started in December 2014.

  The SCAQMD Science & Technology Advancement Office will be requested to provide a BACT determination for the CO emissions levels emitted while operating without duct burner achieved by this facility’s combined-cycle turbines. Achieved-in-practice LAER is based on a minimum of 183 operating days (6 months). The review will require additional data, including CEMS data and the percentage of normal operating hours without duct burning.

- **Avenal Energy Project, California**
  The final PSD permit includes CO emission limits of 1.5 ppm and 2.0 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively, after a 3-year demonstration period during which the CO emissions limit is 2.0 ppm for operating without and with duct burner. The CEC website indicates the license was withdrawn by Applicant on 9/1/15.

- **Palmdale Energy Project (formerly Palmdale Hybrid Power Project), California**
  The final PSD permit specifies CO emission limits of 1.5 ppm and 2.0 ppm, on a 1-hour averaging basis for operating without and with duct burner, respectively, after a 3-year demonstration period during which the CO emissions limit is 2.0 ppm for operating without and with duct burner. This facility was not constructed.

  The CEC website indicates a Petition to Amend was filed on 7/27/15, and the Amendment Preliminary Staff Assessment was released on 3/23/16 for the revised project, now renamed the Palmdale Energy Project. Pg. 4.1-26 of the PSA indicates CO emission concentrations would be limited to 2.0 ppmvd, which is the same as proposed for the AEC combined-cycle turbines.
The available control technologies are ranked according to control effectiveness in the table below. The controlled emission rates are from Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit for Palmdale Hybrid Power Plant. Based on the lack of information for similar units, EMx™ is conservatively being compared as equivalent to oxidation catalyst.

**Table 77 - CO Control Technologies for Combined-Cycle Turbines Ranked by Control Effectiveness**

<table>
<thead>
<tr>
<th>CO Control Technology</th>
<th>Controlled Emission Rate (ppmvd @ 15% O₂, 1-hr average without duct firing)</th>
<th>Controlled Emission Rate (ppmvd @ 15% O₂, 1-hr average with duct firing)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Good combustion practices</td>
<td>8.0 ppm</td>
<td>8.0 ppm</td>
</tr>
<tr>
<td>Oxidation catalyst and good combustion practices</td>
<td>0.9 - 2 ppm</td>
<td>2.0 - 2.4 ppm</td>
</tr>
<tr>
<td>EMx™ and good combustion practices</td>
<td>0.9 - 2 ppm</td>
<td>2.0 – 2.4 ppm</td>
</tr>
</tbody>
</table>

**Simple-Cycle Turbines**
A summary of recent BACT limits for similar simple-cycle, natural gas-fired combustion turbines is provided in the table below.

**Table 78 - Summary of Recent CO BACT Limits for Similar Simple-Cycle, Natural Gas-Fired Combustion Turbines**

<table>
<thead>
<tr>
<th>Facility</th>
<th>Permit Issuance</th>
<th>CO Limit @ 15% O₂</th>
</tr>
</thead>
<tbody>
<tr>
<td>LA City, DWP Scattergood Generating Station, California</td>
<td>2013</td>
<td>4 ppm (1-hr)</td>
</tr>
<tr>
<td>CPV Sentinel, California</td>
<td>2012 &amp; 2013</td>
<td>4 ppm (1-hr)</td>
</tr>
<tr>
<td>Pio Pico Energy Center, California</td>
<td>2012</td>
<td>4 ppm (1-hr)</td>
</tr>
<tr>
<td>Walnut Creek Energy Park, California</td>
<td>2011</td>
<td>4 ppm (1-hr)</td>
</tr>
<tr>
<td>TID Almond 2 Power Plant, California</td>
<td>2010</td>
<td>4 ppm (3-hr)</td>
</tr>
<tr>
<td>Canyon Power Plant, California</td>
<td>2010</td>
<td>4 ppm (1-hr)</td>
</tr>
<tr>
<td>Starwood Power – Midway, California</td>
<td>2008</td>
<td>6 ppm (none)</td>
</tr>
<tr>
<td>Panoche Energy, California</td>
<td>2007</td>
<td>6 ppm (3-hr rolling)</td>
</tr>
</tbody>
</table>

As the above table demonstrates, most projects have CO emission rates that are the same as or higher than the CO emission rate proposed for the AEC.
Step 4: Evaluate most effective controls.

Even assuming that EMx™ is equivalent to oxidation catalyst for controlling CO emission, it was determined to be not as effective as SCR for controlling NOx emissions. As EMx™ would not ensure that the BACT limit of 2.0 ppm NOx for combined-cycle turbines and 2.5 ppm NOx for simple-cycle turbines will be achieved, it is eliminated in this step due to environmental impacts.

**Combined-Cycle Turbines**
Based on the information presented in this BACT analysis, CO emission rates of 2.0 ppm (1-hour) are the lowest CO emission rates achieved in practice at similar sources.

**Simple-Cycle Turbines**
Based on the information presented in this BACT analysis, CO emission rates of 4.0 ppm (1-hour) are the lowest CO emission rates achieved in practice at similar sources.

Step 5: Select the BACT.

**Combined-Cycle Turbines**
Based on a review of the available control technologies for CO emissions from natural gas-fired combined-cycle turbines, the conclusion is that BACT using good combustion practice and oxidation catalyst to control CO emissions to 2.0 ppm (1-hour average) during normal operation. This is the same as the BACT proposed by AES.

**Simple-Cycle Turbines**
Based on a review of the available control technologies for CO emissions from natural gas-fired simple-cycle turbines, the conclusion is that BACT using good combustion practice and oxidation catalyst to control CO emissions to 4.0 ppm (1-hour average) during normal operation. This is the same as the BACT proposed by AES.

D. Top-Down BACT Analysis for Auxiliary Boiler for Nitrogen Oxide (NOx) Emissions

Step 1: Identify all available control technologies.
Available combustion and post-combustion control technologies include good combustion practice, staged air/fuel combustion, low NOx burner, flue gas recirculation (FGR), and SCR.
The FGR system is not as common as some of the other control technologies. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products that act as inerts during combustion of the fuel and air mixture which reduces combustion temperatures, thereby suppressing the thermal NOx mechanism. In addition, FGR reduces NOx formation by lowering the oxygen concentration in the primary flame zone.

Step 2: Eliminate technically infeasible options.
The control technologies identified above are considered technically feasible for natural-gas fired boilers.

Step 3: Rank remaining control technologies.

A summary of recent BACT limits for similar natural gas-fired auxiliary boilers is provided in the table below.

Table 79 - Summary of Recent NOx BACT Limits for Similar Auxiliary Boilers

<table>
<thead>
<tr>
<th>Facility</th>
<th>Permit Issuance</th>
<th>NOx Limit @ 3% O2</th>
</tr>
</thead>
<tbody>
<tr>
<td>El Segundo Power Redevelopment Project, CA</td>
<td>Pending</td>
<td>5 ppm NOx (1-hr)</td>
</tr>
<tr>
<td>Gilroy Cogeneration Project, CA (Add SCR)</td>
<td>2013</td>
<td>5 ppm NOx (1-hr)</td>
</tr>
<tr>
<td>Carroll County Energy, OH</td>
<td>2013</td>
<td>0.02 lb/MMBtu</td>
</tr>
<tr>
<td>Oregon Clean Energy, OR</td>
<td>2013</td>
<td>0.02 lb/MMBtu</td>
</tr>
<tr>
<td>Green Energy Partners/Stonewall, VA</td>
<td>2013</td>
<td>0.011 lb/MMBtu    (9 ppm)</td>
</tr>
<tr>
<td>Palmdale Hybrid Power, CA</td>
<td>2011</td>
<td>9 ppmvd</td>
</tr>
</tbody>
</table>

The control technologies are ranked below in order from least effective to most effective.

Good Combustion Practice, Conventional Burner
Staged Air/Fuel
FGR Alone
Low-NOx Burner with Good Combustion Practice
Low-NOx Burner with FGR
Low-NOx Burner with SCR

For all non-RECLAIM facilities, SCAQMD Rule 1146—Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters requires natural gas-fired boilers with a rated heat input greater
than or equal to 75 MMBtu/hr to meet 5 ppm at 3% O\textsubscript{2} or 0.0062 lbs/10\textsuperscript{6} Btu on or before 1/1/13. An SCR is required to meet the 5 ppm limit.

**Step 4: Evaluate the most effective controls.**

Based on the information presented in this BACT analysis, NOx emission rates of 5.0 ppm (1-hour) are the lowest NOx emission rates achieved in practice at similar sources.

**Step 5: Select the BACT.**

Based on a review of the available control technologies for NOx emissions from natural gas-fired auxiliary boilers, the conclusion is that BACT is the control of NOx emissions to 5.0 ppmvd (1-hour average) during normal operation. AES proposes control with good combustion design and practice, low NOx burner, flue gas recirculation and SCR to achieve emission rates of 5.0 ppm (1-hour) during normal operation. Without the SCR, the NOx emissions would be 10.0 ppmvd.

E. **Top-Down BACT Analysis for Auxiliary Boiler for Particulate Matter (PM\textsubscript{10}) Emissions**

**Step 1: Identify all available control technologies.**

The combustion control and post-combustion control technologies available to control PM\textsubscript{10} from an auxiliary boiler are the same as those described above for the combustion turbines.

**Step 2: Eliminate technically infeasible options.**

The technically infeasible and feasible options are the same as those described above for the combustion turbines.

**Step 3: Rank remaining control technologies.**

The commercially available control measures that are identified in the most stringent BACT determinations for auxiliary boilers are use of pipeline quality natural gas with low sulfur content and good combustion practice. No add-on control devices are technically feasible to control PM\textsubscript{10} emissions from natural-gas-fired boilers.

**Step 4: Evaluate most effective controls.**
Based on the information presented in this BACT analysis, using pipeline quality
natural gas with a low sulfur content and good combustion practice to control PM$_{10}$
emissions is consistent with BACT at similar sources.

**Step 5: Select the BACT.**

Based on the above review, the BACT for PM$_{10}$ emissions from the auxiliary boiler
is using pipeline-quality natural gas with low sulfur and good combustion practice.
This is the same as the BACT proposed by AES.

**F. Top-Down BACT Analysis for Auxiliary Boiler for Carbon Monoxide (CO) Emissions**

**Step 1: Identify all available control technologies.**
The available control technologies are good combustion practice and oxidation
catalyst.

**Step 2: Eliminate technically infeasible options.**
The identified control technologies are considered technically feasible for natural-
gas fired boilers.

**Step 3: Rank remaining control technologies.**
A summary of recent BACT limits for similar natural gas-fired auxiliary boilers is
provided in the table below.

**Table 80 - Summary of Recent CO BACT Limits for Similar Auxiliary Boilers**

<table>
<thead>
<tr>
<th>Facility</th>
<th>Permit Issuance</th>
<th>NOx Limit @ 3% O$_2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>El Segundo Power Redevelopment Project, California</td>
<td>Pending</td>
<td>50 ppm NOx (1-hr)</td>
</tr>
<tr>
<td>Carroll County Energy, Ohio</td>
<td>2013</td>
<td>0.055 lb/MMBtu</td>
</tr>
<tr>
<td>Oregon Clean Energy, Oregon</td>
<td>2013</td>
<td>0.037 lb/MMBtu (= 50 ppm)</td>
</tr>
<tr>
<td>Green Energy Partners/Stonewall, Virginia</td>
<td>2013</td>
<td>0.037 lb/MMBtu (= 50 ppm)</td>
</tr>
<tr>
<td>Palmdale Hybrid Power, California</td>
<td>2011</td>
<td>50 ppm (3-hr)</td>
</tr>
<tr>
<td>AES Huntington Beach (Steam-generating utility boiler)</td>
<td>2004</td>
<td>5 ppm (1-hr), Oxidation Catalyst</td>
</tr>
</tbody>
</table>

The control technologies are ranked below in order from least effective to most
effective.

- Good Combustion Practice
- Oxidation Catalyst
Step 4: Evaluate the most effective controls.
The use of an oxidation catalyst has not been identified as demonstrated technology for auxiliary boilers. Since an auxiliary boiler is used relatively infrequently during the start-up cycles for the combined-cycle turbines, the installation of oxidation catalyst for CO control is not considered cost effective. In Table 80, for the AES Huntington Beach facility, the oxidation catalyst was installed on a large steam-generating utility boiler, which operates relatively continuously.

Since 4/10/1998, SCAQMD Minor Source BACT had required all natural gas–fired, watertube type boilers to meet 100 ppm at 3% O2, and all firetube type boilers to meet 50 ppm at 3% O2, with good combustion practice. Although the auxiliary boiler is a watertube boiler, a guarantee of 50 ppm has been provided by Cleaver Brooks, 6/10/15.

Step 5: Select the BACT.
Based on a review of the available control technologies for CO emissions from auxiliary boilers, the conclusion is that BACT using good combustion practice to control CO emissions to 50 ppm (1-hour average) during normal operation. This is the same as the BACT proposed by AES.

2. Rule 1703(a)(3)(A) Analysis—Certification of Compliance
Stephen O’Kane, Manager, AES Alamitos, LLC, provided a letter, dated 10/23/15, stating that, as a corporate officer of AES Alamitos, LLC, he certifies that all major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by AES in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emissions limitations and standards under the Clean Air Act.

Permit applications for the subject project were submitted to the SCAQMD on 10/23/15 and were deemed complete by SCAQMD on 1/14/16, with the last submittal of additional information received on January 7, 2016. On 1/20/16, SCAQMD mailed a copy of the original Application, including the modeling CDs, to the following contacts for the affected agencies:

Andrea Nick, Air Resource Specialist, Forest Service Region 5
Randy Moore, Regional Forester, U.S. Forest Service, Pacific Southwest Region
Gerardo Rios, U.S. EPA, Region IX
Don Shepherd, National Park Service, Air Resources Division
Tonnie Cummings, Air Resources Specialist, National Park Service, Pacific West Region
On 4/1/16, SCAQMD mailed a copy of the revised Application, including the modeling CDs, to the same agencies. In an e-mail dated 5/6/16, Tonnie Cummings indicated they agree the proposed controls represent BACT and do not anticipate the project would substantially affect any areas managed by National Park Service. Therefore, they have no need to provide further comments on the project.

Comments have not yet been received from the Forest Service.


The air impacts analysis, including modeling, were performed for CO, NO\textsubscript{2} and PM\textsubscript{10}, as follows.

**A. Rule 1703(a)(3)(D)--Pre-Construction Monitoring**

To ensure that the impacts from AEC will not cause or contribute to a violation of an ambient air quality standard or an exceedance of a PSD increment, an analysis of the existing air quality in the project area is necessary. Preconstruction ambient air quality monitoring data is required for the purposes of establishing background pollutant concentrations in the impact area (40 CFR 52.21(m)). However, a facility may be exempted from this requirement if the predicted air quality impacts are less than the significant monitoring concentrations.

<table>
<thead>
<tr>
<th>Pollutant (Averaging Period)</th>
<th>Significant Monitoring Concentration (µg/m\textsuperscript{3})</th>
<th>AEC Maximum Predicted Impact (µg/m\textsuperscript{3}) (Table 57)</th>
<th>Exempt?</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO\textsubscript{2} (1-hour)</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>NO\textsubscript{2} (annual)</td>
<td>14</td>
<td>0.20</td>
<td>Yes</td>
</tr>
<tr>
<td>CO (1-hour)</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>CO (8-hour)</td>
<td>575</td>
<td>44</td>
<td>Yes</td>
</tr>
<tr>
<td>PM\textsubscript{10} (24-hour)</td>
<td>10</td>
<td>1.71</td>
<td>Yes</td>
</tr>
<tr>
<td>PM\textsubscript{10} (annual)</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Since the modeled impacts for NO\textsubscript{2}, CO, and PM\textsubscript{10} are below the respective monitoring thresholds, the project is exempt from the pre-construction monitoring requirement. Consequently, AES may rely on air quality monitoring data collected at SCAQMD monitoring stations. AES has proposed the use of the three most recent years of background CO and annual NO\textsubscript{2} data from the North Long Beach monitoring station (South Coastal Los Angeles County 1), and the three most recent years of background PM\textsubscript{10} data from the South Long Beach monitoring station (South Coastal Los Angeles County 2) for background concentrations.

PRDAS staff informed the applicant’s consultant that their proposed background concentrations reflected the 2009-2013 period but were required to be updated to
Preliminary Determination of Compliance

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170
comparison to the respective Significant Impact Levels and the Class II PSD Increment Standards. PRDAS staff has reviewed the applicant’s analysis.

Table 82 – Maximum Modeled Project Impacts Compared to Class II SILs and PSD Increment Standards

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Time</th>
<th>AEC Maximum Predicted Impact ($\mu g/m^3$) (&lt;Table 57&gt;)</th>
<th>Significant Impact Level ($\mu g/m^3$)</th>
<th>Significant?</th>
<th>PSD Class II Increment Standard ($\mu g/m^3$)</th>
<th>Exceeds Class II SIL?</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO$_2$</td>
<td>1-hr</td>
<td>31.3</td>
<td>7.52</td>
<td>Yes</td>
<td>N/A</td>
<td>Yes, cumulative impact assessment required.</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>0.2</td>
<td>1.0</td>
<td>No</td>
<td>25</td>
<td>No</td>
</tr>
<tr>
<td>CO</td>
<td>1-hr</td>
<td>186</td>
<td>2,000</td>
<td>No</td>
<td>N/A</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>8-hr</td>
<td>44</td>
<td>500</td>
<td>No</td>
<td>N/A</td>
<td>No</td>
</tr>
<tr>
<td>PM$_{10}$</td>
<td>24-hr</td>
<td>1.7</td>
<td>5.0</td>
<td>No</td>
<td>30</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>0.2</td>
<td>1.0</td>
<td>No</td>
<td>17</td>
<td>No</td>
</tr>
</tbody>
</table>

The maximum 1-hour and annual NO$_2$ concentrations include ambient NO$_2$ to NOx conversion ratios of 0.80 and 0.75, respectively.

As shown in the table above, the maximum predicted impacts for annual NO$_2$, 1-hr and 8-hr CO, and 24-hr and annual PM$_{10}$ are below the respective Class II SILs. Therefore, these impacts are less than significant, and no additional PSD analysis is required. Although further analysis to demonstrate compliance with the increment standard is not required, the table includes the increment standard comparison for informational purposes.

The maximum predicted 1-hour NO$_2$ impact of 31.3 $\mu g/m^3$ exceeds the Class II SIL of 7.52 $\mu g/m^3$, with a radius of impact with predicted concentrations greater than 7.52 $\mu g/m^3$ of 1.5 km. Therefore, the cumulative impacts of the AEC and competing sources were required to be assessed for all receptors where the AEC impacts alone exceeded the 1-hour NO$_2$ SIL.

- **Cumulative Impacts of the AEC and Nearby Sources**
  The SCAQMD identified the following two facilities within 10 km of the AEC for inclusion in the cumulative impact assessment. These facilities were selected to be included based on the facility emissions and distance to the project.
• Los Angeles Department of Water and Power, Haynes Generating Station (SCAQMD ID 800074), located in Long Beach, CA, with 10 emission sources.

• Beta Offshore (SCAQMD ID 166073), located in Huntington Beach, CA, with 13 emission sources.

SCAQMD provided the stack locations, stack parameters, and 1-hour NO$_2$ emission rates for the emission sources at these two facilities, and requested that the Beta Offshore emissions sources be modeled as rural sources.

In addition, the SCAQMD also requested that emissions from shipping lane activity off the California coast be included in the cumulative impact assessment. SCAQMD provided the relevant locations, source parameters, and 1-hour NO$_2$ emission rates for the shipping lane activity, and requested that the shipping lane emission sources be modeled as rural sources.

The cumulative impacts of the AEC and competing sources were assessed for all receptors where the AEC impacts alone exceeded the 1-hour NO$_2$ SIL of 7.52 µg/m$^3$. Based on a comparison of these results to the 1-hour NO$_2$ NAAQS of 188 µg/m$^3$, it was determined that there were receptors where the contributions from the AEC combined with those from competing sources and representative background concentrations exceeded the 1-hour NO$_2$ NAAQS. Therefore, the AERMOD-generated output files were reviewed to assess the contribution of the AEC’s emissions at each of the receptors where an exceedance of the 1-hour NO$_2$ NAAQS was modeled. The files show that the maximum contribution for the AEC to any modeled exceedance was less than the 1-hour NO$_2$ Class II SIL of 7.52 µg/m$^3$. Therefore, the AEC’s contribution to each modeled exceedance is less than significant and would not cause or contribute to any modeled exceedance of the 1-hour NO$_2$ NAAQS.

In AES Response Letter, dated 12/11/15, the applicant provided additional information to clarify Table 5.1C.11—Competing Source Results in the original Application. The response included new Table 19-1—Competing Source Results. This table presents: (1) the maximum contribution to a modeled exceedance of the NAAQS from each facility modeled as part of the PSD competing source assessment, and (2) the maximum modeled impact from all competing sources combined with the 3-year average, 98th percentile background concentration.
PRDAS staff has reviewed the applicant’s analysis and provided the updated background concentration, which is incorporated in the table below. The 1-hour NO\textsubscript{2} impact from the project plus cumulative projects plus background is 251.3 µg/m\textsuperscript{3}, which exceeds the 1-hour NO\textsubscript{2} NAAQS of 188 µg/m\textsuperscript{3}. An examination of each facility’s contributions to the modeled exceedances shows that Alamitos’ maximum contributions to the modeled exceedances was 6.9 µg/m\textsuperscript{3}, which is less than the 1-hour NO\textsubscript{2} SIL of 7.52 µg/m\textsuperscript{3}. Therefore, Alamitos’ impacts are less than significant and does not cause or contribute to the modeled exceedance.

### Table 83 - Competing Sources Results

<table>
<thead>
<tr>
<th>Combustion Sources</th>
<th>1-hour NO\textsubscript{2} Concentrations (µg/m\textsuperscript{3})</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEC (max contribution)</td>
<td>6.54 6.36 6.76 6.87 6.75</td>
</tr>
<tr>
<td>Haynes Generating Station (max contribution)</td>
<td>48.0 48.0 48.0 48.0 48.0</td>
</tr>
<tr>
<td>Beta Offshore (max contribution)</td>
<td>0.36 0.61 0.33 0.37 0.73</td>
</tr>
<tr>
<td>Shipping Lanes (max contribution)</td>
<td>101 104 105 102 97.8</td>
</tr>
<tr>
<td>All Sources (max impact)</td>
<td>105 108 108 105 99</td>
</tr>
<tr>
<td>Background Concentration</td>
<td>146.3</td>
</tr>
<tr>
<td>All Sources with Background Concentration\textsuperscript{5}</td>
<td><strong>251.3</strong></td>
</tr>
</tbody>
</table>

The maximum 1-hour NO\textsubscript{2} concentrations include an ambient NO\textsubscript{2} to NO\textsubscript{x} conversion ratio of 0.80.

(3) **Class I Area Impact Analysis**

A Class I impact analysis was conducted to demonstrate that the AEC will not adversely affect air quality-related values (AQRVs) and will not cause or contribute to an exceedance of the Class I Significant Impact Level (SIL) or PSD Class I Increment Standards.

- **Air Quality Related Values**
  
  To evaluate the potential impacts on visibility and deposition at the nearest Class I area, the guidance provided in the Federal Land Manager’s Air Quality Related Values Workgroup (FLAG) Phase I Report (revised 2010) allows an emissions/distance (Q/D) factor of 10 to be used as a screening criteria for sources located more than 50 km from a Class I area. This screening criterion includes all AQRVs. AQRVs are defined by the Federal Land Manager, and typically limit visibility degradation and the deposition of sulfuric acid and nitrogen. Emissions are calculated as the total SO\textsubscript{2}, NO\textsubscript{x}, PM\textsubscript{10}, and sulfuric acid annual emissions (in tpy, based on 24-hour maximum allowable emissions multiplied by 365 days) unless an emission source is limited to time periods shorter than 1 year. Condition nos. A63.2, A63.3, and A63.4
provide annual emissions limits for PM$_{10}$ and SO$_2$ for combined-cycle turbines, simple-cycle turbines, and the auxiliary boiler, respectively. These limits also indirectly limit the NOx emissions from the respective equipment.

On an annual equivalent basis, the combined AEC annual emissions of NOx (354.11 tpy), PM (184.36 tpy), SO$_2$ (29.86 tpy), and sulfuric acid (0 tpy) will be approximately 568.33 tpy. Therefore, the maximum Q/D for the project will be approximately 10.72 ton/km-year, where Q is 568.33 tpy and D is 53 km, the distance to the nearest Class I area, San Gabriel Wilderness.

\[
\text{NOx} = (2 \text{ combined-cycle turbines})(41.93 \text{ tons/yr per turbine})(8760 \text{ hr/4640 hr}) + (4 \text{ simple-cycle turbines})(13.13 \text{ tons/yr per turbine})(8760 \text{ hr/2358 hr}) + (0.68 \text{ tons/yr per auxiliary boiler})(8760 \text{ hr/8760 hr}) = 354,11 \text{ tpy}
\]

\[
\text{PM} = (2 \text{ combined-cycle turbines})(19.72 \text{ tons/yr per turbine})(8760 \text{ hr/4640 hr}) + (4 \text{ simple-cycle turbines})(7.35 \text{ tons/yr per turbine})(8760 \text{ hr/2358 hr}) + (0.68 \text{ tons/yr per auxiliary boiler})(8760 \text{ hr/8760 hr}) = 184.36 \text{ tpy}
\]

\[
\text{SO}_2 = (2 \text{ combined-cycle turbines})(4.59 \text{ tons/yr per turbine})(8760 \text{ hr/4640 hr}) + (4 \text{ simple-cycle turbines})(0.83 \text{ tons/yr per turbine})(8760 \text{ hr/2358 hr}) + (0.19 \text{ tons/yr per auxiliary boiler})(8760 \text{ hr/8760 hr}) = 29.86 \text{ tpy}
\]

Because the factor is greater than the federal Class I area air quality screening criteria of 10, visibility and deposition modeling is required for all Class I areas which exceed the screening criteria and any additional Class I areas requested by the FLM.

In the original Application, the results of the visibility and deposition modeling are found in Appendix 5.1G—Class I Air Quality Related Values Analysis. The Dispersion Modeling Protocol for Air Quality Related Values at Class I Areas Near the Alamitos Energy Center, October 2015, is found in Appendix 5.1F—Dispersion Modeling Protocols. AES indicates the results were prepared as a separate document and submitted to the appropriate FLM for review and approval. The protocol was also indicated to have been submitted to the appropriate FLM for review and approval. In the revised Application, the proposed changes resulted in revisions to Appendix 5.1G, but not to Appendix 5.1F.

On 1/20/16, SCAQMD mailed a copy of the original Application, including the modeling CDs, to the National Park Service, Forest
Services, and EPA. On 4/1/16, SCAQMD mailed a copy of the revised Application, including the modeling CDs, to the same agencies.

In an e-mail dated 5/6/16, Tonnie Cummings, National Park Service, indicated they agree the proposed controls represent BACT and do not anticipate the project would substantially affect any areas managed by National Park Service. Therefore, they have no need to provide further comments on the project.

Comments have not yet been received from the Forest Service.

- **Class I Increment Analysis**
  
  EPA requires an analysis addressing Class I increment impacts for the applicable pollutants regardless of the results of the Class I AQRV analysis. To evaluate the potential impacts on Class I areas near the AEC site, all Class I areas within 300 km of AEC were identified. Based on this survey, the San Gabriel Wilderness, which is approximately 53 km from the AEC site, was identified as the nearest Class I area.

  A summary of the predicted annual NO$_2$, 24-hour PM$_{10}$, and annual PM$_{10}$ impacts and a comparison to the Class I SIL is presented in revised Table 5.1-41-- *AEC Predicted Impacts Compared to the Class I SIL and PSD Class I Increment Standards* in the revised Application.

  A radial receptor ring was placed at a distance of 50 km from the project because 50 km is the maximum receptor distance of the AERMOD model. The predicted impacts from the operation of the AEC are below the SIL, therefore comparison with the increment standard is not required. Since the impact at 50 km is below the SIL, the project would have a negligible impact at the more distant Class I areas and actual ambient air quality impacts at Class I areas are not required to be determined. PRDAS staff has reviewed the applicant’s analysis.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Maximum Predicted Impact at 50 km (µg/m$^3$)</th>
<th>Significance Impact Level (µg/m$^3$)</th>
<th>Exceeds Class I SIL?</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO$_2$</td>
<td>Annual</td>
<td>0.0047</td>
<td>0.1</td>
<td>No</td>
</tr>
<tr>
<td>PM$_{10}$</td>
<td>24-hour</td>
<td>0.056</td>
<td>0.3</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>Annual</td>
<td>0.0046</td>
<td>0.2</td>
<td>No</td>
</tr>
</tbody>
</table>

The annual NO$_2$ concentration includes an ambient NO$_2$ to NOx conversion ratio of 0.75.

---

Preliminary Determination of Compliance

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170
C. Rule 1703(a)(3)(E)—Additional Impacts: Visibility, Soil and Vegetation Impacts as Result of Growth

In addition to assessing the ambient air quality impacts expected for a proposed new source, the PSD regulations require the evaluation of other potential impacts on (1) growth, (2) soils and vegetation, and (3) visibility impairment. The depth of the analysis generally depends on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source’s impact area.

(1) Growth

The growth component involves a discussion of general commercial, residential, industrial, and other growth associated with AEC. AEC consists of the replacement of existing electrical generating utility boilers with newer more efficient combustion turbines that will be entirely located within the existing AGS facility boundaries. As such, AEC is not anticipated to result in general commercial, residential, industrial, or other growth. The resulting ancillary growth is not expected to result in material impacts to air quality or impairment to visibility, soils, and vegetation. The City of Los Alamitos and the general project area is already heavily developed and is close to the Los Angeles metropolitan area. Because of the existing stock of housing and industrial and commercial services and the fact that AEC will replace existing electrical generation within the western Los Angeles basin, AEC is not expected to require or cause any material offsite growth that could impair soils or vegetation. During AEC construction, it is not anticipated that the work force will cause any increase to preexisting housing and services. The limited work force and outside services required for the AEC’s operation once construction is complete also will not materially affect the area. Lastly, by locating AEC on an existing power plant site and due to the urban nature of the project area, the project is not expected to induce growth or to result in impacts to soils and vegetation.

(2) Soil and Vegetation Impacts

The additional impact analysis includes consideration of potential impacts to soils and vegetation associated with AEC.

- Nitrogen Deposition Impacts
  Section 5.2 Biological Resources of the Supplemental AFC, submitted to CEC on 10/26/15, includes an analysis of nitrogen deposition impacts. Nitrogen oxide gases convert to nitrate particulates in a form that is suitable for uptake by most plants and could be used to promote plant growth and primary productivity. Coastal salt marshes are the most common natural habitats in the vicinity of the AEC where nitrogen deposition may occur. Various studies that have nitrogen loading in...
intertidal salt marsh wetlands have found critical loads to range from between 63 and 400 kilograms-nitrogen per hectare per year (kg N ha\(^{-1}\) yr\(^{-1}\)). AES evaluated the wet and dry nitrogen deposition result from depositional nitrogen emissions from AEC using AERMOD (version 15181). Conservative assumptions regarding nitrogen formation and deposition included: (1) 100 percent conversion of nitrogen oxides (NOx) and ammonia (NH\(_3\)) into atmospherically derived nitrogen within the turbine stacks rather than allowing for the conversion to occur over distance and time within the atmosphere, (2) maximum potential emissions for AEC were assumed to occur each year, and (3) all nitrogen emitted was in the form of nitric acid, the most depositionally aggressive species. Based on the above modeling approach, the maximum modeled annual deposition averaged over five years was 3.62 kg N ha\(^{-1}\) yr\(^{-1}\), which occurs on the eastern fence line of the AEC site. Revised Section 5.2, submitted to the CEC on 4/12/16, indicates the maximum modeled annual deposition averaged over five years has been revised to 2.32 kg N ha\(^{-1}\) yr\(^{-1}\). This annual deposition is less than the critical loads, which range between 63 and 400 kg N ha\(^{-1}\) yr\(^{-1}\).

- **Secondary NAAQS**
  
  For most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS will not result in harmful effects, because the secondary NAAQS levels are set to protect public welfare, including animals, plants, soils, and materials.

The dispersion modeling to demonstrate compliance with the primary NAAQS shown in Table 57 also demonstrates that NO\(_2\), SO\(_2\) and PM\(_{10}\) will be in compliance with the secondary NAAQS, as shown in the table below. EPA has not promulgated secondary NAAQS for CO.

**Table 85 - Model Results – Normal Operation for AEC - Compliance with Secondary NAAQS**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Averaging Period</th>
<th>Maximum Predicted Impact (µg/m(^3)) (Table 57)</th>
<th>Background Concentration (µg/m(^3))</th>
<th>Total Predicted Concentration (µg/m(^3))</th>
<th>Federal Secondary NAAQS (µg/m(^3))</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO(_2)</td>
<td>Annual</td>
<td>0.20</td>
<td>47.6</td>
<td>47.8</td>
<td>100</td>
<td>No</td>
</tr>
<tr>
<td>SO(_2)</td>
<td>3-hour</td>
<td>1.7</td>
<td>58.2</td>
<td>59.9</td>
<td>1,300</td>
<td>No</td>
</tr>
<tr>
<td>PM(_{10})</td>
<td>24-hour</td>
<td>1.7</td>
<td>59.0</td>
<td>60.7</td>
<td>150</td>
<td>No</td>
</tr>
</tbody>
</table>
Visibility Impairment—Class II Area Analysis

The application provided a quantitative visibility analysis for Class II areas within 50 km of AEC. The analysis was performed using the VISCREEN plume modeling program pursuant to the procedures outlined in the “Workbook for Plume Visual Impact Screening and Analysis (Revised)” (EPA, 1992), the Park Service’s IMPROVE network suggested visual range, and AERMOD meteorological data. The VISCREEN Tier I assessment was conducted using criteria for Class I areas, because there are currently no thresholds for visibility impacts on Class II areas.

The applicant conducted a survey of California State Parks and Wilderness areas designated as Class II areas within 50 km of AEC. The four Class II areas, identified by the applicant and approved by the SCAQMD for inclusion in the analysis, were evaluated.

The Federal Land Managers’ Air Quality Related Values Workgroup (FLAG) Phase I Report – Revised (2010) guidance document for addressing Class I areas recommends the use of the U.S. Environmental Protection Agency’s (EPA) VISCREEN screening model to assess the plume contrast and color contrast (ΔE) when compared to the sky and terrain backgrounds. The VISCREEN screening model can use a tiered approach to determine if the facility’s emissions would impact visibility at a nearby Class I area.

The VISCREEN screening model was developed to present a visual effect evaluation of emissions from a source as observed from a given vantage point on either a sky or terrain background. Emissions input into the model are assumed to travel along an infinitely long, straight line toward the specified area of concern. A Tier I assessment utilizes conservative assumptions for both plume characteristics and dispersion conditions to determine if the plume would have an impact on visibility. If a Tier I assessment exceeds the FLAG guidance levels of concern for Class I areas of 2.0 for ΔE and 0.05 (absolute value) for the perceptibility threshold, then a Tier II assessment would be conducted. A Tier II assessment provides a more realistic representation of the possible worst-case meteorology and plume transport for a specific area to be analyzed.
The VISCREEN Tier I modeled results for each Class II area evaluated are summarized in *Table 5.1-42—AEC Tier I VISCREEN Results* in the original Application. The maximum modeled values for color difference and contrast are presented for inside the area analyzed, regardless of the VISCREEN modeled lines of sight for the observer. In the revised Application, *Table 5.1-42* has been revised to incorporate the increases in SO₂, NOₓ, and PM₁₀ (no H₂SO₄) annualized emissions and to provide more conservative results.

The VISCREEN Tier I assessment for each Class II area did not exceed the criterion for color contrast or plume contrast, as shown in the table below. As the modeled results are below the conservative Class I area criterion for both color difference and contrast, AEC will not adversely affect visibility at these or other nearby Class II areas.

PRDAS staff has reviewed the applicant’s analysis. The modeling review memo states the evaluation is presented solely for informational purposes as there are no thresholds for visibility impacts on Class II areas.

Table 86 - PSD Class II Tier I VISCREEN Results

<table>
<thead>
<tr>
<th>Class II Area</th>
<th>Minimum Distance (km)</th>
<th>Maximum Distance (km)</th>
<th>Variable</th>
<th>Sky</th>
<th>Terrain</th>
<th>Criteria*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crystal Cove State Park</td>
<td>30.3</td>
<td>35.5</td>
<td>Color Contrast</td>
<td>1.009</td>
<td>1.893</td>
<td>2.0</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Plume Contrast</td>
<td>0.012</td>
<td>0.016</td>
<td>[0.05]</td>
</tr>
<tr>
<td>Water Canyon/ Chino Hills State Park</td>
<td>29.6</td>
<td>42.2</td>
<td>Color Contrast</td>
<td>1.393</td>
<td>1.951</td>
<td>2.0</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Plume Contrast</td>
<td>0.016</td>
<td>0.016</td>
<td>[0.05]</td>
</tr>
<tr>
<td>Kenneth Hahn State Park</td>
<td>34.6</td>
<td>37.3</td>
<td>Color Contrast</td>
<td>0.815</td>
<td>1.594</td>
<td>2.0</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Plume Contrast</td>
<td>0.01</td>
<td>0.014</td>
<td>[0.05]</td>
</tr>
</tbody>
</table>

**Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases**

Rule 1714 was adopted into the SIP on 12/10/12, and became effective on 1/9/13. Upon the effective date, the SCAQMD became the Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permitting authority for sources located within the SCAQMD.

The relevant rule sections are as follows.

(a) This rule sets forth preconstruction review requirements for greenhouse gases (GHG). The provisions of this rule apply only to GHGs as defined by EPA to mean the air pollutant as an aggregate group of six GHGs: carbon dioxide (CO₂), nitrous oxide (N₂O), methane...
(CH₄), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆). All other attainment air contaminants, as defined in Rule 1702 subdivision (a), shall be regulated for the purpose of Prevention of Significant Deterioration (PSD) requirements pursuant to Regulation XVII, excluding Rule 1714.

(c) The provisions of 40 CFR Part 52.21 are incorporated by reference, with the excluded subsections of 40 CFR Part 52.21 listed in (c)(1).

(d)(1) An owner or operator must obtain a PSD permit pursuant to this rule before beginning actual construction, as defined in 40 CFR 52.21(b)(11), of a new major stationary source or major modification to an existing major source as defined in 40 CFR 52.21(b)(1) and (b)(2), respectively.

In May 2010, EPA issued the GHG permitting rule officially known as the “Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule” (GHG Tailoring Rule), in which EPA defined six GHG pollutants (collectively combined and measured as carbon dioxide equivalent [CO₂e]) as NSR-regulated pollutants and therefore subject to PSD permitting, including the preparation of a BACT analysis for GHG emissions.

The EPA’s PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011, provide applicability criteria. Under Tailoring Rule Step 2, the PSD Applicability Test for GHGs in PSD Permits Issued on or after July 1, 2011 indicates that PSD applies to the GHG emissions from a proposed modification to an existing source if any of three sets of applicability criteria are met. The set of applicability criteria applicable to the AEC is as follows:

- Modification is otherwise subject to PSD (for another regulated NSR pollutant), and has a GHG emissions increase and net emissions increase:
  - Equal to or greater than 75,000 TPY CO₂e, and
  - Greater than -0- TPY mass basis

In Utility Air Regulatory Group v. EPA (No. 12-1146), issued 6/23/14, the Supreme Court issued a decision addressing the application of stationary source permitting requirements to greenhouse gases (GHG). The Court said that EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. The Court also said that that the EPA could continue to require that PSD permits, otherwise required based on emissions of conventional pollutants, to contain limitations on GHG emissions based on the application of BACT.
PSD APPLICABILITY ANALYSIS FOR GHGs:
As discussed under the Rule 1703 analysis above, the modification is otherwise subject to PSD for other regulated NSR pollutants, NOx and PM$_{10}$. The following table summarizes the analysis to determine whether GHG emissions are subject to PSD review.

| Table 87 – Prevention of Significant Deterioration Applicability for Greenhouse Gases |
|---------------------------------|------------------|
| GHG Emissions Increase = Alamitos Energy Center Potential to Emit (Table 45) | 1,716,925.57 TPY > 75,000 TPY and > 0 TPY mass basis |
| Alamitos Generating Station Actual Emissions (2013 & 2014 Avg) (Table 14) | 927,761 TPY |
| GHG Net Emissions Increase = AEC PTE – AGS actual | 789,164.57 TPY > 75,000 TPY and > 0 TPY mass basis |
| PSD for Greenhouse Gases Applicable? | Yes |

The greenhouse gases are subject to PSD review because the emissions increase and net emissions increase constitute significant increases.

PSD REQUIREMENTS ANALYSES:
The “PSD and Title V Permitting Guidance for Greenhouse Gases” explains that under the Clean Air Act and applicable regulations, a PSD permit must contain emissions limitations based on application of BACT for each PSD regulated NSR pollutant. A determination of BACT for GHGs should be conducted in the same manner as it is done for any other PSD regulated pollutant. EPA recommends that permitting authorities continue to use the Agency’s five-step “top down” BACT process to determine BACT for GHGs. No other PSD requirements were enumerated.

For criteria pollutants, PSD requirements include pre-construction ambient monitoring, air impacts analyses, and other impacts analysis, as discussed under Rule 1703. As there are currently no NAAQS, CAAQS, SILs or PSD increments standards established for GHGs, the air impacts analysis requirement is not applicable. Further, EPA does not require pre-construction monitoring for GHGs in accordance with 40 CFR 52.21(i)(5)(iii) and 51.166(i)(5)(iii), or Class I areas impact analysis.

Top-Down BACT Analysis
1. **Top-Down BACT Analysis for Combined-Cycle Gas Turbine Power Block and Simple-Cycle Gas Turbine Block for Carbon Dioxide (CO$_2$) Emissions**
The primary sources of GHG emissions will be the natural-gas-fired combined-cycle and simple-cycle combustion turbines. The primary combustion emission is CO$_2$, because the CH$_4$ and N$_2$O emissions are insignificant.

   **Step 1: Identify all available control technologies.**
As determined by EPA and the Department of Energy, the available CO₂ control technologies are:

A. Carbon capture and storage (CCS)
B. Lower Emitting Alternative Technology
C. Thermal efficiency

A. **Carbon Capture and Storage/Sequestration (CSS)**

CCS technology is composed of three main components: (1) CO₂ capture and compression, (2) transport, and (3) storage/sequestration.

**CO₂ Capture and Compression.** Three capture technologies are primarily being considered for CCS: pre-combustion, oxy-combustion, and post-combustion. Pre-combustion capture refers to a process in which solid fuel such as coal is converted into gaseous hydrogen and CO by applying heat under pressure in the presence of steam and oxygen. The CO is converted to CO₂, using shift reactors, and captured before combusting the hydrogen-based fuel. Pre-combustion capture is applicable primarily to gasification plants. Oxy-combustion technology uses air separators to remove the nitrogen from combustion air so that the combustion products are almost exclusively CO₂, thereby reducing the volume of exhaust gases needed to be treated by the carbon capture system. Oxyfuel combustion still requires the development of oxy-fuel combustors and other components with higher temperature tolerances to withstand the high gas turbine exhaust temperatures. The post-combustion capture technologies include three methods, namely sorbent adsorption, physical adsorption, and chemical absorption. Of these technologies, the post-combustion technology is most applicable to AEC.

CCS systems involve use of adsorption or absorption processes to separate and capture CO₂ from the flue gas, with subsequent desorption to produce a concentrated CO₂ stream. The concentrated CO₂ is then compressed to “supercritical” temperature and pressure, a state in which CO₂ exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO₂ would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer, depleted coal seam, or ocean site, or the CO₂ would be used in crude oil production for enhanced oil recovery.

The capture of CO₂ from gas streams can be accomplished using either physical or chemical solvents or solid sorbents. Applicability of different processes to particular applications will depend on temperature, pressure, CO₂ concentration, and contaminants in the gas or exhaust stream. Although CO₂ separation processes have been used for years in the oil and gas industries, the CO₂ concentration of these gas...
streams are significantly higher than the concentration in power plant exhaust. CO$_2$ separation from power plant exhaust has been demonstrated in large pilot-scale tests as discussed below, but it has not been commercially implemented in full-scale power plant applications.

After separation, the CO$_2$ must be compressed to supercritical temperature and pressure for suitable pipeline transport and geologic storage properties. Although compressor systems for such applications are proven commercially available technologies, incorporation of CO$_2$ compression equipment will require the installation of specialized equipment with high operating energy requirements.

**CO$_2$ Transport.** The supercritical CO$_2$ would then be transported to an appropriate location for injection into a suitable storage reservoir. The transport options may include pipeline or truck transport, or in the case of ocean storage, transport by oceangoing vessels.

Because of the extremely high pressures and the unique thermodynamic and dense-phase fluid properties of supercritical CO$_2$, specialized designs are required for CO$_2$ pipelines. Control of potential propagation fractures and corrosion also require careful attention to contaminants such as O$_2$, N$_2$, CH$_4$, water, and hydrogen sulfide.

While transport of CO$_2$ via pipeline is proven technology, doing so in urban areas will present additional concerns. Development of new rights–of–way in congested areas would require significant resources for planning and execution, and public concern about potential for leakage may present additional barriers. Securing a right-of-way easement on public property for the installation and operation of a high-pressure CO$_2$ pipeline could result in extensive delays due to resolving concerns raised by the public based on the perceived hazards associated with the pipeline. Securing sufficient private property for siting a CO$_2$ pipeline would be cost prohibitive within an urban area.

The Technical Advisory Committee for the California Carbon Capture and Storage Review Panel stated in the August 2010 report that there are no existing CO$_2$ pipelines in California. In addition, there are no CO$_2$ pipeline projects underway in California.

**CO$_2$ Storage.** CO$_2$ storage methods include geologic sequestration, oceanic storage, and mineral carbonation. Oceanic storage has not been demonstrated in practice. Geologic sequestration is the process of injecting captured CO$_2$ into deep subsurface rock formations for long-term storage, which includes the use of a deep saline aquifer or depleted coal seams, and the use of compressed CO$_2$ to enhance oil recovery in crude oil production operations.
With geologic sequestration, a suitable geological formation is identified close to the proposed project, and the CO\textsubscript{2} captured from the process is compressed and transported to the sequestration location. CO\textsubscript{2} is injected into that formation at a high pressure and to depths generally greater than 2,625 feet. Below this depth, the pressurized CO\textsubscript{2} remains “supercritical” and behaves like a liquid. Supercritical CO\textsubscript{2} is denser and takes up less space than gaseous CO\textsubscript{2}. Once injected, the CO\textsubscript{2} occupies pore spaces in the surrounding rock, like water in a sponge. Saline water that already resides in the pore space would be displaced by the denser CO\textsubscript{2}. Over time, the CO\textsubscript{2} can dissolve in residual water, and chemical reactions between the dissolved CO\textsubscript{2} and rock can create solid carbonate minerals, more permanently trapping the CO\textsubscript{2}. No pilot studies of CO\textsubscript{2} injection into onshore or offshore geologic formations in the vicinity of the project site have been conducted to date.

**B. Lower Emitting Alternative Technology**

Commercially available and low or non-GHG emitting power production technology include geothermal, hydroelectric, biomass fueled, solar power, nuclear powered, and wind facilities. The Supplemental AFC presents a review of project alternatives to the AEC. The review considered alternative technologies that could feasibly attain most of the project objectives and reduce or eliminate any significant effects of the project. Alternative generating technologies including conventional boiler and steam turbine, simple-cycle combustion turbines only, wind energy, photovoltaic and solar thermal technologies, Kalina combined-cycle (a mixture of ammonia and water is used in place of pure water in the steam cycle), internal combustion engines and energy storage were considered but rejected because of the inability of these technologies to provide generating capacity for local reliability needs, meet peak energy demands, and provide flexible generation with minimum environmental effects.

The proposed AEC design and operation consists of a 2-by-1 combined-cycle turbine power block and a four simple-cycle turbine power block. The applicant has determined that this configuration is the only alternative that meets all of the project objectives. A primary objective is to provide fast starting and stopping, flexible, controllable generation with the ability to ramp up and down through a wide range of electrical output to allow the integration of renewable energy into the electrical grid to satisfy California’s Renewable Portfolio Standard. The lower GHG emitting technologies would fundamentally redefine the project and alter the business purpose. The EPA does not require a BACT analysis to redefine the applicant’s project. As a result, no additional lower emitting alternative technologies are feasible to incorporate into the project without changing the business purpose of the project.
C. **Thermal Efficiency**

Power generation through fossil fuel combustion is a chemical reaction process. Because CO$_2$ emissions are directly related to the quantity of fuel burned, the less fuel burned per amount of energy produced (greater energy efficiency), the lower the GHG emissions per unit of energy produced. The thermal efficiency is defined as the dimensionless ratio of the useful work performed by the process and the heat input to the process. The heat rate, measured in Btu/kWh, is generally used as a thermal efficiency indicator. The thermal efficiency is at the highest when the reaction is at stoichiometric conditions.

The following factors affect the thermal efficiency of a power plant:

- Thermal dynamic cycle selection, combined-cycle versus simple-cycle
- Turbine design
- Fuel selection

The proposed AEC includes both combined- and simple-cycle turbines. In many applications, combined-cycle turbines are more thermally efficient than simple-cycle turbines. The reason is that a combined-cycle turbine is equipped with a heat recovery steam generator that recovers waste heat from the gas turbine that allows the production of more electricity in the steam turbine generator without additional fuel consumption. As California’s renewable energy portfolio continues to grow, a primary objective of the AEC is to support renewable power generation. As the electrical output from renewable resources such as wind and solar plants drops, the AEC must be able to come online quickly. Unlike combined-cycle turbines, simple-cycle turbines can be started up and shut down quickly. With the inclusion of the simple-cycle turbines, AEC is designed to serve both peak and intermediate loads. Operating in either load-following (adjusting power output as demand fluctuates) or partial shutdown mode will become necessary to maintain electrical grid reliability.

AES indicates the operationally flexible turbine class and steam cycle designs selected for the AEC are the most thermally efficient for the project design objectives. For example, the fast start capability of the combined- and simple-cycle turbines minimizes emissions during startup and increases the efficiency of the power plant. Also, the AEC proposes to combust exclusively natural gas, the lowest GHG-emitting fossil fuel available.

Although new power generating system would emit GHG emissions, the high thermal efficiency of new power generating equipment and the system build-out of renewable resources in California would result in a net health reduction of GHG emissions from new and existing fossil resources.
Step 2: Eliminate technically infeasible options.

The second step for the BACT analysis is to eliminate technically infeasible options from the control technologies identified in Step 1. For each option that was identified, a technology evaluation was conducted to assess its technical feasibility. The technology is feasible only when it is available and applicable. A technology that is not commercially available for the scale of the project was considered infeasible. An available technology is considered applicable only if it can be reasonably installed and operated on the proposed project.

A. Carbon Capture and Storage

The technical feasibility of each step of the CCS is discussed below.

**CO₂ Capture and Compression.** Three fundamental types of carbon capture systems are employed throughout various process and energy industries: sorbent adsorption, physical absorption, and chemical absorption.

- **Sorbent Adsorption.** Sorbent-based capture technology can be used for post-combustion capture of CO₂. However, the technology has not been demonstrated on combined-cycle gas turbine power plants. Commercial-scale systems currently in operation contain a significantly higher concentration of CO₂ in the exhaust. A sorbent-based carbon capture process is currently judged to be technologically infeasible for a natural gas-fired commercial power plant application.

- **Physical Absorption.** Physical absorption technology is commercially available for CO₂ removal but has not been demonstrated in practice for power generation applications. Commercial-scale systems currently in operation contain a significantly higher concentration of CO₂ in the exhaust. A physical absorption capture process is currently judged to be technologically infeasible for a commercial power plant application.

- **Chemical Absorption.** A chemical solvent CCS approach would be required to capture the approximate 3 to 5 percent CO₂ emitted from the flue gas generated from the natural-gas-fired systems used at the AEC facility. To date, a chemical solvent technology has not been demonstrated for the operating scale proposed.

The Bellingham Energy Center in Massachusetts was a combined-cycle plant, rated at 320 MW, that operated continuously from 1991 until 2005. This plant captured 330 tons of CO₂ per day, for a capture efficiency of 85 – 95%, from a 40 MW slipstream. The CO₂ was used to supply the local beverage industry.
The Fluor Corp Econamine FG Plus system used was a CO$_2$ recovery process based on a proprietary formulation of mono-ethylene amine (MEA) solvent. The plant operated under difficult gas specifications and contained 14% oxygen and only 3% CO$_2$. In addition, a significant backpressure or pressure fluctuation in the flue gas could not be tolerated. The Bellingham plant was decommissioned in 2005 as a result of financial difficulties, including rising gas prices and discontinuation of tax credits.

The Sumitomo Chemical plant in Japan has a base load natural gas combined-cycle unit with CCS operating on an 8 MW slip-stream that captures about 150 tons of CO$_2$ per day for commercial use in the food and beverage industry. A Fluor Econamine FG carbon capture system has been operating since 1994.

The capture technology has not been scaled up and demonstrated on a large commercial power plant application. Therefore, a solvent-based carbon capture process is currently judged to be technologically infeasible for the AEC.

**Carbon Transportation.** The basic technologies required for CO$_2$ transportation (i.e., pipeline, tanker truck, ship) are in commercial use today for a number of applications and can be considered commercially available for liquid CO$_2$.

**Carbon Storage.** The following discusses the potential use of deep saline aquifers, compressed CO$_2$ to enhance oil recovery in crude oil production operations, and ocean sequestration as potential options for the storage of captured CO$_2$.

- **Enhanced Oil Recovery (EOR).** Although the CO$_2$ could be used for EOR applications in the vicinity of AEC, only pilot-scale projects are known in the region, and only estimates are available on the capacity of these miscible oil fields. Therefore, the exact location, time frame, and needed flow rates for those existing or future EORs are unclear because this information is typically treated as being a trade secret. Furthermore, the feasibility of obtaining the necessary permits to build infrastructure and a pipeline to transport CO$_2$ to these fields through a densely urbanized area is uncertain.

The potential to sell CO$_2$ to industrial or oil and gas operations is infeasible for an operation such as AEC, where daily operation depends on grid dispatch needs, particularly to offset reductions from renewable energy sources. Even if a potential EOR opportunity could be identified, such an operation would typically need a steady supply of CO$_2$. Intermittent CO$_2$ supply from potentially short duration with uncertain daily operation would be virtually impossible to sell on the market, making the EOR option unviable.
At this time, the technical feasibility of using enhanced oil recovery for CO₂ storage for the new power generating system cannot be determined. Therefore CCS using enhanced oil recovery cannot be demonstrated to be technically feasible in practice for the new power generating system.

- **Deep Saline Aquifer.** At this time, the technical feasibility of using deep saline aquifer injection for CO₂ storage for the new power generating system cannot be determined. Based on mapping by DOE’s National Energy Technology Laboratory’s NatCarb viewer, the nearest known saline aquifer sites, located in New Mexico, Utah, and Texas, are undergoing early phases of evaluation. Therefore CCS using enhanced oil recovery cannot be demonstrated to be technically feasible in practice for the new power generating system.

- **Ocean Sequestration.** The effectiveness of ocean sequestration as a full-scale method for CO₂ capture and storage is unclear given the limited availability of injection pilot tests and the ecological impacts to shallow and deep ocean ecosystems. Ocean sequestration is conducted by injecting supercritical liquid CO₂ from either a stationary or towed pipeline at targeted depth interval, typically below 3,000 feet. Long-term effects on the marine environment, including pH excursions, are uncertain. Ocean storage and its ecological impacts are still in the research phase, and not commercially available.

It should be noted that the beverage carbonation use for the CO₂ from the Bellingham Energy Center and the Sumitomo Chemical plant does not qualify as permanent sequestration.

**CSS Feasibility**
According to *EPA’s New Source Review Workshop Manual* (EPA, 1990): “Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice.”

On January 8, 2014, the EPA proposed an NSPS for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines. The action proposed standards for natural gas-fired combustion turbines (NGCC) that are based on modern, efficient natural gas combined-cycle technology as the best system of emission reduction. The action proposed a separate standard of performance for fossil fuel-fired electric utility steam generating units and integrated gasification combined-cycle units that burn coal, petroleum coke and other fossil fuels that is based on partial implementation of carbon capture and storage as the best system of emission reduction. (79 Fed. Reg. 1430)
At that time, the EPA noted that, CCS has not been implemented for NGCC units, and the EPA believes there is insufficient information to make a determination regarding the technical feasibility of implementing CCS at these types of units. The EPA is aware of only one NGCC unit that has implemented CCS on a portion of its exhaust stream [Bellingham Energy Center]. The cyclical operation of the NGCC, combined with the low concentration of CO$_2$ in the flue gas stream, means that the EPA cannot assume that the technology for the coal-fired units can be easily transferred to NGCC without larger scale demonstration projects on units operating more like a typical NGCC. (79 Fed. Reg. 1436)

On 8/3/2015, EPA released the final NSPS. On 10/23/15, the NSPS was published in the Federal Register and codified in 40 CFR part 60, Subpart TTTT, a new subpart specifically created for Clean Air Act 111(b) standards of performance for greenhouse gases from fossil fuel-fired electric generating units (EGUs). The effective date is 10/23/15. (80 Fed. Reg. 64510)

After evaluation of comments received, the EPA again rejected partial CCS as the Best System of Emission Reduction (BSER) because EPA concluded that there is not sufficient information to determine whether implementing CCS for combustion turbines is technically feasible. EPA conceded that while commenters made strong arguments that the technical issues raised at proposal could in many instances be overcome, EPA concluded that there is not sufficient information at this time to determine that CCS is adequately demonstrated for all base load natural-gas fired combustion turbines. While commenters make a strong case that the existing and planned NGCC-with-CCS projects demonstrate the feasibility of CCS for NGCC units operating at steady state conditions, many NGCC units do not operate this way. For example, the Bellingham, MA and Sumitomo NGCC units cited by the commenters operated at steady load conditions with a limited number of starts and stops, similar to the operation of coal-fired boilers. The base load natural gas-fired combustion turbine subcategory includes not only true base load units, but also some intermediate units that cycle more frequently, including fast-start NGCC units that sell more than 50 percent of their potential output to the grid. Fast-start NGCC units [and simple-cycle turbines] are designed to be able to start and stop multiple times in a single day and can ramp to full load in less than an hour. EPA is not aware of any pilot-scale CCS projects that have demonstrated how fast and frequent starts, stops, and cycling will impact the efficiency and reliability of CCS. Furthermore, for those periods in which a NGCC unit is operating infrequently, the CCS system might not have sufficient time to start up. During these periods, no CO$_2$ control would occur. Thus, if the NGCC unit is intended to operate for relatively short intervals for at least a portion of the year, the owner or operator could have to oversize the CCS to increase control during periods of steady state
operation to make up for those periods when no control is achieved by the CCS, leading to increased costs and energy penalties. EPA indicated that while it is optimistic that these hurdles are surmountable, it is simply premature at this point to make a finding that CCS is technically feasible for the universe of combustion turbines that are covered by this rule. EPA noted that the Department of Energy has not yet funded a CCS demonstration project for a NGCC unit, and no NGCC-with-CCS demonstration projects are currently operational or being constructed in the U.S. (80 Fed. Reg. 64614)

In summary, post-combustion carbon capture technologies are still in the developmental stage or installed on small commercial scale projects, a conclusion supported by EPA’s studies. These technologies are not commercially available for the project size of a full-scale commercial power plant. Consequently, CSS is not yet demonstrated as technically feasible for the AEC project.

B. Lower Emitting Technology
As discussed above, commercially available lower emitting technology was determined to be infeasible for the site as it would fundamentally alter the business purpose of the source.

C. Thermal Efficiency
California has established a Greenhouse Gases Emission Performance Standard for California power plants to quantify feasible energy efficiency levels. Senate Bill (SB) 1368 limits long-term investments in baseload generation by the state’s publicly owned utilities to power plants that meet an emissions performance standard jointly established by the CEC and the California Public Utilities Commission (CPUC). The resulting CEC regulations, as codified in California Code of Regulations (CCR), Title 20, Chapter 11, Article 1, establish a standard for baseload generation (defined as with a capacity factor of at least 60 percent) of 1100 pounds CO₂ per megawatt-hour-net. This standard is further discussed below under the rule analysis. Because local publicly owned electric facilities are required to make the determination regarding compliance with the EPS prior into entering into a covered procurement, SCAQMD need not make a determination.

EPA promulgated 40 CFR 60 Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, with an effective date of 10/23/15. These standards are applicable to any stationary combustion turbine that commences construction after 1/8/14 or commences modification or reconstruction after 6/18/14. The two standards applicable to natural-gas fired turbines are summarized below.
Preliminary Determination of Compliance

Step 3: Rank remaining control technologies.

Because carbon capture and sequestration (CCS) and lower emitting alternative technology were determined to be infeasible for the AEC project, these options are not carried forward in the BACT analysis to Step 3. The remaining feasible technology is:

Thermal efficiency

Thermal Efficiency
Thermal efficiency is technically feasible as a control technology for BACT consideration.

Step 4: Evaluate the most effective controls.

Step 4 of the BACT analysis is to evaluate the remaining technically and economically feasible controls and consider whether energy, environmental, and/or economic impacts associated with the remaining control technologies would justify selection of a less-effective control technology. The top-down approach specifies that the evaluation begin with the most-effective technology.

The remaining feasible technology is:
Thermal efficiency

**Thermal Efficiency**

As CCS and lower emitting alternative technologies are not technically feasible, thermal efficiency remains the most effective, technically feasible, and economically feasible GHG control technology for the AEC.

California’s Renewable Portfolio Standard (RPS) requirement was increased from 20 percent by 2010 to 33 percent by 2020, with the adoption of Senate Bill 2 on April 12, 2011. Senate Bill 350 will increase the RPS requirement to 50 percent by 2030. To meet the new RPS requirements, the amount of natural gas generation will have to be significantly increased. The AEC will aid in the effort to meet California’s RPS standard because a significant attribute of the AEC is that the combined- and simple-cycle facility can operate similarly to a peaking plant but at higher thermal efficiency. Based on design, the combined-cycle turbines are capable of achieving full load operation within 15 minutes of initiating a warm or hot startup. The simple-cycle turbines can achieve full load operation within 10 minutes of initiating a startup. This allows an increased use of wind power and other renewable energy sources, with backup power available from the AEC.

A database review of BACT determinations identified six recently-permitted facilities with natural gas-fired combustion turbines for which a GHG BACT analysis was performed. Each of the projects proposed the use of combined-cycle configurations to produce commercial power, and the BACT analyses for each of the projects concluded that thermal efficiency was the only feasible combustion control technology.

- EPA issued the PSD Permit for the Palmdale Hybrid Power Project in October 2011. This project consists of a hybrid of natural gas fired combined-cycle generating system (two GE 7FA combustion gas turbines and one shared steam turbine) integrated with solar thermal generating system. Based on EPA’s analysis CCS was eliminated as a control option because it was deemed economically infeasible.

- EPA issued the PSD Permit for the Lower Colorado River Authority (LCRA) Project in November 2011. This project consists of a natural gas fired combined-cycle generating system with two GE 7FA combustion gas turbines and a shared steam turbine. Based on the review of the available control technologies for GHG emissions, EPA concluded that BACT for LCRA was the use of new thermally efficient combustion turbines with applicable GHG emission limit.

- The Bay Area Air Quality Management District issued the PSD permit for the Calpine Russell City Energy Center in 2010. According to a presentation by
Calpine, thermal efficiency was the only feasible combustion control technology considered as CCS was determined to be not commercially available. Thermal efficiency was found to be the top level of control feasible for a combined-cycle power plant, and hence was the technology selected at GHG BACT for Russell City.

- EPA issued the PSD Permit for the Pio Pico Energy Center Project in November 2012. The project consists of three simple-cycle GE LMS100 generators. EPA concluded that BACT was the use of new thermally efficient combustion gas turbines with applicable GHG emission limits.

- SCAQMD issued the PSD Permit for the LA City, DWP Scattergood Generating Station in 2013. The project consisted of one GE 7FA combined-cycle gas turbine and two simple-cycle GE LMS100 generators. SCAQMD concluded that BACT was the use of new thermally efficient combustion gas turbines with applicable GHG emission limits.

- SCAQMD issued the PSD Permit for the Pasadena City, Dept. of Water & Power in 2013. The project consisted of one LM6000 combined-cycle gas turbine. SCAQMD concluded that BACT was the use of new thermally efficient combustion gas turbines with applicable GHG emission limits.

As demonstrated by the EPA and SCAQMD permits, thermal efficiency is the most cost effective control technology for GHG emissions from power plants. The proposed General Electric Model 7FA.05 combined-cycle turbines and the General Electric Model LMS-100 PB simple-cycle turbines are acceptable for GHG PSD permits under the BACT thermal efficiency requirement.

**Step 5: Select the BACT.**

Based on the above analysis, thermal efficiency is the only technically and economically feasible alternative for CO\textsubscript{2}/GHG emissions control for the AEC project. The current design of the facility meets the BACT requirement for GHG emission reductions.

BACT also requires applicable GHG emission limits, implemented by permit conditions, as follows.

**Combined-Cycle Turbines**

Condition E193.14 limits the CO\textsubscript{2} emissions to 610,480 tpy per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO\textsubscript{2} emissions is limited to 937.88 pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations below.
Simple-Cycle Turbines
Condition E193.15 limits the CO2 emissions to 120,765 tpy per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO2 emissions is limited to 1356.03 pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations above.

2. Top-Down BACT Analysis for Combined-Cycle Gas Turbine Power Block and Simple-Cycle Gas Turbine Power Block for Sulfur Hexafluoride (SF\textsubscript{6}) Emissions

The only GHG emitted from circuit breakers is sulfur hexafluoride (SF\textsubscript{6}). SF\textsubscript{6} is used as a gaseous dielectric medium in electrical circuit breakers, switching equipment, and other high voltage electrical components. The circuit breakers for the combined-cycle gas turbine power block and the simple-cycle gas turbine power block will have a potential for fugitive emissions of SF\textsubscript{6} through leaks.

Step 1: Identify all available control technologies.
The following control technologies are available.

A. Circuit Breakers Not Containing GHGs
Dielectric oil and compressed air circuit breakers do not contain any GHG pollutants. No other alternative materials to SF\textsubscript{6} are currently available.

B. Totally Enclosed SF\textsubscript{6} Circuit Breakers with Leak Detection Systems
These breakers are designed as a totally enclosed hermetically sealed pressure system with a specified maximum leak rate and an alarm warning when a certain percentage of the SF\textsubscript{6} has escaped. The best equipment can be guaranteed to leak at a rate of no more than 0.5 weight percent per year. The use of an alarm identifies potential leak problems to allow the amount leaked to be minimized.

No add-on control options for GHG emissions are currently available due to the nature of the electrical system containing the SF\textsubscript{6}.

Step 2: Eliminate technically infeasible options.
Both control options are technically feasible.

Step 3: Rank remaining control technologies.

Dielectric oil or compressed air circuit breakers would have a CO\textsubscript{2}e emission rate of 0 tpy.

Enclosed-pressure SF\textsubscript{6} circuit breakers with 0.5% (by weight) annual leakage rate and leak detection systems will have a CO\textsubscript{2}e emission rate of 74.55 tons per calendar year, as calculated above.
Step 4: Evaluate the most effective controls.

Despite decades of research to develop a desirable alternative to SF₆, none has been developed. SF₆ remains the preferred gas for electrical insulation and for arc quenching and current interruption equipment used in the transmission and distribution of electricity. The following properties make SF₆-based circuit breakers superior to the alternatives: (1) high thermal conductivity, (2) high dielectric strength, and (3) fast thermal and dielectric recovery. In addition, the National Institute of Standards and Technology (NIST) reported in 1977 that equipment insulated with SF₆ uses significantly less land and has relatively low radio and audible noise emissions, relative to dielectric oil and compressed air circuit breakers. Therefore, dielectric oil and compressed air circuit breakers are eliminated as the top-ranked control option because of adverse environmental and energy impacts.

Step 5: Select the BACT.

Based on the above review, BACT for the circuit breakers is the use of enclosed-pressure SF₆ circuit breakers with a maximum annual leakage rate of 0.5% by weight and a 10% by weight leak detection system, and an annual emission cap.

The above BACT determination is in agreement with the EPA’s determination for the Pio Pico Energy Center. The Pio Pico PSD permit included conditions requiring the installation of enclosed-pressure SF₆ circuit breakers with a maximum annual leakage rate of 0.5% by weight. The circuit breakers were required to be equipped with a 10% by weight leak detection system, which was required to be calibrated in accordance with manufacturer’s specifications. The manufacturer’s specifications and records of all calibrations were required to be maintained on site. The CO₂e emissions from the circuit breakers were subject to an annual emissions limit.

The operator is required to calculate the SF₆ emissions due to leakage from the circuit breakers by using the mass balance in equation DD-1 at 40 CFR Part 98, Subpart DD, on an annual basis. Section 98.303 sets forth equation DD-1 and is reproduced below.

§98.303 CALCULATING GHG EMISSIONS.

(a) Calculate the annual SF₆ and PFC emissions using the mass-balance approach in Equation DD-1 of this section:

\[ \text{User Emissions} = (\text{Decrease in SF}_6 \text{ Inventory}) + (\text{Acquisitions of SF}_6) - (\text{Disbursements of SF}_6) - (\text{Net Increase in Total Nameplate Capacity of Equipment Operated}) \]  

(Eq. DD-1)

where:
Decrease in SF₆ Inventory = (pounds of SF₆ stored in containers, but not in energized equipment, at the beginning of the year) − (pounds of SF₆ stored in containers, but not in energized equipment, at the end of the year).

Acquisitions of SF₆ = (pounds of SF₆ purchased from chemical producers or distributors in bulk) + (pounds of SF₆ purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear) + (pounds of SF₆ returned to facility after off-site recycling).

Disbursements of SF₆ = (pounds of SF₆ in bulk and contained in equipment that is sold to other entities) + (pounds of SF₆ returned to suppliers) + (pounds of SF₆ sent off site for recycling) + (pounds of SF₆ sent off-site for destruction).

Net Increase in Total Nameplate Capacity of Equipment Operated = (The Nameplate Capacity of new equipment in pounds, including hermetically sealed-pressure switchgear) − (Nameplate Capacity of retiring equipment in pounds, including hermetically sealed-pressure switchgear).

(Note that Nameplate Capacity refers to the full and proper charge of equipment rather than to the actual charge, which may reflect leakage).

(b) Use Equation DD-1 of this section to estimate emissions of PFCs from power transformers, substituting the relevant PFC(s) for SF₆ in the equation.

Further, EPA stated in a response to public comment that the BACT requirements to equip the circuit breakers with a leak detection system and appropriately calibrate such system are not redundant to CARB’s Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear (California Code of Regulations, Subchapter 10, Article 4, Subarticle 3.1, §95350-§95359).

Accordingly, facility condition F52.2 is included to enforce the BACT requirements for circuit breakers, using the same language as in the Pio Pico PSD permit. Annual CO₂e emissions from circuit breakers will be limited to 74.55 tons per calendar year. The maximum CO₂e from the combined-cycle turbine power block is 17.44 tpy, and from the simple-cycle turbine power block is 57.11 tpy.

3. **Top-Down BACT Analysis for Auxiliary Boiler for Carbon Dioxide (CO₂) Emissions**

Natural gas combustion in the auxiliary boiler will produce GHG emissions. The GHG will primarily be CO₂.

**Step 1: Identify all available control technologies.**

The auxiliary boiler operates at maximum load only when assisting the startup of a combined-cycle turbine and operates at minimum turndown firing rate the remainder of the time.

There are no add-on controls for GHG emissions that are technically feasible for boilers. Available control technologies are as follows:
1. **Low Carbon Fuel**
   The carbon content of the fuel, relative to its Btu value, has a significant impact on GHG emissions. The following emission factors for CO\(_2\) are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised April 4, 2014.

   Natural Gas = 53.06 kg CO\(_2\)/MMBtu = 117 lb CO\(_2\)/MMBtu
   Diesel Fuel Oil No. 2 = 73.96 kg CO\(_2\)/MMBtu = 163 lb CO\(_2\)/MMBtu

   AES proposes to use exclusively natural gas, which is the lowest GHG emitting fuel available.

2. **Good Combustion Practices**
   Good combustion practices can reduce fuel usage and GHG emissions.

   **Step 2: Eliminate technically infeasible options.**
   Both control options are technically feasible.

   **Step 3: Rank remaining control technologies.**
   The exclusive use of natural gas is more effective than good combustion practices.

   **Step 4: Evaluate the most effective controls.**
   The exclusive use of natural gas is the most effective control.

   **Step 5: Select the BACT.**
   Both the exclusive use of natural gas and good combustion practices are BACT. This is the same as the BACT proposed by AES.

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**Regulation XX—RECLAIM**

- **Rule 2002—Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx)**
  (c)(2)(C) specifies the applicable starting emission factor is found in Table 1—RECLAIM NOx Emission Factor. For Major NOx Sources, these emission factors are required to be used until the CEMS is certified, not to exceed one year after start of unit operation.

  - Turbines
    From Rule 2002, Table 1:
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“Reported Value” means the emissions factors are required to be calculated. For turbines, two NOx emission factors are required for use in the interim reporting period before the CEMS is certified.

**Combined-Cycle Turbines:** Condition A99.1 specifies the interim emission factor for the commissioning period during which the CTGs are assumed to be operating at uncontrolled levels. From Table 20 above, the emission factor is 16.66 lb/mmcf. Condition A99.2 specifies the interim emission factor for the normal operating period after commissioning has been completed and before the CEMS is certified, during which the CTGs are assumed to be operating at BACT levels. From Table 22 above, the emission factor is 8.35 lb/mmcf.

**Simple-Cycle Turbines:** Condition A99.3 specifies the interim emission factor for the commissioning period during which the CTGs are assumed to be operating at uncontrolled levels. From Table 36 above, the emission factor is 25.24 lb/mmcf. Condition A99.4 specifies the interim emission factor for the normal operating period after commissioning has been completed and before the CEMS is certified, during which the CTGs are assumed to be operating at BACT levels. From Table 38 above, the emission factor is 11.21 lb/mmcf.

- **Auxiliary Boiler**
  From Rule 2002, Table 1:

<table>
<thead>
<tr>
<th>Nitrogen Oxides Basic Equipment</th>
<th>Fuel</th>
<th>“Throughput” Units</th>
<th>Starting Ems Factor*</th>
<th>2000 (Tier I) Ending Emission Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boilers, Heaters, Steam Gens****</td>
<td>Natural Gas</td>
<td>Mmcf</td>
<td>38.460</td>
<td>38.460</td>
</tr>
</tbody>
</table>

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Accordingly, condition A99.5 specifies the interim RECLAIM emission factor is 38.46 lbs NOx/mmcf during the interim period prior to CEMS certification.

As Rule 2012(h)(6) provides the Facility Permit holder which installs a new major source at an existing facility shall install, operate, and maintain all required or elected monitoring, reporting, and recording systems no later than 12 months after the initial startup of the major NOx source, the use of these interim emission factors shall not exceed one year after start of unit operation.
• **Rule 2005—New Source Review for RECLAIM**
  This rule sets forth pre-construction review requirements for modifications to RECLAIM facilities.

  • **(c)(1)(A)—BACT**
    See the Rule 1703(a)(2)—Top-Down BACT analysis, above.

  • **(c)(1)(B)—Modeling**
    For existing RECLAIM facilities, the Executive Offer shall not approve an application for a Facility Permit Amendment to authorize the installation of a new source which results in an emission increase, unless the applicant demonstrates that the operation of the source will not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A of the rule. Rule 2000(c)(71) defines “source” as “any individual unit, piece of equipment or process which may emit an air contaminant and which is identified, or required to be identified, in the RECLAIM Facility Permit.” Therefore, modeling is required on a per permit unit basis.

    Rule 1304(a) provides an exemption from the modeling requirements of Rule 1303(b)(1), but not Rule 2005(c)(1)(B). (The standards in Appendix A are outdated. The modeling analysis below is based on current ambient air quality standards.)

    The revised Application indicates that although each combustion emission unit was modeled, the results in *Table 5.1-39*—Rule 2005 Air Quality Thresholds and Standards Applicable to the AEC (per emission unit) are only for the emission unit causing the highest modeled concentrations, which is one combined-cycle turbine.

    As shown in the table below, the peak 1-hour and annual NO₂ impacts plus the highest background values do not exceed the most stringent air quality standards, as demonstrated in the above table.

    PRDAS staff has reviewed the applicant’s analysis and provided a corrected maximum predicted impact for the federal 1-hour standard and updated background concentrations, which are incorporated in the table below.

    **Table 88 – Rule 2005 Modeled Results – Normal Operation for a Single Combined-Cycle Turbine**

    | Pollutant | Averaging Period | Maximum Predicted Impact (µg/m³) | Background Concentration (µg/m³) | Total Predicted Concentration (µg/m³) | State Standard CAAQS (µg/m³) | Federal Standard, Primary NAAQS (µg/m³) | Exceeds Threshold? |
    |-----------|------------------|----------------------------------|----------------------------------|-------------------------------------|-----------------------------|----------------------------------------|-------------------|
    | NO₂       | 1-hour           | 13.8                             | 255.5                            | 286.8                               | 339                         | --                                     | No                |
    |           | Federal 1-hour   | 12.4                             | 146.3                            | 159.1                               | --                          | 188                                    | No                |
    |           | Annual           | 0.1                              | 47.6                             | 47.7                                | 57                          | 100                                    | No                |

    The maximum 1-hour and annual NO₂ concentrations include ambient NO₂ to NOx conversion ratios of 0.80 and 0.75, respectively.
(c)(2)—Offsets

Paragraph (c)(2) requires RECLAIM facilities to hold sufficient RTCs to offset the first year of operation’s emissions increase from a new, relocated, or modified source before commencement of such operation. Before Rule 2005 was amended on 6/3/11, Rule 2005(f)(1) required RECLAIM facilities to hold RTCs for each subsequent compliance year prior to each compliance year for the same sources. Further, facilities subject to this NSR hold requirement were generally required to hold and not transfer out of their Allocation accounts the specified RTCs for each year until the compliance year was over.

On 6/3/11, Rule 2005 was amended to remove existing facilities that do not have emissions greater than the level of their 1994 allocation plus non-tradable credits (NTCs) from section (f)(1). Per Rule 2000(c)(35), an existing facility is “any facility that submitted Emission Fee Reports pursuant to Rule 301 – Permit Fees, for 1992 or earlier years, or with valid District Permits to Operate issued prior to October 15, 1993, and continued to be in operation or possess valid District permits on October 15, 1993.” Per Rule 2000(c)(51), a new facility is “any facility which has received all District Permits to Construct on or after October 15, 1993.”

Existing facilities that do not have emissions greater than the level of their 1994 allocation plus NTCs are only subject to the “hold” requirement for the first year of operation of each source with an emissions increase (the period commencing at the start of operation and concluding 364 days later; 365 days later if the period includes a leap day).

A determination is required here regarding whether AEC is subject to the RTC hold requirement the first year only (condition I297), or the first year and each subsequent year (condition I296). Southern California Edison (SCE) installed all six utility boilers by 1966, which is prior to 10/15/93. The AES Corporation purchased the power plant from SCE in 1998. Subsequently, AES Alamitos received change of operator permits, not Permits to Construct, for the power plant in 1999. The NOx RTCs initially allocated was 704,485 pounds. The RTCs required for the first year of operation of the combined-cycle turbines and auxiliary boiler are 218,105 pounds. The RTCs required for the first year of operation of the simple-cycle turbines are 274,300 pounds. From Table 45, the NOx potential to emit for AEC for a normal operating year is 274,120.0 pounds (137.06 tpy). All RTC requirements are less than the initial allocation. Therefore, since the AEC will be an existing facility that will not exceed the initial allocation, it will be required to hold RTCs for the first year of operation only for each NOx-emitting equipment.

Rule 2005(d) specifies the RECLAIM credit calculation shall be based on the potential to emit or on a permit condition limiting the source’s emissions.

- RTCs Required to Be Held the First Year of Operation Combined-Cycle Turbines
Conditions I297.1 and I297.2 will require each turbine to hold 108,377 pounds of RTCs the first year (Table 24).

Simple-Cycle Turbines
Conditions I297.3, I297.4, I297.5, and I297.6 will require each turbine to hold 68,575 pounds of RTCs the first year (Table 40).

Auxiliary Boiler
Condition I297.7 will require auxiliary boiler to hold 1351 pounds of RTCs the first year from the annual emissions calculations above.

- RTCs Required to Be Purchased Prior to Issuance of Turbine Permits
  The commercial operation of the combined-cycle turbines and auxiliary boiler is scheduled for second quarter 2020. The commercial operation of the simple-cycle turbines is scheduled for third quarter 2021.

  Section B: RECLAIM Annual Emission Allocation, printed 4/29/16, indicates the NOx RTC holding for 1/2020 through 12/2020 is 432,413 lbs NOx, which is more than the 218,105 lbs required for the first year of operation of the two combined-cycle turbines and the auxiliary boiler. The NOx RTC holding for 1/2021 through 12/2021 is 394,195 lbs NOx, which is more than the 274,300 lbs required for the first year of operation of the four simple-cycle turbines.

- Years Subsequent to First Year
  Pursuant to Rule 2005, AEC is not required to hold a specific number of RTCs subsequent to the first year of operation. For subsequent years, Rule 2004(b)(1) specifies actual NOx emissions will determine the number of RTCs required to be held. Compliance with RECLAIM requirements is enforced by the Compliance Dept.

  (e)--Trading Zone Restrictions
  See Rule 1303(b)(3) analysis above.

  (g)—Additional Federal Requirements for Major Stationary Sources
  For (g)(1) - (g)(4), see Rule 1303(b)(5) analysis above.

  (h)—Public Notice
  See Rule 212 analysis above.

  (i)—Rule 1401 Compliance
  See Rule 1401 analysis above.
Rule 2012-RECLAIM Monitoring Recording and Recordkeeping Requirements

The purposes of this rule is to establish the monitoring, reporting and recordkeeping requirements for NOx emissions under the RECLAIM program.

Classification as Major NOx Source

- **Combined-Cycle Turbines**: Rule 2012(c)(1)(C) classifies any gas turbine rated greater than or equal to 2.9 megawatts excluding any emergency standby equipment or peaking unit as a major NOx source. The combined-cycle turbines are each rated at 236.645 MW-gross at 28 ºF. Therefore, these turbines are major NOx sources.

- **Simple-Cycle Turbines**: The simple-cycle turbines are each rated at 100.438 MW-gross at 59 ºF. Rule 2012(c)(1)(D) classifies a “peaking unit” as a RECLAIM process unit, however. Rule 2012 Protocol, Attachment F--Definitions defines a “peaking unit” as “a turbine used intermittently to produce energy on a demand basis and does not operate more than 1300 hours per year.” The simple-cycle turbines are not peaking units because they are permitted to operate 2358 hours per year. Therefore, under Rule 2012(c)(1)(C), they are major NOx sources.

- **Auxiliary Boiler**: Rule 2012(c)(1)(A)(i) classifies any boiler with a maximum rated capacity greater than or equal to 40 but less than 500 million Btu per hour and an annual heat input greater than 90 billion Btu per year as a major NOx source. The auxiliary boiler is rated at 70.8 MMBtu/hr. From the emissions calculations above, the annual heat input is 189.12 billion Btu/yr. Therefore, the auxiliary boiler is a major NOx source.

Compliance Schedule

Rule 2012(h)(6) provides that the Facility Permit holder which installs a new major source at an existing facility shall install, operate, and maintain all required or elected monitoring, reporting, and recording systems no later than 12 months after the initial startup of the major NOx source. During the interim period between the initial startup of the major NOx source and the provisional certification date of the CEMS, the Facility Permit holder shall comply with the monitoring, reporting, and recordkeeping requirements of paragraphs (h)(2) and (h)(3) of this rule. (Condition D82.2 and D82.3 implement this requirement.)

Paragraph (h)(2) provides that interim reports shall be submitted monthly for major and large sources. Paragraph (h)(3) provides that the Facility Permit holder shall install, maintain, and operate a totalizing fuel meter for each major source. Rule 2012, Appendix A, Chapter 2 states on pg. Rule 2012A-2-1 that major sources shall be allowed to use an interim reporting procedure to measure and record NOx emissions on a monthly basis according to the requirements specified in Chapter 3 for large sources. Chapter 3 states on pg. Rule 2012A-3-1 that the interim reporting is specified in subdivision D, paragraph 1. Paragraph 1, in turn, provides that the interim reporting shall be based on fuel usage and emission factor(s).
See Rule 2002 above for further discussion on interim emission factors.

Regulation XXX—Title V Permits
The proposed project is considered as a “significant permit revision” to the RECLAIM/Title V permit for this facility. Rule 3000(b)(31) specifies that a “significant permit revision” includes “installation of new equipment subject to a New Source Performance Standard (NSPS) pursuant to 40 CFR Part 60, or a National Emission Standard for Hazardous Air Pollutants (NESHAP) pursuant to 40 CFR Part 61 or 40 CFR Part 63.”

Pursuant to Rule 3003(j), a proposed permit incorporating this permit revision will be submitted to EPA for a 45-day review. Pursuant to Rule 3006(a), all public participation procedures will be followed prior to the issuance of the permit.

Pursuant to Rule 3006(a)(1)(B), the public notice is required to include the following:

i) The identity and location of the affected facility;
ii) The name and mailing address of the facility’s contact person;
iii) The identity and address of the SCAQMD as the permitting authority processing the permit;
iv) The activity or activities involved in the permit action;
v) The emissions change involved in any permit revision;
vi) The name, address, and telephone number of a person whom interested persons may contact to review additional information including copies of the proposed permit, the application, all relevant supporting materials, including compliance documents as defined in paragraph (b)(5) of Rule 3000, and all other materials available to the Executive Officer that are relevant to the permit decision;
vii) A brief description of the public comment procedures provided; and
viii) The time and place of any proposed permit hearing that may be held or a statement of the procedures to request a proposed permit hearing if one has not already been requested.

The Title V public notice will be combined with the Rule 212(g) notice. The public notice periods for both are anticipated to run concurrently for a single 30-day public comment period. (The Rule 212 public notice requirements are discussed above under the Rule 212 analysis above.)

FEDERAL REGULATIONS
40 CFR 60 Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units
On January 8, 2014, EPA withdrew the proposal for the new source performance standard (NSPS), Subpart TTTT, for carbon dioxide emissions that had been published on April 13, 2012 for new affected fossil fuel-fired electric utility generating units. In a separate action on the same day, the EPA
proposed new standards of performance for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines. (79 Fed. Reg. 1430)

For the new proposed NSPS, the EPA considered two options for codifying the requirements. Under the first option, EPA proposed to codify the standards of performance for the respective sources within existing 40 CFR Part 60 subparts. Applicable GHG standards for electric utility steam generating units would be included in subpart Da and applicable GHG standards for stationary combustion turbines would be included in subpart KKKK. In the second option, the EPA co-proposed to create a new subpart TTTT (as in the original proposal for this rulemaking) and to include all GHG standards of performance for covered sources in that newly created subpart. (79 Fed. Reg. 1436-1437)

On 8/3/2015, EPA promulgated the final NSPS, after receiving more than two million comments. The NSPS was published in the Federal Register and codified in 40 CFR part 60, Subpart TTTT, a new subpart specifically created for Clean Air Act 111(b) standards of performance for greenhouse gases from fossil fuel-fired electric generating units (EGUs). The effective date was 10/23/15. (80 FR 64510)

The following sets forth the applicability requirements, emissions standards, applicability analysis, and thermal efficiency calculations for the combined- and single-cycle turbines.

- **Applicability Requirements**
  
  Under the applicability requirements, the analysis below shows the final NSPS is applicable to the proposed combined- and simple-cycle turbines.

  §60.5509 Am I subject to this subpart?

  (a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any stationary combustion turbine that commenced construction after January 8, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (a)(2) of this section.

  (1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel), and

  (2) Serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system.

  **Analysis:** Construction for the AEC will commence after January 8, 2014, if the permits are approved.

  §60.5580 defines “base load rating” to mean “the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions….” ISO
conditions mean 15 deg C (59 °F) ambient temperature, 60% relative humidity, and 14.70 psia.

**Combined-Cycle Turbine:**

1. From Table 15, the turbine base load rating is 2032 MMBtu/hr (LHV) at 100% load, 59 °F and 60% relative humidity (case 12). The 2032 MMBtu/hr rating is higher than the 250 MMBtu/hr threshold.

2. The turbine generator rating is 230.459 MW-net plus one-half of the steam turbine generator rated at 215.402 MW-net is equal to 338.16 MW-net (case 12), which is higher than the 25 MW-net threshold.

**Simple-Cycle Turbine:**

1. From Table 31, the turbine rating is 795 MMBtu/hr (LHV) at 100% load, 59 °F and 60% relative humidity (case 12). The 795 MMBtu/hr base load rating is higher than the 250 MMBtu/hr threshold.

2. The turbine generator rating of 99.087 MW-net is higher than the 25 MW-net threshold.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (b)(10) of this section.

1. Your EGU is a steam generating unit or IGCC that is currently and always has been subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

2. Your EGU is capable of combusting 50 percent or more non-fossil fuel and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

3. Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than the product of the unit's net design efficiency and the unit's potential electric output or 219,000 MWh, whichever is greater.

4. Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.
(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (e.g., not connected to a natural gas pipeline).

(9) The proposed Washington County EGU project….

(10) The proposed Holcomb EGU project….

Analysis: The new NSPS is applicable to the proposed combined- and simple-cycle turbines, because they do not meet any of the above non-applicability criteria.

• Applicable Emissions Standards
The NSPS created three subcategories with different standards for each. These subcategories are base load natural-gas fired units, non-base load natural gas-fired units, and multi-fuel-fired units. The two gas-fired subcategories and associated standards are discussed below.

§60.5520 What CO2 emission standard must I meet?
(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO2 in excess of the applicable CO2 emission standard specified in Table 1 or Table 2 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.
Table 2 of Subpart TTTT of Part 60 – CO₂ Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction after January 8, 2014 and Reconstruction after June 18, 2014

<table>
<thead>
<tr>
<th>Affected EGU</th>
<th>CO₂ Emission Standard</th>
</tr>
</thead>
<tbody>
<tr>
<td>Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.</td>
<td>450 kg of CO₂ per MWh of gross energy output (1,000 lb CO₂/MWh); or 470 kilograms (kg) of CO₂ per megawatt-hour (MWh) of net energy output (1,030 lb/MWh)</td>
</tr>
<tr>
<td>Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating month rolling average basis.</td>
<td>50 kg CO₂ per gigajoule (GJ) of heat input (120 lb CO₂/MMBtu)</td>
</tr>
</tbody>
</table>

§60.5525 What are my general requirements for complying with this subpart?
Compliance with the applicable CO₂ emission standard of this subpart shall be determined on a 12-operating-month rolling average basis.

§60.5580 What definitions apply to this subpart?
*Design efficiency* means the rated overall net efficiency (e.g., electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (e.g., CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass)....

*Potential electric output* means 33 percent or the base load rating design efficiency at the maximum electric production rate (e.g., CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by $10^6$ Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12 month potential electric output capacity).

**Analysis:** If a turbine operates above the product of the “design efficiency” or 50%, whichever is less, and “potential electric output” on a 12-operating-month and 3-year-rolling average basis, the standard is 1000 lb CO₂/MWh-gross, which is the standard for base load natural gas-fired units. If the turbines operate below the product of the “design efficiency” or 50%, whichever is less, and “potential
electric output” on the same basis, the standard is 120 lb CO₂/MMBtu, which is the standard for non-base load natural gas-fired units with a small allowance for distillate oil. This latter standard is readily achievable because the CO₂ emission rate of natural gas is 117 lb CO₂/MMBtu.

**Combined-Cycle Power Block:**
All turbines will operate on natural gas 100% of the time.

Page 2-6 of the original Application indicates the design efficiency is 56 percent on a LHV basis. Thus, 50 percent will be used because it is less. The potential electric output will be calculated using the net MW ratings (case 12), instead of the formula in the definition.

Design efficiency or 50%, whichever is less * potential electric output =

\[(0.50) \times (0.25 \times 1200 + 0.5 \times 1070) \times (8760) = 1,481,141 \text{ MWh-net}\]

If a combined-cycle turbine generates more electricity than 1,481,141 MWh-net, it will need to comply with the 1000 lb CO₂/MWh-gross emission limit. If it generates less, it will need to comply with the 120 lb CO₂/MMBtu standard.

As shown in the thermal efficiency calculations below, the combined-cycle GHG efficiency is estimated as 937.88 lb CO₂/MWh-gross, assuming an 8 percent performance degradation.

**Simple-Cycle Turbines:**
Each turbine will operate on natural gas 100% of the time.

Page 2-7 of the original Application indicates the design efficiency is 41 percent on a LHV basis, which is less than 50%.

Design efficiency x potential electric output = (0.41) * (99.087 MW-net/turbine) * (8760 hr/year) = 355,880.9 MWh-net

If any simple-cycle turbine generates more electricity than 355,880.9 MWh-net/yr, it will need to comply with the 1000 lb CO₂/MWh-gross emission limit. For each turbine, the permitted annual net electric sales is 233,647 MWh-net/turbine (calculated as 99.087 MW-net/turbine x 2358 permitted hours, including startups and shutdowns). Since the permitted annual net electric sales is significantly less than the potential electric output threshold, the applicable standard is 120 lb CO₂/MMBtu. As the AEC is natural-gas fired only, the
turbines are expected to emit CO$_2$ at a rate at 117 lb CO$_2$/MMBtu, thereby complying with the 120 lb CO$_2$/MMBtu standard.

As shown in the thermal efficiency calculations below, the simple-cycle GHG efficiency is estimated as 1356.03 lb CO$_2$/MWh-gross, assuming an 8 percent performance degradation. The inability to meet the 1000 lb CO$_2$/MWh-gross emission limit is expected for these non-base load turbines.

- **Thermal Efficiency Calculations**
  The second step is to perform thermal efficiency calculations to determine whether the proposed combined- and simple-cycle turbines will be able to comply with the emission standard of 1000 lb CO$_2$/MWh-gross, in the event that the combined-cycle power block or any simple-cycle turbines meet the above applicability criteria, including the sales criteria.

- **Combined-Cycle Power Block**
  For the combined-cycle power block, the annual operating schedule proposed by AES for the thermal efficiency calculations is 4100 hours normal operations, 80 cold starts, 420 combined hot and warm starts, and 500 shutdowns, in the revised Application. These are the totals for the combined-cycle block, consisting of the two combined-cycle turbines.

  This schedule is the same as the permitted annual operating schedule for each turbine of 4100 hours normal operations, 80 cold starts, 420 combined hot and warm starts, and 500 shutdowns. The permitted annual operating schedule represents the maximum operating schedule and allows the facility the flexibility to operate as necessary to meet the emission standard. To comply with the 1000 lb CO$_2$/MWh-gross, it will be necessary for AES to adjust the actual number of operating hours, starts, and shutdowns.

  Table 89 provides the annual hours for each configuration (1-on-1, 2-on-1), net plant power electrical output, net plant heat rate, gross heat rate, net heat rate, gross power output, average net electrical output, and average net heat rate for the four load scenarios for the two configurations.

- **Simple-Cycle Turbine**
  For each turbine, the annual operating schedule proposed by AES for the thermal efficiency calculations is 2000 hours normal operations, 500 startups, and 500 shutdowns for each turbine. This schedule is the same as the permitted schedule.

  Table 90 provides the annual normal operating hours for each turbine, net electrical output, net heat rate, gross heat rate, gross power output, and average net heat rate for the three load scenarios.
### Table 89 - Heat Rates and Electrical Production – Expected Operating Profile for Combined-Cycle Power Block

<table>
<thead>
<tr>
<th>Plant Output</th>
<th>Percent</th>
<th>44 (Minimum Turndown)</th>
<th>63</th>
<th>81</th>
<th>100 (Baseload)</th>
<th>44 (Minimum Turndown)</th>
<th>63</th>
<th>81</th>
<th>100 (Baseload)</th>
<th>Expected Annual Hours</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hours per Configuration per Year</td>
<td>Hrs/Yr</td>
<td>900</td>
<td>3200</td>
<td>4100</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Plant Electrical Output</td>
<td>kW</td>
<td>169,219</td>
<td>218,066</td>
<td>268,635</td>
<td>328,051</td>
<td>349,244</td>
<td>446,187</td>
<td>547,390</td>
<td>665,162</td>
<td>1-on-1 Configuration</td>
</tr>
<tr>
<td>Net Plant Heat Rate</td>
<td>Btu/kWh-LHV</td>
<td>7,061</td>
<td>6,327</td>
<td>6,275</td>
<td>6,155</td>
<td>6,842</td>
<td>6,184</td>
<td>6,159</td>
<td>6,071</td>
<td>2-on-1 Configuration</td>
</tr>
<tr>
<td>Gross Heat Rate, LHV</td>
<td>Btu/kWh-LHV</td>
<td>6,664</td>
<td>6,034</td>
<td>6,003</td>
<td>5,911</td>
<td>6,485</td>
<td>5,912</td>
<td>5,925</td>
<td>5,869</td>
<td></td>
</tr>
<tr>
<td>Net Heat Rate</td>
<td>Btu/kWh-HHV</td>
<td>7,834</td>
<td>7,020</td>
<td>6,962</td>
<td>6,829</td>
<td>7,592</td>
<td>6,862</td>
<td>6,834</td>
<td>6,736</td>
<td></td>
</tr>
<tr>
<td>Gross Power Output</td>
<td>kW</td>
<td>179,299</td>
<td>228,654</td>
<td>280,802</td>
<td>341,561</td>
<td>368,492</td>
<td>466,722</td>
<td>568,975</td>
<td>688,095</td>
<td></td>
</tr>
<tr>
<td>Average Net Electrical Output</td>
<td>kW</td>
<td>245,993</td>
<td>501,996</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Net Heat Rate</td>
<td>Btu/kWh-HHV</td>
<td>7162</td>
<td>7006</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Table 90 - Heat Rates and Electrical Production – Permitted Operating Profile for Simple-Cycle Turbine

<table>
<thead>
<tr>
<th>Plant Output</th>
<th>Percent</th>
<th>100</th>
<th>75</th>
<th>50</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Hours per Year</td>
<td>Hrs/Yr</td>
<td>2000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Electrical Output</td>
<td>kW</td>
<td>97,864</td>
<td>72,527</td>
<td>47,565</td>
</tr>
<tr>
<td>Net Heat Rate</td>
<td>Btu/kWh-LHV</td>
<td>8,060</td>
<td>8,778</td>
<td>10,359</td>
</tr>
<tr>
<td>Gross Heat Rate, LHV</td>
<td>Btu/kWh-LHV</td>
<td>7,950</td>
<td>8,618</td>
<td>10,073</td>
</tr>
<tr>
<td>Net Heat Rate, HHV</td>
<td>Btu/kWh-HHV</td>
<td>8,946</td>
<td>9,744</td>
<td>11,498</td>
</tr>
<tr>
<td>Gross Power Output</td>
<td>kW</td>
<td>99,215</td>
<td>73,878</td>
<td>48,916</td>
</tr>
<tr>
<td>Average Net Heat Rate</td>
<td>Btu/kWh-HHV</td>
<td>10,063</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
• **Combined-Cycle Power Block**
  
  Schedule: 900 hr for 1-on-1, 3200 hr 2-on-1, for total of 4100 hr normal operations
  80 cold starts, total for both turbines
  420 hot/warm starts (332 hot starts + 88 warm starts), total for both turbines
  500 shutdowns, total for both turbines

  **Startup and Shutdown Durations and Net Heat Rates**
  
  In the revised Application, AES provided the required heat rates for the cold, hot/warm startups for the baseload to completion period.

  Cold Startup Duration, 60 min—20 min (0.33 hr) for first fire to baseload.
  40 min (0.67 hr) from baseload to completion.

  Hot/Warm Startup Duration, 30 min—15 min (0.25 hr) for first fire to baseload.
  15 min (0.25 hr) from baseload to completion.

  Cold, Hot/Warm Startup Heat Rates—
  
  First fire to baseload—19,585 Btu/kWh-HHV-net
  AES assumed rate to be 2.5 times the 44% load heat rate of 7834 Btu/kWh-HHV-net for the 1-on-1 configuration.

  AES clarified the 2.5 multiplier was based on inspection of the startup heat rate for other combustion turbines. These other combustion turbines had a minimum load heat input of 11,189 btu/kWh-LHV and start up heat rate of 18,267 btu/kWh-LHV. The ratio of the startup heat rate to the minimum load heat rate is approximately 1.6, which was increased to 2.5 to be conservative for AEC.

  Baseload to completion—7,162 Btu/kWh-HHV-net
  AES assumed rate to be the same as the average net heat rate for the 1-on-1 configuration for simplicity.

  Shutdown, 30 min—Full 30 min (0.5 hr) for baseload to no fuel combustion

  Shutdown Heat Rates—11,751 Btu/kWh-HHV-net
  AES assumed rate to be 1.5 times the 44% load rate of 7834 Btu/kWh-HHV-net for the 1-on-1 configuration.

  AES clarified the 1.5 multiplier was based on inspection of the shutdown heat rate for other combustion turbines. These other combustion turbines had a minimum load heat input of 11,189 btu/kWh-LHV and a shutdown heat rate 16,520 btu/kWh-LHV. The ratio of the shutdown heat rate to the minimum load heat rate is approximately 1.5.
Annual Hours for Startups and Shutdowns

- **Startup Hours (first fire to baseload)**
  
  \[
  (80 \text{ cold starts/yr})(0.33 \text{ hr}) + (420 \text{ warm or hot starts/yr})(0.25 \text{ hr}) = 131.4 \text{ hr/yr}
  \]

- **Startup Hours (baseload to completion)**
  
  \[
  (80 \text{ cold starts/yr})(0.67 \text{ hr}) + (420 \text{ warm or hot starts/yr})(0.25 \text{ hr}) = 158.6 \text{ hr/yr}
  \]

- **Shutdown Hours (baseload to no fuel)**
  
  \[
  (500 \text{ shutdown/yr})(0.5 \text{ hr}) = 250 \text{ hr/yr}
  \]

**Overall Net Heat Rate (without degradation)**

\[
\frac{[(7162 \text{ Btu/kWh-HHV} \times 900 \text{ hrs for 1-on-1}) + (7006 \text{ Btu/kWh-HHV} \times 3200 \text{ hrs for 2-on-1}) + (19,585 \text{ Btu/kWh-HHV} \times 131.4 \text{ hr}) + (7162 \text{ Btu/kWh-HHV} \times 158.6 \text{ hr}) + (11,751 \text{ Btu/kWh-HHV} \times 250 \text{ hr})]}{(900 + 3200 + 131.4 + 158.6 + 250 \text{ hr})} = 7653.47 \text{ Btu/kWh-HHV-net}
\]

**GHG Efficiency (without degradation)**

\[
\frac{(7653.47 \text{ Btu/kWh-HHV-net}) (1000 \text{ kWh/MWh})(\text{MMBtu}/1,000,000 \text{ Btu})}{[(53.06 \text{ kg CO}_2/\text{MMBtu-HHV})(2.2046 \text{ lb/kg})]} = 895.27 \text{ lb CO}_2/\text{MWh-HHV-net}
\]

**GHG Efficiency, gross (without degradation)**

\[
(895.27 \text{ lb CO}_2 /\text{MWh-HHV-net}) (0.97 \text{ MWh-net} / \text{MWh-gross}) = 868.41 \text{ lb CO}_2/\text{MWh-HHV-gross}
\]

**GHG Efficiency (with degradation)**

AES assumes a maximum of 8% degradation can occur.

\[
\text{GHG Efficiency, net (with degradation)} = (895.27 \text{ lb CO}_2 /\text{MWh-HHV-net}) (1 + 0.08) = 966.89 \text{ lb CO}_2/\text{MWh-HHV-net}
\]

\[
\text{GHG Efficiency, gross (with degradation)} = (868.41 \text{ lb CO}_2 /\text{MWh-HHV-gross}) (1 + 0.08) = 937.88 \text{ lb CO}_2/\text{MWh-HHV-gross}
\]
**Preliminary Determination of Compliance**

**Alamitos Energy Center**
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170

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**Annual Capacity Factor**
Annual Capacity Factor \[= \frac{[(245,993 \text{ kW average net electrical output (for 1-on-1)} \times 900 \text{ hours/year}) + (501,996 \text{ kW average net electrical output (for 2-on-1)} \times 3,200 \text{ hours per year})]}{(665,162 \text{ kW (for 2-on-1 at 100\% CTG Load)} \times 8,760 \text{ hrs})} \times 100\% = 31.37\%\]

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**Compliance Demonstration**
If the combined-cycle block operates above the “design efficiency” of 56\% (or 50\%, whichever is less), the 1000 lb CO\textsubscript{2}/MWh-gross standard is applicable. The applicant has provided thermal emissions calculations for 31.37\% capacity factor. Since GHG efficiency increases with increased capacity factor, the 937.88 lb CO\textsubscript{2}/MWh-HHV-gross (with degradation) demonstrates that the combined-cycle block can meet the 1000 lb CO\textsubscript{2}/MWh-gross standard.

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**Conditions E193.11, E193.12, E193.14**
Condition E193.11 provides the 1000 lbs per gross megawatt-hours CO\textsubscript{2} emission limit (inclusive of degradation) shall only apply if a turbine supplies greater than 1,481,141 MWh-net electrical output to a utility distribution system on both a 12-operating-month and a 3-year rolling average basis. Compliance with the 1000 lbs per gross megawatt-hours CO\textsubscript{2} emission limit (inclusive of degradation) is determined on a 12-operating month rolling average basis.

Condition E193.12 provides the 120 lbs/MMBtu CO\textsubscript{2} emission limit shall only apply if a turbine supplies no more than 1,481,141 MWh-net electrical output to a utility distribution system on either a 12-operating-month or a 3-year rolling average basis. Compliance with the 120 lbs/MMBtu CO\textsubscript{2} emission limit is determined on a 12-operating month rolling average basis.

Condition E193.14 limits the CO\textsubscript{2} emissions to 610,480 tpy per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO\textsubscript{2} emissions is limited to 937.88 pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations above.

The condition includes a formula for the calculation of greenhouse gases (tons CO\textsubscript{2}). Based on fuel consumption, where FF is the monthly fuel usage in millions standard cubic feet:

\[
\text{GHG (CO}_2\text{) (tons/month)} = \{(53.06 \text{ kg CO}_2\text{/MMBtu}) \times \{(2.2046 \text{ lb/kg})(\text{ton/2000 lb}) \times (1050 \text{ MMBtu/MMcf}) \times FF \} = 61.41 \times FF
\]

---

**Simple-Cycle Turbine**
Schedule: 2000 hr per turbine
500 startups per turbine
500 shutdowns per turbine
Startup and Shutdown Durations and Net Heat Rates
In the revised Application, AES provided the required heat rates for the startups for the baseload to completion period.

Startup Duration, 30 min—10 min (0.17 hr) for first fire to baseload.
20 min (0.33 hr) from baseload to completion.

Startup Heat Rate—
First fire to baseload net heat rate—28,746 Btu/kWh-HHV-net
AES assumed rate to be 2.5 times the 50% load heat rate of 11,498 Btu/kWh-HHV-net.

Baseload to completion net heat rate—10,063 Btu/kWh-HHV-net
AES assumed rate to be the same as the average net heat.

Shutdown Duration, 13 min – Full 13 min (0.22 hr) for baseload to no fuel combustion

Shutdown Net Heat Rate—17,248 Btu/kWh-HHV-net
AES assumed rate to be 1.5 times the 50% load rate of 11,498 Btu/kWh-HHV-net.

Annual Hours for Startups and Shutdowns
- Startup Hours (first fire to baseload)
  (500 cold starts/yr)(0.17 hr) = 85 hr/yr

- Startup Hours (baseload to completion)
  (500 cold starts/yr)(0.33 hr) = 165 hr/yr

- Shutdown Hours = (500 shutdowns, per turbine)(13 min/shutdown)(hr/60 min) = 108 hr

Overall Net Heat Rate (without degradation)
Overall Net Heat Rate (without degradation) =

\[
\frac{((\text{Avg net heat rate} \times \text{annual hrs}) + 
(\text{Startup heat rate FIRST FIRE TO BASELOAD} \times \text{Annual hours FIRST FIRE TO BASELOAD}) + 
(\text{Startup heat rate BASELOAD TO COMPLETION} \times \text{Annual hours BASELOAD TO COMPLETION}) + 
(\text{Shutdown heat rate BASELOAD TO NO FUEL} \times \text{Annual hours BASELOAD TO NO FUEL}))}{\text{Total annual hrs}}
\]

\[
\frac{((10,063 \text{ Btu/kWh-HHV-net} \times 2000 \text{ hrs}) + (28,746 \text{ Btu/kWh-HHV} \times 85 \text{ hr}) + (10,063 \text{ Btu/kWh-HHV} \times 165 \text{ hr}) + (17,248 \text{ Btu/kWh-HHV} \times 108 \text{ hr})}{(2000 + 85 + 165 + 108 \text{ hr})} = 11,065.56 \text{ Btu/kWh-HHV-net}
\]
GHG Efficiency (without degradation)

GHG Efficiency, net (without degradation) =
\[
\frac{[(11,065.56 \text{ Btu/kWh-HHV-net}) (1000 \text{ kWh/MWh})(\text{MMBtu/1,000,000 Btu})] [(53.06 \text{ kg CO}_2/\text{MMBtu-HHV})(2.2046 \text{ lb/kg})]}{53.06} = 1294.41 \text{ lb CO}_2/\text{MWh-HHV-net}
\]

GHG Efficiency, gross (without degradation) =
\[
(1294.41 \text{ lb CO}_2/\text{MWh-HHV-net}) (0.97 \text{ MWh-net / MWh-gross}) = 1255.58 \text{ lb CO}_2/\text{MWh-HHV-gross}
\]

GHG Efficiency (with degradation)

AES assumes a maximum of 8% degradation can occur.

GHG Efficiency, net (with degradation) = (1294.41 lb CO\textsubscript{2} /MWh-HHV-net) (1 + 0.08) = 1397.96 lb CO\textsubscript{2} /MWh-HHV-net

GHG Efficiency, gross (with degradation) = (1255.58 lb CO\textsubscript{2} /MWh-HHV-gross) (1 + 0.08) = 1356.03 lb CO\textsubscript{2} /MWh-HHV-gross

***Compliance Demonstration

The 1356.03 lb CO\textsubscript{2} /MWh-HHV-gross demonstrates that each simple-cycle turbine is unable to meet the 1000 lb CO\textsubscript{2} /MWh-gross standard. This is expected because the standard is for baseload turbines. Since simple-cycle turbines are permitted to operate as non-baseload units, the relevant performance standard is the fuel-based heat input standard of 120 lb CO\textsubscript{2} /MMBtu of heat input. Compliance with this standard can be demonstrated by combusting natural gas as the exclusive fuel.

- Condition E193.13 and E193.15
  Condition E193.13 provides the 120 lbs/MMBtu CO\textsubscript{2} emission limit for non-base load turbines shall apply. Compliance with the 120 lbs/MMBtu CO\textsubscript{2} emission limit is determined on a 12-operating month rolling average basis.

  Condition E193.15 limits the CO\textsubscript{2} emissions to 120,765 tpy per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO\textsubscript{2} emissions is limited to 1356.03 pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations above.

40 CFR 60 Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

§60.40Da(a)(1) & (2)—Except as specified in paragraph (e), the affected facility to which this subpart applies is each electric utility steam generating unit that is capable of combusting more than 73 MW (250 MMBtu/hr) heat input; and for which construction, modification, or reconstruction is commenced.
after September 18, 1978. This subpart is not applicable to the combined-cycle turbines, because the
heat recovery steam generators are unfired and not equipped with duct burners.

40 CFR 60 Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam
Generating Units
§60.40b(a)—This subpart applies to each steam generating unit that commences construction after
June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of
greater than 29 MW (100 MMBtu/hr). This subpart is not applicable to the combined-cycle turbines
because the heat recovery steam generators are unfired and not equipped with duct burners.

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.

Analysis: Subpart Dc is applicable to the auxiliary boiler, rated at 70.8 MMBtu/hr, because the
initial construction will be commenced after June 9, 1989.

§60.48c(g)(2) As an alternative to meeting the requirements of paragraph (g)(1) [requires the
recording and maintenance of records of the amount of each fuel combusted during each operating
day], the owner or operator of an affected facility that combusts only natural gas, wood, fuels using
fuel certification in §60.48c(f) to demonstrate compliance with the 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.

Analysis: There are no emission standards, compliance, stack testing, or emission monitoring
requirements for natural gas fired boilers. This boiler will combust only natural gas.

This paragraph requires the recording of the calendar monthly usage of natural gas and the use
of a non-resettable totalizing fuel meter.

Rule 2012 requires this RECLAIM major NOx source to meet stringent requirements regarding
the recording of calendar monthly usage and the use of a non-resettable totalizing fuel meter.
Moreover, Rule 2012 requires a NOx CEMS which is not required by this subpart. Section F:
RECLAIM Monitoring and Source Testing of the facility permit is comprised of a standard list
of operating conditions for RECLAIM facilities, including requirements for NOx major
sources. Pursuant to permitting procedure, permit conditions enforcing standard RECLAIM
requirements are not added to a facility permit. In contrast, RECLAIM conditions regarding
the number of RTCs required and interim emission factors are included as permit conditions
because they are based on emissions calculations that are specific to a facility.
40 CFR Part 60 Subpart GG--NSPS for Stationary Gas Turbines
Subpart GG establishes requirements for stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr (10.7 gigajoules per hour), based on lower heating value, which commences construction, modification, or reconstruction after October 3, 1997 and are not subject to subpart KKKK. Subpart KKKK is applicable to stationary combustion turbines with a heat input greater than 10 MMBtu/hr (10.7 gigajoules per hour), based on higher heating value, which commenced construction, modification or reconstruction after February 18, 2005. The proposed combined- and simple-cycle turbines are subject to the requirements of 40 CFR Subpart KKKK (see below) and thus are exempt from the requirements of this subpart per §60.4305(b).

40 CFR Part 60 Subpart KKKK-- NSPS for Stationary Gas Turbines
Subpart KKKK establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

§60.4305
(a)—This subpart is applicable to stationary combustion turbines with a heat input greater than 10 MMBtu/hr (10.7 gigajoules per hour), based on the higher heating value of the fuel, which commenced construction, modification or reconstruction after February 18, 2005. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to the turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining the peak heat input. However, this part does apply to emissions from any associated HRSG and duct burners.

(b)—Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc.

Analysis: This subpart is applicable to the combined-cycle turbines, rated at 2275 MMBtu/hr at 28 ºF each, and the simple-cycle turbines, rated at 882 MMBtu/hr at 59 ºF each.

§60.4320(a)—Gas turbines are required to meet the NOx emission limits specified in Table 1 of this subpart. Table 1 provides NOx emission standards based on combustion turbine type and heat input at peak rate. For a new natural-gas fired turbine with a heat input at peak load of greater than 850 MMBtu/hr, the NOx emission limit is 15 ppmv @ 15% O₂.

Analysis: Since the combined- and simple-cycle turbines are rated at greater than 850 MMBtu/hr each, an emissions limit of 15 ppmv NOx will be included for these turbines. The combined-cycle turbines will meet the BACT limit of 2.0 ppmv @ 15% O₂, and the simple-cycle turbines will meet the BACT limit of 2.5 ppmv @ 15% O₂. Compliance with this section is expected.
§60.4330(a)(2)—Gas turbines are required to comply with (a)(1), (a)(2), or (a)(3) to meet the sulfur dioxide emission limit. Paragraph (a)(1) specifies the turbine exhaust gas shall not contain SO\textsubscript{2} in excess of 0.90 lbs/MWh gross output. Paragraph (a)(2) specifies the fuel shall not contain total potential sulfur emissions in excess of 0.060 lb SO\textsubscript{2}/MMBtu heat input for units located in continental areas.

Analysis: The 0.90 lbs/MWh is a stack limit that requires annual source testing for verification pursuant to §60.4415. The 0.06 lb/MMBtu is a fuel based limit which will require fuel monitoring (§60.4360) or fuel supplier data (§60.4365). As discussed in the analysis for §60.4365 below, the natural-gas fired turbines are expected to be in compliance with the 0.06 lb/MMBtu limit. Accordingly, an emissions limit of 0.06 lb/MMBtu SO\textsubscript{2} will be included for the combined- and simple-cycle turbines, pursuant to this subpart.

§60.4340—To demonstrate compliance for NOx if water or steam injection is not used, an alternative to the required annual performance testing is the installation and operation of a continuous monitoring system consisting of a certified NOx and O\textsubscript{2} CEMS.

Analysis: For this project, monitoring of the emissions from each combined- and simple-cycle turbine will be achieved with a CEMS certified in accordance with Rule 2012.

§60.4360—The total sulfur content of the fuel being fired in the turbine must be monitored using total sulfur methods described in §60.4415, except as provided in §60.4365, discussed below.

§60.4365—An election may be made not to monitor the total sulfur content of the fuel combusted in the turbine pursuant to the monitoring requirements in §60.4370, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO\textsubscript{2}/MMBtu heat input for units located in continental areas. Two sources of information may be used to make the required demonstration: (1) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and has potential sulfur emissions of less than 26 ng SO\textsubscript{2}/J (0.060 lb SO\textsubscript{2}/MMBtu) heat input for continental areas, or (2) Representative fuel sampling data which show the sulfur content of the fuel does not exceed 26 ng SO\textsubscript{2}/J (0.060 lb SO\textsubscript{2}/MMBtu).

Analysis: Rule 431.1 limits pipeline natural gas to 16 ppmv sulfur limit (calculated as H\textsubscript{2}S) specified in this rule. The 16 ppmv sulfur is equivalent to 1.0 grain/100 SCF (0.0626285 grain/100 SCF per 1 ppm), which is significantly less than 20 grains/100 SCF.

Further, Southern California Gas Company, Tariff Rule No. 30—Transportation of Customer-Owned Gas, allows up to 0.75 gr. S/100 scf total sulfur.
**40 CFR Part 63 Subpart YYYY—NESHAPs for Stationary Combustion Turbines**

This regulation applies to gas turbines located at major sources of HAP emissions. The applicability of federal requirements governing HAPs is dependent on whether a facility is a major source or area source for HAPs. A "major source" means “any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.” An “area source” means “any stationary source of hazardous air pollutants that is not a major source.”

**Combined-Cycle Turbines**
Ammonia and propylene are toxic air contaminants for the purpose of Rule 1401, but not federal hazardous air pollutants. Therefore, the single highest HAP emissions are for formaldehyde.

From Table 26 above, the formaldehyde emissions from the combined-cycle turbines is 3.64 tpy (2 * 1.82 tpy/turbine). The total combined HAPs is 8.10 tpy (2 * 4.05 tpy/turbine).

**Simple-Cycle Turbines**
From Table 42 above, the formaldehyde emissions from the simple-cycle turbines is 1.44 tpy (4 * 0.36 tpy/turbine). The total combined HAPs is 3.2 tpy (4 * 0.80 tpy/turbine).

**Auxiliary Boiler**
From Table 30 above, the formaldehyde emissions from the auxiliary boiler is 0.00111 tpy. The total combined HAPs is 0.0074 tpy. These emissions are for 365 days per year.

**Facility**
The total combined formaldehyde emissions from all sources is 5.08 tpy, which is less than 10 tpy. The total combined HAPs from all sources is 11.31 tpy, which is less than 25 tpy. Therefore, the AEC is an area source for HAPS, not a major source. The requirements of this regulation do **not** apply.

**40 CFR Part 63, Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources**

§63.11193—This subpart is applicable to owner or operator of industrial, commercial, or institutional boiler as defined in §63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in §63.2, except as specified in §63.1195.

§63.11237—“Industrial boiler” means “a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.”

To convert $0.75 \text{ gr S}/100 \text{ scf}$ to units of lb SO$_2$/MMBtu--

\[
\text{(0.75 gr S/100 ft}^3) \times \frac{1 \text{ lb/7000 gr}}{\text{ ft}^3/913 \text{ Btu [LHV]}(1 \text{E+06 Btu/MMBtu})(64 \text{ lb SO}_2/32 \text{ lb S}) = 0.0023 \text{ lb SO}_2/\text{MMBtu} < 0.06 \text{ lb SO}_2/\text{MMBtu limit}
\]
Analysis: As determined for Subpart YYYY, the AEC will be an area source. The auxiliary boiler will be an industrial boiler.

§63.11195—The types of boilers listed in paragraphs (a) through (g) of this section are not subject to this subpart and to any requirements in this subpart.

(e) A gas-fired boiler as defined in this subpart.

§63.11237—“Gas-fired boiler” includes any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Analysis: As a gas-fired boiler, the auxiliary boiler is not subject to this subpart.

40 CFR Part 64 – Compliance Assurance Monitoring
The Compliance Assurance Monitoring (CAM) rule, 40 CFR Part 64, specifies the monitoring, reporting, and recordkeeping criteria that is required to be conducted by Title V facilities to demonstrate ongoing compliance with emission limitations and standards. The rule is intended to provide “reasonable assurance” that the control systems are operating properly to maintain compliance with the emission limits.

In general, CAM applies to emissions units that meet all of the following conditions:

- the unit is located at a major source for which a Title V permit is required; and
- the unit is subject to an emission limitation or standard; and
- the unit uses a control device to achieve compliance with a federally enforceable limit or standard; and
- the unit has potential pre-control emissions (Title V renewal) or post-control emissions (initial Title V or revision) of at least 100% of the major source amount; and
- the unit is not otherwise exempt from CAM.

The combined- and simple-cycle turbines, and auxiliary boiler are located at a major source for which a Title V permit is required.

Combined-Cycle Turbines
For the combined-cycle turbines, the NOx, CO, and VOC emissions are subject to BACT limits. Each turbine is controlled with an SCR and CO catalyst to meet BACT limits. For each turbine, the highest annual post-control NOx, CO, and VOC emissions are higher than the major source thresholds. Specifically, the NOx emissions are 54.19 tpy (commissioning year), which is higher than the 10 tpy major source threshold. The CO emissions are 129.58 tpy (commissioning year), which is higher than the 50 tpy threshold. The VOC emissions are 30.07 tpy (commissioning year), which is higher than
the 10 tpy threshold. Thus, the CAM regulations are applicable to the combined-cycle turbines for NOx, CO, and VOC.

For each turbine, a continuous emission monitoring system (CEMS) will be installed for NOx and for CO. The NOx CEMS will be certified in accordance with Rule 2012 requirements, and the CO CEMS will be certified in accordance with Rule 218 requirements. 40 CFR Part 64.2(b)(1)(vi) provides that the requirements of this part shall not apply to an emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in §64.1. §64.1 defines “continuous compliance determination method” to mean “a method, specified by the applicable standard or an applicable permit condition, which: (1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and (2) Provides data either in units of the standard or correlated directly with the compliance limit.” Since the NOx and CO CEMS qualify as continuous compliance determination methods, the CEMS provide an exemption from this subpart for NOx and CO.

This subpart also applies to the VOC emissions because the VOC BACT limit is achieved with the assistance of the oxidation catalyst. The oxidation catalyst is primarily installed to control CO emissions, but also controls VOC emissions to a minor degree. The CO catalyst is located at the outlet of the turbine and designed to provide the required control efficiency at the expected turbine exhaust temperature range. There are no operational requirements for the CO catalyst. To assure that the catalyst is not exhausted, each turbine is required to be source tested every three years for VOC pursuant to condition D29.3.

**Simple-Cycle Turbines**

For the simple-cycle turbines, the NOx, CO, and VOC emissions are subject to BACT limits. Each turbine is controlled with an SCR and CO catalyst to meet BACT limits. For each turbine, the highest annual post-control NOx and CO emissions are higher than the major source thresholds. Specifically, the NOx emissions are 34.29 tpy (commissioning year), which is higher than the 10 tpy major source threshold. The CO emissions are 50.7 tpy (commissioning year), which is higher than the 50 tpy threshold. The VOC emissions are 9.3 tpy (commissioning year), which is lower than the 10 tpy threshold. Thus, the CAM regulations are applicable to the simple-cycle turbines for NOx and CO.

The analysis for the combined-cycle turbines are also applicable to the simple-cycle turbines. Since the NOx and CO CEMS qualify as continuous compliance determination methods, the CEMS provide an exemption from this subpart for NOx and CO.

**Auxiliary Boiler**

For the auxiliary boiler, the NOx and CO are subject to BACT limits. The boiler is controlled with an SCR to meet the BACT limit for NOx. The highest annual post-control NOx emissions is lower than the major source threshold. Specifically, the NOx emissions are 0.68 tpy, which is lower than the 10 tpy major source threshold. Thus, the CAM regulations are not applicable to the auxiliary boiler.
40 CFR Part 68—Chemical Accident Prevention Programs
§68.1—This part sets forth the list of regulated substances and thresholds and the requirements for owners or operators of stationary sources concerning the prevention of accidental releases.

§68.10(a)—An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process shall comply with the requirements of this part.

§68.130(a)—Regulated toxic and flammable substances are listed with the associated threshold quantities in Tables 1, 2, 3, and 4 to §68.130. Table 1 to §68.130—List of Regulated Toxic Substances and Threshold Quantities for Accidental Release Prevention [Alphabetical Order—77 Substances] listed “ammonia (anhydrous)” with a threshold quantity of 10,000 lbs, and “ammonia (conc 20% or greater)” with a threshold quantity of 20,000 lbs.

Because the two new ammonia tanks (Devices D163, D164) installed with the AEC project will contain 19% ammonia, not anhydrous ammonia or ammonia with a 20% or greater concentration, Part 68 is not applicable. Therefore, facility condition F24.1, which requires compliance with the accidental release prevention requirements pursuant to 40 CFR Part 68, is not applicable to the new tanks.

Facility condition F24.1 is applicable to the four existing ammonia tanks (Devices D19, D151, D152, and D153) in Section D, because they are permitted to use 29% aqueous ammonia. Condition F24.1 will be removed from the facility permit after the four existing tanks are removed from the facility.

Regulation XXXI—Acid Rain Permit Program (40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 - Acid Rain Provisions)
Acid Rain provisions are designed to control SO\textsubscript{2} and NOx emissions that could form acid rain from fossil fuel fired combustion devices in the electricity generating industry. Facilities are required to cover SO\textsubscript{2} emissions with “SO\textsubscript{2} allowances” or purchase of SO\textsubscript{2} offsets on the open market. The facility is also required to monitor SO\textsubscript{2} emissions through use of fuel gas meters and gas constituent analysis (use of emission factors is also acceptable in certain cases), or with the use of exhaust gas CEMS. The AEC facility will comply with the monitoring requirements of the acid rain provisions with the use of gas meters in conjunction with natural gas default sulfur data as allowed by the Acid Rain regulations (Appendix D to 40 CFR Part 75). If additional SO\textsubscript{2} credits are needed, AEC will obtain the credits from the SO\textsubscript{2} trading market. Based on the above, compliance with this rule is expected.

STATE REGULATIONS
California Environmental Quality Act (CEQA)
CEQA applies to projects undertaken by a public agency, funded by a public agency, or requires an issuance of a permit by a public agency. A “project” means the whole of an action that has a potential for resulting in physical change to the environment, and is an activity that may be subject to several
discretionary approvals by government agencies. A project is exempt from CEQA if by statute, if considered ministerial or categorical, where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment.

The AEC project is subject to CEQA because there are no applicable exemptions. The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger. On 10/26/15, AES submitted a Supplemental Application for Certification (SAFC) (13-AFC-01) for the amended AEC. On 4/12/16, AES submitted revised Air Quality, Biological Resources, and Public Health Assessment sections. The CEC's 12-month licensing process is a certified regulatory program under CEQA. The CEC is the lead agency for the project.

The CEC will publish the Preliminary Staff Assessment (PSA) after the SCAQMD issues the Preliminary Determination of Compliance (PDOC). Typically, the PSA will indicate CEC is the CEQA lead agency, and CEC staff conducts its environmental analysis in accordance with the requirements of CEQA, and no additional environmental impact report (EIR) is required because the CEC’s site certification program has been certified by the California Resources Agency as meeting all requirements of a certified regulatory program. Further, the CEC’s siting regulations require staff to independently review the SAFC and assess whether the list of environmental impacts contained is complete and additional or more effective mitigation measures are necessary, feasible, and available.

The PSA examines environmental, public health and safety, and engineering aspects of the proposed AEC, based on the information provided by the applicant, government agencies (such as the SCAQMD), interested parties, and other sources available at the time the PSA was prepared. Further, the PSA also recommends measures to mitigate significant and potentially significant environmental effects, which take the form of conditions of certification for construction, operation, maintenance, and eventual closure of the project, if approved by the CEC. The PSA describes how the implementation of the conditions of certification would reduce potential adverse impacts to insignificant levels and ensure that the project’s emissions are mitigated to less than significant.

California Code of Regulations (CCR), Title 20, Chapter 11—Greenhouse Gases Emission Performance Standard, Article 1—Provisions Applicable to Powerplants 10 MW and Larger (SB 1368)

The California Emissions Performance Standard (EPS) of 1100 lbs CO₂/MW-hour-net of electricity applies to local publicly owned electric utilities. California regulations stipulate that no local publicly owned electric utility shall enter into a covered procurement if greenhouse gases emissions from the power plant(s) subject to the covered procurement exceed the EPS. A “covered procurement” is defined in §2901(d) as “(1) A new ownership investment in a base load generation power plant, or (2) A new or renewed contract commitment, including a lease, for the procurement of electricity with a term of five years or greater by a local publicly owned electric utility with: (A) a base load generation power plant, unless the power plant is deemed compliant, or (B) any generating units added to a deemed-compliant base load generation power plant that combined result in an increase of 50 MW or more to the power plant’s rated capacity.”

Alamitos Energy Center
Application Nos. 579140, 579142-143, -145, -147, -150, -152, -158, 579160-170
The local publicly owned electric utility from which AES secures a covered procurement is required to submit a compliance filing to the California Energy Commission. The Commission then issues a decision on whether the covered procurement complies with the EPS.

The applicable sections of the regulation are reproduced below, with the rule analysis following.

§ 2900. Scope.
This Article applies to covered procurements entered into by local publicly owned electric utilities. The greenhouse gases emission performance standard established in section 2902(a) applies to any generation, regardless of capacity, supplied under a covered procurement. The provisions requiring local publicly owned electric utilities to report covered procurements, including Sections 2908, 2909, and 2910, apply only to covered procurements involving powerplants 10 MW and larger.

§ 2901. Definitions.
(a) "Annualized plant capacity factor" means the ratio of the annual amount of electricity produced, measured in kilowatt hours, divided by the annual amount of electricity the powerplant could have produced if it had been operated at its maximum permitted capacity during all hours of the year, expressed in kilowatt hours.

(b) "Baseload generation" means electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent.

(c) “Combined-cycle natural gas" means a powerplant that employs a combination of one or more natural gas turbines and one or more steam turbines in which electricity is produced in the steam turbine from otherwise lost waste heat exiting from one or more of the gas turbines.

(k) “Permitted capacity" means the rated capacity of the powerplant unless the maximum output allowed under the operating permit is the effective constraint on the maximum output of the powerplant.

(l) "Powerplant" means a facility for the generation of electricity, and is:
(1) a single generating unit; or
(2) multiple generating units that meet the following conditions:
   (A) the generating units are co-located;
   (B) each generating unit utilizes the same fuel and generation technology; and
   (C) one or more of the generating units are operationally dependent on another.
(m) "Rated capacity" means the powerplant's maximum rated output. For combustion or steam generating units, rated capacity means generating capacity and shall be calculated pursuant to Section 2003.

(Pursuant to § 2003(a), the "generating capacity" of an electric generating facility means the maximum gross rating of the plant's turbine generator(s), in megawatts ("MW"), minus the minimum auxiliary load.)

(a) The greenhouse gases emission performance standard (EPS) applicable to this chapter is 1100 pounds (0.5 metric tons) of carbon dioxide (CO₂) per megawatt hour (MWh) of electricity.

(b) Unless otherwise specified in this Article, no local publicly owned electric utility shall enter into a covered procurement if greenhouse gases emissions from the powerplant(s) subject to the covered procurement exceed the EPS.

§ 2903. Compliance with the Emission Performance Standard.
(a) Except as provided in Subsection (b), a powerplant's compliance with the EPS shall be determined by dividing the powerplant's annual average carbon dioxide emissions in pounds by the powerplant's annual average net electricity production in MWh. This determination shall be based on capacity factors, heat rates, and corresponding emissions rates that reflect the expected operations of the powerplant and not on full load heat rates.

§ 2905. Annual Average Electricity Production.
(a) Except as provided in Subsection (b), a powerplant's annual average electricity production in MWh shall be the sum of the net electricity available for all of the following: use onsite or at a host site in a commercial or industrial process or for sale or transmission from the powerplant.

Analysis:
Because § 2900 provides that local publicly owned electric facilities shall make a determination regarding compliance with the EPS prior into entering into a covered procurement, SCAQMD need not make a determination.

Thermal efficiency calculations are provided above to demonstrate compliance with 40 CFR 60 Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units. For the purpose of showing compliance with the requirements of Subpart TTTT only, the thermal efficiency calculations indicate the greenhouse gas efficiency, with 8% degradation, for the combined-cycle block is 966.89 lb CO₂/MWh-HHV-net.
RECOMMENDATION
Based on the above analysis, it is recommended that the FDOC be published following the conclusion of the required review and comment periods for the CEC, EPA, other agencies and public, subject to any comments received during these periods. After the CEC issues the Final Commission Decision, the Permits to Construct may be issued.
APPENDIX – PLANNING, RULE DEVELOPMENT & AREA SOURCES (PRDAS) MODELING REVIEW MEMO, DATED 5/20/16
SOUTH COAST AIR QUALITY MANAGEMENT SCAQMD
MEMORANDUM

DATE: May 20, 2016
TO: Andrew Lee
FROM: Ian MacMillan

SUBJECT: Modeling Review of AES Alamitos Energy Center Project (Facility ID #115394) (A/N: 579140, 579142, 579143, 579145, 579147, 579150, 579152, 579158, 579160-579170)

As you requested, Planning, Rule Development & Area Sources (PRDAS) staff reviewed the dispersion modeling analysis and health risk assessment (HRA) conducted for the AES Alamitos Energy Center located at 690 North Studebaker Road in the city of Long Beach. The project consists of replacing six utility boilers with one two-on-one Combined-Cycle Gas Turbine (CCGT) power block, one simple cycle power block with four Simple-Cycle Gas Turbines (SCTG), and an auxiliary boiler. The dispersion modeling analysis and HRA (report) and electronic files were submitted for PRDAS staff review along with the modeling request memo dated December 18, 2015. A revised report and electronic files were also submitted for review on January 14, 2016 and again on April 6, 2016.

SUMMARY OF MODELING REVIEW

• Modeling Conducted Pursuant to SCAQMD Regulations XIII Requirements
  ✓ SCAQMD Rule 1304(a)(2) provides an exemption from the modeling requirement of Rule 1303(b)(1) for the installation of the new turbines since AES is permanently retiring their existing electric steam utility boilers. The modeling requirements of Rule 1303(b)(1) do apply to the proposed auxiliary boiler. The modeled impacts from the auxiliary boiler are below all thresholds in Rule 1303.

• Modeling Conducted Pursuant to SCAQMD Regulation XIV Requirements
  ✓ The project’s health risks are less than the Rule 1401 cancer and non-cancer permit limits of 10 in one million (for permit units with T-BACT), and hazard index of 1, respectively. The auxiliary boiler’s health risks are less than the Rule 1401 cancer and non-cancer permit limits of 1 in one million (for permit units without T-BACT), and hazard index of 1, respectively.

• Modeling Conducted Pursuant to SCAQMD Regulation XX Requirements
  ✓ All equipment in the proposed project is subject to SCAQMD Rule 2005 review for NO₂. Modeled impacts from each piece of equipment are below all ambient air quality thresholds for NO₂.

• Modeling Conducted Pursuant to Federal Prevention of Significant Deterioration (PSD) Requirements
  ✓ The project is subject to PSD regulations for NO₂, PM₁₀, and greenhouse gases (GHG). Although CO was determined not to be subject to PSD, the impacts from CO emissions were reviewed since they were included in the analysis. Impacts were compared to applicable Class I and II significant impact levels (SIL). The project’s CO and PM₁₀ impacts do not exceed the SIL and no further PSD analysis is needed. Since the project’s NO₂ impacts exceeded the 1-hour NO₂ SIL, a cumulative impact assessment was
The modeled concentration in the cumulative impact analysis exceeded the federal 1-hour NO$_2$ National Ambient Air Quality Standard (NAAQS). However, the project's contribution to the exceedance is less than the SIL, therefore, the project is not considered a significant source and does not cause or contribute to the modeled NAAQS exceedance. No further PSD analysis is required.

- The project's impacts on visibility and deposition at the nearest Class I area did not exceed the screening threshold. Additional information is provided in the detailed comments below on an additional analysis requested by EPA Region 9 on visibility in Class II areas.

- **Modeling Conducted Pursuant to CEQA**
  - SCAQMD is both a responsible agency and a commenting agency under CEQA for this project. As noted above in the memo summary, the modeling analysis conforms to SCAQMD regulations and SCAQMD does not have any comments.

**DETAILED COMMENTS ON THE MODELING REVIEW**

- **AERMOD Dispersion Modeling Approach**
  - The applicant utilized AERMOD (version 15181) for the air dispersion modeling, which is the current EPA approved model.
  - The applicant used meteorological data from the SCAQMD's Long Beach station, which is appropriate for the project.
  - The AERMOD modeling generally conforms to the SCAQMD's dispersion modeling methodology.
  - The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1 – 6, 9 – 10, and 12 of the latest requesting memos and are assumed to be correct.
  - The applicant used the monitoring data for SRA 4, South Coastal Los Angeles County monitoring stations. PRDAS staff used the most recent three years of data available (2012-2014) to determine the background concentrations. The predicted modeled impacts were added to the background concentrations for comparison to the ambient air quality standards.
  - The U.S. EPA approved NO$_2$ to NO$_x$ conversion ratios of 0.80 and 0.75 were used for evaluating 1-hour and annual NO$_2$ impacts from the project, respectively.
  - The receptor grid area covered is adequate to determine the maximum impacts from the project.
  - Since there are no restrictions on the operating hours for the auxiliary boiler, PRDAS staff's evaluation assumed continuous operations of 8,760 hours/year (24 hours/day, 7 days/week, and 52 weeks/year). For the combined-cycle turbines, the permit was evaluated at 4,640 operating hours per year and 2,358 hours per year for the simple-cycle turbines.
  - PRDAS staff reproduced the modeling analysis and our results are summarized below.
Modeling Review for Compliance with Applicable Federal, State, and Local Regulations

1. Federal PSD Air Quality Analyses

✓ The proposed project is subject to PSD review for NO\textsubscript{2} and PM\textsubscript{10}; therefore, the project’s impacts are compared to the corresponding U.S. EPA SILs for each pollutant\(^1\). CO was determined by AQMD Engineering staff to not be subject to PSD; however, as the analysis was included in the report, PRDAS staff reviewed the analysis and the results are included below.

a. Class I Areas

✓ The nearest Class I area to the project site is the San Gabriel Wilderness, which is approximately 53 km away. A radial receptor ring was placed at a distance of 50 km from the project (50 km is the maximum receptor distance of the AERMOD model).

✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1 - 6 of the report and are assumed to be correct. The results are summarized in Table A.

<table>
<thead>
<tr>
<th>Pollutant &amp; Averaging Time</th>
<th>Project’s Modeled Operational Impact ((\mu g/m^3))</th>
<th>Class I SIL ((\mu g/m^3))</th>
<th>Exceeds Class I SIL?</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO\textsubscript{2}, Annual</td>
<td>0.0047</td>
<td>0.1</td>
<td>No</td>
</tr>
<tr>
<td>PM\textsubscript{10}, 24-hr</td>
<td>0.056</td>
<td>0.32</td>
<td>No</td>
</tr>
<tr>
<td>PM\textsubscript{10}, Annual</td>
<td>0.0046</td>
<td>0.2</td>
<td>No</td>
</tr>
</tbody>
</table>

b. Class II Areas

✓ The project applicant identified four Class II areas in the project vicinity – Crystal Cove State Park, Water Canyon State Park, Chino Hills State Park, and Kenneth Hahn State Park.

✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1 - 6 of the report and are assumed to be correct. The results are summarized in Table B.

✓ The U.S. EPA established a new 1-hour NO\textsubscript{2} standard of 0.100 ppm (or 188 \(\mu\)g/m\(^3\)) that became effective on April 12, 2010. In order to show compliance with the federal 1-hour NO\textsubscript{2} standard, the applicant used the maximum hourly emissions from startup, shutdown, and normal operations. Given the number of startups and shutdowns, the emissions from these events cannot be considered as intermittent, as described in the U.S. EPA’s memo dated March 1, 2011. Emissions from commissioning were not included because commissioning is a once in a lifetime event and the form of the standard involves a three year average of the 98\textsuperscript{th} percentile of the annual distribution of daily maximum 1-hour concentrations.

\(^1\) Commissioning activities are not to be included per discussion with U.S. EPA Region 9 staff.
Table B – Total Project Operational Impacts to Class II Areas

<table>
<thead>
<tr>
<th>Pollutant &amp; Averaging Time</th>
<th>Project’s Modeled Operational Impact (µg/m³)</th>
<th>Class II SIL (µg/m³)</th>
<th>Exceeds Class II SIL?</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO, 1-hr</td>
<td>186</td>
<td>2,000</td>
<td>No</td>
</tr>
<tr>
<td>CO, 8-hr</td>
<td>44</td>
<td>500</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, 1-hr</td>
<td>31.3</td>
<td>7.5 a</td>
<td>Yes</td>
</tr>
<tr>
<td>NO₂, Annual b</td>
<td>0.2</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀, 24-hr</td>
<td>1.7</td>
<td>5</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀, Annual</td>
<td>0.2</td>
<td>1</td>
<td>No</td>
</tr>
</tbody>
</table>

Note: a Interim/Proposed SIL, not yet finalized.

b The conversion of NOₓ to NO₂ was done using the Tier 2 conversion ratio of 0.75 for annual.

✓ The maximum 1-hour NO₂ impact from the proposed project is 31.3 µg/m³. This impact exceeds the U.S. EPA 1-hour NO₂ SIL of 7.52 µg/m³. Therefore, a cumulative impact assessment is necessary.

✓ For the cumulative impact assessment, two facilities (Los Angeles Department of Water and Power’s Haynes Generating Station and Beta Offshore) as well as emissions from shipping lane activity off the coast were included in the analysis based on their facility emissions and distance to the project. The conversion of NOₓ to NO₂ was done using the Tier 2 ARM, with a value of 0.8 for the 1-hour averaging period. Following the form of the standard, the 1-hour NO₂ impact from the project plus cumulative projects plus background is 251.3 µg/m³, which is greater than the federal 1-hour NO₂ standard of 188 µg/m³. Examining each facility’s contributions to the modeled exceedances, the project’s maximum contributions to the modeled exceedances was 6.9 µg/m³, which is less than the 1-hour NO₂ SIL of 7.52 µg/m³. Therefore, the project is not considered a significant source and does not cause or contribute to the modeled exceedance.

c. Visibility Impact Analysis for Class I and Class II Areas

✓ In order to estimate the potential impacts on visibility and deposition at the nearest Class I areas, a screening criteria was used for projects located more than 50 km away from a Class I area. The emissions/distance (Q/D) is calculated using the project’s total annual emissions of SO₂, NOₓ, PM₁₀, and H₂SO₄ (based on 24-hour maximum allowable emissions) divided by the distance between the project and the nearest Class I area. The project’s total annual emissions are 568 TPY. The Q/D ratio is 10.7, which is greater than the threshold of 10; therefore, modeling of visibility and deposition impacts to Class I areas is required.

✓ The Air Quality Related Values (AQRV) analysis has been submitted to the Federal Land Manager (FLM) for review and approval.

✓ Additionally, the project’s impacts on visibility in Class II areas were also analyzed pursuant to EPA Region 9 request. The evaluation below is presented solely for informational purposes as there are no thresholds for visibility impacts on Class II areas. The project utilized the criteria and thresholds for Class I areas, which is conservative. Visibility impacts are based on the calculation of two factors – plume contrast and color
contrast (ΔE) of the plume when compared to the sky and terrain backgrounds. For Class I areas, the criteria used is based on a perceptibility threshold of 0.05 (absolute value) for contrast and 2.0 for ΔE.

✓ The project applicant identified four Class II areas in the project vicinity – Crystal Cove State Park, Water Canyon State Park, Chino Hills State Park, and Kenneth Hahn State Park. Using the Level 1 VISSCREEN analysis, all of the Class II areas were screened out and do not require further analysis.

✓ Currently, there are no established thresholds for Class II areas; therefore, it is not possible to determine if the project presents a significant visibility impact to Class II areas.

2. Rule 2005 Air Quality Analyses

✓ The proposed project is subject to SCAQMD Rule 2005 review for NO₂. Each combustion emission unit was modeled separately, and the maximum results are presented below.

✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1 – 6 of the report and are assumed to be correct.

✓ As shown in Table C, NO₂ modeled concentrations per emission unit, when added to the highest background values, are below applicable ambient air quality standards.

Table C – Impacts for Rule 2005

<table>
<thead>
<tr>
<th>Pollutant &amp; Averaging Time</th>
<th>Maximum Modeled Concentration (µg/m³)</th>
<th>Background Concentration a (µg/m³)</th>
<th>Total Concentration (µg/m³)</th>
<th>California AAQS b (µg/m³)</th>
<th>Federal AAQS b (µg/m³)</th>
<th>Exceeds Threshold ?</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂, 1-hour d</td>
<td>13.8</td>
<td>255.5</td>
<td>286.8</td>
<td>339</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, 1-hour d</td>
<td>12.4</td>
<td>146.3</td>
<td>159.1</td>
<td>-</td>
<td>188 c</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, Annual d</td>
<td>0.1</td>
<td>47.6</td>
<td>47.7</td>
<td>57</td>
<td>100</td>
<td>No</td>
</tr>
</tbody>
</table>

Note: a Maximum values for NO₂ from SRA 4, South Coastal Los Angeles County monitoring stations for the last three years (2012-2014).
b Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted.
c On April 12, 2010, the U.S. EPA established a new 1-hour NO₂ standard of 100 ppb (188 µg/m³). The form of the federal 1-hour NO₂ standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations.
d The conversion of NOₓ to NO₂ was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

3. SCAQMD Regulation XIII - Impacts During Normal Operations

✓ The auxiliary boiler is subject to the modeling requirements of Regulation XIII and the Rule 1303 thresholds apply.

✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 1 – 6 of the report and are assumed to be correct.

✓ As shown in Table D, the modeled concentrations from the auxiliary boiler, when added to the highest background values, are below the applicable ambient air quality standards.
Table D - Impacts during Normal Operation – Auxiliary Boiler

<table>
<thead>
<tr>
<th>Attainment Pollutant &amp; Averaging Time</th>
<th>Maximum Modeled Concentration (µg/m³)</th>
<th>Background Concentration a (µg/m³)</th>
<th>Total Concentration (µg/m³)</th>
<th>California AAQS b (µg/m³)</th>
<th>Federal AAQS b (µg/m³)</th>
<th>Exceeds Threshold ?</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO, 1-hr</td>
<td>10</td>
<td>4,237</td>
<td>4,247</td>
<td>23,000</td>
<td>40,000</td>
<td>No</td>
</tr>
<tr>
<td>CO, 8-hr</td>
<td>6</td>
<td>2,977</td>
<td>2,983</td>
<td>10,000</td>
<td>10,000</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, 1-hr c</td>
<td>1.2</td>
<td>255.5</td>
<td>256.7</td>
<td>339</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, 1-hr c</td>
<td>1.1</td>
<td>146.3</td>
<td>147.4</td>
<td>-</td>
<td>188 d</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, Annual c</td>
<td>0.03</td>
<td>47.6</td>
<td>47.63</td>
<td>57</td>
<td>100</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 1-hr</td>
<td>0.5</td>
<td>58.2</td>
<td>58.7</td>
<td>655</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 1-hr</td>
<td>0.5</td>
<td>30.1</td>
<td>30.6</td>
<td>-</td>
<td>196 e</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 3-hr</td>
<td>0.5</td>
<td>58.2</td>
<td>58.7</td>
<td>-</td>
<td>1,300</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 24-hr</td>
<td>0.1</td>
<td>7.9</td>
<td>8.0</td>
<td>105</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀, 24-hr</td>
<td>0.3</td>
<td>59.0</td>
<td>59.3</td>
<td>-</td>
<td>150</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀, 24-hr</td>
<td>0.3</td>
<td>50</td>
<td>150</td>
<td>2.5</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀, Annual</td>
<td>0.04</td>
<td>20</td>
<td>-</td>
<td>1</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>PM₂.₅, 24-hr</td>
<td>0.1</td>
<td>-</td>
<td>35</td>
<td>2.5</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>PM₂.₅, Annual</td>
<td>0.04</td>
<td>12</td>
<td>12</td>
<td>1</td>
<td>-</td>
<td>No</td>
</tr>
</tbody>
</table>

Note: a Maximum values for CO, NO₂, PM₁₀, and SO₂ from SRA 4, South Coastal Los Angeles monitoring stations for the last three years (2012-2014). b Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted. c The conversion of NOₓ to NO₂ was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual. d On April 12, 2010, the U.S. EPA established a new 1-hour NO₂ standard of 100 ppb (188 µg/m³). The form of the federal 1-hour NO₂ standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA’s memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO₂ standard does not apply. e On June 2, 2010, the U.S. EPA established a new 1-hour SO₂ standard of 75 ppb (196 µg/m³). The form of the federal 1-hour SO₂ standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations. f The South Coast Air Basin is designated non-attainment for the state PM₁₀ standards, and state and federal PM₂.₅ standards; therefore, project increments are compared to the significant change thresholds in Rule 1303.

4. SCAQMD Regulation XIV - Health Risk Impacts

✓ The applicant performed the risk assessment with the Hot Spots Analysis and Reporting Program Version 2 (HARP2, version 16088).
The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 18, 19, 21, 22, 24, and 25 of the report and are assumed to be correct.

As shown in Table E, the peak cancer risk for the proposed project is 1.1 in one million for a resident and 0.1 in one million for a worker. Based on a radius of 0.63 km and a population density of 7,000 persons/km², the cancer burden is estimated to be 0.0097. This is below the cancer burden threshold of 0.5.

Tables F through H summarize the health risk impacts by permit unit.

### Table E - Health Risk Impacts - Total Project

<table>
<thead>
<tr>
<th>Receptor Type</th>
<th>Cancer Risk</th>
<th>Chronic Hazard Index</th>
<th>Acute Hazard Index</th>
<th>Cancer Risk Threshold</th>
<th>Chronic HI Threshold</th>
<th>Acute HI Threshold</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resident</td>
<td>1.1 in one million</td>
<td>2.80 E-03</td>
<td>1.76 E-02</td>
<td>10 in one million</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
<tr>
<td>Sensitive</td>
<td>1.0 in one million</td>
<td>2.62 E-03</td>
<td>1.68 E-02</td>
<td>10 in one million</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
<tr>
<td>Worker</td>
<td>0.1 in one million</td>
<td>3.64 E-03</td>
<td>1.88 E-02</td>
<td>10 in one million</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
</tbody>
</table>

Note: *For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million.

### Table F - Health Risk Impacts - By Permit Unit - CCGT

<table>
<thead>
<tr>
<th>Receptor Type</th>
<th>Cancer Risk</th>
<th>Chronic Hazard Index</th>
<th>Acute Hazard Index</th>
<th>Cancer Risk Threshold</th>
<th>Chronic HI Threshold</th>
<th>Acute HI Threshold</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resident</td>
<td>0.5 in one million</td>
<td>1.22 E-03</td>
<td>6.57 E-03</td>
<td>10 in one million</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
<tr>
<td>Sensitive</td>
<td>0.5 in one million</td>
<td>1.71 E-03</td>
<td>5.81 E-03</td>
<td>10 in one million</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
<tr>
<td>Worker</td>
<td>0.02 in one million</td>
<td>1.71 E-03</td>
<td>6.72 E-02</td>
<td>10 in one million</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
</tbody>
</table>

Note: *For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million.
Table G – Health Risk Impacts – By Permit Unit - SCGT

<table>
<thead>
<tr>
<th>Receptor Type</th>
<th>Cancer Risk</th>
<th>Chronic Hazard Index</th>
<th>Acute Hazard Index</th>
<th>Cancer Risk Threshold</th>
<th>Chronic HI Threshold</th>
<th>Acute HI Threshold</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resident</td>
<td>0.05 in one million</td>
<td>1.26 E-04</td>
<td>1.75 E-03</td>
<td>10 in one million *</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
<tr>
<td>Sensitive</td>
<td>0.02 in one million</td>
<td>4.59 E-05</td>
<td>1.64 E-03</td>
<td>10 in one million *</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
<tr>
<td>Worker</td>
<td>0.002 in one million</td>
<td>1.37 E-04</td>
<td>3.85 E-03</td>
<td>10 in one million *</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
</tbody>
</table>

Note: * For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million.

Table H – Health Risk Impacts – Auxiliary Boiler

<table>
<thead>
<tr>
<th>Receptor Type</th>
<th>Cancer Risk</th>
<th>Chronic Hazard Index</th>
<th>Acute Hazard Index</th>
<th>Cancer Risk Threshold</th>
<th>Chronic HI Threshold</th>
<th>Acute HI Threshold</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resident</td>
<td>0.01 in one million</td>
<td>2.84 E-05</td>
<td>3.18 E-04</td>
<td>1 in one million *</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
<tr>
<td>Sensitive</td>
<td>0.01 in one million</td>
<td>1.94 E-05</td>
<td>1.01 E-04</td>
<td>1 in one million *</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
<tr>
<td>Worker</td>
<td>0.001 in one million</td>
<td>9.67 E-05</td>
<td>4.90 E-04</td>
<td>1 in one million *</td>
<td>1.0</td>
<td>1.0</td>
<td>No</td>
</tr>
</tbody>
</table>

Note: * For permit units without TBACT, the Rule 1401 cancer risk threshold is 1 in one million. For permit units with TBACT, the Rule 1401 cancer risk threshold is 10 in one million.

5. Fumigation Air Quality Analyses

✓ Since there are tall stacks along the shoreline, the shoreline fumigation and inversion break-up impacts of the project were analyzed since during these short term events the maximum impacts could be higher.

✓ Both inversion break-up and shoreline fumigation were evaluated in the report for 1-hour NO₂, 1-hour, 3-hour, and 24-hour SO₂, 1-hour and 8-hour CO, and 24-hour PM₁₀. Because these meteorological phenomena do not persist for long periods, only the shorter averaging periods (≤ 8 hrs) should be considered.

✓ AERSCREEN (version 15181) was utilized for the analysis. The modeling parameters for the worst-case operating scenarios were used for each of the modeled pollutants and averaging times. AERSCREEN is the model U.S. EPA recommends to analyze impacts from inversion break-up and shoreline fumigation. However, AERSCREEN cannot provide results that correspond to the federal ambient air quality standards for NO₂ and SO₂ due to the form of those standards. For these pollutants, the maximum value is reported in the table below instead of the 98th or 99th percentile, respectively.
For all of the sources, shoreline fumigation was not calculated by AERSCREEN as the plume height was below the thermal internal boundary layer heights for the distance to the shoreline.

As shown in Table I, inversion break-up impacts, combined with background concentrations, are below the applicable ambient air quality standards.

Table 1 – Impacts during Normal Operations for Inversion Break-Up – Total Project

<table>
<thead>
<tr>
<th>Attainment Pollutant &amp; Averaging Time</th>
<th>Maximum Modeled Concentration (µg/m³)</th>
<th>Background Concentration a (µg/m³)</th>
<th>Total Concentration (µg/m³)</th>
<th>Federal AAQS b (µg/m³)</th>
<th>California AAQS (µg/m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂, 1-hr</td>
<td>414</td>
<td>4,237</td>
<td>4,651</td>
<td>40,000</td>
<td>23,000</td>
</tr>
<tr>
<td>CO₂, 8-hr</td>
<td>138</td>
<td>2,977</td>
<td>3,115</td>
<td>10,000</td>
<td>10,000</td>
</tr>
<tr>
<td>NO₂, 1-hr</td>
<td>69.4</td>
<td>255.5</td>
<td>324.9</td>
<td>-</td>
<td>339</td>
</tr>
<tr>
<td>SO₂, 1-hr</td>
<td>4.9</td>
<td>58.2</td>
<td>63.1</td>
<td>-</td>
<td>655</td>
</tr>
<tr>
<td>SO₂, 3-hr</td>
<td>4.9</td>
<td>58.2</td>
<td>63.1</td>
<td>1,300</td>
<td>-</td>
</tr>
</tbody>
</table>

Note: a Maximum values for CO₂, NO₂, PM₁₀, and SO₂ from SRA 4, South Coastal Los Angeles monitoring stations for the last three years (2012-2014).

b Both the California and Federal AAQS values listed are not to be exceeded. The federal NO₂ and SO₂ standards cannot be evaluated with AERSCREEN due to the form of those standards and are not considered in this analysis.

6. Modeling Review of Project Impacts for CEC’s CEQA Evaluation

SCAQMD is both a responsible agency and a commenting agency under CEQA for this project. As noted above in the memo above, the modeling analysis conforms to SCAQMD regulations and SCAQMD does not have any comments.

a. Impacts During Commissioning

The two combined-cycle gas turbines and four simple-cycle turbines are not subject to the modeling requirements of Regulation XIII per Rule 1304(a)(2); therefore the Rule 1303 thresholds do not apply. However, the applicant included a modeling analysis of the impacts from the new turbines and the auxiliary boiler in support of the CEC’s CEQA document and PRDAS staff reviewed the modeling in the report.

Turbof: commissioning is an once-in-a-lifetime event. A total of six scenarios were modeled. Three scenarios were modeled for the two CCTG’s, all of which included the auxiliary boiler in normal operation. Three scenarios were modeled for the four SCTG’s, all of which included the auxiliary boiler in normal operation as well. The auxiliary boiler will be installed and commissioned prior to the first fire of the combined-cycle gas turbines.

The stack parameters and emission rates modeled are consistent with the parameters listed in Tables 9, 10, and 12 of the Engineering Memorandums and are assumed to be correct.
<table>
<thead>
<tr>
<th>Attainment Pollutant &amp; Averaging Time</th>
<th>Maximum Modeled Concentration (µg/m³)</th>
<th>Background Concentration a (µg/m³)</th>
<th>Total Concentration (µg/m³)</th>
<th>California AAQS b (µg/m³)</th>
<th>Federal AAQS b (µg/m³)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO, 1-hr</td>
<td>1,231</td>
<td>4,237</td>
<td>5,468</td>
<td>23,000</td>
<td>40,000</td>
<td>No</td>
</tr>
<tr>
<td>CO, 8-hr</td>
<td>835</td>
<td>2,977</td>
<td>3,812</td>
<td>10,000</td>
<td>10,000</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, 1-hr</td>
<td>67.6</td>
<td>255.5</td>
<td>323.1</td>
<td>339</td>
<td>- d</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, Annual</td>
<td>0.3</td>
<td>47.6</td>
<td>47.9</td>
<td>57</td>
<td>100</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 1-hr</td>
<td>2.2</td>
<td>58.2</td>
<td>60.4</td>
<td>655</td>
<td>196 c</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 3-hr</td>
<td>1.9</td>
<td>58.2</td>
<td>60.1</td>
<td>-</td>
<td>1,300</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 24-hr</td>
<td>0.6</td>
<td>7.9</td>
<td>8.5</td>
<td>105</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀, 24-hr</td>
<td>1.6</td>
<td>59.0</td>
<td>60.6</td>
<td>-</td>
<td>150</td>
<td>No</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Non-attainment Pollutant &amp; Averaging Time</th>
<th>Maximum Modeled Concentration (µg/m³)</th>
<th>California AAQS b (µg/m³)</th>
<th>Federal AAQS b (µg/m³)</th>
<th>Rule 1303 Thresholds b (µg/m³)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM₁₀, 24-hr</td>
<td>1.6</td>
<td>50</td>
<td>150</td>
<td>2.5</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀, Annual</td>
<td>0.2</td>
<td>20</td>
<td>-</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>PM₂.₅, 24-hr</td>
<td>1.1</td>
<td>-</td>
<td>35</td>
<td>2.5</td>
<td>No</td>
</tr>
<tr>
<td>PM₂.₅, Annual</td>
<td>0.2</td>
<td>12</td>
<td>12</td>
<td>1</td>
<td>No</td>
</tr>
</tbody>
</table>

Note: a Maximum values for CO, NO₂, PM₁₀, and SO₂ from SRA 4, South Coastal Los Angeles monitoring stations for the last three years (2012-2014).

b Since the Rule 1303 thresholds do not apply, the AAQS and Rule 1303 thresholds shown here are for informational purposes only.

c The conversion of NOₓ to NO₂ was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

d On April 12, 2010, the U.S. EPA established a new 1-hour NO₂ standard of 100 ppb (188 µg/m³). The form of the federal 1-hour NO₂ standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO₂ standard does not apply.

e On June 2, 2010, the U.S. EPA established a new 1-hour SO₂ standard of 75 ppb (196 µg/m³). The form of the federal 1-hour SO₂ standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.
Table K – Impacts during Commissioning for SCGT’s and CCGT’s and Auxiliary Boiler in Normal Operation

<table>
<thead>
<tr>
<th>Attainment Pollutant &amp; Averaging Time</th>
<th>Maximum Modeled Concentration (µg/m³)</th>
<th>Background Concentration a (µg/m³)</th>
<th>Total Concentration (µg/m³)</th>
<th>California AAQS b (µg/m³)</th>
<th>Federal AAQS b (µg/m³)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO, 1-hr</td>
<td>470</td>
<td>4,237</td>
<td>4,707</td>
<td>23,000</td>
<td>40,000</td>
<td>No</td>
</tr>
<tr>
<td>CO, 8-hr</td>
<td>240</td>
<td>2,977</td>
<td>3,217</td>
<td>10,000</td>
<td>10,000</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, 1-hr</td>
<td>61.9</td>
<td>255.5</td>
<td>317.4</td>
<td>339</td>
<td>- d</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, Annual</td>
<td>0.2</td>
<td>47.6</td>
<td>47.8</td>
<td>57</td>
<td>100</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 1-hr</td>
<td>2.1</td>
<td>58.2</td>
<td>60.3</td>
<td>655</td>
<td>196 e</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 3-hr</td>
<td>1.7</td>
<td>58.2</td>
<td>59.9</td>
<td>-</td>
<td>1,300</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 24-hr</td>
<td>0.5</td>
<td>7.9</td>
<td>8.4</td>
<td>105</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀, 24-hr</td>
<td>1.7</td>
<td>59.0</td>
<td>60.7</td>
<td>-</td>
<td>150</td>
<td>No</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Non-attainment Pollutant &amp; Averaging Time</th>
<th>Maximum Modeled Concentration (µg/m³)</th>
<th>California AAQS (µg/m³)</th>
<th>Federal AAQS (µg/m³)</th>
<th>Rule 1303 Thresholds b (µg/m³)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM₁₀, 24-hr</td>
<td>1.7</td>
<td>50</td>
<td>150</td>
<td>2.5</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀, Annual</td>
<td>0.2</td>
<td>20</td>
<td>-</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>PM₂.₅, 24-hr</td>
<td>1.3</td>
<td>35</td>
<td>2.5</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>PM₂.₅, Annual</td>
<td>0.2</td>
<td>12</td>
<td>12</td>
<td>1</td>
<td>No</td>
</tr>
</tbody>
</table>

Note: a Maximum values for CO, NO₂, PM₁₀, and SO₂ from SRA 4, South Coastal Los Angeles monitoring stations for the last three years (2012-2014).

b Since the Rule 1303 thresholds do not apply, the AAQS and Rule 1303 thresholds shown here are for informational purposes only.

c The conversion of NOₓ to NO₂ was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

d On April 12, 2010, the U.S. EPA established a new 1-hour NO₂ standard of 100 ppb (188 µg/m³). The form of the federal 1-hour NO₂ standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA’s memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO₂ standard does not apply.

e On June 2, 2010, the U.S. EPA established a new 1-hour SO₂ standard of 75 ppb (196 µg/m³). The form of the federal 1-hour SO₂ standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.

b. Impacts During Normal Operations

✓ The two CCGT’s and four SCGT’s are not subject to the modeling requirements of Regulation XIII per Rule 1304(a)(2); therefore, the Rule 1303 thresholds do not apply. However, the applicant included a modeling analysis of the impacts from the new turbines and the auxiliary boiler in support of the CEC’s CEQA document and PRDAS staff reviewed the modeling in the report.

✓ The stack parameters and emission rates modeled are consistent with the parameters listed in Table 1 – 6 of the report and are assumed to be correct.
Table 1.— Impacts during Normal Operation – Total Project

<table>
<thead>
<tr>
<th>Attainment Pollutant &amp; Averaging Time</th>
<th>Maximum Modeled Concentration (µg/m³)</th>
<th>Background Concentration a (µg/m³)</th>
<th>Total Concentration (µg/m³)</th>
<th>California AAQS b (µg/m³)</th>
<th>Federal AAQS b (µg/m³)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO, 1-hr</td>
<td>186</td>
<td>4,237</td>
<td>4,423</td>
<td>23,000</td>
<td>40,000</td>
<td>No</td>
</tr>
<tr>
<td>CO, 8-hr</td>
<td>44</td>
<td>2,977</td>
<td>3,021</td>
<td>10,000</td>
<td>10,000</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, 1-hr c</td>
<td>31.3</td>
<td>255.5</td>
<td>286.8</td>
<td>-</td>
<td></td>
<td>No</td>
</tr>
<tr>
<td>NO₂, 1-hr c</td>
<td>22.6</td>
<td>146.3</td>
<td>168.9</td>
<td>-</td>
<td>188 d</td>
<td>No</td>
</tr>
<tr>
<td>NO₂, Annual c</td>
<td>0.2</td>
<td>47.6</td>
<td>47.8</td>
<td>57</td>
<td>100</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 1-hr</td>
<td>2.1</td>
<td>58.2</td>
<td>60.3</td>
<td>655</td>
<td>196 e</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 3-hr</td>
<td>1.7</td>
<td>58.2</td>
<td>59.9</td>
<td>-</td>
<td>1,300</td>
<td>No</td>
</tr>
<tr>
<td>SO₂, 24-hr</td>
<td>0.5</td>
<td>7.9</td>
<td>8.4</td>
<td>105</td>
<td></td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀, 24-hr</td>
<td>1.7</td>
<td>59.0</td>
<td>60.7</td>
<td>-</td>
<td>150</td>
<td>No</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Non-attainment Pollutant &amp; Averaging Time</th>
<th>Maximum Modeled Concentration (µg/m³)</th>
<th>California AAQS b (µg/m³)</th>
<th>Federal AAQS b (µg/m³)</th>
<th>Rule 1303 Thresholds b (µg/m³)</th>
<th>Exceeds Any Threshold?</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM₁₀, 24-hr</td>
<td>1.7</td>
<td>50</td>
<td>150</td>
<td>2.5</td>
<td>No</td>
</tr>
<tr>
<td>PM₁₀, Annual</td>
<td>0.2</td>
<td>20</td>
<td>-</td>
<td>1</td>
<td>No</td>
</tr>
<tr>
<td>PM₂₅, 24-hr</td>
<td>1.3</td>
<td>-</td>
<td>35</td>
<td>2.5</td>
<td>No</td>
</tr>
<tr>
<td>PM₂₅, Annual</td>
<td>0.2</td>
<td>12</td>
<td>12</td>
<td>1</td>
<td>No</td>
</tr>
</tbody>
</table>

Note: a Maximum values for CO, NO₂, PM₁₀, and SO₂ from SRA 4, South Coastal Los Angeles monitoring stations for the last three years (2012-2014).

b Since the Rule 1303 thresholds do not apply, the AAQS and Rule 1303 thresholds shown here are for informational purposes only.

c The conversion of NOₓ to NO₂ was done using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.
d On April 12, 2010, the U.S. EPA established a new 1-hour NO₂ standard of 100 ppb (188 µg/m³). The form of the federal 1-hour NO₂ standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA’s memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, the federal 1-hour NO₂ standard does not apply.
e On June 2, 2010, the U.S. EPA established a new 1-hour SO₂ standard of 75 ppb (196 µg/m³). The form of the federal 1-hour SO₂ standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations.

Modeling staff spent a total of 240 hours on this review. Please direct any questions to Melissa Sheffer at ext. 2346.

cc: Vicky Lee
JW:MS