

CLARK COUNTY
DEPARTMENT OF AIR QUALITY AND
ENVIRONMENTAL MANAGEMENT
500 South Grand Central Parkway, Box 555210, Las Vegas, Nevada 89155
Part 70 Operating Permit
Source: 393
Issued in accordance with the
Clark County Air Quality Regulations (AQR)

ISSUED TO: SAGUARO POWER COMPANY

SOURCE LOCATION:

8000 West Lake Mead Parkway
Henderson, NV 89015
T22S, R62E, Section 11, 12, 13, 14
Hydrographic Basin Number: 212

SOURCE ADDRESS:

8000 West Lake Mead Parkway,
Henderson, NV 89015

NATURE OF BUSINESS:

SIC Code 4911 - Electric Services
NAICS: 22111 - Electric Power Generation

RESPONSIBLE OFFICIAL:

Name: Monte Ash
Title: Plant Manager
Phone: (702) 558-1311
Fax Number: (702) 564-2753

Permit Issuance: August 10, 2009

Expiration Date: August 9, 2014

**ISSUED BY: CLARK COUNTY DEPARTMENT OF AIR QUALITY AND ENVIRONMENTAL
MANAGEMENT**



Tina Gingras
Assistant Director, Clark County DAQEM

EXECUTIVE SUMMARY

Saguaro Power Company (SPC) is a major source of NO_x, CO, and TCS (NH₃) and a minor source for PM₁₀, SO_x, VOC, and HAP. SPC is located at 8000 West Lake Mead Parkway, Henderson, Nevada 89015, in the Las Vegas Valley airshed, hydrographic basin number 212. Hydrographic basin 212 is basic nonattainment for CO, PM₁₀, and ozone, and PSD for all other regulated air pollutants. Saguaro Power Company (SPC) operates two General Electric (GE), 35.0 MW, natural gas combustion turbine generators (CTGs) with heat recovery steam generators (HRSG), a 23.1 MW extraction/condensing steam turbine generator system and two waste heat recovery steam generators with four, 25 MMBtu/hr each supplemental firing duct burners. All generating and support processes at the site are grouped under the Standard Industrial Classification (SIC) 4911 – Electric Services (NAICS: 22111 - Electric Power Generation).

The following table summarizes the potential to emit (PTE) for each regulated air pollutant:

PM ₁₀	NO _x	CO	SO _x	VOC	HAP	NH ₃
37.94	165.46	90.23	11.30	13.86	8.95	45.01

All general and specific conditions in the permit are federally enforceable unless explicitly denoted otherwise [AQR 19.4.2].

TABLE OF CONTENTS

I.	ACRONYMS	4
II.	GENERAL CONDITIONS	5
A.	GENERAL REQUIREMENTS	5
B.	MODIFICATION, REVISION, RENEWAL REQUIREMENTS	Error! Bookmark not defined.
C.	REPORTING/NOTIFICATIONS/PROVIDING INFORMATION REQUIREMENTS	Error! Bookmark not defined.
D.	COMPLIANCE REQUIREMENTS	Error! Bookmark not defined.
III.	SOURCE-WIDE POTENTIAL TO EMIT (PTE) SUMMARY	9
IV.	EMISSION UNITS AND APPLICABLE REQUIREMENTS	9
A.	EMISSION UNITS	9
B.	EMISSION LIMITATIONS AND STANDARDS	10
1.	Emission Limits	10
2.	Production Limits	12
3.	Emission Controls	13
C.	MONITORING	14
D.	TESTING	15
E.	RECORD KEEPING	16
F.	REPORTING	17
V.	OTHER REQUIREMENTS	18
VI.	PERMIT SHIELD	19
VII.	ATTACHMENTS	19

I. ACRONYMS

Table I-1: List of Acronyms

Acronym	Term
AQR	Clark County Air Quality Regulations
ATC	Authority to Construct
ATC/OP	Authority to Construct/Operating Permit
BCC	Clark County Board of County Commissioners
BHP	Brake Horse Power
CAO	Field Corrective Action Order
CE	Control Efficiency
CF	Control Factor
CFR	United States Code of Federal Regulations
CO	Carbon Monoxide
CPI	Urban Consumer Price Index
DAQEM	Clark County Department of Air Quality & Environmental Management
EF	Emission Factor
EPA	United States Environmental Protection Agency
EU	Emission Unit
HAP	Hazardous Air Pollutant
HP	Horse Power
kW	kiloWatt
MMBtu	Millions of British Thermal Units
NAC	Nevada Administrative Code
NAICS	North American Industry Classification System
NEI	Net Emission Increase
NO _x	Nitrogen Oxides
NOV	Notice of Violation
NRS	Nevada Revised Statutes
NSPS	New Source Performance Standards
NSR	New Source Review
OP	Operating Permit
PM ₁₀	Particulate Matter less than 10 microns
ppm	Parts per Million
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
scf	Standard Cubic Feet
SCC	Source Classification Codes
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO _x	Sulfur Oxides
TCS	Toxic Chemical Substance
TSD	Technical Support Document
VOC	Volatile Organic Compound

II. GENERAL CONDITIONS

A. GENERAL REQUIREMENTS

1. The Permittee shall comply with all terms and conditions of this permit. Any permit noncompliance constitutes a violation of the Clean Air Act (Act) and is grounds for enforcement action; for permit termination, revocation and reissuance or modification; or for denial of a permit renewal application. *[AQR 19.4.1.6.a]*
2. If any term or condition of this permit becomes invalid as a result of a challenge to a portion of this permit, the other terms and conditions of this permit shall not be affected and shall remain valid. *[AQR 19.4.1.5]*
3. The Permittee shall pay all permit fees pursuant to AQR Section 18. Failure to pay Part 70 permit fees may result in citations or suspensions or revocation of the Part 70 Permit. *[AQR 19.4.1.7]*
4. The permit does not convey any property rights of any sort, or any exclusive privilege. *[AQR 19.4.1.6.d]*
5. The Permittee shall not hinder, obstruct, delay, resist, interfere with, or attempt to interfere with the Control Officer, or any individual to whom authority has been duly delegated for the performance of any duty by the AQR. *[AQR 5.1]*
6. The Permittee owning, operating, or in control of any equipment or property who shall cause, permit, or participate in any violation of the AQR shall be individually and collectively liable to any penalty or punishment imposed by and under the AQR. *[AQR 8.1]*
7. The Permittee shall continue to comply with applicable requirements for which the Permittee is in compliance. *[AQR 19.3.3.8.b]*
8. Any Permittee who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. *[AQR 19.3.2]*
9. The Permittee may request confidential treatment of any records in accordance with AQR Section 19. Emission data, standards or limitations [all terms as defined in 40 CFR 2.301(a)] or other information as specified in 40 CFR 2.301 shall not be considered eligible for confidential treatment. The Administrator and the Control Officer shall each retain the authority to determine whether information is eligible for confidential treatment on a case-by-case basis. *[AQR 19.3.1.3 and 40 CFR 2.301]*

B. MODIFICATION, REVISION, RENEWAL REQUIREMENTS

1. The Permittee shall not make a modification, as defined in AQR Section 0, to the existing source prior to receiving an ATC from the Control Officer. *[AQR 12.1.1.1]*
2. The permit may be modified, revoked, reopened and reissued, or terminated for cause. The filing of a request by the Permittee for the permit modification, revocation, reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[AQR 19.4.1.6.c]*
3. Any request for a permit revision must comply with the requirements of AQR Section 19. *[AQR 19.5]*

4. The Permittee shall not build, erect, install or use any article, machine, equipment or process, the use of which conceals an emission, which would otherwise constitute a violation of an applicable requirement. *[AQR 80.1 and 40 CFR 60.12]*
5. No permit revisions shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in the permit, provided the Permittee conforms to the applicable requirements of AQR Sections 12 and 58. *[AQR 19.4.1.11]*
6. For purposes of permit renewal, the Permittee shall submit a timely and complete application. A timely application is one submitted between six (6) months and 18 months prior to the date of permit expiration. *[AQR 19.3.1.1.c]*
7. Permit expiration terminates the Permittee's right to operate unless a timely and complete renewal application has been submitted consistent with AQR Subsections 19.3.1.1.c and 19.5.2 in which case the permit shall not expire and all terms and conditions of the permit shall remain in effect until the renewal permit has been issued or denied. *[AQR 19.5.3.2]*

C. REPORTING/NOTIFICATIONS/PROVIDING INFORMATION REQUIREMENTS

1. The Permittee shall furnish to the Control Officer, within a reasonable time, any information that the Control Officer may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the Permittee shall also furnish to the Control Officer copies of records required to be kept by the permit or, for information claimed to be confidential, the Permittee may furnish such records directly to the Control Officer along with a claim of confidentiality. *[AQR 19.4.1.6]*
2. The Permittee shall allow the Control Officer or an authorized representative, upon presentation of credentials:
 - a. entry upon the Permittee's premises where the source is located, or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
 - b. access to inspect and copy, at reasonable times, any records that must be kept under conditions of the permit;
 - c. access to inspect, at reasonable times, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
 - d. access to sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the permit or applicable requirements. *[AQR 4.3 and 19.4.3.2]*
3. Upon request of the Control Officer, the Permittee shall provide such information or analyses as will disclose the nature, extent, quantity or degree of air contaminants which are or may be discharged by such source, and type or nature of control equipment in use, and such disclosures be certified by a professional engineer registered in the state. In addition to such report, the Control Officer may designate an authorized agent to make an independent study and report as to the nature, extent, quantity or degree of any air contaminants which are or may be discharged from source. An authorized agent so designated is authorized to inspect any article, machine, equipment, or other contrivance necessary to make the inspection and report. *[AQR 4.4]*

D. COMPLIANCE REQUIREMENTS

1. The Permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the terms and conditions of this permit. *[AQR 19.4.1.6.b]*
2. Any person who violates any provision of this operating permit, including, but not limited to, any application requirement; any permit condition; any fee or filing requirement; any duty to allow or carry out inspection, entry or monitoring activities or any requirements by DAQEM is guilty of a civil offense and shall pay civil penalty levied by the Air Pollution Control Hearing Board/Hearing Officer of not more than \$10,000. Each day of violation constitutes a separate offense. *[AQR 9.1]*
3. Any person aggrieved by an order issued pursuant to AQR 9.1 is entitled to review as provided in Chapter 233B of NRS. *[AQR 9.12]*
4. The Permittee shall comply with the requirements of 40 CFR 61, Subpart M, of the National Emission Standard for Asbestos for all demolition and renovation projects. *[AQR 13.1.7]*
5. Requirements for compliance certification with terms and conditions contained in the operating permit, including emission limitations, standards, or work practices, are as follows:
 - a. the Permittee shall submit compliance certifications annually in writing to the Control Officer (500 Grand Central Parkway, Box 555210, Las Vegas, NV 89155) and the Administrator at USEPA Region IX (Director, Air and Toxics Divisions, 75 Hawthorne St., San Francisco, CA 94105). A compliance certification for the previous calendar year will be due on January 30 of each year;
 - b. compliance shall be determined in accordance with the requirements detailed in AQR 19.4.1.3, record of periodic monitoring, or any credible evidence; and
 - c. the compliance certification shall include:
 - i. identification of each term or condition of the permit that is the basis of the certification;
 - ii. the Permittee's compliance status and whether compliance was continuous or intermittent;
 - iii. methods used in determining the compliance status of the source currently and over the reporting period consistent with Subsection 19.4.1.3; and
 - iv. other specific information required by the Control Officer to determine the compliance status of the source. *[AQR 19.4.3.5]*
6. The Permittee shall report, in writing, to the Control Officer (500 Grand Central Parkway, Box 555210, Las Vegas, NV 89155) deviations from permit requirements as soon as practicable but not to exceed ten (10) calendar days from discovery of the deviation. Such reports shall include the probable cause of such deviations and any corrective actions or preventative measures taken. *[AQR 19.4.1.3]*
7. The Permittee shall report to the Control Officer any upset, breakdown, malfunction or emergency, as defined in Section 0, which cause emissions of regulated air pollutants in excess of any limits set by regulation or by this permit. The report shall be in two parts as specified below *[AQR 25.2]*:
 - a. within one (1) hour of the onset of the event, the report shall be communicated by phone (702) 455-5942, or by fax (702) 383-9994.

- b. within 72 hours of the onset of the event, the detailed written report shall be submitted. Such reports shall include the probable cause of the excess emissions, emission calculations and any corrective actions taken.
8. The Permittee shall include a certification of truth, accuracy, and completeness by a responsible official when submitting any application form, report, or compliance certification pursuant to this operating permit. This certification and any other certification required shall state, "Based on the information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." This statement shall be followed by the signature and printed name of the responsible official certifying compliance and the date of signature. [AQR 19.3.4]

E. PERFORMANCE TESTING REQUIREMENTS

1. Upon request of the Control Officer, the Permittee shall test or have tests performed to determine the emissions of air contaminants from any source whenever the Control Officer has reason to believe that an emission in excess of that allowed by the DAQEM regulations is occurring. The Control Officer may specify testing methods to be used in accordance with good professional practice. The Control Officer may observe the testing. All tests shall be conducted by reputable, qualified personnel. [AQR 4.5]
2. Upon request of the Control Officer, the Permittee shall provide necessary holes in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices, as may be necessary for proper determination of the emission of air contaminants. [AQR 4.6]
3. The Permittee shall submit for approval a performance testing protocol which contains testing, reporting, and notification schedules, test protocols, and anticipated test dates to the Control Officer (500 Grand Central Parkway, Box 555210, Las Vegas, NV 89155) not less than 45 nor more than 90 days prior to the anticipated date of the performance test. [AQR 14.10]
4. The Permittee shall provide all requests for any alternative test methods to EPA for approval. [AQR 14.1 and 40 CFR 60.8(b)]
5. The Permittee shall submit a report describing the results of each performance test to the Control Officer within 60 days from the end of the performance test. [AQR 14.12]
6. Pursuant to AQR Section 10, the Permittee of any stationary source or emission unit that fails to demonstrate compliance with the emissions standards or limitations during any subsequent performance test shall submit a compliance plan to the Control Officer within 90 days from the end of the performance test. [AQR 10.1]
7. The Control Officer may require additional or more frequent performance testing. [AQR 4.5]

III. SOURCE-WIDE POTENTIAL TO EMIT (PTE) SUMMARY

[Authority for all values, limits, and conditions in this section: NSR ATC 393 Modification 6, Amendment 1, (10/04/2006) and NSR ATC 393, Modification 7, Revision 2, (12/15/2008)]

Saguaro Power Company is a major source for NO_x, CO, and TCS (NH₃) and a minor source for PM₁₀, SO_x, VOC, and HAP:

Table III-1: Source-wide PTE (tons per year) ¹

Pollutant	PM ₁₀	NO _x	CO	SO _x	VOC	HAP	NH ₃
PTE Totals	37.94	165.46	90.23	11.30	13.86	8.95	45.01
Major Source Thresholds	70	50	70	100	50	25²	1.0

¹Total emissions are based on the worst-case scenario between natural gas combustion and fuel oil combustion in the turbines.

²25 tons for combination of all HAPs (no single HAP exceeds 10 tons).

IV. EMISSION UNITS AND APPLICABLE REQUIREMENTS

A. EMISSION UNITS

The stationary source covered by this Part 70 Operating Permit (OP) is defined to consist of the emission units and associated appurtenances summarized in Table IV-A-1 and Table IV-A-2. [AQR 19.2.1 and 19.3.3.3]

Table IV-A-1: List of Emission Units (EU)

EU	Description
A01	GE Combustion Turbine Generator #1; M/N: PG6541B with a fired HRSG, S/N: 295525, 35 MW; 35 MEQ
A02	GE Combustion Turbine Generator #2; M/N: PG6541B with a fired HRSG, S/N: 295524, 35 MW; 35 MEQ
A03	Detroit Diesel Starter Engine, Model 71237300, S/N: 12VA083956, Combustion Turbine Generator #1 (445 hp)
A04	Detroit Diesel Starter Engine, Model 71237300, S/N: 12VA083901, Combustion Turbine Generator #2 (445 hp)
A05	Indeck/Volcano Auxiliary Boiler #1; 249 MMBtu/hr; M/N: 0-7-2000; S/N: N/A
A06	Nebraska Auxiliary Boiler #2; 86 MMBtu/hr; M/N: NOS 2A/S-55; S/N: 032-88
A08	Fuel Oil Storage Tank (750,000 gallon)
A09a	Thermal-Dynamics Towers Inc., Cooling Tower; M/N: TD-3030-3-2424CF; S/N: N/A; 19,185 gpm total, 3,800 mg/L TDS, 0.0006% drift, Cell 1
A09b	Thermal-Dynamics Towers Inc., Cooling Tower; M/N: TD-3030-3-2424CF; S/N: N/A; 19,185 gpm total, 3,800 mg/L TDS, 0.0006% drift, Cell 2
A09c	Thermal-Dynamics Towers Inc., Cooling Tower; M/N: TD-3030-3-2424CF; S/N: N/A; 19,185 gpm total, 3,800 mg/L TDS, 0.0006% drift, Cell 3
F01	Fuel Oil Transfer Pumps
F02	Fuel Oil Unloading
F03	Natural Gas Metering Station
F04	Natural Gas Coalescing Filters
F05	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733, 25 MMBtu/hr, Skid # 1
F05a	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733, 25 MMBtu/hr, Skid # 1
F06	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733, 25 MMBtu/hr, Skid # 2
F06a	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733, 25 MMBtu/hr, Skid # 2

EU	Description
F07	Lube Oil System – CTG-01
F08	Lube Oil System – CTG-02
F09	Lube Oil System – STG-03
F11	Ammonia Storage and Injection, 12,000 gallons

Table IV-A-2: Insignificant Activities

EU	Description
F10	Facility Maintenance (Painting)

B. EMISSION LIMITATIONS AND STANDARDS

[Authority for all values, limits, and conditions in this section: NSR ATC 393 Modification 6, Amendment 1, (10/04/2006) and NSR ATC 393, Modification 7, Revision 2, (12/15/2008)]

1. Emission Limits

- a. Neither the actual nor the allowable emissions shall exceed the calculated PTE for each emission unit listed in Tables IV-B-1, IV-B-2, IV-B-3 and IV-B-4.

Table IV-B-1: Source PTE, Including Startup and Shutdown (tons per 12-month rolling)

EU	PM ₁₀	NO _x	CO	SO _x	VOC	HAP	NH ₃
A01 ¹	14.43	69.20	39.40	6.30	4.01	1.98	21.81
A02 ¹	14.43	69.20	39.40	6.30	4.01	1.98	21.81
A03	0.09	0.90	0.23	0.06	0.03	0.01	0.00
A04	0.09	0.90	0.23	0.06	0.03	0.01	0.00
A05 ²	1.33	7.96	10.08	0.13	0.89	0.48	0.00
A05 ³	6.65	15.92	0.98	0.65	4.47	4.47	0.00
A06	1.29	9.34	9.99	0.15	1.08	0.48	0.00
A08	0.00	0.00	0.00	0.00	0.05	0.01	0.00
A09a, A09b, A09c	0.96	0.00	0.00	0.00	0.00	0.00	0.00
F01	0.00	0.00	0.00	0.00	0.01	0.00	0.00
F02	0.00	0.00	0.00	0.00	0.01	0.00	0.00
F03	0.00	0.00	0.00	0.00	0.05	0.00	0.00
F04	0.00	0.00	0.00	0.00	0.04	0.00	0.00
F05	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F05a	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F06a	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F07	0.00	0.00	0.00	0.00	0.02	0.01	0.00
F08	0.00	0.00	0.00	0.00	0.02	0.01	0.00
F09	0.00	0.00	0.00	0.00	0.02	0.01	0.00
F11	0.00	0.00	0.00	0.00	0.00	0.00	1.39

¹ Annual emissions based on worst-case scenario of 480 hours/rolling 12-months of fuel oil combustion and 8,280 hours/rolling 12-months of natural gas combustion.

²Emissions from Indeck/Volcano boiler (EU: A05) prior to installation of the low-NO_x burners and CO oxidation catalyst.

³Emissions from Indeck/Volcano boiler (EU: A05) after installation of the low-NO_x burners and CO oxidation catalyst.

Table IV-B-2: Source Potential to Emit (pounds per hour)

EU	PM ₁₀	NO _x	CO	SO _x	VOC	HAP	NH ₃
A01 ^{1,2}	2.50	15.20	9.00	0.27	0.92	0.46	4.98
A01 ^{1,3}	17.00	26.30	9.00	21.64	2.00	0.54	4.98
A02 ^{1,2}	2.50	15.20	9.00	0.27	0.92	0.46	4.98
A02 ^{1,3}	17.00	26.30	9.00	21.64	2.00	0.54	4.98
A03	1.43	14.38	3.75	0.92	0.41	0.03	0.00
A04	1.43	14.38	3.75	0.92	0.41	0.03	0.00
A05 ⁴	1.52	9.09	11.50	0.15	1.02	0.46	0.00
A05 ⁵	1.52	3.64	0.22	0.15	1.02	1.02	0.00
A06	0.43	3.11	3.33	0.05	0.05	0.16	0.00
A09a, A09b, A09c	0.22	0.00	0.00	0.00	0.00	0.00	0.00
F11	0.00	0.00	0.00	0.00	0.00	0.00	0.32

¹Short-term emissions based on worst-case scenario between natural gas combustion and fuel oil combustion in the turbines

²Emissions from the combustion of natural gas in the turbine, the emissions from the duct burners are included.

³Emissions from the combustion of distillate oil in the turbine.

⁴Emissions from Indeck/Volcano boiler (EU: A05) prior to installation of the low-NO_x burners and CO oxidation catalyst.

⁵Emissions from Indeck/Volcano boiler (EU: A05) after installation of the low-NO_x burners and CO oxidation catalyst.

Table IV-B-3: Emissions Concentration Limitations in ppmvd

EU	O ₂ Standard	NO _x (ppmvd)		CO (ppmvd)	
		Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
A01 ¹	15%	10	17	10	10
A02 ¹	15%	10	17	10	10
A05 ²	3%	30	N/A	400	N/A
A05 ³	3%	12	N/A	1.2	N/A
A06	3%	30	N/A	400	N/A

¹ Emissions from the combustion of natural gas or distillate are calculated using a four-hour rolling average not to include startup or shutdown.

² Emission concentration limits for Indeck/Volcano boiler (EU: A05).

³ Emission concentration limits for Indeck/Volcano boiler (EU: A05) after completion of the boiler modification.

Table IV-B-4: Startup and Shutdown Emissions per Emission Unit (pounds/hour)⁴

EU	PM ₁₀	NO _x	CO	SO _x	VOC	HAP	NH ₃
A01 ^{1,3}	2.5	65.00	9.00	0.27	0.94	0.46	2.04
A02 ^{1,3}	2.5	65.00	9.00	0.27	0.94	0.46	2.04
A01 ^{2,3}	17.00	104.00	9.00	21.64	0.17	0.54	2.04
A02 ^{2,3}	17.00	104.00	9.00	21.64	0.17	0.54	2.04
A05	1.87	9.11	9.24	0.15	1.34	0.47	---

¹Emissions from the combustion of natural gas in the turbine.

²Emissions from the combustion of distillate oil in the turbine.

³Startup has duration of one hour.

⁴Start-up and shut-down emission rates are to be used to calculate compliance with annual emissions limits. Emission factors will be used when CEMS data is not available.

- b. The Permittee shall not allow visible emissions from each turbine/HRSG stack, starter engine exhaust and boiler stacks to exceed 20 percent opacity when viewed in accordance with EPA Method 9.

2. Production Limits

- a. The Permittee shall, under all conditions, maintain and operate the source in a manner consistent with good air pollution control practice for minimizing emissions as required by 40 CFR 60.11.

Table IV-B-5: Enforceable Fuel Limitations for Combustion Equipment

Equipment	Fuel Type	Max. Hourly MMBtu	Max. Rolling 12-months MMBtu
Each Combustion turbine ¹	Natural gas	447	3,915,720
Each Duct burner	Natural gas	25	219,000
Indeck/Volcano Boiler ²	Natural gas	249	218,124
Indeck/Volcano Boiler ²	Hydrogen gas	249	218,124
Indeck/Volcano Boiler ³	Natural gas	249	2,181,240
Indeck/Volcano Boiler ³	Hydrogen gas	249	2,181,240
Nebraska Auxiliary Boiler	Natural gas	85	510,000

¹Based upon 8,760 hours at 100 percent load at 105 °F.

² Fuel limitations for Indeck/Volcano boiler (EU: A05).

³ Fuel limitations for Indeck/Volcano boiler (EU: A05) after completion of the boiler modification (Mod 7, Rev 2).

- b. The natural gas fuel rate shall be limited to 447 MMBtu/hour for each combustion turbine based on an annual average, the lower heating value (LHV), and standard conditions. Standard conditions shall be defined as 105 degrees F, 13.78 psia at 16 percent relative humidity.
- c. The Permittee is allowed to operate each turbine unit (EU: A01 and A02) while combusting low sulfur diesel fuel (<0.05 percent sulfur by weight), after each turbine unit has demonstrated compliance with the emission standards by conducting performance testing in accordance with Section D of this permit.
- d. Upon demonstration of compliance with the emission standards, the Permittee may operate each turbine unit (EU: A01 and A02) up to 480 hours per rolling 12-months while combusting low sulfur diesel fuel (<0.05 percent sulfur by weight). Diesel fuel consumption shall be limited to 3,035 gallons per hour for each turbine.
- e. The Permittee shall limit heat input of each duct burner to 25 MMBtu/hour.
- f. The Permittee shall not fire fuel oil in the turbines during the summer months (June 1 - August 31) except when there is a loss of natural gas, or testing is required.
- g. The Permittee shall operate each turbine starter engine (EU: A03 and A04) no more than 125 hours per rolling 12-months. The engines shall combust only low sulfur (<0.05 percent sulfur by weight) diesel fuel.
- h. A startup period is defined as the period of time of no more than one (1) hour immediately following the application of a load. Startup periods shall be included in determining compliance with rolling 12-months emissions limits for the emission units being started.
- i. A shutdown period shall begin when heat input falls below 50 percent of nameplate capacity and ends when combustion has ceased, the duration of the shutdown period should not exceed 60 minutes. Shutdown periods shall be included in determining compliance with rolling 12-months emissions limits for the emission units being shutdown.
- j. Emissions from startup and shutdown events, as provided in Table-IV-B-3, when combined with the turbine emissions during normal operations, shall not exceed the rolling 12-months limits outlined in Table IV-B-1.
- k. The Permittee shall combust only natural gas, hydrogen gas, or a combination of natural gas and hydrogen fuel in the Indeck/Volcano boiler (EU: A05).

- l. The Permittee shall limit the operation of the Indeck/Volcano boiler (EU: A05) to 218,124 MMBtu/12-month rolling average of natural gas and 218,124 MMBtu/12-month rolling average of hydrogen fuel in any calendar year.
- m. After modification of the Indeck/Volcano boiler (EU: A05), the operation shall be limited to 2,181,240 MMBtu/rolling 12-months of natural gas and hydrogen fuel for any calendar year.
- n. A startup period of the Volcano boiler (EU: A05) is defined as the period of time of no more than one hundred (100) minutes immediately following the firing of the burner. Startup periods shall be included in determining compliance with rolling 12-months emissions for the Volcano boiler.
- o. A shutdown period of the Volcano boiler (EU: A05) shall begin when heat input falls below 15 percent of nameplate capacity and ends when combustion has ceased and shall not exceed 1 hour. Shutdown periods shall be included in determining compliance with rolling 12-months emissions limits for the Volcano boiler.
- p. The Permittee shall use emission factors presented in Table IV-B-4, for any clock hour in which a start-up/shut-down event occurs and valid CEMS data is not available.
- q. The Permittee shall operate the Nebraska boiler (EU: A06) no more than 6,000 hours per rolling 12-months. Only natural gas and/or hydrogen fuel shall be combusted in the boiler.
- r. The Permittee shall limit the throughput of fuel oil through the storage tank (EU: A08) to 3,083,214 gallons per rolling 12-months.

3. Emission Controls

- a. The Permittee shall install, maintain and operate SCR on each of the turbine units (EU: A01 and A02). The Permittee shall operate SCR at all times the associated turbine unit is operating excluding periods of startup and shutdown. Each SCR system on all turbine units shall be operated in accordance with manufacturer's specifications
- b. The Permittee shall further control NO_x emissions from turbine units (EU: A01 and A02) with steam injection.
- c. The Permittee shall operate the turbine units applying good combustion practice.
- d. The Permittee shall operate each SCR system such that NO_x and NH₃ emissions do not exceed the limitations listed in Tables IV-B-2 and IV-B-3 excluding startups and shutdowns.
- e. The Permittee shall operate each turbine and duct burner combination such that they do not emit NO_x in concentrations greater than 17 ppmvd NO_x at 15 percent O₂ while combusting fuel oil or greater than 10 ppmvd NO_x at 15 percent O₂ while combusting natural gas during a four-hour rolling average not to include startup or shutdown.
- f. The Permittee shall operate each turbine and duct burner combination such that they do not emit CO in concentrations greater than 10 ppmvd CO at 15 percent O₂ while combusting either fuel oil or natural gas during a four-hour rolling average not to include startup or shutdown.
- g. The Permittee shall not exceed emission limits listed in Table IV-B-2 for NO_x and CO for turbines (EUs: A01 and A02) for any four-hour rolling averaging period as determined by the CEMS as described in Section IV-E, excluding any startup or shutdown periods.
- h. The Permittee shall not exceed emission limits listed in Table IV-B-2 for NO_x and CO for Indeck/Volcano boiler (EU: A05) for any three-hour rolling averaging period as determined by the CEMS as described in Section IV-E, excluding any startup or shutdown periods.

- i. The Permittee shall control SO_x exhaust emissions from each combined cycle system by the exclusive use of pipeline quality natural gas with a maximum total sulfur content of 0.50 grains/100 dscf and good combustion practice.
- j. The Permittee shall control PM₁₀ exhaust emissions from each combined cycle system by properly maintained and periodically replaced inlet air filters preceding each turbine, per manufacturer's specifications and good operating practice.
- k. The Permittee shall operate the Indeck/Volcano boiler (EU: A05) such that it emits neither more than 30 ppmvd NO_x nor 400 ppmvd CO, corrected to three (3) percent O₂ during a three-hour rolling average not to include startup or shutdown.
- l. After installation of the low-NO_x burner coupled with CO Oxidation Catalyst, the Permittee shall operate the Indeck/Volcano boiler (EU: A05) such that it emits neither more than 12 ppmvd NO_x nor 1.2 ppmvd CO, corrected to three (3) percent O₂ during three-hour rolling average not to include startup or shutdown.
- m. The Permittee shall operate the Nebraska boiler (EU: A06) such that it emits neither more than 30 ppmvd NO_x nor 400 ppmvd CO, corrected to three (3) percent O₂, not to include startup or shutdown.
- n. The Permittee shall operate and maintain the cooling tower in accordance with the manufacturer's recommendations. No chromium-containing compounds shall be used for water treatment; therefore, 40 CFR 63 Subpart Q is not applicable to this source.
- o. The Permittee shall equip each cooling tower with drift eliminators with a manufacturer's maximum drift rate of 0.0006 percent.
- p. The Permittee shall maintain the cooling water such that the maximum TDS content shall not exceed 3,800 ppm (EU: A09a, A09b, and A09c).
- q. The Permittee must comply with the control requirements contained in this section. If there is inconsistency between standards or requirements, the most stringent standard or requirement shall apply.

C. MONITORING

- 1. The Permittee shall install, calibrate, maintain, operate, and certify CEMS for NO_x, CO, and O₂ on each turbine (EUs: A01 and A02) in accordance with 40 CFR 60. Each CEMS shall include an automated data acquisition and handling system. Each system shall monitor and record at least the following data:
 - a. four-hour rolling averages of exhaust gas concentration for each of NO_x, CO, and diluent O₂;
 - b. exhaust gas flow rate (by direct or indirect methods);
 - c. fuel flow rate;
 - d. hours of operation;
 - e. hourly, daily and quarterly accumulated mass emissions of NO_x and CO;
 - f. hours of downtime of the CEMS.
- 2. The Permittee shall install, calibrate, maintain, operate, and certify CEMS for NO_x, CO and O₂ on Indeck/Volcano boiler unit (EU: A05) in accordance with 40 CFR 60. Each CEMS shall include an automated data acquisition and handling system. Each system shall monitor and record at least the following data:
 - a. three-hour rolling averages of exhaust gas concentration for each of NO_x, CO and diluent O₂;

- b. exhaust gas flow rate (by direct or indirect methods);
 - c. fuel flow rate;
 - d. hours of operation;
 - e. hourly, daily and quarterly accumulated mass emissions of NO_x and CO;
 - f. hours of downtime of the CEMS.
3. The Permittee shall submit all periodic audit procedures and QA/QC procedures for CEMS to conform to the provisions of 40 CFR 60 Subpart B, Appendix F.
 4. The Permittee shall conduct annual relative accuracy test audits (RATA) of the CO, NO_x and O₂ CEMS.
 5. The Permittee shall install a fuel flow meter for each combined cycle turbine, each duct burner, and the auxiliary Indeck/Volcano boiler, and shall monitor the natural gas fuel flow rate of each emission unit with a continuous monitoring system. The primary method for demonstrating compliance with this requirement is demonstrated by a Data Acquisition System (DAS).
 6. The Permittee shall use an ammonia parametric emission monitoring system (PEMS) to monitor compliance with ammonia pounds-per-hour and tons-per-rolling 12-months limits. The PEMS data shall be reported quarterly and annually. The PEMS calculates the mass emissions by multiplying an ammonia emission factor (AEF) by each turbine's annual actual operating hours. The AEF, in pounds per hour, is determined for each turbine during its required periodic performance test. This factor shall be used until the next performance test.
 7. The Permittee shall continue to monitor the TDS in the cooling tower circulating water monthly using a DAQEM approved method. [AQR 19.4.1.3]
 8. The Permittee shall perform visual emissions checks each calendar quarter on a plant-wide level for each emission unit. If visible emissions are observed, then corrective actions shall be taken to minimize the emissions and the opacity of emissions shall be visually determined in accordance with 40 CFR 60 Appendix A: Reference Method 9. [AQR 19.4.1.3(a) and 40 CFR 70.6]

D. TESTING

1. To demonstrate initial compliance with the CO, NO_x, PM₁₀, VOC, and NH₃ emissions limitations in this permit, the Permittee shall conduct a performance test on the turbines (EUs: A01 and A02) using natural gas no later than 180 days after initial startup and within 60 days after achieving the maximum production rate at which the affected facility will be operated. This testing has been completed on January 13, 1992.
2. Subsequent performance testing shall be conducted on the turbines (EUs: A01 and A02) at least once every five (5) years thereafter. [AQR 19.4.1.3]
3. To demonstrate initial compliance with emissions limitations during use of diesel fuel, the Permittee shall conduct a performance test on any turbine (EUs: A01 and A02) using diesel no later than 180 days after initial startup and within 60 days after achieving the maximum production rate at which the affected facility will be operated. This testing has been completed on January 13, 1992.
4. Compliance with the emission standards for EUs: A01 and A02 in Sections IV-B-3-e & f shall be demonstrated by performance testing prior to operating either turbine using diesel fuel. [AQR 19.4.1.3]

5. To demonstrate initial compliance with the CO and NO_x emissions limitations, the Permittee shall conduct a performance test on the auxiliary boilers (EUs: A05 and A06) no later than 180 days after initial startup and within 60 days after achieving the maximum production rate at which the affected facility will be operated. This testing has been completed for EU A06. An initial performance test shall be performed on EU A05 after installation of the low-NO_x burner coupled with CO Oxidation Catalyst (NSR Mod. 7, Rev 2). Subsequent performance testing shall be conducted on the auxiliary boilers (EUs: A05 and A06) at least once every five (5) years thereafter. [AQR 19.4.1.3]
6. Table IV-A-1 summarizes performance test methods [AQR 19.4.1.3]

Table IV-D-1: Performance Testing Requirements (40 CFR 60, Appendix A)

Test Point	Pollutant	Method
Turbine Exhaust Stack	NO _x	Chemiluminescence Analyzer (EPA Method 7E)
Turbine Exhaust Stack	CO	EPA Method 10
Turbine Exhaust Stack	VOC	EPA Method 25a
Turbine Exhaust Stack	NH ₃ Slip	Method Preapproved by DAQEM/EPA
Turbine Exhaust Stack	PM ₁₀	EPA Method 201/202 or 201A/202
Turbine Exhaust Stack	Opacity	EPA Method 9
Boiler Exhaust Stack	NO _x	Chemiluminescence Analyzer (EPA Method 7E)
Boiler Exhaust Stack	CO	EPA Method 10
Stack Gas Parameters	---	EPA Methods 1, 2, 3, 4

7. The Permittee shall submit complete and comprehensive final performance test reports to the Control Officer within 60 days from the end of each performance test. [AQR 19.4.1.3]
8. Pursuant to AQR Subsection 49.5, the Permittee shall conduct a burner efficiency test (boiler tune-up) and inspection on the auxiliary boilers (EU: A05 and A06) semi-annually. The burner efficiency test is to be conducted in accordance with the manufacturer's recommendations and specifications for good combustion practices. The Permittee may use an alternative method to determine burner efficiency upon prior approval from the Control Officer. [AQR 12.8 and AQR 19.4.1.3]

E. RECORD KEEPING

1. All records and logs, or a copy thereof, shall be kept on-site for a minimum of five (5) years from the date the measurement or data was entered. [AQR 19.4.1.3]
2. Records and logs shall contain, at minimum, the following information [AQR 19.4.1.3]:
 - a. the magnitude and duration of excess emissions, notifications, monitoring system performance, malfunctions, corrective actions taken, etc., as required by 40 CFR 60.7;
 - b. CEMS audit results or accuracy checks, corrective actions, etc., as required by 40 CFR 60, Appendix F, and the CEMS quality assurance plan;
 - c. certificates of representation for the designated representative and the alternate designated representative;
 - d. hours of operation for each turbine with diesel and natural gas separately and, as applicable, each duct burner;
 - e. dates, times, and duration of each startup and shutdown cycle;

- f. startup and shutdown short-term total emissions per turbine in pounds per hour and rolling 12-months emissions in tons per year;
 - g. sulfur content of natural gas as certified by the supplier;
 - h. supplier name of diesel fuel, sulfur content of diesel fuel and the method used to determine to sulfur content of the diesel fuel;
 - i. daily, monthly, quarterly and rolling 12-months quantity of natural gas and diesel fuel consumed in each gas turbine;
 - j. quarterly and rolling 12-months quantity of diesel fuel used for each starter engine;
 - k. quarterly and rolling 12-months quantity of natural gas and hydrogen fuel used for Indeck/Volcano boiler;
 - l. daily, monthly, quarterly and rolling 12-months quantity of natural gas fuel used for Nebraska boiler;
 - m. quarterly and rolling 12-months amount of diesel fuel loaded into the storage tank;
 - n. quantity of ammonia consumed per rolling 12-months;
 - o. TDS content of tower circulation water;
 - p. quality assurance plan for all CEMS and
 - q. results of the last performance test conducted in addition to any other performance tests conducted within the last five (5) years.
3. Sulfur content of natural gas fuel shall be verified by the Permittee at least quarterly and verifications shall be based on reports or written data from the gas supplier, as required by 40 CFR 60. [AQR 19.4.1.3]
4. Sulfur content of diesel fuel shall be certified by the supplier with each fuel delivery. [AQR 19.4.1.3]
5. For all Inspections, visible emission checks, and testing required under monitoring, logs, reports, and records shall include at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). [AQR 12.8.1.f]
6. Records and data required by this permit to be maintained by the Permittee may, at the Permittee's expense, be audited at any time by a third party selected by the Control Officer. This third party shall be subject to the same business confidentiality terms binding DAQEM during investigations and data gathering. [AQR 19.4.1.3]
7. The Permittee shall maintain a Risk Management Plan (RMP) for the storing, handling, and use of ammonia or any chemicals subject to accidental release prevention regulations pursuant to 40 CFR 68. The Permittee shall submit an RMP to the Administrator by the date specified in 40 CFR 68.10 and shall certify compliance with the requirements of Part 68 as part of the annual compliance certification. [AQR 19.4.1.3]

F. REPORTING

- 1. The Permittee shall submit quarterly reports within 30 days after the end of each calendar quarter. [AQR 12.8 and 19.4.1.3]
- 2. Each quarterly report shall [AQR 12.8 and AQR 19.4.1.3]:

- a. include, as the first page of text, a signed certification containing the sentence, "I certify that, based on information and belief formed after reasonable inquiry, the statements contained in this document are true, accurate and complete." This statement shall be signed and dated by a responsible official of the company;
 - b. include quarterly summaries of items listed in Conditions IV-E-3-a through m;
 - c. include quarterly summaries of any permit deviations, their probable cause and corrective actions or preventative actions taken;
 - d. be based on the calendar quarter (including partial calendar quarters);
 - e. be submitted within 30 days after the end of the calendar quarter; and
 - f. be addressed to the attention of the Control Officer.
3. Regardless of the date of issuance of this permit, the schedule for the submittal of reports to the Control Officer shall be as follows [AQR 12.8 and 19.4.1.3]:

Table IV-F-1: Reporting Schedule.

Quarter	Applicable Period	Due Date ¹	Required Contents
1	January, February, March	April 30 each year	Quarterly Report for 1st Calendar Quarter
2	April, May, June	July 30 each year	Quarterly Report for 2nd Calendar Quarter
3	July, August, September	October 30 each year	Quarterly Report for 3rd Calendar Quarter
4	October, November, December	January 30 each year	Quarterly Report for 4th Calendar Quarter
4	Calendar Year	January 30 Each year	Annual Compliance Certification Report

¹ If the due date falls on a Saturday, Sunday or legal holiday, then the submittal is due on the next regularly scheduled business day.

4. The Permittee shall report Upset/Breakdowns or Emergencies, as defined in Section 0, to the Control Officer within one (1) hour of the onset of the event. [AQR 12.8 and 19.4.1.3]
5. The release of one (1) gallon or more of ammonia during transfer operations (from tanker truck to injection port) shall be considered an upset/breakdown. [AQR 12.8 and 19.4.1.3]
6. The Control Officer reserves the right to require additional reports and reporting to verify compliance with permit conditions, permit requirements and requirements of applicable regulations. [AQR 4.4 and 19.4.1.3]
7. The Permittee shall submit an annual emissions inventory by March 31 to the Control Officer and shall include the emission factors and calculations used to determine the emissions from each permitted emission unit, even if that unit was not operated. [AQR 12.8 and 19.4.1.3]

V. OTHER REQUIREMENTS

1. It is the Permittee's responsibility to satisfy all federal requirements to which the source is subject. [AQR 19.4.1.6a]
2. The Permittee shall not use, sell, or offer for sale any fluid as a substitute material for any motor vehicle, residential, commercial, or industrial air conditioning system, refrigerator freezer unit, or other cooling or heating device designated to use a chlorofluorocarbon (CFC) or hydrochlorofluorocarbon (HCFC) compound as a working fluid, unless such fluid has been

approved for sale in such use by the Administrator. The Permittee shall keep record of all paperwork relevant to the applicable requirements of 40 CFR 82 on site. [40 CFR 82]

- The SPC is the cogeneration facility exempted based on the applicability criteria defined in Part 72.6(b)(5); therefore, the provisions Acid Rain regulation do not apply. [40 CFR 72.6]

VI. PERMIT SHIELD

Compliance with the terms contained in this permit shall be deemed compliance with the following applicable requirements in effect on the date of permit issuance:

Table VI-1: Applicable Requirements Related to Permit Shield

Citation	Title
40 CFR Subpart Db	Standards of Performance for New Stationary Sources (NSPS) – Industrial-Commercial-Institutional Steam Generating Units
40 CFR Subpart Dc	Standards of Performance for New Stationary Sources (NSPS) – Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR Subpart GG	Standards of Performance for New Stationary Sources (NSPS) – Stationary Gas Turbines

VII. ATTACHMENTS

APPLICABLE REGULATIONS

REQUIREMENTS SPECIFICALLY IDENTIFIED AS APPLICABLE:

- Nevada Revised Statutes (NRS), Chapter 445B.
- Clark County Air Quality Regulations (CCAQR) Applicable CCAQR Sections:

Citation	Title
CCAQR Section 0	Definitions
CCAQR Section 2	Air Pollution Control Board
CCAQR Section 4	Control Officer
CCAQR Section 5	Interference with Control Officer
CCAQR Section 6	Injunctive Relief
CCAQR Section 8	Persons Liable for Penalties – Punishment: Defense
CCAQR Section 9	Civil Penalties
CCAQR Section 10	Compliance Schedule
CCAQR Section 11	Ambient Air Quality Standards
CCAQR Section 12	Preconstruction Review for New or Modified Stationary Sources
CCAQR Section 12.5	Air Quality Models
CCAQR Section 17	Dust Control Permit for Construction Activities Including Surface Grading and Trenching
CCAQR Section 18	Permit and Technical Service Fees
CCAQR Section 19	40 CFR Part 70 Operating Permits
CCAQR Section 20	Emission Standards for Hazardous Air Pollutants for Source Categories (NESHAP)
CCAQR Section 21	Acid Rain Permits
CCAQR Section 24	Sampling and Testing - Records and Reports
CCAQR Section 25	Upset/Breakdown, Malfunctions
CCAQR Section 26	Emissions of Visible Air Contaminants

Citation	Title
CCAQR Section 28	Fuel Burning Equipment
CCAQR Section 29	Sulfur Contents of Fuel Oil
CCAQR Section 35	Diesel Engine Powered Electrical Generating Equipment
CCAQR Section 40	Prohibition of Nuisance Conditions
CCAQR Section 41	Fugitive Dust
CCAQR Section 42	Open Burning
CCAQR Section 43	Odors in the Ambient Air
CCAQR Section 55.5	Preconstruction review for New or Modified Stationary Sources in the 8-Hour Ozone Nonattainment Area
CCAQR Section 60	Evaporation and Leakage
CCAQR Section 70	Emergency Procedures
CCAQR Section 80	Circumvention
CCAQR Section 90	Fugitive Dust from Open Areas and Vacant Lots
CCAQR Section 91	Fugitive Dust from Unpaved Roads, Unpaved Alleys, and Unpaved Easement Roads
CCAQR Section 92	Fugitive Dust from Unpaved Parking Lots

3. Clean Air Act, as amended (CAAA), Authority: 42 U.S.C. § 7401, et seq.
4. Title 40 of the Code of Federal Regulations (40 CFR) Applicable 40 CFR Subsections:

Citation	Title
40 CFR Part 52.21	Prevention of Significant Deterioration (PSD)
40 CFR Part 52.1470	SIP Rules
40 CFR Part 60, Subpart A	Standards of Performance for New Stationary Sources (NSPS) – General Provisions
40 CFR Part 60, Subpart Db	Standards of Performance for New Stationary Sources (NSPS) – Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60, Subpart Dc	Standards of Performance for New Stationary Sources (NSPS) – Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60, Subpart GG	Standards of Performance for New Stationary Sources (NSPS) – Stationary Gas Turbines
40 CFR Part 60	Appendix A, Method 9 or equivalent, (Opacity)
40 CFR Part 68	Chemical Accident Prevention Provisions
40 CFR Part 70	Federally Mandated Operating Permits
40 CFR Part 82	Protection of Stratospheric Ozone

TECHNICAL SUPPORT DOCUMENT

TECHNICAL INFORMATION PRESENTED IN REVIEW OF AN
APPLICATION FOR A PART 70 OPERATING PERMIT

SUBMITTED BY

SAGUARO POWER COMPANY

for

SAGUARO POWER COMPANY

Part 70 Operating Permit Number: 393
SIC Code - 4911: Electric Utility Services



Clark County
Department of Air Quality and Environmental Management
Permitting Section

August 2009

EXECUTIVE SUMMARY

The Saguaro Power Company (SPC) is located at 8000 West Lake Mead Parkway, Henderson, Nevada 89015, in the Las Vegas Valley airshed, hydrographic basin number 212. Hydrographic basin 212 is basic nonattainment for CO, PM₁₀, and ozone, and PSD for all other regulated air pollutants.

Saguaro Power Company (SPC) operates two General Electric (GE), 35.0 MW, natural gas combustion turbine generators (CTGs) with heat recovery steam generators (HRSG), a 23.1 MW extraction/condensing steam turbine generator system and two waste heat recovery steam generators with four, 25 MMBtu/hr each supplemental firing duct burners. These units are permitted to fire on hydrogen gas, natural gas and fuel No. 2 distillate oil. There are also two auxiliary boilers that are used to provide continuous steam supply. In addition, SPC operates a cooling tower, two diesel fired turbine starter engines, a fuel oil storage tank, and an ammonia storage and injection system. All generating and support processes at the site are grouped under the Standard Industrial Classification (SIC) 4911 – Electric Services (NAICS: 22111 - Electric Power Generation). The potential emissions for the source are shown in the table below.

Table 1: Maximum Facility PTE (tons per year)

PM ₁₀	NO _x	CO	SO _x	VOC	HAP	NH ₃
37.94	165.46	90.23	11.30	13.86	8.95	45.01

Clark County Department of Air Quality and Environmental Management (DAQEM) has delegated authority to implement the requirements of the Part 70 operating permit program. The SPC emits particulate matter (PM₁₀), carbon monoxide (CO), oxides of nitrogen (NO_x), oxides of sulfur (SO_x), volatile organic compounds (VOCs), hazardous air pollutants (HAP), and ammonia (NH₃). The source is a major source for NO_x, CO, and NH₃.

Initial Part 70 Operating Permit was issued on February 29, 2000; Part 70 OP Administrative Revision One was issued on November 8, 2001; and ATC/OP Modification 7, Revision 0, was issued on March 19, 2008. DAQEM received the renewal Title V application on June 18, 2003. Applications for Title V permit revisions were received to incorporate various ATCs issued after the initial Title V permit. Based on the information submitted by the applicant and a technical review performed by the DAQEM staff, the DAQEM proposes the renewal of a Part 70 Operating Permit to Saguaro Power Company.

This Technical Support Document (TSD) accompanies the proposed Part 70 Operating Permit for Saguaro Power Company.

TABLE OF CONTENTS

	Page
I. SOURCE INFORMATION.....	4
A. General.....	4
B. Description of Process.....	4
C. Permitting History.....	5
D. Operating Scenario.....	8
E. Proposed Exemptions.....	12
II. EMISSIONS INFORMATION.....	12
A. Source-wide Potential to Emit.....	12
B. Equipment Description.....	12
C. Emission Units and PTE.....	14
D. Testing.....	19
E. Continuous Emissions Monitoring.....	20
III. REGULATORY REVIEW.....	21
A. Local Regulatory Requirements.....	21
B. Federally Applicable Regulations.....	26
IV. COMPLIANCE.....	29
A. Compliance Certification.....	29
B. Compliance Summary.....	30
C. 40 CFR Subparts Db, Dc and GG Streamlining Demonstration for Shielding Purposes.....	37
D. Summary of Monitoring for Compliance.....	40
V. EMISSION REDUCTION CREDITS (OFFSETS).....	43
VI. ADMINISTRATIVE REQUIREMENTS.....	43

I. SOURCE INFORMATION

A. General

Permittee	Saguaro Power Company
Mailing Address	8000 West Lake Mead Parkway Henderson, NV 89015
Contacts	Monte Ash, General Manager
Phone Number	(702) 558-1131
Fax Number	(702) 564-2735
Source Location	8000 West Lake Mead Parkway Henderson, NV 89015
Hydrographic Area	212
Township, Range, Section	T22S, R62E, Section 11, 12, 13, 14
SIC Code	4911 – Electric Services
NAICS Code	22111 - Electric Power Generation

B. Description of Process

Saguaro Power Company (SPC) produces electrical power and thermal energy (steam). The electrical energy is transmitted to Nevada Power Company electrical grid for distribution to consumers. The steam is sold to the manufacturing facilities. The SPC is defined as a cogeneration facility because it generates and sells two useful forms of energy.

SPC operates two General Electric (GE), 35.0 MW, natural gas combustion turbine generators (CTGs) with heat recovery steam generators (HRSG), a 23.1 MW extraction/condensing steam turbine generator system and two waste heat recovery steam generators with four, 25 MMBtu/hr each supplemental firing duct burners. These units are permitted to fire on hydrogen gas, natural gas and fuel No. 2 distillate oil. There are also two auxiliary boilers that are used to provide continuous steam supply. In addition, SPC operates a cooling tower, two diesel fired turbine starter engines, a fuel oil storage tank, and an ammonia storage and injection system.

Fuel is supplied to the combustion chambers where it is mixed with the compressed air and the mixture is ignited. The thermal energy of the combustion gases exiting the combustors is transformed into rotating mechanical energy as the gases expand through the turbine sections of the CTGs. The rotating mechanical energy is converted into electrical energy via a shaft on each CTG connected to an electrical generator. The high temperature, pressurized gas produced by the combustion expands through the turbine blades, driving the electric generator and the compressor. The rotating mechanical energy generated by the steam turbine is converted into electrical energy via a shaft connected to an electrical generator. The exhaust gases will exit to the atmosphere after leaving the turbine, having already passed through an

oxidation catalyst for CO control and selective catalytic reduction (SCR) system for NO_x control. Power cycle heat rejection is accomplished with a cooling tower.

The Thermal-Dynamics cooling tower is a 3-cell mechanical draft unit a circulation rate of 6,395 gallons per minute per cell or 19,185 gallons per minute total. Total dissolved solids are limited to 3,800 ppm with operation allowed 8,760 hours annually. The tower is fitted with high efficiency mist eliminators rated at 0.0006 percent.

The SPC emits particulate matter (PM₁₀), carbon monoxide (CO), oxides of nitrogen (NO_x), oxides of sulfur (SO_x), volatile organic compounds (VOCs), hazardous air pollutants (HAP), and ammonia (NH₃). Saguaro is a major source for NO_x, CO, and NH₃.

The SPC NO_x and CO emissions are monitored with continuous emission monitoring system (CEMS). The ammonia (NH₃) parametric emissions monitoring system (PEMS) is used to demonstrate compliance with ammonia emission limits. The monitoring system generates a log of data and provides alarm signals to the control room when the level of emissions exceeds preselected limits.

C. Permitting History

The SPC is regulated by the Clark County Department of Air Quality and Environmental Management (DAQEM), and has Title V permit. The SPC facility is a major source for NO_x, CO, and NH₃. Initial Part 70 Operating Permit was issued on February 29, 2000; Part 70 OP Administrative Revision One was issued on November 8, 2001; and ATC/OP Modification 7, Revision 0, was issued on March 19, 2008. DAQEM received the renewal Title V application on June 18, 2003. SPC did not propose any changes to the current Part 70 OP. However, there were few NSR permits issued after the renewal application submission and changes implemented in these permits have to be incorporated into the Part 70 OP.

Table I-C-1: NSR Permits Issued to Saguaro Power Company

Date Issued	Permit Number	Description
11/21/2008	ATC Modification 7, Revision 2	Revision of the existing ATC/OP to describe enforceable limits and the source-wide PTE.
03/19/2008	ATC/OP Modification 7, Revision 0	Modification of the existing ATC/OP included installation of a new super low-NO _x burner and CO oxidation catalyst on Volcano 249 MMBtu/hr auxiliary boiler in order to accommodate the increased throughput.
08/05/2008 (expired on 12/31/2008)	ATC Modification 6, Revision 2	Alternate operating scenario, the modification qualified as a Section 502(b)(10) change to the Part 70 source in accordance with Clark County Air Quality Regulations, Section 19.4.1.8.
10/04/2006	ATC/OP Modification 6, Amendment 1	This amendment of ATC/OP Modification 6 was issued because the previously issued ATC/OP Mod 6 was never signed by the source and therefore the source did not have a valid ATC/OP.
06/21/2006	ATC/OP Modification 6	Modification of the ATC/OP included update of HAP emissions for all emissions units, update of SO _x emissions for the turbines, update of emission calculations, inclusion of VOC deminimus units, removal of the portable diesel generator, and update of ammonia PEMS calculations. Permit was never signed by the source.

Date Issued	Permit Number	Description
06/16/1999	ATC/OP Modification 5	Modification of the ATC/OP included update in calculation method of PTE based on CEMS, performance testing, and records of hours of operation. The seasonal emission limits were replaced with one year-round limit.
12/10/1997	OP Modification 4	Modification of the Section 16 OP included replacement of the 136.4 MMBtu/hr natural gas fired boiler for steam generation with a new 247.0 MMBtu/hr boiler.
07/24/1997	ATC Modification 4	Section 12 ATC (A393) Authority to Construct – Replacement of existing 136.4 MMBtu/hr natural gas fired boiler for steam generation with a new 247.0 MMBtu/hr boiler.
04/12/1996	Temporary OP Modification 3	Section 16 OP (A039308) Addition of diesel power generator with time limit conditions; record keeping, and reporting.
03/31/1995	OP Modification 2	Section 16 OP (A58010) Addition of Nebraska natural gas or hydrogen fired boiler for steam generation with time limit conditions; record keeping, and reporting. The emission offset requirement was included in the permit.
01/05/1995	ATC Modification 2	Section 12 ATC (A0393) Authority to Construct - Nebraska natural gas or hydrogen fired boiler for steam generation.
04/02/1993	OP Revised	Section 16 OP (A39301 through A39307) Revised permit conditions for two GE turbines, two diesel starter engines, lime storage silo, soda ash storage silo, and auxiliary boiler.
06/18/1992	OP	Section 16 OP (A39301 and A39302) Operating permit with conditions for two GE turbines, a steam turbine, two HRSG with supplemental duct firing and a SCR for NO _x control.
11/22/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39307) Nebraska Boiler, Model N38-7-89, 190.5 MMBtu/hr SPC OP, indicates no conditions; no record keeping, and no reporting.
11/22/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39306) Lime Silo SPC OP, indicates no conditions; no record keeping, and no reporting.
11/22/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39305) Soda Ash Silo SPC OP, indicates no conditions; no record keeping, and no reporting.
11/22/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39304) Detroit Diesel Engine, Model 7123 – 7300, 600 hp (# 1) SPC OP, indicates no conditions; no record keeping, and no reporting.
11/22/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39303) Detroit Diesel Engine, Model 7123 – 7300, 600 hp (# 2) SPC OP, indicates no conditions; no record keeping, and no reporting.
11/21/1991	ATC Modification 1	Authority to Construct, Modification 1, addition of two 600 hp diesel engines, soda ash storage silo, and lime silo.
07/25/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39302) GE Frame G5418Turbine (#2) SPC OP, natural gas, with SCR, indicates no conditions; no record keeping, and no reporting.
07/25/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39301) GE Frame G5418Turbine (#1) SPC OP, natural gas, with SCR, indicates no conditions; no record keeping, and no reporting.
06/17/1991	ATC	Section 12 ATC (A393) Authority to Construct permit with conditions for two GE turbines, a steam turbine, two HRSG with supplemental duct firing and a SCR for NO _x control.
08/10/1990	ATC	Section 12 ATC (A393) Authority to Construct permit with conditions for two GE turbines, a steam turbine, two HRSG.

On October 9, 2007, SPC applied for modification of the existing ATC/OP. The source requested to increase throughput of the 249 MMBtu/hr Indeck/Volcano boiler (EU: A05) to combust only natural gas and/or a combination of natural gas and hydrogen with the operation limited to 2,181,240 MMBtu/year fuel. SPC proposed to install a new super low-NO_x burner and CO oxidation catalyst in order to accommodate the increased throughput. The equipment manufacturer guarantees an operating emission limit of 12 ppm NO_x when burning natural gas only, as well as mixture of natural gas and hydrogen. In addition, SPC proposed a 1.2 ppm CO emission rate from the boiler. The modification required Lowest Achievable Emission Rate (LAER) for CO as SPC is a major source in the Hydrographic Basin 212 CO Serious Nonattainment area.

The source determined the use of 10 ppm CO burner coupled with an Oxidation Catalyst will drop the CO emissions to 1.2 ppm. These controls are considered LAER for CO. This modification does not trigger offsetting requirements specified in AQR Section 59, the proposed modification changed the boiler status from Dc to Db and requires an installation and operation of a CEMS on the unit.

On July 18, 2008, the source applied for the amendment of the existing ATC/OP. The source requested to authorize a temporary alternative operating scenario. The proposed temporary operating scenario allowed for the operation of the Volcano boiler (EU: A05) beyond the natural gas throughput level of 218,124 MMBtu/year. Consequently, throughput of the 249 MMBtu/hr Volcano boiler (EU: A05) to combust only natural gas and/or a combination of natural gas and hydrogen will be increased to 1,132,452 MMBtu/year (4,548 hours per year at 100% capacity).

To offset the emissions increase, SPC proposed to decrease the allowable hours of operation of each combustion turbine by 3,011 hours per turbine, as compared to the past actual operating hours (actual average of 2006 and 2007). The operating hours for CTG 1 (EU: A01) were limited to 4,950 hours per year and the operating hours for CTG 2 (EU: A02) were limited to 4,476 hours per year. The change potentially reduced the NO_x emissions by 29.04 tons and CO emissions by 5.98 tons, as compared to the actual past emissions. The temporary alternative scenario also reduced VOC, HAP, NH₃, SO_x and PM₁₀ emissions.

The modification qualified as a Section 502(b) (10) change to the Part 70 source in accordance with Clark County Air Quality Regulations, Section 19.4.1.8.

Table I-C-2: BACT Determinations for Saguaro Power Company

EU	Description	BACT Technology	BACT Limit
A01, A02	35 MW natural gas-fired electric turbine generators, with HRSG, supplemental duct-firing	Low-NO _x burners, SCR, steam injection, natural gas combustion	10 ppmvd NO _x on 8-hour average at 15% O ₂ (natural gas); 17 ppmvd NO _x on 8-hour average at 15% O ₂ (fuel oil); 10 ppmvd CO on 8-hour average at 15% O ₂ (natural gas and fuel oil).
A03, A04	Detroit Diesel Starter Engines	Turbocharged, Aftercooled, Low sulfur diesel fuel (< 0.05%)	No limit imposed.
A05	Indeck/Volcano Auxiliary Boiler #1; 249 MMBtu/hr	Low-NO _x burners with FGR; CO oxidation system	12 ppmvd NO _x on 3-hour average at 3% O ₂ ; 1.2 ppmvd CO on 3-hour average at 3% O ₂ .

EU	Description	BACT Technology	BACT Limit
A06	Nebraska Auxiliary Boiler #2; 86 MMBtu/hr	Sole use of pipeline quality natural gas; good combustion practices	30 ppmvd NO _x on 8-hour average at 3% O ₂ ; 400 ppmvd CO on 8-hour average at 3% O ₂ .
A09a, A09b, A09c	Thermal-Dynamics Towers Inc., Cooling Tower; 19,185 gpm total	Limit of TDS; drift loss eliminators	3,800 mg/L TDS, 0.0006% drift loss.
F05, F05a, F06, F06a	John Zink Model LDR-11-LE Supplemental Duct Burner, 25 MMBtu/hr	Low-NO _x burners, SCR, steam injection, natural gas combustion	10 ppmvd NO _x on 8-hour average at 15% O ₂ (natural gas); 17 ppmvd NO _x on 8-hour average at 15% O ₂ (fuel oil); 10 ppmvd CO on 8-hour average at 15% O ₂ (natural gas and fuel oil).

D. Operating Scenario

Combustion Turbine Generators (CTG)

SPC operates two GE frame 6 (PG6541B) combined-cycle CTGs rated at 34.93 megawatts (at one atmosphere pressure, ambient temperature of 105°F and 16 percent relative humidity). At standard conditions the CTGs maximum heat input is 422 MMBtu/hr (lower heating value). The CTG's primarily fire natural gas but are permitted to fire distillate fuel oil for up to 480 hours per year per CTG. The CTGs are operated as base-load units, and are permitted to operate 365 days per year. The CTG's incorporate steam injection to control oxides of nitrogen (NO_x) emissions.

The CTGs exhaust to a three pressure HRSG that incorporates two sets of duct burners. One duct burner set is capable of firing a maximum of 25 MMBtu/hr (HHV) of hydrogen (supplied by the adjacent chemical manufacturer). The other set of duct burners is capable of firing a maximum of 25 MMBtu/hr of natural gas (HHV). The duct burners (for each CTG) are rated at 50 MMBtu/hr (HHV).

The HRSG's also include selective catalytic reduction systems (SCR) for the control of oxides of nitrogen (NO_x) emissions. The SCR system uses anhydrous ammonia as a reactant in the presence of a catalyst to convert NO_x to elemental nitrogen. The SCR system includes one anhydrous ammonia storage tank with vaporizers, piping, mixing systems, and an injection grid for each CTG.

An exhaust gas blower extracts exhaust gas from the exhaust stacks (for each CTG) for use by the adjacent chemical manufacturer as a source of carbon dioxide. The CTG's design incorporates a diesel-fired starter engine used to start the CTG's. These starter engines are integral to the CTG design and are enclosed within the CTG enclosures.

The CTG's incorporate a system to wash the compressor section of the units with demineralized water or with an aqueous-based cleaning solution. Washes can be performed while the units are operating and during outages. Manufacturers' information doesn't list any HAPs present in the wash solution.

Starter Engines

Each CTG design incorporates a diesel starter engine (EUs: A03 and A04) which provides the necessary power to initiate the start up sequence for the CTG's. These engines are permitted

to operate 125 hours per year per engine. The criteria pollutant emissions are based on permitted emission limits. The HAP emission estimates are based on EPA AP-42 emission factors.

Auxiliary Boilers

SPC currently has two auxiliary boilers that supply steam to their customers during periods when the CTG's are not in operation. The larger of the two is a natural gas-fired boiler rated at 249 MMBtu/hr (LHV) heat input (EU: A05). This boiler is permitted to operate up to 8,760 hours per year firing only natural gas and hydrogen gas. This boiler's design incorporates Low-NO_x burners and flue gas recirculation to control NO_x emissions and CO oxidation system for CO control.

The second auxiliary boiler (EU: A06) is rated to produce 70,000 pounds per hour of steam at a heat input of 86 MMBtu/hr (LHV). This boiler is permitted to operate 6,000 hours per year firing only natural gas and/or hydrogen gas. This boiler's design incorporates Low-NO_x burners and flue gas recirculation to control NO_x emissions.

Water Treatment Chemical Storage

The SPC facility operates three water treatment systems: a boiler make-up, a boiler pH and steam drum chemistry system, and a cooling tower water make-up system.

The boiler make-up water treatment system has a primary system which is a leased trailer-mounted ion exchange system used to treat make-up water for steam production. This trailer-mounted system is taken off site for regeneration (by the vendor) and does not emit any pollutants to the atmosphere. A back-up ion exchange-based boiler make-up water system is located on site. This system is permitted, but only used as a back-up system to the primary system. The back-up system is capable of being regenerated using hydrochloric acid and sodium hydroxide. The sodium hydroxide (NaOH) and hydrochloric acid (HCl) are stored as aqueous solutions in closed-top containers. The HCl storage tank vents to a scrubbing system where the gases vented during filling of the tank are bubbled through a container of water, any HCl mist in the vent gas will be absorbed by the water with negligible HCl emitted to the atmosphere.

The second water treatment system is the boiler pH and steam drum chemistry system. This system uses mono-, di-, tri-sodium phosphates, an oxygen scavenging product, and an amine-based product to control the boiler water chemistry. The sodium phosphate products are stored as both dilute aqueous solutions and dry powders in closed-top containers. The oxygen scavenging and amine-based products are stored as dilute liquids in closed-top containers. Product manufacturers report that no regulated pollutants are contained in these products.

The third water treatment system is the cooling tower make-up system. This water treatment system uses lime (CaO), soda ash (Na₂CO₃), and hydrochloric acid to treat the cooling tower make-up water. The calcium oxide and soda ash are stored as solids in storage silos with fabric filter vents. The HCl is used to control pH and is not expected to be emitted. The silos will emit emissions of soda ash and calcium oxide in the form of particulate matter.

Distillate Fuel Oil Firing

In the event of a curtailment of natural gas, the SPC facility is capable of firing fuel oil in the CTGs for up to 480 hours per year per CTG or a total of 960 hours of fuel oil firing per year.

These emissions include emission controls for NO_x in the form of steam injection/SCR and include duct burner emissions.

Fuel Oil System

The SPC receives, stores, and transports distillate fuel oil. The fuel oil is stored in a white, 750,000 gallon fixed roof storage tank. The storage tank's only emission point is an atmospheric vent with a pressure relief valve installed to control vapor emissions. The storage tank's annual average temperature is 77°F. The emissions are based on EPA AP-42 emission factors (section 4.3-5) and the annual average temperature. All emissions for the fuel oil tank are assumed to be VOC emissions.

The fuel oil is received at an unloading station located outside the main SPC facility to the North. The receiving station consists of a manifold system with capabilities of accepting deliveries from either tanker trucks or rail cars. The manifold is connected to an unloading pump located inside the SPC fence line that pumps the fuel oil from the unloading vessel to the onsite storage tank.

Fuel oil is transferred from the storage tank to the CTGs and starter engines by a pumping system. The pumping system consists of two electric-driven pumps with underground piping. The fuel oil transfer and receiving fugitive emission estimates are based on the maximum allowable fuel oil usage and EPA emission factors for valves, flanges, and pumps.

Cooling Tower

Waste heat is rejected to the atmosphere by a mechanical-draft, three-cell cooling tower. The cooling tower uses the principal of evaporation to reject this heat. In the cooling process, a fraction of the cooling water escapes the cooling tower as cooling tower drift. The SPC cooling tower circulates 9,600,000 pounds per hour of water with a drift rate of 0.0006 percent of the cooling capacity. The cooling tower total dissolved solids (TDS) content is controlled to approximately 3,800 ppm. It is assumed that TDS will become particulate matter when the water mist or drift is emitted from the cooling tower.

Emission estimates for the cooling tower are based on the above data, and assume that the cooling tower is operated 8760 hours per year.

The cooling tower uses gaseous chlorine for biological growth control. The chlorine is injected into a slipstream of water which is mixed with the cooling tower water. The chlorine content of the cooling tower water is controlled to approximately 0.2 ppm (with a maximum chlorine concentration of 0.5 ppm). The SPC facility uses approximately 2.6 tons of chlorine per year or 0.60 pounds per hour. Chlorine reacts with water to form hypochlorous acid (HOCl) which is classified as HAP. A review of available emission factor literature did not reveal emission factors for chlorine or hypochlorous acid from cooling towers. Additionally, given the quantity of chlorine used, and the low drift rate for the cooling tower, the emissions of hypochlorous acid are insignificant.

Natural Gas Conveyance System

The natural gas conveyance system at SPC is comprised of a metering station which is located to the north of the SPC facility, a filtering station, the CTG gas control and metering enclosures, and the HRSG duct burner control and metering skids. These systems contain many valves,

flanges, and seals which all leak to a minor extent. The first phase of developing an emission estimate for the natural gas system was to perform a valve, flange, and seal inventory. This inventory was broken down by location and included the metering station, filtration system, the CTG gas control and metering enclosures, and the duct burner skids. The CTG natural gas conveyance systems were primarily underground and were not capable of being inventoried. The valve and flange inventories and EPA emission factors were used to calculate the natural gas emissions. The natural gas emissions were converted into volatile organic compound emissions by assuming that 10 percent of the natural gas is non-methane hydrocarbons (or VOC).

Lubricating Oil System

The CTGs and steam turbine have lubricating (lube) oil systems to provide a constant supply of oil to bearings, gears, and other components requiring lubrication. The oil supply systems are pressurized. The oil in the lubricated components is typically at atmospheric pressure and requires an atmospheric vent. The CTG vents are equipped with a blower and a coalescing mist eliminator. The steam turbine lube oil vent is equipped with a blower and precipitator-type mist eliminator.

As with the natural gas conveyance system, these systems leak to a minor extent. An inventory of the valves and flanges was performed as the basis for the fugitive emission estimates from these lube oil systems. The valve and flange inventory and EPA emission factors were used to estimate the emissions of lube oil. A review of the material data safety sheet for the lube oil determined that the oil contained less than 5 percent (by weight) volatile organic compounds (VOC). The VOC emission estimate was assumed to be 5 percent of the system oil leaks (calculated using the EPA emission factor).

Ammonia Storage and Injection System

The SCR system uses anhydrous ammonia to control NO_x emissions from the CTGs. This ammonia is stored in a pressure vessel (common to both CTGs) and is transported to the SCR control and injection skids via welded piping. A valve and flange inventory and EPA emissions factors were used to estimate the ammonia emission from the ammonia storage and injection system.

Miscellaneous Emissions

SPC plans on painting the entire source within the next five years. Architectural coatings can result in emissions of VOCs. SPC has solicited quotes from painting contractors to provide proposals to paint the facility, and to provide an estimate of the VOC emissions. Based on these estimates, it would require approximately 600 gallons each of primer and top-coat paint with a VOC content of 109 and 207 grams per liter, respectively. The hourly emissions were estimated assuming that the paint would cure over a three-day period and emissions would be constant over the curing period.

The SPC facility conducts maintenance operations requiring the use of a variety of materials and products. These materials include paints, lubricants, cements/adhesives, greases, hydraulic fluids, cutting oils, spray foam, welding rods, fuel oil, contact cleaners, and antifreeze. These materials are purchased from local vendors and typically range in size from several ounces to gallon size containers. Lubricating oils used in the CTG's and other equipment are stored in larger sized containers (55-gallon drums). Emissions estimates associated with these materials were not performed.

Other activities at the SPC have the potential to generate air emissions. Some of these activities are metal cutting and welding (arc, gas, and plasma), use of pressure washing systems, the water chemistry laboratory, gasoline-powered (less than 5 hp) water pumps, parts cleaning, and glove booth abrasive cleaning. Most of these activities are intermittent in nature and occur infrequently with the exception of the water chemistry lab. The lab uses standard test kits developed by chemical supply companies containing buffer solutions and standardized reagents in small quantities (typically less than one gallon and generally less than one quart). These chemical solutions are all aqueous solutions.

Other activities which potentially could generate air emissions are computer (laser) printer and photocopier usage, general cleaning (using household consumer cleaning products), and repaving of the parking areas. SPC also maintains an uninterruptible power system based on gel cell and lead-acid batteries. Again, emission estimates for these operations were not performed due to the insignificant contribution of these sources on the emission estimate.

In addition to these activities, SPC operates numerous refrigeration-type air conditioning systems containing chlorofluorocarbons (CFC) which are regulated by the Title 40 Code of Federal Regulations, Part 82. These CFC-containing systems provide space cooling (for personnel and equipment) and are closed systems except when being maintained or repaired. SPC contracts with a certified contractor for the maintenance and repair of these CFC-containing units. The CFC emissions and applicability of Title 40 Code of Federal Regulations, Part 82 are not considered in this application due to the nature of these potential emissions (if any) and the fact that SPC contracts out the maintenance of these units to a maintenance organization with certified technicians.

E. Proposed Exemptions

There are no exemptions.

II. EMISSIONS INFORMATION

A. Source-wide Potential to Emit

Saguaro Power Company is a major source for NO_x, CO, and TCS (NH₃) and a non-major source for PM₁₀, SO_x, VOC, and HAP:

Table II-A-1: Source-wide PTE (tons per year)

Pollutant	PM ₁₀	NO _x	CO	SO _x	VOC	HAP	NH ₃
PTE Totals	37.94	165.46	90.23	11.30	13.86	8.95	45.01
Major Source Thresholds	70	50	70	70	50	25²	1.0

¹Total emissions are based on the worst-case scenario between natural gas combustion and fuel oil combustion in the turbines.

³25 tons for combination of all HAPs (no single HAP exceeds 10 tons).

B. Equipment Description

The air emission source equipment and associated major equipment is listed below. In addition, common support equipment exists to support the power generation equipment.

Power Equipment

1. Two (2) GE (Frame PG 6514B) single shaft, simple cycle, nominal 35 MW combustion turbines, with:

- a. Natural gas, hydrogen gas, or fuel oil firing,
 - b. Inlet air filters with filter cleaning system,
 - c. Fire detection and protection system,
 - d. Hydrogen cooled electric generator,
 - e. Emission Units Identification A01 and A02.
2. Two (2) heat recovery steam generators (HRSG), with:
 - a. 3-pressure boiler system, with single reheat,
 - b. Multi-element duct burners, with burner management system,
 - c. Selective catalytic reduction (SCR) system for NO_x control,
 - d. Exhaust stack, equipped with continuous emissions monitoring system (CEMS) for NO_x and CO, as well as NH₃ slip.
 3. Two (2) John Zink Model LDR-11-LE, supplementary duct burners, natural gas and/or hydrogen fired, 25 MMBtu/hr maximum heat input each, Gas Skid CTG-01 (Emission Unit Identification F05 and F05a).
 4. Two (2) John Zink Model LDR-11-LE, supplementary duct burners, natural gas and/or hydrogen fired, 25 MMBtu/hr maximum heat input each, Gas Skid CTG-02 (Emission Unit Identification F06 and F06a).
 5. Two (2) Detroit diesel starter engines, 293 kW (445 hp) each, one engine with each turbine generator (Emission Unit Identification A03 and A04).
 6. One (1) General Electric steam turbine generator, with:
 - a. 3-pressure, single reheat, condensing configuration,
 - b. Hydrogen cooled electric generator.

Common Support Equipment

1. One (1) No. 2 diesel fuel storage tank, fixed roof, 75,000 gallon capacity (Emission Unit Identification A08).
2. Fuel oil unloading station, manifold system for unloading trucks and railcars (Emission Unit Identification F02).
3. Fuel oil transfer pumps, two electric-driven pumps with under ground piping (Emission Unit Identification F01).
4. One (1) auxiliary Indeck/Volcano boiler, natural gas and/or hydrogen fired, 249 MMBtu/hr maximum heat input, low-NO_x burners, with FGR, SCR and oxidizing catalyst system for controlling NO_x and CO, (Emission Unit Identification A05).
 - a. Exhaust stack, equipped with continuous emissions monitoring system (CEMS) for NO_x and CO, as well as NH₃ slip.
5. One (1) auxiliary Nebraska boiler, natural gas and/or hydrogen fired, 86 MMBtu/hr maximum heat input, low-NO_x burners, with FGR, (Emission Unit Identification A06).
6. One (1) ammonia storage tank, 12,000 gallons, anhydrous ammonia, sealed system (Emission Unit Identification F11).
7. Thermal-Dynamics cooling water system, a 3-cell mechanical draft unit a circulation rate of 6,395 gallons per minute per cell or 19,185 gallons per minute total (Emission Unit Identification A09a, A09b, A09c).
8. The natural gas conveyance system, comprised of a metering station, a filtering station, the CTG gas control and metering enclosures, and the HRSG duct burner control (Emission Unit Identification F03 and F04).

Miscellaneous Ancillary Equipment

1. Ancillary equipment as necessary to ensure efficient, safe and reliable operation:
 - a. Administration and control room building,

- b. Warehouse and maintenance building,
- c. Various water storage tanks,
- d. Various chemical storage tanks,
- e. Electrical switchyard,
- f. Storage structure.

C. Emission Units and PTE

Table II-C-1: List of Emission Units

EU	Description	SCC	Type ¹
A01	GE Combustion Turbine Generator #1; M/N: PG6541B with a fired HRSG, S/N: 295525, 35 MW; 35 MEQ	2010010 1	TR1,ME Q
A02	GE Combustion Turbine Generator #2; M/N: PG6541B with a fired HRSG, S/N: 295524, 35 MW; 35 MEQ	2010010 1	TR1,ME Q
A03	Detroit Diesel Starter Engine, Model 71237300, S/N: 12VA083956, Combustion Turbine Generator #1 (445 hp)	2010010 2	CE2
A04	Detroit Diesel Starter Engine, Model 71237300, S/N: 12VA083901, Combustion Turbine Generator #2 (445 hp)	2010010 2	CE2
A05	Indeck/Volcano Auxiliary Boiler #1; 249 MMBtu/hr; M/N: 0-7-2000; S/N: N/A	3100041 4	F1
A06	Nebraska Auxiliary Boiler #2; 86 MMBtu/hr; M/N: NOS 2A/S-55; S/N: 032-88	3100041 4	F1
A08	Fuel Oil Storage Tank (750,000 gallon)	4030101 9	T1
A09a	Thermal-Dynamics Towers Inc., Cooling Tower; M/N: TD-3030-3-2424CF; S/N: N/A; 19,185 gpm total, 3,800 mg/L TDS, 0.0006% drift, Cell 1	3850010 1	P1
A09b	Thermal-Dynamics Towers Inc., Cooling Tower; M/N: TD-3030-3-2424CF; S/N: N/A; 19,185 gpm total, 3,800 mg/L TDS, 0.0006% drift, Cell 2	3850010 1	P1
A09c	Thermal-Dynamics Towers Inc., Cooling Tower; M/N: TD-3030-3-2424CF; S/N: N/A; 19,185 gpm total, 3,800 mg/L TDS, 0.0006% drift, Cell 3	3850010 1	P1
F01	Fuel Oil Transfer Pumps	3060081 3	DM
F02	Fuel Oil Unloading	3060081 6	DM
F03	Natural Gas Metering Station	2088880 2	DM
F04	Natural Gas Coalescing Filters	2088880 2	DM
F05	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733, 25 MMBtu/hr, Skid # 1	2010010 1	DF1
F05a	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733, 25 MMBtu/hr, Skid # 1	2010010 1	DF1
F06	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733, 25 MMBtu/hr, Skid # 2	2010010 1	DF1
F06a	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733, 25 MMBtu/hr, Skid # 2	2010010 1	DF1
F07	Lube Oil System – CTG-01	3060081 3	---
F08	Lube Oil System – CTG-02	3060081 3	---
F09	Lube Oil System – STG-03	3060081	---

EU	Description	SCC	Type ¹
		3	
F11	Ammonia Storage and Injection, 12,000 gallons	4078169 9	---

¹Type code is an emissions unit designation for billing purposes: TR1=turbine 2.5 Megawatt or larger, MEQ=Megawatt Equivalent Fee (MWE x Fee), CE2 = stationary IC engine 351-800 hp, F1= fuel burning equipment, P1 = process equipment. Fees are listed in AQR Section 18.

Table II-C-2: Insignificant Activities

EU	Description
F10	Facility Painting

Emission calculations for the SPC not covered in this permitting action will be described in this TSD; however, some of the specific information regarding emission factors, fuel characteristics, and other site-specific information previously considered will not be presented in this document.

Turbines (EU: A01 and A02)

Potential particulate emissions for natural gas combustion in the turbines were estimated based on a manufacturer's guarantee of 2.5 pounds per hour. Operating 8,280 hours per year on this fuel will provide an annual emission rate of 10.35 tons of PM₁₀ per year. The guarantee also applies to diesel fuel oil combustion, which was rated at 17 pounds of PM₁₀ per hour. Operating a maximum of 480 hours per year on this fuel will provide an annual PM₁₀ emission rate of 4.08 tons per year. The total maximum particulate emissions are 17 pounds per hour (using fuel oil as the worst case) and 14.43 tons per year.

Potential NO_x emissions are based on an accepted emission limit of 10 ppmvd at 15 percent oxygen for natural gas combustion and 17 ppmvd at 15 percent oxygen for fuel oil combustion. The specific "F Factor" for the fuel is unknown, but using default factors 8,740 dscf/MMBtu for natural gas and 9,920 dscf/MMBtu for fuel oil, the estimated maximum NO_x PTE would be 29.79 pounds per hour (using fuel oil as the worst case) and 75.61 tons per year. This is reasonably close to the permitted NO_x limits of 26.3 pounds per hour (using fuel oil as worst case) and 69.20 tons per year; therefore the permit will not need to be changed. The following is the methodology to convert from ppmvd to pounds per hour:

$$\text{ppm} / 1,000,000 * 46.01 \text{ pounds/pound-mol NO}_x / \text{MV ft}^3/\text{pound-mol gas} * \text{F dscf/MMBtu} * [20.9 / (20.9 - \%O_2)] = \text{pounds NO}_x/\text{MMBtu}$$

ppm = emission limit in ppmvd

MV = molar volume of gas (default is 385 ft³/pound-mol)

F = "F Factor" (dscf/MMBtu)

%O₂ = percent oxygen at which the standard is set (whole number)

The Btu ratings for the fuels are calculated as follows:

Natural gas – 447 MMBtu/hour (design rate)

Fuel oil – 3,035 gallons/hour * 7.13 pounds/gallon * 19,289 Btu/pound / 1,000,000 Btu/MMBtu = 417.41 MMBtu/hour

Therefore:

$$\text{MMBtu/hour} * \text{pounds NO}_x/\text{MMBtu} = \text{pounds/hour NO}_x$$

Potential CO emissions are based on an accepted emission limit of 10 ppmvd at 15 percent oxygen for both natural gas and fuel oil combustion. The methodology is the same as the NO_x

emission calculations. The estimated CO potential using the same default “F Factors” is 17.53 pounds per hour (using fuel oil as the worst case) and 45.87 tons per year. DAQEM has concern with the short-term emission limit, but Saguaro Power has accepted this limit and no adjustments are warranted. The natural gas limit listed in the permit is reasonably close to the estimate, so it does not require adjustment.

Potential SO_x emissions for the natural gas combustion were calculated using a default emission factor of 0.0006 pounds/MMBtu, which were listed in the footnotes of AP-42 Table 3.1-2a.

Potential emissions from fuel oil combustion were calculated as follows:

$$3,035 \text{ gallons/hour} * 7.13 \text{ pounds/gallon} * 0.05/100 (\% \text{ S}) * 64 \text{ pounds/pound-mol SO}_2 / 32 \text{ pounds/pound-mol S} = 21.64 \text{ pounds/hour SO}_2$$
$$21.64 \text{ pounds/hour} * 480 \text{ hours/year} / 2,000 \text{ pounds/ton} = 5.19 \text{ tons/year}$$

Because fuel oil combustion is the worst case, it is considered the short-term (pound-per-hour) limit for each combustion turbine.

VOC emissions are based on the emission factors for natural gas and fuel oil combustion from AP-42 Table 3.1-2a. Because potential VOC emissions from fuel oil are the worst case, it is considered the short-term (pound-per-hour) limit for each combustion turbine.

Ammonia emissions are based on a manufacturer’s guarantee of 4.98 pounds per hour for both natural gas and fuel oil. Assuming 8,760 hours per year of operation, the potential ammonia emissions are 21.81 tons per year.

HAP emissions for natural gas combustion are based on the emission factors from AP-42 Table 3.1-3. HAP emissions for fuel oil combustion are based on the emission factors from AP-42 Tables 3.1-4 and 3.1-5. Because the natural gas emissions are based on 8,280 hours per year and the fuel oil emissions are based on 480 hours per year, the sum total of all HAPs is considered to be the total HAP emission limit for the permit. Individual HAP delineations are provided in Attachment 1. Because potential HAP emissions from fuel oil are the worst case, it is considered the short-term (pound-per-hour) limit for each combustion turbine.

Turbine Starter Engines (EU: A03 and A04)

The two diesel-fired starter engines each have a rating of 445 horsepower. Their emissions were calculated on a Btu rating basis to provide a consistent rating number for emissions calculations instead of switching between horsepower and Btus. The Btu rating was derived as follows:

$$33.5 \text{ gallons/hour} * 7.13 \text{ pounds/gallon} * 19,289 \text{ Btu/pound} = 4.61 \text{ MMBtu/hour}$$

The particulate emission factor was taken from AP-42 Table 3.3-1. The SO_x, NO_x, CO, and VOC factors were numbers provided by the manufacturer. The HAP emission factors were taken from AP-42 Table 3.3-2. The sum total of all individual HAPs was considered to represent the total permitted HAP limit for these units.

Indeck/Volcano Boiler (EU: A05)

The emissions for this unit were calculated using manufacturer’s emission factors, except for HAP. The HAPs were calculated using the emission factors from AP-42 Table 1.4-3 and an assumed heating value of 1,020 Btu per standard cubic foot of natural gas. The sum total of all individual HAPs was considered to be the total permitted HAP emission for this unit. The

controlled emissions of 12 ppmv NO_x and 1.2 ppmv CO are achieved by low-NO_x burner with FGR and CO oxidation system.

Nebraska Boiler (EU: A06)

The emissions for this unit were calculated using manufacturer's emission factors, except for CO, SO_x and HAP. CO was determined by a performance test. The actual factor is unavailable, but available documentation suggests that the permit limit may be slightly higher than what is in the file. SO₂ was calculated using the emission factors from AP-42 Table 1.4-2 and an assumed heating value of 1,020 Btu per standard cubic foot. The HAPs were calculated using the emission factors from AP-42 Table 1.4-3 and an assumed heating value of 1,020 Btu per standard cubic foot of natural gas. The sum total of all individual HAPs was considered to be the total permitted HAP limit for this unit.

Fuel Oil Storage Tank (EU: A08)

Emissions were updated from the previous submittal and calculated using the TANKS 4.0 program for a vertical fixed roof tank using the following parameters:

1. Shell height = 40 feet
2. Diameter = 58 feet
3. Maximum liquid height = 40 feet
4. Average liquid height = 40 feet
5. Turnovers = 3.9
6. Shell color = white/white, good condition
7. Roof color = white/white, good condition
8. Roof type = dome, 4 feet high, 58 foot radius

The emissions from the storage of diesel fuel at Saguaro amount to 103.08 pounds per year of VOCs according to the program. At 8,760 hours per year, this translates into 0.01 pounds per hour and 0.05 tons per year. Based on fuel oil storage tanks elsewhere in Clark County, it can be assumed that HAPs are 0.3 percent of the VOC emissions. This translates into 3.53E-05 pounds per hour and 1.55E-04 tons per year.

Cooling Tower (EUs: A09a, A09b, and A09c)

The cooling tower emissions are calculated using the drift loss method outlined in AP 42.

Fugitive Emissions from Pipes

Emissions were estimated using the number of types of connectors and correlating them with the SOCFI Average Emission Factors from Table 2-1 of EPA-453/R-95-017, Protocol for Equipment Leak Emission Estimates. Each emission factor is provided in units of kilograms per hour per source. It is then converted to pounds per hour by multiplying the factor by 2.205 pounds per kilogram. Taking into account the type of liquid or vapor that is being carried by the connected piping, the number of each type of connector is multiplied by the emission factor to obtain leak emissions in pounds per hour and then converted to tons per year using 8,760 hours per year.

Table II-C-3: Source Potential to Emit, Including Startup and Shutdowns^{1, 2}

EU	PM ₁₀		NO _x		CO		SO _x		VOC		HAP		NH ₃	
	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy
A01 ¹	---	14.43	---	69.20	---	39.40	---	6.30	---	4.01	---	1.98	---	21.81
A01 ^{2, 3}	2.50	---	15.20	---	9.00	---	0.27	---	0.92	---	0.46	---	4.98	---
A01 ^{2, 4}	17.00	---	26.30	---	9.00	---	21.64	---	2.00	---	0.54	---	4.98	---
A02 ¹	---	14.43	---	69.20	---	39.40	---	6.30	---	4.01	---	1.98	---	21.81
A02 ^{2, 3}	2.50	---	15.20	---	9.00	---	0.27	---	0.92	---	0.46	---	4.98	---
A02 ^{2, 4}	17.00	---	26.30	---	9.00	---	21.64	---	2.00	---	0.54	---	4.98	---
A03	1.43	0.09	14.38	0.90	3.75	0.23	0.92	0.06	0.41	0.03	0.03	0.01	0.00	0.00
A04	1.43	0.09	14.38	0.90	3.75	0.23	0.92	0.06	0.41	0.03	0.03	0.01	0.00	0.00
A05 ⁵	1.52	1.33	9.09	7.96	11.50	10.08	0.15	0.13	1.02	0.89	0.46	0.48	0.00	0.00
A05 ⁶	1.52	6.65	3.64	15.92	0.22	0.98	0.15	0.65	1.02	4.47	1.02	4.47	0.00	0.00
A06	0.43	1.29	3.11	9.34	3.33	9.99	0.05	0.15	0.05	1.08	0.16	0.48	0.00	0.00
A08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.05	0.01	0.01	0.00	0.00
A09a, A09b, A09c	0.22	0.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00	0.00
F02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00	0.00
F03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.05	0.01	0.00	0.00	0.00
F04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.01	0.00	0.00	0.00
F05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F05a	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F06a	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.00	0.00
F08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.00	0.00
F09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.00	0.00
F11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.32	1.39
Total PTE	39.03	37.94	88.11	165.4 6	29.05	90.23	45.32	14.06	3.81	13.85	2.26	8.94	10.28	45.01

¹ Annual emissions based on worst-case scenario of 480 hours/year of fuel oil combustion and 8,280 hours/year of natural gas combustion.

² Short-term emissions based on worst-case scenario between natural gas combustion and fuel oil combustion in the turbines

³ Emissions from the combustion of natural gas in the turbine, the emissions from the duct burners are included.

⁴ Emissions from the combustion of distillate oil in the turbine.

⁵ Emissions from Indeck/Volcano boiler (EU: A05) prior to installation of the low-NO_x burners and CO oxidation catalyst.

⁶ Emissions from Indeck/Volcano boiler (EU: A05) after installation of the low-NO_x burners and CO oxidation catalyst.

Table II-C-4: Emission Concentration Limitations in ppmvd

EU	O ₂ Standard	NO _x (ppmvd)		CO (ppmvd)	
		Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
A01 ¹	15%	10	17	10	10
A02 ¹	15%	10	17	10	10
A05 ²	3%	30	N/A	400	N/A
A05 ³	3%	12	N/A	1.2	N/A
A06	3%	30	N/A	400	N/A

¹ Emissions from the combustion of natural gas or distillate are calculated using a four-hour rolling average not to include startup or shutdown.

² Emission concentration limits for Indeck/Volcano boiler (EU: A05).

³ Emission concentration limits for Indeck/Volcano boiler (EU: A05) after completion of the boiler modification.

Table II-C-5: Startup and Shutdown Emissions per Emission Unit (pounds/hour)⁴

EU	PM ₁₀	NO _x	CO	SO _x	VOC	HAP	NH ₃
A01 ^{1,3}	2.5	65.00	9.00	0.27	0.94	0.46	2.04
A02 ^{1,3}	2.5	65.00	9.00	0.27	0.94	0.46	2.04
A01 ^{2,3}	17.00	104.00	9.00	21.64	0.17	0.54	2.04
A02 ^{2,3}	17.00	104.00	9.00	21.64	0.17	0.54	2.04
A05	1.87	9.11	9.24	0.15	1.34	0.47	---

¹ Emissions from the combustion of natural gas in the turbine.

² Emissions from the combustion of distillate oil in the turbine.

³ Startup has a duration of one hour.

⁴ Start-up and shut-down emission rates are to be used to calculate compliance with annual emissions limits. Emission factors will be used when CEMS data is not available.

Table II-C-6: Source Allowable Emissions¹

Pollutant	PM ₁₀	NO _x	CO	SO _x	VOC	HAP	NH ₃
lbs/hour	39.03	88.11	29.05	45.32	3.81	2.26	10.28
tons/year	37.94	165.46	90.23	11.30	13.86	8.95	45.01

¹ Total emissions are based on the worst-case scenario between natural gas combustion and fuel oil combustion in the turbines.

D. Testing

Performance testing is subject to 40 CFR 60 Subpart A; 40 CFR 60 Subpart GG; 40 CFR 60 Subpart Db; 40 CFR 60 Subpart Dc; DAQEM Guideline on Performance Testing and Section 49 of the Air Quality Regulations. Initial performance testing for the turbines was completed on May 14, 2002. Any additional required testing will be performed using the following methods:

Table II-D-1: Performance Testing Requirements (40 CFR 60, Appendix A)

Test Point	Pollutant	Method
Turbine Exhaust Stack	NO _x	Chemiluminescence Analyzer (EPA Method 7E)
Turbine Exhaust Stack	CO	EPA Method 10 analyzer
Turbine Exhaust Stack	VOC	EPA Method 25a
Turbine Exhaust Stack	NH ₃ Slip	Method Preapproved by DAQEM/EPA
Turbine Exhaust Stack	PM ₁₀	EPA Method 201/202 or 201A/202
Turbine Exhaust Stack	Opacity	EPA Method 9
Boiler Exhaust Stack	NO _x	Chemiluminescence Analyzer (EPA Method 7E)
Boiler Exhaust Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	---	EPA Methods 1, 2, 3, 4

Annual Relative Accuracy Test Audits (RATA) testing must be performed on each NO_x, CO, and O₂ Continuous Emissions Monitoring Systems (CEMS).

The amended OP issued in October 2002 includes performance testing requirements. Performance testing for turbine operation using natural gas shall be conducted annually and within 60 days of the anniversary date of the previous performance test. The performance testing is subject to DAQEM's "Guideline on Performance Testing" (Revised 09/05/03).

The performance testing for turbine operation using diesel fuel shall be conducted only prior to diesel fuel combustion. The source is permitted to operate each turbine unit (EU: A01 and A02) while combusting low sulfur diesel fuel (<0.05 percent sulfur by weight), only when all performance testing requirements are met. Combusting diesel fuel allows for continuous operation while the natural gas supply is disturbed. However, in practice the source was never required to use diesel fuel for regular operation, but conducted performance tests as scheduled. The tests required refitting of the equipment for diesel combustion and resulted in increased emissions of pollutants.

E. Continuous Emissions Monitoring

The pollutant-specific emission units at the facility are two GE natural gas-fired combined-cycle combustion turbine/generators, each equipped with low-NO_x burners (EUs: A01 and A02). These units are permitted to fire on hydrogen gas, natural gas and fuel No. 2 distillate oil. The exhaust gases will exit to the atmosphere after leaving the turbine, having already passed through an oxidation catalyst for CO control and selective catalytic reduction (SCR) system for NO_x control. There are also two auxiliary boilers that are used to provide continuous steam supply (EUs: A05 and A06).

According to EPA AP-42, Section 3.1.3.1, NO_x emissions are strongly dependent on the high temperatures developed in the combustor. The NO_x is formed by three different mechanisms. Thermal NO_x is formed during thermal dissociation and subsequent reaction of N₂ and O₂ molecules in the combustion air. Most thermal NO_x is formed in the high temperature stoichiometric flame pockets downstream of the fuel injections where combustion air has mixed sufficiently with the fuel to produce peak temperature at fuel/air interface. Prompt NO_x, which is formed from early reactions of N₂ molecules, is usually negligible when compared to the amount of thermal NO_x formed. The third mechanism, fuel NO_x, is negligible when natural gas is burned. Consequently, during natural gas combustion essentially all NO_x formed is thermal NO_x. Maximum reduction of thermal NO_x can be achieved by control of temperature, for given stoichiometry.

To demonstrate continuous direct compliance with all emission limitations for NO_x and CO specified in this permit, the source operates continuous emission monitoring system (CEMS) for NO_x, CO and O₂ on each turbine (EU: A01 and A02) and Indeck/Volcano boiler unit (EU: A05) in accordance with 40 CFR 60. Each CEMS includes an automated data acquisition and handling system. Each system shall monitor and record at least the following data:

- a. exhaust gas concentration of NO_x, CO and diluent O₂;
- b. exhaust gas flow rate (by direct or indirect methods);
- c. fuel flow rate,
- d. hours of operation;
- e. four-hour rolling averages for each of NO_x and CO concentration (EUs: A01 and A02),

- f. three-hour rolling averages for each of NO_x and CO (EU: A05);
- g. hourly , daily and quarterly accumulated mass emissions of NO_x, CO and NH₃;
- h. hours of downtime of the CEMS.

Each CEMS shall be installed, calibrated, operational, and certified prior to issuance of an operating permit. A quality assurance plan for all CEMS includes auditing schedules, reporting schedules, design specifications, and other quality assurance requirements for the each CEMS. Required periodic audit procedures and QA/QC procedures for CEMS shall conform to the provisions of 40 CFR 60 Subpart B, Appendix F. Relative accuracy test audits (RATA) of the CO, NO_x and O₂ CEMS shall be conducted at least annually. The facility shall install a fuel flow meter for each combined cycle turbine, each duct burner, and the auxiliary Indeck/Volcano boiler, and shall monitor the natural gas fuel flow rate of each emission unit with CEMS. The primary method for demonstrating compliance with this requirement is demonstrated by a Data Acquisition System (DAS).

SPC must also operate an ammonia predictive emissions monitoring system (PEMS) on each combined cycle emission unit stack. The ammonia PEMS is based on the principle that NO_x reduction occurs at a 1:1 molar ratio with ammonia. Typically though, more ammonia is injected than is "theoretically" needed because the physical process doesn't allow for ideal conditions like complete mixing, uniform ammonia flow, gas flow, temperature distributions, etc. The unreacted ammonia slips through the catalyst bed and out of the stack as ammonia emissions.

The PEMS uses two (2) NO_x readings, an ammonia flow reading and several constants to calculate an estimate of ammonia emissions. One (1) NO_x reading is from an analyzer at the SCR inlet, and the other is from the stack CEMS analyzer. These measure the change in NO_x across the SCR (always a reduction), which is converted to an ideal ammonia usage based on the stoichiometric principle noted above. This is then subtracted, on a molar basis, from actual ammonia usage and converted to an ammonia concentration going out of the stack. The calculation is carried out in the CEMS and stored in the computer that stores the CEMS parameters.

III. REGULATORY REVIEW

A. Local Regulatory Requirements

DAQEM has determined that the following public law, statutes and associated regulations are applicable:

1. Clean Air Act, as amended (CAAA), Authority: 42 U.S.C. § 7401, et seq.;
2. Title 40 of the Code of Federal Regulations (CFR); including Part 70 and others;
3. Nevada Revised Statutes (NRS), Chapter 445; Sections 401 through 601;
4. Portions of the AQR included in the State Implementation Plan (SIP) for Clark County, Nevada. SIP requirements are federally enforceable. All requirements from Authority to Construct permits and Section 16 Operating Permits issued by DAQEM are federally enforceable because these permits were issued pursuant to SIP-included sections of the AQR; and
5. Portions of the AQR not included in the SIP. These locally applicable requirements are locally enforceable only.

The Nevada Revised Statutes (NRS) and the Clean Air Act Amendments (CAAA) are public laws that establish the general authority for the Regulations mentioned.

The DAQEM Part 70 (Title V) Program received Final Approval on November 30, 2001 with publication of that approval appearing in the Federal Register December 5, 2001 Vol. 66, No. 234. AQR Section 19 - Part 70 Operating Permits [Amended 07/01/04] details the Clark County Part 70 Operating Permit Program. These regulations may be accessed on the Internet at: http://www.co.clark.nv.us/air_quality/Regs.htm

Local regulations contain sections that are federally enforceable and sections that are locally enforceable only. Locally enforceable only rules have not been approved by EPA for inclusion into the State Implementation Plan (SIP). Requirements and conditions that appear in the Part 70 OP which are related only to non-SIP rules are notated as locally enforceable only.

Table III-A-1: AQR Section 12 and 55 Summary Table

	PM ₁₀	NO _x	CO	SO _x	VOC	HAP
Source PTE (tpy)	37.94	165.46	90.23	11.30	13.86	8.95
Nonmajor Source	< 70 tpy	< 50 tpy	< 70 tpy	≤ 100 tpy	< 50 tpy	≤ 25 tpy

Discussion: SPC is a major source of NO_x, CO, and NH₃. As part of the original New Source Review Analysis all of these emissions triggered notice of proposed action.

Table III-A-2: Clark County DAQEM – Air Quality and State Implementation Plan with Facility Compliance or Requirement

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
0. Definitions	applicable definitions	yes	entire source
1. Definitions	applicable definitions – “Affected Facility”, “Air Contaminant”, “Air Pollution Control Committee”, “Area Source”, “Atmosphere”, “Board”, “Commercial Off-Road Vehicle Racing”, “Dust”, “Existing Facility”, “Existing Gasoline Station”, “Fixed Capital Cost”, “Fumes”, “Health District”, “Hearing Board”, “Integrated Sampling”, “Minor Source”, “Mist”, “New Gasoline Station”, “New Source”, “NIC”, “Point Source”, “Shutdown”, “Significant”, “Single Source”, “Smoke”, “Source of Air Contaminant”, “Special Mobile Equipment”, “Standard Commercial Equipment”, “Standard Conditions”, “Start Up”, “Stop Order”, “Uncombined Water”, and “Vapor Disposal System”	yes	entire source
2. Air Pollution Control Board	all subsections	yes	entire source
4. Control Officer	all subsections	yes	entire source
5. Interference with Control Officer	all subsections	yes	entire source
6. Injunctive Relief	all subsections	yes	entire source
8. Persons Liable for Penalties - Punishment: Defense	all subsections	yes	entire source

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
9. Civil Penalties	all subsections	yes	entire source
10. Compliance Schedule	when applicable; applicable subsections	yes	entire source
11. Ambient Air Quality Standards	applicable subsections	yes	entire source
12. Preconstruction Review for New or Modified Stationary Sources	All subsections <u>except</u> the following: § 12.2.18 HAP Sources in Clark County. § 12.2.20 Additional Requirements for STATIONARY SOURCES with Beryllium, Mercury, Vinyl Chloride, or Asbestos EMISSIONS in Clark County	yes	The turbine was installed and permitted before Section 12 applicability. There were no reported turbine modifications with emissions increases since installation. Section 12 applies to diesel-powered standby generator. The Part 70 OP requires NPC to comply with all applicable requirements with respect to new or modified emission units.
13. Emission Standards for Hazardous Pollutants	Condition A-37 is the EPA-required standard condition concerning asbestos.	no	entire source
14. New Source Performance Standards	CCAQR Section 14.1.56: Subpart GG Standards of Performance for Gas Turbines CCAQR Section 14.1.14: Subpart Db Standards of Performance for Industrial – Commercial – Institutional Steam Generating Units CCAQR Section 14.1.15: Subpart Dc - Standards of Performance for Industrial – Commercial – Institutional Steam Generating Units CCAQR Section 14.1.26: Subpart Kb - Standards of Performance for Storage Vessels for Petroleum Liquids	no	Turbines, Indeck/Volcano Boiler, Nebraska Boiler, Fuel Storage Tank
16. Operating Permits	all subsections	yes	entire source
17. Dust Control Permit and Construction Activities	all subsections	yes	entire source
18. Permit and Technical Service Fees	§ 18.1 Operating Permit Fees § 18.2 Annual Emission Unit Fees § 18.4 New Source Review Application Review Fee § 18.5 Part 70 Application Review Fee § 18.6 Annual Part 70 Emission Fee § 18.14 Billing Procedures	yes	entire source

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
19. Part 70 Operating Permit Federal Approval (11/25/01)	§ 19.2 Applicability § 19.3 Part 70 Permit Applications § 19.4 Part 70 Permit Content § 19.5 Permit Issuance, Renewal, Re-openings, and Revisions § 19.6 Permit Renewal by the EPA and Affected States § 19.7 Fee Determination and Certification	N/A	entire source
20. Emission Standards for Hazardous Air Pollutants for Source Categories	all subsections	yes	No emission unit is subject to a federal MACT standard.
21. Acid Rain Permits	all subsections	yes	An acid rain permit is not required.
22. Acid Rain Continuous Emissions Monitoring	all subsections	yes	An acid rain permit is not required.
24. Sampling and Testing - Records and Reports	§ 24.1 Requirements for installation and maintenance of sampling and testing facilities § 24.2 Requirements for emissions record keeping § 24.3 Requirements for the record format § 24.4 Requirements for the retention of records by the emission sources	yes	entire source
25.1 Upset/Breakdown, Malfunctions	§ 25.1 Requirements for the excess emissions caused by upset/breakdown and malfunctions	no	entire source
25.2 Upset/Breakdown, Malfunctions	§ 25.2 Reporting and Consultation	yes	entire source
26. Emission of Visible Air Contaminants	§ 26.1 Limit on opacity (\leq 20 percent for 3 minutes in a 60-minute period)	yes	entire source
28. Fuel Burning Equipment	Emission Limitations for PM	yes	entire source
29. Sulfur Contents of Fuel Oil	Sulfur content shall be equal to or less than 0.05 percent sulfur by weight	no	Turbines, Starter Engines
35. Diesel Engine Powered Electrical Generating Equipment	all subsections	yes	The Part 70 permit limits use of the emergency generator to testing, maintenance, and emergencies, and prohibits its use for dispatchable peak shaving.
40. Prohibitions of Nuisance Conditions	§ 40.1 Prohibitions	no	entire source
41. Fugitive Dust	§ 41.1 Prohibitions	yes	entire source
42. Open Burning	§ 42.2	no	entire source
43. Odors In the Ambient Air	§ 43.1 Prohibitions coded as Section 29	no	entire source
55. Preconstruction Review for New or Modified Stationary Sources in the 8-hour Ozone Nonattainment Area	all subsections	no	entire source
60. Evaporation and Leakage	all subsections	yes	entire source
70. Emergency Procedures	all subsections	yes	entire source

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
80. Circumvention	all subsections	yes	entire source
81. Provisions of Regulations Severable	all subsections	yes	entire source
90. Fugitive Dust from Open Areas and Vacant Lots	all subsections	no	entire source
91. Fugitive Dust from Unpaved Roads, Unpaved Alleys, and Unpaved Easement Roads	all subsections	no	entire source
92. Fugitive Dust from Unpaved Parking Lots	all subsections	no	entire source

AQR SECTION 11 - AMBIENT AIR QUALITY STANDARDS [Amended 07/01/04] (*in part*)

Discussion: Saguaro Power Company is a major source located in Hydrographic Area (HA) 212 (Las Vegas Valley). The source consists of two turbine generators, two starter engines, two boilers, one cooling tower and other equipment. Minor source baseline dates for NO_x (October 21, 1988) and SO₂ (June 29, 1979) have been triggered in HA 212.

DAQEM modeled the source using AERMOD to track the Prevention of Significant Deterioration (PSD) increment consumption. Stack data submitted by the applicant were supplemented with information available for similar emission units. Five years (1999 to 2003) of meteorological data from the McCarran Station and Desert Rock Station were used in the model. United States Geological Survey (USGS) 7.5-minute Digital Elevation Model (DEM) terrain data was used to calculate elevations. Table 1 presents the results of the modeling.

Table III-A-3: PSD Increment Consumption

Pollutant	Averaging Period	PSD Increment Consumption by the Source (µg/m ³)	Location of Maximum Impact	
			UTM X (m)	UTM Y (m)
SO ₂	3-hour	51.54 ¹	679215	3990313
SO ₂	24-hour	30.15 ¹	679215	3990313
SO ₂	Annual	0.20	679215	3990313
NO _x	Annual	5.14	679215	3990313

¹Modeled 2nd High Concentration

Table III-A-3 shows the location of the maximum impact and the potential PSD increment consumed by the source at that location. The impacts are below the PSD increment limits.

B. Federally Applicable Regulations

40 CFR PART 60-STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

Subpart A - General Provisions

40 CFR § 60.7-Notification and record keeping.

Discussion: This regulation requires notification to DAQEM of modifications, opacity testing, records of malfunctions of process equipment and/or continuous monitoring device, and performance test data. These requirements are found in the Part 70 OP. DAQEM requires records to be maintained for five years, a more stringent requirement than the two (2) years required by § 60.7.

40 CFR § 60.8 - Performance tests.

Discussion: These requirements are found in the Part 70 OP. Notice of intent to test, the applicable test methods, acceptable test method operating conditions, and the requirement for three runs are outlined in this regulation. DAQEM requirements for initial performance testing are identical to § 60.8. DAQEM also requires periodic performance testing on emission units based upon throughput or usage. More discussion is in this document under the compliance section.

40 CFR § 60.11 - Compliance with standards and maintenance requirements.

Discussion: Subpart GG also requires fuel monitoring and sampling to meet a standard. Subpart GG requirements are addressed in the Part 70 permit. Section 26 of the AQR is more stringent than the federal opacity standards, setting a maximum of 20 percent obscuration except for three (3) minutes in any 60-minute period. SPC shall operate in a manner consistent with this section of the regulation.

40 CFR § 60.12 – Circumvention.

Discussion: This prohibition is addressed in the Part 70 OP. This is also local rule § 80.1.

40 CFR § 60.13 - Monitoring requirements.

Discussion: This section requires that CEMS meet Appendix B and Appendix F standards of operation, testing and performance criteria. Part 70 OP contains the CEMS conditions and citations to Appendix B and F. In addition, the QA plan approved for the CEMS follows the requirements outlined including span time and recording time.

Subpart GG - Standards of Performance for Stationary Gas Turbines

40 CFR § 60.330 - Applicability and designation of affected facility.

Discussion: Subpart GG applies to two (2) turbines at this source.

40 CFR § 60.332 - Standard for nitrogen oxides.

Discussion: See Table IV-C-1.

40 CFR § 60.333 - Standard for sulfur dioxide.

Discussion: See Table IV-C-1. The sole use of pipeline-quality natural gas with total sulfur content less than 0.8 percent (8000 ppmw) satisfies this requirement.

40 CFR § 60.334 - Monitoring of operations.

Discussion: The source installed, calibrated, maintains and operates a continuous monitoring system.

40 CFR § 60.335 - Test methods and procedures.

Discussion: These requirements are found in the conditions for performance testing found in the Part 70 OP.

Subpart Db - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

40 CFR § 60.40b – Applicability and delegation of authority.

Discussion: The auxiliary Volcano boiler (EU: A05) is subject to the provisions of this subpart. It has a rated capacity of 249 MMBtu per hour.

40 CFR § 60.42b – Standard for sulfur dioxide (SO₂).

Discussion: This section does not pertain to boilers that exclusively fire natural gas.

40 CFR § 60.43b – Standard for particulate matter (PM).

Discussion: This section does not pertain to boilers that exclusively fire natural gas.

40 CFR § 60.44b – Standard for nitrogen oxides (NO_x).

Discussion: See Table IV-C-1.

Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR § 60.40c – Applicability and delegation of authority.

Discussion: The auxiliary Nebraska boiler (EU: A06) is rated 86 MMBtu per hour; therefore, Subpart Dc is applicable to this emission unit.

40 CFR § 60.42c – Standard for sulfur dioxide (SO₂).

Discussion: This section does not pertain to boilers that exclusively fire natural gas.

40 CFR § 60.43c – Standard for particulate matter (PM).

Discussion: This section does not pertain to boilers that exclusively fire natural gas.

40 CFR § 60.48c – Reporting and recordkeeping requirements.

Discussion: These are addressed in the Part 70 operating permit.

Subpart Kb - Standards of Performance for Organic Volatile Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

40 CFR § 60.110b – Applicability and designation of affected facility,

Discussion: The fuel storage tank (EU: A08) is not a subject to the provisions of this subpart because a storage vessel capacity is greater than 151 cubic meters (m³) and the maximum true vapor pressure of the stored liquid is less than 3.5 kilopascals (kPa).

Subpart KKKK - Standards of Performance for Stationary Combustion Turbines

40 CFR § 60.4305 – Applicability.

Discussion: The two (2) turbines (EUs: A01 and A02) are not subject to the provisions of this subpart because these turbines commenced construction, modification, or reconstruction before February 18, 2005.

40 CFR PART 64 - COMPLIANCE ASSURANCE MONITORING

40 CFR § 64.2 – Applicability.

Discussion: The CAM Rule is not applicable to the auxiliary boilers (EUs: A05 and A06), the starter engines (EUs: A03 and A04), or the fuel oil storage (EU: A08) based on the applicability statement outlined in 40 CFR 64.2(a) (2), i.e., no control devices are used on these units to achieve compliance with any emission limitation or standard for a regulated air pollutant. The gas turbines are exempt from the CAM Rule for NO_x and CO based on the exemption outlined in 40 CFR 64.2(b)(1)(vi). The permit specifies a continuous compliance determination method for the NO_x and CO limitations in the form of a CEMS, required for Part 60 compliance. The CAM Rule is not applicable to these units for SO_x based on the applicability statement outlined in 40 CFR 64.2(a) (2). The CAM Rule is not applicable to these units for PM₁₀, HAPs or NH₃ based on the applicability statement outlined 40 CFR 64.2(a) (2). Combustion turbines/duct heaters (EUs: A01 and A02) are also not CAM-applicable for VOC emissions based on the exemption outlined in 40 CFR 64.2(a) (3), i.e., the potential pre-control emissions are less than the major threshold.

40 CFR PART 72 - ACID RAIN PERMITS REGULATION

Subpart A – Acid Rain Program General Provisions

40 CFR § 72.6 – Applicability.

Discussion: SPC is the cogeneration facility exempted based on the applicability criteria defined in Part 72.6 (b)(5); therefore, the provisions of this regulation do not apply.

40 CFR PART 73 – ACID RAIN SULFUR DIOXIDE ALLOWANCE SYSTEM

Discussion: SPC is not a subject of 40 CFR Part 72; therefore, the provisions of this regulation do not apply.

40 CFR PART 75 - CONTINUOUS EMISSION MONITORING

Discussion: SPC is not subject to the Acid Rain emission limitations of 40 CFR Part 72; therefore, the facility is not subject to the monitoring requirements of this regulation.

IV. COMPLIANCE

A. Compliance Certification

19.3.3.9 Requirements for compliance certification:

(a) Regardless of the date of issuance of this Part 70 OP, the schedule for the submittal of reports to the DAQEM Compliance Reporting Supervisor shall be as follows:

Table IV-A-1: Reporting Schedule

Quarter	Applicable Period	Due Date	Required Contents
1	January, February, March	April 30 each year	Quarterly Report for 1 st Calendar Quarter
2	April, May, June	July 30 each year	Quarterly Report for 2 nd Calendar Quarter
3	July, August, September	October 30 each year	Quarterly Report for 3 rd Calendar Quarter
4	October, November, December	January 30 each year	Quarterly Report for 4 th Calendar Quarter
4	Calendar Year	January 30 Each year	Annual Compliance Certification Report

¹ If the due date falls on a Saturday, Sunday or legal holiday, then the submittal is due on the next regularly scheduled business day.

- (b) A statement of methods used for determining compliance, including a description of monitoring, recordkeeping, and reporting requirements and test methods.
- (c) A schedule for submission of compliance certifications during the permit term.
- (d) A statement indicating the source's compliance status with any applicable enhanced monitoring and compliance certification requirements of the Act.

B. Compliance Summary

Table IV-B-1: Compliance Summary Table - AQR

Citation	Title	Applicability	Applicable Test Method	Compliance Status
CCAQR Section 0	Definitions.	Applicable – SPC will comply with all applicable definitions as they apply.	SPC will meet all applicable test methods should new definitions apply.	SPC complies with applicable requirements.
CCAQR Section 4	Control Officer.	Applicable – The Control Officer or his representative may enter into SPC property, with or without prior notice, at any reasonable time for purpose of establishing compliance.	SPC will allow Control Officer to enter Station property as required.	SPC complies with applicable requirements.
CCAQR Section 11 [Ambient Air Quality Standards.	Applicable – SPC is a source of air pollutants.	SPC demonstrated compliance in the ATC permit application with air dispersion modeling.	SPC complies with applicable requirements.
CCAQR Section 12.1	General application requirements for construction of new and modified sources of air pollution.	Applicable – SPC applied for and the ATC permit was issued before commencing construction.	SPC received the ATC permit to construct.	SPC complies with applicable requirements.
CCAQR Section 12.2.2	Requirements for specific air pollutants: PM ₁₀ emission source located in the Serious Non-Attainment Area.	Applicable – SPC has PM ₁₀ PTE < 70 TPY.	All new or modified emission units at the SPC will meet LAER requirement.	SPC complies with applicable requirements.
CCAQR Section 12.2.7	Requirements for specific air pollutants: CO sources located in the Serious Non-Attainment Area.	Applicable – SPC has CO PTE > 70 TPY.	All new or modified emission units at the SPC will meet LAER requirement.	SPC complies with applicable requirements.
CCAQR Section 12.2.12	Requirements for specific air pollutants: VOC sources located in the VOC Management Area.	Not Applicable – SPC is located in Hydrographic Area 212.	Not Applicable.	Not Applicable.
CCAQR Section 12.2.14	Requirements for specific air pollutants: NO _x sources located in the NO _x Management Area.	Applicable – SPC has NO _x PTE > 50 TPY.	All new or modified emission units at the SPC will meet BACT requirement.	SPC complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
CCAQR Section 12.2.16	Requirements for specific air pollutants: SO ₂ sources located in the PSD area.	Applicable – SPC has SO ₂ PTE > 40 TPY.	All new or modified emission units at the SPC will meet BACT requirement.	SPC complies with applicable requirements. Sulfur content of natural gas will not exceed 0.75 grains per 100 dscf (based on 12-month rolling average).
CCAQR Section 12.2.19	Requirements for specific air pollutants: TCS sources in Clark County	Applicable – SPC does have ammonia (NH ₃) emissions at 45.01 TPY and NH ₃ is a locally regulated TCS. The BACT requirement for NH ₃ is 10 ppm or less for ammonia slip, and acceptable monitoring.	The BACT requirement for NH ₃ is 10 ppm or less NH ₃ slip, and acceptable monitoring. The CTGs/HRSGs meet BACT requirements based on meeting the 10-ppm NH ₃ slip limit with PEMS monitoring.	SPC complies with applicable requirements.
CCAQR Section 12.5	Air Quality Models	Applicable – Dispersion modeling will be performed as required for any future major modifications.	As applicable, future dispersion modeling will be performed in ATC permit modifications will be in accordance with provisions of 40 CFR Part 51, Appendix W.	SPC complies with applicable requirements.
CCAQR Section 12.7	Continuous Emission Monitoring (CEM) Systems	Applicable – SPC has NO _x and CO PTE > 100 TPY. NO _x and CO CEMS installed on all stacks and meets provisions of 40 CFR Parts 60 and 75.	Station submitted all required protocols/test plans per ATC permit prior to CEMS certification. CEMS certification was approved by DAQEM.	Station complies with applicable requirements.
CCAQR Section 14.1.1 Subpart A	New Source Performance Standards (NSPS) General Provisions	Applicable – SPC is an affected facility under the regulations. Section 14 is locally enforceable; however, the NSPS standards referenced are federally enforceable.	Applicable monitoring, recordkeeping and reporting requirements.	SPC complies with applicable requirements.
CCAQR Section 14.1.14 Subpart Db	New Source Performance Standards – Standards of Performance for Industrial - Commercial – Institutional Steam Generating Units	Applicable – SPC has the natural gas-fired steam generating unit with heat input greater than 100 MMBtu/hr.	The Volcano boiler meets the applicable NO _x emission standard. NO _x emissions determined by EPA Method 7E.	SPC complies with applicable requirements.
CCAQR Section 14.1.15 Subpart Dc	New Source Performance Standards – Standards of Performance for Small Industrial - Commercial – Institutional Steam Generating Units	Applicable – SPC has the natural gas-fired steam generating unit with heat input less than 100 MMBtu/hr, but greater than 10 MMBtu/hr.	The Nebraska boiler meets the applicable NO _x emission standard. NO _x emissions determined by EPA Method 7E.	SPC complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
CCAQR Section 14.1.56 Subpart GG	Standards of Performance for New Stationary Sources (NSPS) – Stationary Gas Turbines	Applicable – The two (2) SPC turbines are natural gas-fired units with heat input greater than 10 MMBtu/hr.	The two (2) turbines meet the applicable NO _x emission standard. NO _x emissions determined by EPA Method 7E.	SPC complies with applicable requirements.
CCAQR Section 16	DAQEM Operating Permits	Applicable – Any emission unit of stationary source must apply for and obtain a DAQEM operating permit Station applied for the operating permit from DAQEM.	SPC applied for and received operating permit from DAQEM prior to commercial operation.	SPC complies with applicable requirements.
CCAQR Section 17	Dust Control Permit for Construction Activities Including Surface Grading and Trenching	Applicable – SPC will need to apply for dust control permit in event construction activity greater than ¼ acre (aggregate) or trench at least 100 ft in length (and aggregate acreage greater than ¼ acre).	SPC applied for permits as needed during initial construction and conformed to required best management practices in dust control permit. Station will continue to do so in future as needed.	SPC complies with applicable requirements.
CCAQR Section 18	Permit and Technical Service Fees	Applicable – SPC will be required to pay all required/applicable permit and technical service fees.	SPC is required to pay all required/applicable permit and technical service fees.	SPC complies with applicable requirements.
CCAQR Section 19	40 CFR Part 70 Operating Permits	Applicable – SPC is a major stationary source and under Part 70 the initial Title V permit application was submitted as required. Renewal applications are due between 6 and 18 months prior to expiration. Revision applications will be submitted within 12 months or commencing operation of any new emission unit. Section 19 is both federally and locally enforceable	SPC reviewed the initial Part 70 permit dated January 15, 2003. This renewal application was submitted before June 15, 2007. Applications for new units will be submitted within 12 months of startup.	SPC complies with applicable requirements.
CCAQR Section 21	Acid Rain Permits	Not Applicable – SPC is exempt from acid rain regulations based on 40 CFR 72.6 (b)(5).	Not Applicable.	Not Applicable.
CCAQR Section 22	Acid Rain Continuous Emission Monitoring	Not Applicable – SPC is exempt from acid rain regulations based on 40 CFR 75.2 (b)(2).	Not Applicable.	Not Applicable.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
CCAQR Section 25	Upset/Breakdown, Malfunctions	Applicable – Any upset, breakdown, emergency condition, or malfunction which causes emissions of regulated air pollutants in excess of any permit limits shall be reported to Control Officer. Section 25.1 is locally and federally enforceable.	Any upset, breakdown, emergency condition, or malfunction in which emissions exceed any permit limit shall be reported to the Control Officer within one (1) hour of onset of such event.	SPC complies with applicable requirements.
CCAQR Section 26	Emissions of Visible Air Contaminants	Applicable – Opacity for the SPC combustion turbine must not exceed 20 percent for more than three (3) minutes in any 60-minute period.	Compliance determined by EPA Method 9	SPC complies with applicable requirements.
CCAQR Section 27	Particulate Matter from Process Weight Rate	Applicable – SPC emission units are required to meet the maximum weight based on maximum design rate of equipment.	Compliance determined by meeting maximum particulate matter discharge rate based on process rate from AQR Table 27-1.	SPC complies with applicable requirements.
CCAQR Section 28	Fuel Burning Equipment	Applicable – The PM emission rate for the combustion the turbines and boilers is well below those established based on Section 28 requirements.	Maximum allowable PM emission rate determined from equation in Section 28.	SPC complies with applicable requirements.
CCAQR Section 29	Sulfur Content of Fuel Oil	Applicable – The diesel fuel that will be burned in the emergency generator engine at the SPC will require low sulfur fuel with sulfur content less than 0.05 percent by weight. Section 29 is locally enforceable only.	Fuel sulfur content verification obtained from fuel oil supplier.	SPC complies with applicable requirements.
CCAQR Section 40	Prohibition of Nuisance Conditions	Applicable – No person shall cause, suffer or allow the discharge from any source whatsoever such quantities of air contaminants or other material which cause a nuisance. Section 40 is locally enforceable only.	SPC air contaminant emissions controlled by pollution control devices or good combustion in order not to cause a nuisance.	SPC complies with applicable requirements.
CCAQR Section 41	Fugitive Dust	Applicable – SPC shall take necessary actions to abate fugitive dust from becoming airborne.	Station utilizes appropriate best practices to not allow airborne fugitive dust.	SPC complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
CCAQR Section 42	Open Burning	Applicable – In event SPC burns combustible material in any open areas, such burning activity will have been approved by Control Officer in advance. Section 42 is a locally enforceable rule only.	SPC will contact the DAQEM and obtain approval in advance for applicable burning activities as identified in the rule.	SPC complies with applicable requirements.
CCAQR Section 43	Odors in the Ambient Air	Applicable – An odor occurrence is a violation if the Control Officer is able to detect the odor twice within a period of an hour, if the odor causes a nuisance, and if the detection of odors is separated by at least fifteen minutes. Section 43 is a locally enforceable rule only.	SPC will not operate its facility in a manner which will cause odors. SPC is a natural gas fired facility and is not expected to cause odors.	SPC complies with applicable requirements.
CCAQR Section 49	Emission Standards for Boilers and Steam Generators Burning Fossil Fuels	Applicable – The SPC auxiliary boilers are subject to performance testing and burner efficiency testing requirements. The heat recovery steam generators (HRSG) are exempt under Section 49.3.2.	SPC submitted required test protocols prior to initial performance testing. Tests reported within 60 days. DAQEM approves test reports.	SPC complies with applicable requirements.
CCAQR Section 55	Preconstruction review for New or Modified Stationary Sources in the 8-Hour Ozone Nonattainment Area	Applicable – SPC is located in Las Vegas Valley airshed (hydrographic area 212) and will need to meet the applicable emission control requirements at times of future modifications.	In the event Station undertakes a major modification, the facility will have to apply BACT and LAER control requirements.	SPC complies with applicable requirements.
CCAQR Section 70.4	Emergency Procedures	Applicable – SPC submitted an emergency standby plan for reducing or eliminating air pollutant emissions in the Section 16 Operating Permit Application.	SPC submitted an emergency standby plan and received the Section 16 Operating Permit.	SPC complies with applicable requirements.

Table IV-B-2: Compliance Summary Table – Federal Regulations

Citation	Title	Applicability	Applicable Test Method	Compliance Status
40 CFR Part 52.21	Prevention of Significant Deterioration (PSD)	Applicable – SPC PTE > 100 TPY and is listed as one of the 28 source categories.	BACT analysis, air quality analysis using modeling, and visibility and additional impact analysis performed for original ATC permits.	SPC complies with applicable sections as required by PSD regulations.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
40 CFR Part 52.1470	SIP Rules	Applicable – SPC is classified as a Title V source, and SIP rules apply.	Applicable monitoring and record keeping of emissions data.	SPC is in compliance with applicable state SIP requirements including monitoring and record keeping of emissions data.
40 CFR Part 60, Subpart A	Standards of Performance for New Stationary Sources (NSPS) – General Provisions	Applicable – SPC is an affected facility under the regulations.	Applicable monitoring, recordkeeping and reporting requirements.	SPC complies with applicable requirements.
40 CFR Part 60, Subpart Db	Standards of Performance for New Stationary Sources (NSPS) – Industrial-Commercial-Institutional Steam Generating Units	Applicable – SPC has emission units that are subject to the requirements of this subpart.	Applicable monitoring, recordkeeping and reporting requirements.	SPC complies with applicable requirements.
40 CFR Part 60, Subpart Dc	Standards of Performance for New Stationary Sources (NSPS) – Small Industrial-Commercial-Institutional Steam Generating Units	Applicable – SPC has emission units that are subject to the requirements of this subpart.	Applicable monitoring, recordkeeping and reporting requirements.	SPC complies with applicable requirements.
40 CFR Part 60, Subpart GG	Standards of Performance for New Stationary Sources (NSPS) – Stationary Gas Turbines	Applicable – The SPC two turbines are natural gas-fired units with heat input greater than 10 MMBtu/hr.	Applicable monitoring, recordkeeping and reporting requirements.	SPC complies with applicable requirements.
40 CFR Part 60	Appendix A, Method 9 or equivalent, (Opacity)	Applicable – Emissions from stacks are subject to opacity standards.	Opacity determined by EPA Method 9.	SPC complies with applicable requirements.
40 CFR Part 63	Emission Standards for Hazardous Air Pollutants	Not Applicable – SPC has a total HAPs limit less than an aggregate total of 25 TPY. No single HAP is greater than 10 TPY.	Not Applicable.	Not Applicable.
40 CFR Part 64	Compliance Assurance Monitoring	Not Applicable – SPC have CEMS to monitor NO _x and CO emissions, the NH ₃ emissions are continuously monitored with PEMS. SPC is exempt from CAM regulations based on 40 CFR 64.2 (b)(1)(Vi).	SPC continuously monitors NO _x and CO emissions with CEMS. NH ₃ emissions are monitored with PEMS.	SPC complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
40 CFR Part 68	Chemical Accident Prevention Provisions	Applicable – SPC stores and handles anhydrous ammonia (NH ₃).	Construction approval and a Risk Management Plan (RMP) were required for the Nevada Department of Environmental Protection for storage and use of NH ₃ . SPC adheres to SPC management programs.	SPC complies with applicable requirements.
40 CFR Part 70	Federally Mandated Operating Permits	Applicable – SPC is a major stationary source and under Part 70 the initial Title V permit application was submitted as required. Renewal applications are due between 6 and 18 months prior to expiration. Revision applications will be submitted within 12 months or commencing operation of any new emission unit.	SPC reviewed the initial Part 70 permit dated February 29, 2000. The renewal application was submitted on June 18, 2003. Applications for new units will be submitted within 12 months of startup.	SPC complies with applicable requirements.
40 CFR Part 72	Acid Rain Permits Regulation	Not Applicable – SPC is exempt from acid rain regulations based on 40 CFR 72.6 (b)(4).	Not Applicable.	Not Applicable.
40 CFR Part 73	Acid Rain Sulfur Dioxide Allowance System	Not Applicable – SPC is exempt from acid rain regulations based on 40 CFR 73.2 (a).	Not Applicable.	Not Applicable.
40 CFR Part 75	Acid Rain CEMS	Not Applicable – SPC is exempt from acid rain regulations based on 40 CFR 75.2 (b)(2).	Not Applicable.	Not Applicable.
40 CFR Part 82	Protection of Stratospheric Ozone	Applicable – SPC is subject to stratospheric ozone regulations based on 40 CFR 82.4.	Applicable.	Applicable.

C. 40 CFR Subparts Db, Dc and GG Streamlining Demonstration for Shielding Purposes

Table IV-C-1: Streamlining Demonstration

Regulation (40 CFR)	Regulatory Standard	Permit Limit	Value Comparison				Averaging Period Comparison			Streamlining Statement for Shielding Purposes
			Relevant Heat Input or Load Level ¹	Standard Value, in Units of the Permit Limit	Permit Limit Value	Is Permit Limit Equal or More Stringent?	Standard Averaging Period	Permit Limit Averaging Period	Is Permit Limit Equal or More Stringent?	
60.332 (GG)	75 ppmvd NO _x @ 15% O ₂ ⁽¹⁾	10.0 ppmvd NO _x @ 15% O ₂ (natural gas)	N/A	75 ⁽¹⁾	10.0	Yes	4 hour	4 hour	Yes	The permit limit is more stringent than the standard, based upon both concentration and averaging time. Compliance with the permit demonstrates compliance with the standard.
60.332 (GG)	75 ppmvd NO _x @ 15% O ₂ ⁽¹⁾	17.0 ppmvd NO _x @ 15% O ₂ (fuel oil)	N/A	75 ⁽¹⁾	17.0	Yes	4 hour	4 hour	Yes	The permit limit is more stringent than the standard, based upon both concentration and averaging time. Compliance with the permit demonstrates compliance with the standard.
60.333 (GG)	150 ppmvd (326 lbs/hr) SO _x @ 15% O ₂ ⁽¹⁾	0.27 lb/hr SO _x @ 15% O ₂ (natural gas)	N/A	326	0.27	Yes	4 hour	4 hour	Yes	The permit limit is more stringent than the standard, based upon both concentration and averaging time. Compliance with the permit demonstrates compliance with the standard.
60.333	0.8% of S by weight	0.05% of S by weight	N/A	0.8	0.05	Yes	N/A	N/A	N/A	The permit limit is more stringent than the standard, based

Regulation (40 CFR)	Regulatory Standard	Permit Limit	Value Comparison				Averaging Period Comparison			Streamlining Statement for Shielding Purposes
			Relevant Heat Input or Load Level ¹	Standard Value, in Units of the Permit Limit	Permit Limit Value	Is Permit Limit Equal or More Stringent?	Standard Averaging Period	Permit Limit Averaging Period	Is Permit Limit Equal or More Stringent?	
(GG)										upon both concentration. Compliance with the permit demonstrates compliance with the standard.
60.43b (Db)	20% Opacity	20% Opacity	N/A	20	20	Yes	60-minute period, excepting 6 minutes	60-minute period, excepting 3 minutes	Yes	The permit limit is more stringent than the standard, based upon averaging time/duration allowed. Compliance with the permit demonstrates compliance with the standard.
60.44b (Db)	0.20 lb NO _x per MMBtu (192 ppm @ 15% O ₂)	12.0 ppm NO _x @ 15% O ₂	N/A	192.0	12.0	Yes	30-day rolling	3 hour	Yes	The permit limit is more stringent than the standard, based upon both concentration and averaging time. Compliance with the permit demonstrates compliance with the standard.
60.42c (Dc)	SO ₂ Standards Not Applicable for Natural Gas	0.05 lbs/hr, Natural Gas	N/A	N/A	0.05 lbs/hr	Yes	N/A	N/A	N/A	Federal standard is not applicable for Natural Gas. The permit limit is more stringent
60.43c (Dc)	PM Standards Not Applicable for Natural Gas	0.43 lbs/hr, Natural Gas	N/A	N/A	0.43 lbs/hr	Yes	N/A	N/A	N/A	Federal standard is not applicable for Natural Gas. The permit limit is more stringent

Regulation (40 CFR)	Regulatory Standard	Permit Limit	Value Comparison				Averaging Period Comparison			Streamlining Statement for Shielding Purposes
			Relevant Heat Input or Load Level ¹	Standard Value, in Units of the Permit Limit	Permit Limit Value	Is Permit Limit Equal or More Stringent?	Standard Averaging Period	Permit Limit Averaging Period	Is Permit Limit Equal or More Stringent?	
	Gas									

¹ The 60.332 NO_x standard is a formula; the value used here (75 ppmvd) is the minimum possible value of the standard for any emission unit.

Note: Formulas used: $EF = Cd * Cf * Fd * 20.9 / (20.9 - \%O_2)$ and $E = EF * HI$

where:

EF = emission rate (lb/MMBtu);

Cd = emission concentration (ppmvd);

Cf for NO_x = 1.194E-07 (lb NO_x/dscf ppm);

Fd = 8,710 dscf/MMBtu, dry basis F factor for O₂ dilution for natural gas;

%O₂ = 15% (the oxygen volume at the stated limit);

E = mass emission rate (lb/hr); and

HI = heat input (MMBtu/hr).

D. Summary of Monitoring for Compliance

Table IV-D-1: Compliance Monitoring

EU	Process Description	Monitored Pollutants	Applicable Subsection Title	Requirements	Compliance Monitoring
A01, A02 F05/F05a F06/F06a	Combustion turbines/duct burner units	CO, NO _x , SO ₂ , PM ₁₀ , VOC, HAPs, NH ₃	Section 12, Section 19, Section 55 40 CFR Subpart GG 40 CFR Subpart Db	Annual and short-term emission limits.	CEMS for NO _x and CO. PEMS for NH ₃ . Stack testing for NO _x and CO by EPA Methods as outlined in Part 70 Permit. Compliance for PM ₁₀ , SO ₂ , VOC and HAPs shall be based on sole use of pipeline quality natural gas as fuel and emission factors. Compliance for PM ₁₀ , SO ₂ , VOC and HAPs shall be based on sole use of low sulfur diesel fuel and emission factors. Recording is required for compliance demonstration.
A01, A02 F05/F05a F06/F06a	Combustion turbines/duct burner units	Opacity	AQR Section 26	Less than twenty percent opacity except for three (3) minutes in any 60-minute period.	Use of natural gas as fuel and good combustion practices as well as EPA Method 9 performance testing upon the request of the Control Officer.

EU	Process Description	Monitored Pollutants	Applicable Subsection Title	Requirements	Compliance Monitoring
A05	Auxiliary boiler	CO, NO _x , SO ₂ , PM ₁₀ , VOC, HAPs	Section 12, Section 19, Section 49, Section 55 40 CFR Subpart Db	Annual and short-term emission limits.	<p>CEMS for NO_x and CO.</p> <p>PEMS for NH₃.</p> <p>Stack testing for NO_x and CO by EPA Methods as outlined in Part 70 Permit.</p> <p>Compliance for PM₁₀, SO₂, VOC and HAPs shall be based on sole use of pipeline quality natural gas as fuel and emission factors.</p> <p>Compliance for PM₁₀, SO₂, VOC and HAPs shall be based on sole use of low sulfur diesel fuel and emission factors.</p> <p>Recording is required for compliance demonstration.</p>
A06	Auxiliary boiler	CO, NO _x , SO ₂ , PM ₁₀ , VOC, HAPs	Section 12, Section 19, Section 49, Section 55 40 CFR Subpart Dc	Annual and short-term emission limits.	<p>Stack testing for NO_x and CO by EPA Methods as outlined in Part 70 Permit.</p> <p>Compliance for PM₁₀, SO₂, VOC and HAPs shall be based on sole use of natural gas as fuel and emission factors.</p> <p>Recording is required for compliance demonstration.</p>
A05, A06	Auxiliary boilers	Opacity	AQR Section 26	Less than twenty percent opacity except for three (3) minutes in any 60-minute period.	Sole use of natural gas as fuel and EPA Method 9 performance testing upon the request of the Control Officer.

EU	Process Description	Monitored Pollutants	Applicable Subsection Title	Requirements	Compliance Monitoring
A03, A04	Starter Engines	CO, NO _x , SO ₂ , PM ₁₀ , VOC, HAPs	Section 12, Section 19, Section 55	Annual and short-term emission limits.	Compliance for regulated pollutants shall be based on sole use of low-sulfur diesel fuel and emission factors. Recording is required for compliance demonstration.
A03, A04	Starter Engines	Opacity	AQR Section 26	Less than twenty percent opacity except for three (3) minutes in any 60-minute period.	Sole use of low-sulfur diesel fuel and EPA Method 9 performance testing upon the request of the Control Officer.

V. EMISSION REDUCTION CREDITS (OFFSETS)

The source is subject to offset requirements in accordance with Section 59 of the Clark County Air Quality Regulations. Offset requirements and associated mitigation are pollutant-specific.

VI. ADMINISTRATIVE REQUIREMENTS

Section 19 requires that DAQEM identify the original authority for each term or condition in the Part 70 Operating Permit. Such reference of origin or citation is denoted by [*italic text in brackets*] after each Part 70 Permit condition.

DAQEM proposes to issue the Part 70 Operating Permit conditions on the following basis:

Legal:

On December 5, 2001 in Federal Register Volume 66, Number 234 FR30097 the EPA fully approved the Title V Operating Permit Program submitted for the purpose of complying with the Title V requirements of the 1990 Clean Air Act Amendments and implementing Part 70 of Title 40 Code of Federal Regulations.

Factual:

Saguaro Power Company has supplied all the necessary information for DAQEM to draft Part 70 Operating Permit conditions encompassing all applicable requirements and corresponding compliance.

Conclusion:

DAQEM has determined that SPC will continue to determine compliance through the use of CEMS, PEMS, performance testing, quarterly reporting, and daily recordkeeping, coupled with annual certifications of compliance. DAQEM proceeds with the decision that a Part 70 Operating Permit should be issued as drafted to SPC for a period not to exceed five (5) years.



DEPARTMENT OF AIR QUALITY & ENVIRONMENTAL MANAGEMENT

500 S Grand Central Parkway 1st Fl · Box 555210 · Las Vegas, NV 89155-2510
(702) 455-5942 · Fax (702) 383-9994

Lewis Wallenmeyer Director · Alan Pinkerton Assistant Director · Tina Gingras Assistant Director

**FINAL ACTION REPORT PART 70 OPERATING PERMIT
RENEWAL**

**Saguaro Power Company
Source: 393**

Public Notice: Review-Journal May 4, 2009
Public Comments: May 4, 2009 to June 2, 2009

Comments Received:
Saguaro Power Company, Inc.

Public Hearings: No public hearing was held.

Issuance date: August 10, 2009
Expiration date: August 09, 2014

Copies of comments received and responses to those comments are part of this final action report. All responders shall receive an electronic copy of this report, the final Part 70 OP (Title V), and the final TSD.

**COMMENTS RECEIVED FROM SAGUARO POWER COMPANY AND DAQEM
RESPONSE**

DAQEM received comments for the source on May 11, 2009 and the complete comments are provided. DAQEM incorporated the suggested changes as applicable. The responses are provided below:

1. All of the emission limits presented in table IV-B-1 of the draft permit were compared with corresponding limits in the Authority to Construct/Operating Permit (ATC/OP) Modification 7, Revision 2. Several values listed in the draft table are higher than the ATC/OP Modification 7, Revision 2 values. Sulfur oxide (SO_x) emissions for EUs: A01 and A02 have increased from 5.19 tons to 6.30 tons, while Hazardous Air Pollutants (HAPs) emissions for EU: A06 has increased, from 0.40 tons to 0.48 tons. Saguaro believes these changes in value may be typographical errors and wanted to point them out to the agency.

DAQEM Response:

The Authority to Construct (ATC), Modification 7, Revision 2, includes replacement of the 249 MMBtu/hr steam boiler (EU: A06) and installation of the new low-NO_x burners and CO oxidation catalyst. The replacement of the boiler is not finalized, and the source PTE for HAPs is based on ATC/OP Modification 6, Amendment 1. The SO_x emissions from turbines when burning fuel oil were calculated as follows:

$3,035 \text{ gallons/hour} * 7.13 \text{ pounds/gallon} * 0.05/100 (\% \text{ S}) * 64 \text{ pounds/pound-mol SO}_2 / 32 \text{ pounds/pound-mol S} = 21.64 \text{ pounds/hour SO}_2$
 $21.64 \text{ pounds/hour} * 480 \text{ hours/year} / 2,000 \text{ pounds/ton} = 5.19 \text{ tons/year}$

The SO_x PTE for turbines (EU: A01 and A02) did not account for SO_x emissions from the natural gas burning and these emissions are added to the annual PTE for the turbines. The corrected PTE is included in the Part 70 OP.

2. There appears to be a typographical mistake in the draft permit Section IV.B.2.p. The referenced table in this section should be Table IV-B-4, not Table IV-B-3. The fourth footnote in Table IV-B-4 states, "emission factors in the table will be used when CEMS data is not available". The same wording should be included in the Section B.2.p, since both areas (Table IV-B-4 and Section IV.B.2.p) are addressing emission factors for the Volcano boiler (EU A05). Once the language from the Table's IV-B-4 fourth footnote is incorporated into Section IV.B.2.p, BAI suggests that Section B.2.p should state the following, *The Permittee shall use emission factors presented in Table IV-B-4, for any clock hour in which a start-up/shut-down event occurs and valid CEMS data are not available.*

DAQEM Response:

The proposed language was included in the Part 70 OP.

3. Section IV.B.3.m in the draft permit requires an eight-hour rolling average be recorded for emissions from the Nebraska boiler (EU A06). CEMS monitoring is not required for the Nebraska boiler. Saguro plans to show compliance with the emission limits for EU: A06 by performing periodic performance tests and complying with semi-annual burner efficiency tests (boiler tune-ups) as outlined in the Section IV.D, and requests that the eight-hour rolling average wording be removed from the permit.

DAQEM Response:

The proposed change was included in the Part 70 OP.

4. Table IV.B.4 changes the averaging time for determining compliance with the combustion turbine BACT limits from an 8-hour rolling average to a 4-hour rolling average. We believe that this change was made to make the averaging time consistent with the NSPS averaging time under Subpart GG for sources that choose to demonstrate compliance with the NSPS NO_x limit using a CEM. However, the NO_x limit under Subpart GG (there is no CO limit under Subpart GG) is considerably higher than the limit imposed in the permit. As you know, reducing the averaging time of the permit limit has the result of making the permit limit even more stringent. We do not believe that there is any basis for increasing the stringency of this limit at this time. As EPA stated when it issued the Subpart GG revisions in 2004, "nothing in the final rule is intended to impose new requirements for turbines constructed between 1977 and the effective date of the final rule amendments [July 8, 2004]." 69 Fed. Reg. 41351. In addition, there is also the clear statement in 40 CFR 60.334(c) that "if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO_x emission limit under §60.332, that approved procedure may continue to be used." The Saguro plant relies on its SCR to meet the NSPS limit. In addition, the DAQEM previously

approved Saguaro's use of NO_x CEMS with an 8-hour averaging period for demonstrating compliance with its NO_x limit. Because the permit NO_x limit is so much more stringent than the NSPS NO_x limit, this was also viewed as demonstrating compliance with the NSPS. Based on the language in the rule and the preamble, we do not believe that it is appropriate to increase the stringency of our NO_x and CO BACT limits based on Subpart GG. Nor do we believe that there is any other basis for doing so. Therefore, Saguaro requests that the DAQEM revise Table IV.B.4 and Section IV.C.1 to require that compliance be based on an 8-hour rolling average—i.e., return to the current permit language.

DAQEM Response:

DAQEM conducted review of 40 CFR Subpart GG and concluded that CEMS compliance demonstration with NO_x standard for turbines EU: A01 and A02 should be based on "4-hour rolling average NO_x concentration", as stated in 40 CFR 60.334(j)(iii)(A). Consequently, the permit conditions remain unchanged.

5. Section IV.C.2 in the draft permit stipulates that a CEMS system be installed on the Indeck/Volcano boiler. Saguaro would like to clarify that the CEMS for the Indeck/Volcano boiler (EU: A05) will be installed once the ATC/OP Modification 7 is implemented. Saguaro proposes the following to clarify the requirement: *Once ATC/OP Modification 7 is implemented the Permittee shall install, calibrate, maintain, operate, and certify CEMS for NO_x, CO and O₂ on the Indeck/Volcano boiler unit (EU: A05)...*

DAQEM Response:

The monitoring conditions in the Part 70 OP are derived from 393 ATC, Modification 7, Revision 2 and 393 ATC/OP Modification 6, Amendment 2. Both NSR permits have CEMS requirements for Indeck/Volcano boiler unit (EU: A05). DAQEM concludes that the present permit language is accurate.

6. Section IV.C.4 states: *The Permittee shall conduct annual relative accuracy test audits (RATA) of the CO, NO_x, NH₃ and O₂ CEMS.* The inclusion of NH₃ in this requirement is thought to be an oversight since the facility does not utilize a CEMS system for measurement of ammonia emissions. Section IV.C.6 outlines an ammonia parametric emission monitoring system (PEMS) for monitoring compliance with ammonia emission limits. Therefore, we suggest that the condition be revised to refer only to CO, NO_x, and O₂.

DAQEM Response:

The proposed language was included in the Part 70 OP.

7. Section IV.C.8 requires that: *The Permittee shall perform daily visual emissions observation by an individual trained in Method 9 to verify compliance with the opacity limit of 20 percent.* Since combustion turbines using natural gas produce no particulate matter and no discernable opacity, Saguaro would like to propose that the requirement outlined in Section IV.C.8 apply while burning diesel fuel only. Utilizing diesel fuel in combustion turbines has been known to generate emissions that are detectable during opacity observations. Saguaro believes that observing emissions during periods when

this fuel is being utilized achieves DAQEM's intent under the regulation and would require readings be taken during periods when the possibility of a high opacity could occur.

DAQEM Response:

The permit condition was revised to reflect DAQEM requirements for similar sources in Las Vegas Valley airshed. The following condition was included in the Part 70 OP (Condition IV-C-8):

The Permittee shall perform visual emissions checks each calendar quarter on a plant-wide level for each emission unit. If visible emissions are observed, then corrective actions shall be taken to minimize the emissions and the opacity of emissions shall be visually determined in accordance with 40 CFR 60 Appendix A: Reference Method 9. [AQR 19.4.1.3(a) and 40 CFR 70.6]

8. The performance testing requirements in Table IV-D-1 list methods 5 or 5A for PM₁₀ from the turbine exhaust stack. Methods 201/202 or 201A/202 were previously listed as requirements for the facility and provided essentially the same results. Saguaro requests that the original test methods be listed in the table. If DAQEM requires the new method be listed, Saguaro requests that a footnote be added to Table IV-D-1 that states: *An alternative method may be used if previously approved by the Control Officer.*

DAQEM Response:

The proposed change was included in the Part 70 OP.

9. Section IV.E.2.g states: *sulfur content of diesel fuel and natural gas as certified by the supplier with each fuel delivery, supplier name, and the method used to determine to sulfur of the diesel fuel.* The final "to" in the section should be replaced with "the". More substantively, since natural gas is supplied to the facility via a Southwest Gas pipeline on a continuous basis the requirement for certification per delivery is troublesome. Saguaro requests that sulfur content of natural gas be verified quarterly as stated in Section IV.E.4.

DAQEM Response:

Sulfur content verification with each fuel delivery is required for diesel fuel only. The natural gas sulfur content should be verified quarterly. The permit language was revised to clarify these requirements:

Records and logs shall contain, at minimum, the following information [AQR 19.4.1.3]:

- a. *sulfur content of natural gas as certified by the supplier;*
- b. *supplier name of diesel fuel, sulfur content of diesel fuel and the method used to determine to sulfur content of the diesel fuel;*

10. It appears that the natural gas sulfur verification requirement listed in Section IV.E.3 is repeated in the second sentence of Section IV.E.4 and thus should be removed.

DAQEM Response:

Frequency of sulfur content verification for natural gas and diesel is specified in conditions IV-E-3 and IV-E-4. The permit language was revised to clarify these requirements:

- IV-E-3. Sulfur content of natural gas fuel shall be verified by the Permittee at least quarterly and verifications shall be based on reports or written data from the gas supplier, as required by 40 CFR 60. [AQR 19.4.1.3]
- IV-E-4. Sulfur content of diesel fuel shall be certified by the supplier with each fuel delivery. [AQR 19.4.1.3]

11. In the Section VII. Attachments, Saguario would like to request removal of item 1. (Nevada Revised Statutes (NRS) Chapter 445B) since Chapter 445B is not applicable, in its entirety, to the source. Saguario also requests the removal of item 3. (Clean Air Act) since the Act is not a specific applicable regulation and there are large sections of the Act that do not apply to the source. In addition, regarding Item 2. (Clark County Air Quality Regulations), Acid Rain Continuous Emissions Monitoring Section is listed as Section 20 and should be designated Section 22. Saguario also requests that the Section 20 Title: Emission Standards for Hazardous Air Pollutants for Source Categories (NESHAP) have the following clarification added: "Area Source applicable regulations only".

DAQEM Response:

The regulations listed in the Section VII – Attachments of to the permit are mentioned as a reference and there is no implication that these regulations apply in their entirety to the source. Consequently, DAQEM will leave Section VII of the Part 70 OP unchanged.

12. The proposed draft permit requires that annual emissions be quantified on a rolling 12-month basis. Saguario would like the DAQEM to clarify how the rolling 12-month period is defined. Saguario proposes that a rolling block 12-month period be utilized that breaks the rolling annual average into monthly increments. New annual averages would be determined based on the previous 12 consecutive months with a new 12-month period beginning on the first day of each month. It is essential that Saguario know what the increments associated with the rolling totals are for record keeping and compliance purposes. Saguario requests that the DAQEM clarify how the rolling 12-month requirements are to be calculated so as to ensure compliance.

DAQEM Response:

DAQEM calculates a rolling 12-month total as sum of the emissions for the past 12 months calculated on the 1st of each month. This determination is consistent for other sources.

All the corrections/changes mentioned in the comments above have been incorporated in the final Part 70 OP.

Grace Bautista

From: Grace Bautista
Sent: Monday, August 10, 2009 1:09 PM
To: 'monte.ash@nrgenergy.com'
Cc: Richard Beckstead; Santosh Mathew; Piotr Nowinski; 'Kohn.Roger@epamail.epa.gov'; 'shalev.omer@epa.gov'
Subject: Saguaro Power Company_Source 00393_Issuance of Part 70 Operating Permit
Importance: High
Attachments: 00393_T5_20090810_PER.pdf; 00393_T5_20090810_TSD.pdf; 00393_T5_20090810_FAR.pdf

Tracking:

Recipient	Delivery
'monte.ash@nrgenergy.com'	
Richard Beckstead	Delivered: 8/10/2009 1:09 PM
Santosh Mathew	Delivered: 8/10/2009 1:09 PM
Piotr Nowinski	Delivered: 8/10/2009 1:10 PM
'Kohn.Roger@epamail.epa.gov'	
'shalev.omer@epa.gov'	

Mr. Ash:

Enclosed are the final Title V operating permit, the Technical Support Document and Final Action Report for the above-referenced source. The above documents are being submitted to EPA Region IX for their files.

If you need additional information, you may contact Piotr Nowinski at (702) 455-5942.

Please confirm receipt of this email.

Thank you.

Grace A. Bautista
Administrative Secretary
Department of Air Quality & Environmental Management
Clark County, Nevada
(702) 455-0131 (Direct Line)
(702) 383-9994 (Fax)
bautista@co.clark.nv.us

Please consider the environment before printing this email 