TECHNICAL SUPPORT DOCUMENT

TECHNICAL INFORMATION PRESENTED IN REVIEW OF AN APPLICATION FOR AN "AUTHORITY TO CONSTRUCT" PERMIT FOR A MODIFIED STATIONARY SOURCE

SUBMITTED BY

BROADBENT & ASSOCIATES, INC.

for

SAGUARO POWER COMPANY

Source: 393
Modification: 8
Revision: 0

SIC Code 4911: Electric Utility Services

PROPOSED

Clark County
Department of Air Quality and Environmental Management
Permitting Section

October 2010

Nowinski

EXECUTIVE SUMMARY

The Saguaro Power Company (SPC) is located at 435 Fourth Street, Henderson, Nevada 89015, in the Las Vegas Valley airshed, hydrographic basin 212. Hydrographic basin 212 is nonattainment for PM_{10} and ozone, and attainment 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 and natural gas. 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, and an ammonia storage and injection system. All generating and support processes at the site are grouped under the Standard Industrial Classification (SIC) SIC 4911: Electric Services (NAICS 22111: Electric Power Generation). The SPC emits particulate matter (PM_{10}), carbon monoxide (CO), oxides of nitrogen (NO_x), oxides of sulfur (SO_x), volatile organic compounds (VOCs), hazardous air pollutants (HAP), and ammonia (NH_3). The source was a major source for CO, NO_X and NH_3 prior to the proposed modification.

The SPC is planning the addition of three new LM-6000 natural gas turbines with this modification. The LM-6000 turbines will be equipped with a Selective Catalytic Reduction (SCR) system and a CO Oxidation Catalyst. The control system should limit exhaust concentration to 10 ppm of NO_x and 2.0 ppm of CO (3-hour average at 15% O_2). In addition, ammonia storage and injection units and an additional fourth cell on the existing cooling tower will be added. The existing turbine units (EUs A01 and A02) and the Nebraska boiler (EU A06) are modified by installing CO oxidation catalyst.

PROPOSED

This Technical Support Document (TSD) accompanies the proposed NSR ATC Permit for Saguaro Power Company.

TABLE OF CONTENTS

Page

I. ACRONYMS 4

II. SOURCE INFORMATION 5

A. General 5
B. Description of Process 5
C. Permitting Action 6

III. EMISSIONS INFORMATION 8

A. Source-wide Potential to Emit 8
B. Emission Units and PTE 8
D. Testing 10
E. Continuous Emissions Monitoring 11

IV. REGULATORY REVIEW 12

A. Review of Section 12 and 55 12
B. Other Applicable Regulations 13
C. Compliance Demonstration 13
D. Mitigation 14

V. CONTROL TECHNOLOGY 14

A. NO_x Control Technology Options 15
B. BACT Analysis 19
D. CO BACT Analysis 21

VI. INCREMENT 22

VII. PUBLIC NOTICE 25

VIII. PERMITING HISTORY 25

ATTACHMENTS 27

PROPOSED

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
CE	Control Efficiency
CEM	Continuous Emissions Monitoring System
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
$PM_{2.5}$	Particulate Matter less than 2.5 microns
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
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_X	Sulfur Oxides
TCS	Toxic Chemical Substance
TSD	Technical Support Document
VOC	Volatile Organic Compound

PROPOSED

II. SOURCE INFORMATION

A. General

Permittee	Saguaro Power Company
Mailing Address	P.O. Box 90849, Henderson, Nevada 89009-0849
Contacts	Larry Flashberg
Phone Number	(702) 558-1134
Fax Number	(702) 564-2735
Source Location	435 Fourth Street, Henderson, Nevada 89015
Hydrographic Area	212
Township, Range, Section	T22S, R62E, Section 11, 12, 13, 14
SIC Code	4911: Electric Services
NAICS Code	22112: Fossil Fuel Electric Power Generation

B. Description of Process

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

SPC currently operates two combined cycle General Electric (GE), 35.0 MW each, natural gas combustion turbine generators (CTGs) with four, 25 MMBtu/hr each, supplemental firing duct burners, two heat recovery steam generators (HRSG) and a 23.1 MW extraction/condensing steam turbine generator system. These units are permitted to fire on hydrogen gas and natural gas. 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, 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 mechanical energy is converted into electrical energy via 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 exhaust gases will exit to the atmosphere after

PROPOSED

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 with 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 proposed addition of a cell with a circulation rate of 7,666 gallons per minute.

The SPC emits particulate matter (PM_{10}), carbon monoxide (CO), oxides of nitrogen (NO_x), oxides of sulfur (SO_x), volatile organic compounds (VOCs), hazardous air pollutants (HAP), and ammonia (NH_3). Saguaro was a major source for CO, NO_X and NH_3 prior to the proposed modification according to the Air Quality Regulations that existed as of June 30, 2010.

The SPC NO_x and CO emissions are monitored with continuous emission monitoring system (CEMS). The ammonia (NH_3) 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 Action

The SPC is currently a major source for Nitrogen Oxides (NO_X) and Carbon Monoxide (CO). The proposed modification will reduce CO emissions below the major source threshold, thereby qualifying this source to be re-designated as a synthetic minor source for CO. According to prior AQR, the permitting action qualified as a major modification for ammonia due to a Net Emissions Increase (NEI) exceeding the major modification threshold of 1 ton/year for Toxic Chemical Substances (TCS). However, on July 1, 2010 the AQR were revised and NH_3 is no longer regulated by DAQEM. In addition to ammonia, the proposed changes will constitute a major modification for PM_{10}. The proposed changes for NO_X, SO_2, and VOC are considered minor modifications.

The modification includes addition of three simple cycle GE LM-6000 turbines with a nominal power rating of 44.2 Megawatt (MW) each, which will be equipped with Dry Low NO_X (DLN) Burners, Selective Catalytic Reduction, and Oxidation Catalysts as emission controls. The control system should limit exhaust to concentrations of 2 ppm of NO_x and 2.0 ppm of CO (3-hour average at 15% O_2). The turbines will be exclusively natural gas fired. Ammonia storage and injection units and an additional fourth cell on the existing cooling tower will be added.

The SPC will install Oxidation Catalysts on the existing turbines (EUs A01 and A02) as well as the Nebraska Boiler (EU: A06). SPC is requesting to update the permit operating conditions for the existing turbines (EUs: A01 and A02) to reflect a changeover from hourly operational restrictions to total MMBtu use-based operational restrictions. The

PROPOSED

operation of the new turbines will be presented on an MMBtu/year basis as well. The two existing turbines will be limited to a combined total of 4,246,500 MMBtu/year based on lower heating value (LHV), and the three new turbines will be limited to a combined total of 5,215,500 MMBtu/year (LHV).

The application for Modification 8 was deemed complete on February 19, 2009. On July 1, 2010 the AQR were revised and some of the original determinations have been updated.

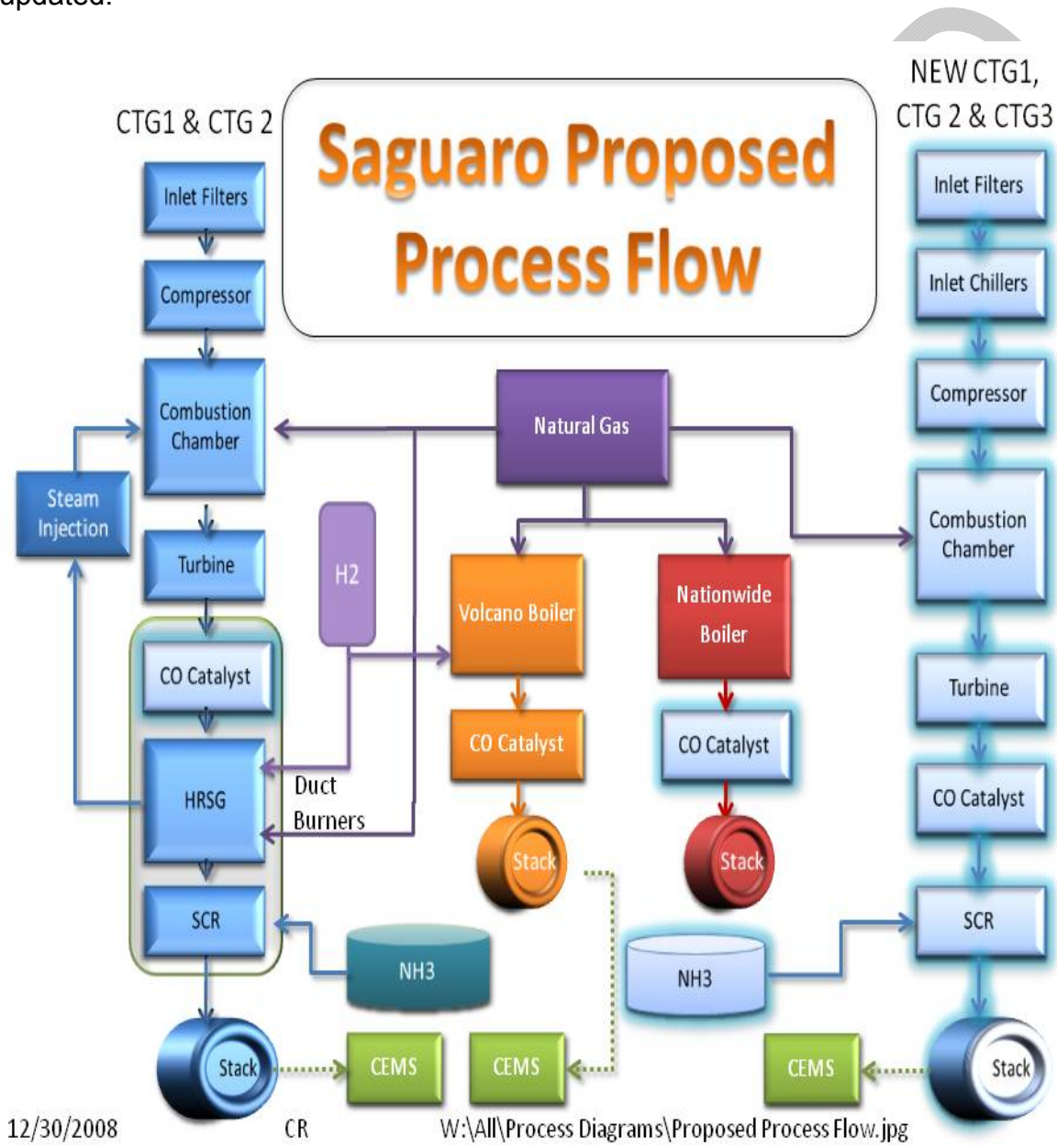

Figure 2. Saguaro Power Company Process Flow Diagram (NSR ATC 393, Modification 8). Note: The Nationwide Boiler in the figure is EU: A06 (Nebraska Boiler)

III. EMISSIONS INFORMATION

A. Source-wide Potential to Emit

1. Saguaro Power Company is a major source for NO_x; a synthetic minor source for CO, and a minor source for SO_x, VOC, and HAP, as summarized in Table III-A-1:

Table III-A-1: Source-wide PTE (tons per rolling 12-months)

Pollutant	PM_{10}	NO_x	CO	SO_x	VOC	HAP
PTE Totals	**50.65**	**120.18**	**18.84**	**9.68**	**19.12**	**9.84**
Major Source Thresholds	**70**	**50**	**100**	**100**	**50**	**25[1]**

[1]25 tons for combination of all HAPs (no single HAP exceeds 10 tons).

B. Emission Units and PTE

1. Following is the list of emission units affected by this modification. Emission units A01, A02 and A06 are existing emission units that are modified and EUs A09d, A10, A11, A12 and F11 are new emission units.

Table III-B-1: List of Emission Units (EU)

EU	Description	Rating	Make	Model #	Serial #	SCC
A01	Combustion Turbine Generator # 1 with HRSG, Natural Gas-fired; SCR and Oxidation Catalyst	447 MMBtu/hr; 35 MW	General Electric	PG6541B	295525	20100101
A02	Combustion Turbine Generator # 2 with HRSG, Natural Gas-fired; SCR and Oxidation Catalyst	447 MMBtu/hr; 35 MW	General Electric	PG6541B	295524	20100101
A06	Auxiliary Boiler	86 MMBtu/hr	Nebraska	NOS 2A/S-55	032-88	31000414
A09a	4-cell cooling tower, 3,800 ppm TDS, 0.0006% drift loss; Cell 1	7,666 gpm	Thermal-Dynamics Towers, Inc.	TD-3030-3-2424CF	N/A	38500101
A09b	4-cell cooling tower, 3,800 ppm TDS, 0.0006% drift loss; Cell 2	7,666 gpm	Thermal-Dynamics Towers, Inc.	TD-3030-3-2424CF	N/A	38500101
A09c	4-cell cooling tower, 3,800 ppm TDS, 0.0006% drift loss; Cell 3	7,666 gpm	Thermal-Dynamics Towers, Inc.	TD-3030-3-2424CF	N/A	38500101
A09d	4-cell cooling tower, 3,800 ppm TDS, 0.0006% drift loss; Cell 4	7,666 gpm	Thermal-Dynamics Towers, Inc.	TD-3030-3-2424CF	N/A	38500101
A10	Simple Cycle Combustion Turbine, Unit 1	366 MMBtu/hr; 44.2 MW	General Electric	LM-6000	TBD	20100101
A11	Simple Cycle Combustion Turbine, Unit 2	366 MMBtu/hr; 44.2 MW	General Electric	LM-6000	TBD	20100101

PROPOSED

EU	Description	Rating	Make	Model #	Serial #	SCC
A12	Simple Cycle Combustion Turbine, Unit 3	366 MMBtu/hr; 44.2 MW	General Electric	LM-6000	TBD	20100101
F11	Ammonia Storage and Injection	12,000 gallons	N/A	N/A	N/A	40781699

2. The units or activities listed in Table III-B-2 of this permit are present at this source, but are insignificant pursuant to AQR Section 19. The emissions from these units or activities, when added to the PTE of the source, do not contribute to making the source major for any pollutant other than NO_x, CO and NH_3.

Table III-B-2: Insignificant EU or Activities

EU	Description
F03	Natural Gas Metering Station
F04	Natural Gas Coalescing Filters
F07	Lube Oil System – CTG-01
F08	Lube Oil System – CTG-02
F09	Lube Oil System – CTG-03
F10	Facility Maintenance (Painting)

Table III-B-3: Source PTE, Including Startup and Shutdowns (tons per rolling 12-months)

EU	PM_{10}	NO_x	CO	SO_x	VOC	HAP	NH_3
A01[1]	11.87	72.19	4.27	1.28	4.37	2.19	23.57
A02[1]							
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]	8.18	15.92	0.98	0.65	5.89	4.47	0.00
A06[3]	1.29	9.34	0.38	0.15	1.38	0.48	0.00
A09a,b,c,d	0.72	0.00	0.00	0.00	0.00	0.00	0.00
A10[4]	28.41	20.93	12.75	7.48	7.27	2.69	39.12
A11[4]							
A12[4]							
F05, F05a	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F06, F06a	0.00	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	1.39
Source PTE	**50.65**	**120.18**	**18.84**	**9.68**	**19.12**	**9.85**	**64.08**

[1]Annual emissions are based on 4,246,500 MMBtu/year of natural gas combustion between EU: A01 and A02. The average fuel flow rate is 447 MMBtu/hr (LHV).
[2]Emissions from the Indeck/Volcano boiler (EU: A05) after installation of the low-NO_x burners and CO oxidation catalyst (ATC Modification 7 was issued on November 21, 2008) .
[3]Emissions from the Nebraska boiler (EU: A06) after installation of the CO oxidation catalyst.
[4]Annual emissions are based on 5,215,000 MMBtu/year of combined natural gas combustion for EU: A10, A11 and A12. The average fuel flow rate is 366 MMBtu/hr (LHV).

Table III-B-4: Source PTE, Excluding Startup and Shutdown (lbs/hr)

EU	PM_{10}	NO_x	CO	SO_x	VOC	HAP	NH_3
A01	2.50	15.20	0.90	0.27	0.92	0.46	4.96
A02	2.50	15.20	0.90	0.27	0.92	0.46	4.96

PROPOSED

EU	PM_{10}	NO_x	CO	SO_x	VOC	HAP	NH_3
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[1]	1.87	3.64	0.22	0.15	1.34	1.02	0.00
A06[2]	0.43	3.11	0.13	0.05	0.46	0.16	0.00
A09a,b,c,d	0.16	0.00	0.00	0.00	0.00	0.00	0.00
A10	3.99	2.94	1.79	1.05	1.02	0.38	5.49
A11	3.99	2.94	1.79	1.05	1.02	0.38	5.49
A12	3.99	2.94	1.79	1.05	1.02	0.38	5.49
F05, F05a	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F06, F06a	0.00	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
Source PTE	**22.29**	**74.73**	**15.02**	**5.73**	**7.57**	**3.35**	**26.71**

[1]Emissions from the Indeck/Volcano boiler (EU: A05) after installation of the low-NO_x burners and CO oxidation catalyst.
[1]Emissions from the Nebraska boiler (EU: A06) after installation of the CO oxidation catalyst.

Table III-B-5: Enforceable Emissions Limitations in ppmvd [1]

EU	O_2 Standard	NO_X	CO	NH_3
A01	15%	10	2.0	10
A02	15%	10	2.0	10
A10	15%	2.0	2.0	10
A11	15%	2.0	2.0	10
A12	15%	2.0	2.0	10
A06	3%	30	2.0	---

[1] Emissions from the combustion of natural gas are calculated using a three-hour rolling average not to include startup or shutdown

Table III-B-6: Startup and Shutdown Emissions per Emission Unit (lbs/hr) [1]

EU	PM_{10}	NO_X	CO	SO_x	VOC	HAP	NH_3
A01, A02	2.5	65.00	9.00	0.27	0.94	0.46	2.04
A10, A11, A12	2.5	4.60	2.60	0.27	0.96	0.46	2.04

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

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; 40 CFR 60 Subpart KKKK; DAQEM Guideline on Performance Testing and AQR Section 49. The required testing will be performed using the following methods:

Table III-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 Methods 18 or 25a
Turbine Exhaust Stack	NH_3 Slip	Method Preapproved by DAQEM/EPA
Turbine Exhaust Stack	PM_{10}	EPA Method 5, 201a and 202
Turbine Exhaust Stack	Opacity	EPA Method 9
Boiler Exhaust Stack	NO_X	Chemiluminescence Analyzer (EPA Method 7E)

PROPOSED

Test Point	Pollutant	Method
Boiler Exhaust Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	---	EPA Methods 1, 2, 3, 4, or Method 19

Annual Relative Accuracy Test Audits (RATA) testing must be performed on each NO_X, CO, and O_2 Continuous Emissions Monitoring Systems (CEMS).

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".

E. Continuous Emissions Monitoring

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 O_2 on each turbine (EU: A01, A02, A10, A11, and A12) and 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 O_2;
b. exhaust gas flow rate (by direct or indirect methods);
c. fuel flow rate,
d. hours of operation;
e. three-hour rolling averages for each of NO_X and CO concentration (EUs: A01, A02, A10, A11, A12),
f. hourly , daily and quarterly accumulated mass emissions of NO_X and CO; and
g. 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 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 O_2 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 may 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 1.26:1 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 un-reacted ammonia slips through the catalyst bed and out of the stack as ammonia emissions.

PROPOSED

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.

IV. REGULATORY REVIEW

A. Review of Section 12 and 55

Since the application for modification 8 was deemed complete prior to the effective date of the current AQR, the NSR analysis was performed based on AQR existed prior to July 1, 2010. Pursuant to AQR Section 12 and 55, SPC is a major source of NO_X and TCS (NH_3) and a synthetic minor for CO. See the table below:

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

	PM_{10}	NO_X	CO	SO_X	VOC	HAP	NH_3
Source PTE (tpy)	**50.65**	**120.18**	**18.84**	**9.68**	**19.12**	**9.84**	**64.08**
	21.31	**114.97**	**18.10**	**2.22**	**3.89**	**4.11**	**17.46**
NEI	**29.34**	**5.21**	**0.74**	**7.46**	**15.23**	**5.73**	**46.62**
Nonmajor Source	< 70 tpy	< 50 tpy	< 100 tpy	≤ 100 tpy	< 50 tpy	≤ 25 tpy	≤ 1 tpy
Control Technology	BACT	BACT	LAER	BACT	BACT	BACT	BACT
Notice of Proposed Action	If NEI ≥ 15 tpy	If NEI ≥ 20 tpy	If NEI ≥ 10 tpy	If NEI ≥ 40 tpy	If NEI ≥ 20 tpy	If PTE or NEI ≥ 10 tpy	If PTE or NEI ≥ 1 tpy
Preconstruction Ambient Air Monitoring	If NEI ≥ 25 tpy	If NEI ≥ 40 tpy	No	If NEI ≥ 40 tpy	No	No	No
Postconstruction Ambient Air Monitoring	If NEI ≥ 25 tpy	If NEI ≥ 40 tpy	No	If NEI ≥ 40 tpy	No	No	No
Additional Impact Analysis	If NEI ≥ 25 tpy	If NEI ≥ 40 tpy	No	If NEI ≥ 40 tpy	No	No	No

Table IV-A-2: Emission Inventory (2006 and 2007)

	PM_{10}	NO_X	CO	SO_X	VOC	HAP	NH_3
2006	22,77	114.87	18.31	2.37	4.05	4.34	18.69
2007	19.86	115.06	17.88	2.07	3.73	3.87	16.23
Average	**21.31**	**114.97**	**18.10**	**2.22**	**3.89**	**4.11**	**17.46**

The NEI calculations above were generated using the average actual emissions from the modified units for the last two full years normal plant operation (2006 and 2007), and

PROPOSED

potential emissions of the new and modified units. The source operated for half of 2008 under alternative scenario and the turbines were not operated.

B. Other Applicable Regulations

The source is subject to AQR. The source is a Part 70 source and 40 CFR 60 Subparts A (General Provisions); Dc (EU: A06); GG (EU: A01 and A02), KKKK (EUs: A10, A11, and A12); and 40 CFR 70 apply.

The existing two combined cycle turbines (EUs: A01 and A02) are classified as the cogeneration facility and are exempted form provisions of Acid Rain regulations based on the applicability criteria defined in 40 CFR Part 76.6(b)(5).

The three simple cycle GE LM-6000 turbines (EUs: A10, A11 and A12) are subject to the Acid Rain Regulations 40 CFR 72-75. The source will submit a timely Acid Rain Permit application under separate cover.

C. Compliance Demonstration

Excluding start-up or shut-down periods not to exceed 180 minutes per unit for both events, any exceedance of the hourly, three–hour rolling, daily, or annual CO and/or NO_X emissions limitations as determined by the CEMS shall be considered a violation of the emission limit imposed and may result in enforcement action.

SPC may 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 1.26:1 molar ratio with ammonia. The un-reacted ammonia slips through the catalyst bed and out of the stack as ammonia emissions. 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.

The Permittee shall install a fuel flow meter for each combined cycle turbine, each duct burner, and the Indeck/Volcano boiler, and shall monitor the natural gas fuel flow rate of each emission unit with Data Acquisition System (DAS) and Continuous Emission Monitoring System (CEMS). The primary method for demonstrating compliance with this requirement is demonstrated by DAS.

The fuel flow meters for combined cycle turbines, duct burners, and the Indeck/Volcano boiler continuously transmit signals to the plant main Digital Control System (DCS) where data is converted into the flow rates. In turn, these fuel flow rates are transmitted to the plant Data Acquisition System (DAS), which also captures the emission concentrations from the CEMS. DAS averages the fuel flows and emission concentrations and calculates one minute, 15 minutes, three hours, and eight hours averages for both concentrations and emission rates in pounds per hours for each

PROPOSED

measured emission unit. The DAS retains these values on the hard drive for five years. In addition, the DSC has a computerized system that continuously records the input fuel data and prints out a fuel report every six hours.

The Nebraska boiler (EU: A06) is not connected to DAS. The Permittee maintains records of monthly, quarterly and annual (12-month rolling total) of natural gas fuel used for Nebraska boiler.

D. Mitigation

The source has no CO offset requirements from this modification.

V. CONTROL TECHNOLOGY

The LM-6000 natural gas turbines are classified as simple cycle gas turbines. Simple cycle gas turbines are commonly used in the power industry and can be designed to generate small or large amounts of power. They are easier and faster to construct and have the ability to be turned on and off within minutes. This operational flexibility is utilized during the highest power demands labeling this type of turbines as peaking power units. It is anticipated that peaking power units operate anywhere from several hours per day to several hundred hours per year, depending solely on the market demands.

The LM-6000 turbines are custom designed to fit the needs of industrial power generation such as: an expanded turbine section to convert thrust into shaft power, supports and struts for mounting on a steel or concrete deck, and reworked control packages for power generation. Maximum nominal horsepower rating on these units amounts to 54,610 shaft horsepower (hp).

General Electric (GE) has several packages for industrial LM6000s, with Spray Inter-cooling (SPRINT), water injection, and Spray Mist Evaporative Cooling (SMEC). These configurations are designed to improve efficiency, power output, and reduce emissions. The SPRINT injects water into the engine between the low pressure and high pressure compressors. The water injection system injects water into the primary or secondary fuel nozzle inputs.

Saguaro hereby requests the installation of LM-6000 turbines with SPRINT and Dry Low NO_x (DLN) combustor technologies. When the source submitted the application, Clark County AQR required LAER for CO and the analysis of control technologies was conducted accordingly. In the meantime, the area status was reclassified to attainment for CO. However, the NSR analysis was performed based on the AQR existed at the time of application and the original NSR determinations remain in effect. .

With the technology development and increase in environmental regulations throughout the last several decades, turbines are offered with standard combustion controls, such as DLN and wet injection. Based on this industry standard it is safe to assume baseline

PROPOSED

emissions for natural gas combustion turbines with these types of combustion controls. The NO_x reduction potential for DLN and wet injection are comparable and can be considered interchangeable standard turbine control technologies. Therefore, the LM6000 simple cycle natural gas turbine with DLN will be considered as the baseline in this analysis.

DLN is guaranteed at 25 ppmvd NO_x at 15% O_2. This emission limit corresponds to the 40 CFR 60 Subpart KKKK, 25 ppm NO_x emission standard for new turbines firing natural gas with a heat input at peak load greater than 50 MMBtu/hr and less than 850 MMBtu/hr, based on the higher heating value (HHV). Saguaro is proposing to group and operate the three new turbines on the MMBtu/year basis. The three new turbines will be limited to a combined total of 5,215,500 MMBtu/year. For the purpose of calculating baseline emissions, the overall MMBtu/year was divided by three and by the average fuel flow of 366 MMBtu/hr (LHV), to determine the corresponding operating hours. The baseline emissions for this analysis are calculated for 4,750 hours per turbine. Manufacturer emission data was utilized to calculate CO, NO_X, PM, SO_2, and VOC emissions. HAP emissions were calculated using AP-42.

A. NO_x Control Technology Options

Nitrogen Oxides (Nitric Oxides (NO) + Nitrogen Dioxides (NO_2)) are divided into two classes, thermal NO_x and organic NO_x. The thermal NO_x is formed from oxidation of the free nitrogen in the combustion air or fuel. The amount of thermal NO_x created increases with the fuel to air ratio, firing temperature, combustor inlet air temperature, and residence time in the flame zone. The organic NO_x is formed through oxidation of organically bound nitrogen in the fuel. The amount of organic NO_x formed is significantly lower than the thermal NO_x. The NO_x emissions depend highly on the type of fuel used, with No. 2 fuel oil resulting with highest NO_x emissions and natural gas with the lowest NO_x emissions. This section will present and describe all emission control technologies available.

Nitrogen oxide control methods are divided into two categories, combustion and post-combustion controls. A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NO_x emissions required. The following types of emission controls will be examined in this analysis:

<u>Technical Feasibility Considerations NO_x Control Options</u>
Upon thorough review of all the possible emission controls for NO_x, Saguaro had to eliminate several technologies based on technical infeasibility. Technically infeasible technologies are incompatible and/or not as effective with the LM-6000 turbines configuration. The following are the potential control technologies for a simple cycle combustion turbine LM-6000:

- Dry Combustion Control (Dry low NO_x)
- Selective Non Catalytic Reduction (SNCR)

PROPOSED

- Non Selective Catalytic Reduction (NSCR)
- Selective Catalytic Reduction (SCR)
- SCONOx with $SCOSO_x$ catalyst

The analysis of aforementioned technologies will also depend on Carbon Monoxide (CO) LAER requirements. Based on thorough research and communication with DAQEM, LM6000 LAER for CO is 2.0 ppmvd (3-hr average). This level of control will be achieved with a combination of appropriate NO_x control technology and the implementation of a CO Oxidation Catalyst. This limitation will be taken into consideration while determining technical feasibility for NO_x control options.

Dry Combustion Controls

As discussed earlier, Dry low-NO_x combustion (DLN) is considered a baseline control for purposes of this analysis since the LM-6000 turbines can not be purchased and installed without either the DLN or comparable Wet Combustion Control. DLN is described here for informational purposes only. DLN uses a lean mixture of gaseous fuel and compressed air to avoid formation of high temperature zones where high levels of NO_x are created. The lean mixture of gaseous fuel is produced by incorporating excess air to the mixture. This process enables cooling of the flame in the primary combustion zone, thus reducing formation of NO_x, and it requires a custom designed mixing chamber for each turbine. DLN, or in the LM-6000's case, PD-Sprint, is one of the standard LM-6000 configurations as combustion control for NO_x emissions. Since DLN with the combination of an Oxidation Catalyst provides required threshold for CO emissions, it will be listed as a technically feasible technology.

Selective Non Catalytic Reduction (SNCR)

SNCR uses a nitrogen based reagent (ammonia or urea) in a chemical reaction to reduce NO_x into molecular nitrogen and water vapor. It is primarily used in boilers. The reagent is injected into the post combustion exhaust gas. SNCR system NO_x removal efficiency depends on the range of the processing temperatures; the most favorable temperature range is 1600ºF and 2100ºF. Urea is more advantageous as a reagent because it is not toxic, less volatile, and easier to handle and store. Urea also has higher efficiency in penetrating farther into the flue gas, hence enhancing the mixing with the flue gas. The SNCR system injects the reagent directly into the combustion chamber, where the flue gas is directly mixed with the reagent. SNCR injection and control system is capable of reducing NO_x emissions by 60% or greater. As already mentioned, the efficiency of SNCR is determined by the exhaust gas temperature, and since the LM6000 exhaust temperature range is significantly lower (840ºF to 920ºF), SNCR's efficiency will be compromised. Based on this limitation, SNCR is not a viable control option for NO_x emissions.

Non-Selective Catalytic Reduction (NSCR)

NSCR uses a catalyst for removing NO_x emissions from the exhaust gas. This technology is primarily used in the industries that utilize rich burning internal combustion engines, such as the automobile industry. The removal efficiency of the NSCR depends on high fuel concentrations with minimal oxygen present. This type of environment (low

PROPOSED

oxygen concentration) does not occur in the combustion turbine exhaust hence NSCR is not a technically feasible control technology.

Selective Catalytic Reduction (SCR)

SCR reduces NO_x in the exhaust gas. The reduction process is activated by injecting a nitrogen based agent (reagent), such as ammonia or urea, into the post combustion flue gas. With the help of a metal-based catalyst, the reagent reacts selectively with the flue gas NO_x within a specific temperature range to reduce the NO_x into molecular nitrogen (N_2) and water vapor (H_2O). The metal based catalyst has activated sites and increases the rate of the reduction reaction. The catalyst is made of active metals or ceramics with a highly porous structure.

The SCR process starts with injecting nitrogen based reagent such as ammonia or urea into the ductwork, downstream of the combustion unit. The exhaust gas mixes with the reagent and enters a reactor module containing catalyst, where it diffuses through the catalyst. The main factors in determining the removal efficiency are: temperature, the amount of reducing agent, injection grid designs, and catalyst activity. Catalyst removal efficiency can be compromised by: poisoning of active sites by flue gas constituents, thermal sintering of active sites to high temperatures within reactor, blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and erosion due to high gas velocities.

Since natural gas fired units contain lower levels of NO_x, sulfur, and PM in the exhaust gas, less catalyst will be required, making natural gas fired units with SCR more cost effective. SCR systems are able to provide up to 90% NO_x removal efficiency. SCR will be considered as a feasible control technology in the top-down BACT analysis for NO_x emissions. Based on BACT/RACT/LAER permitted emission limits, SCR at 5.0 ppmvd (3-hr average) NO_x and 2.0 ppmvd (3-hr average) NO_x were evaluated by the source. These limits are offset by a greater degree of ammonia slip, to be discussed later in this document, at rates of 5 ppmvd (3-hr average) and 10 ppmvd (3-hr average) respectively.

$SCONO_x$

The $SCONO_X$ system is efficient at reducing NO_x, CO, and VOC emissions. SCONOx does not use ammonia injection; therefore it does not produce ammonia slip. SCONOx uses a catalyst to reduce nitrogen oxide from natural gas fired, water injected turbines. The catalyst is coated with a potassium carbonate (K_2CO_3) and it oxidizes carbon monoxide (CO) to carbon dioxide (CO_2), nitric oxide (NO) to nitrogen dioxide (NO_2), and Volatile Organic Compounds (VOCs) to CO_2 and water. The NO_2 is absorbed by the catalyst, while CO_2 is released into the environment. Once the catalyst gets saturated with potassium nitrites (KNO_2) and potassium nitrates (KNO_3), it needs to be regenerated. Dilute hydrogen gas is used as a regeneration agent and it converts KNO_2 and KNO_3 to K_2CO_3, water and elemental nitrogen. SCONOx technology requires an operating temperature range of 300ºF to 700ºF.

Sulfur in natural gas interferes with the $SCONO_x$ effectiveness; hence an additional catalyst ($SCOSO_x$) is required prior to the $SCONO_x$ catalyst. $SCOSO_x$ works on the

PROPOSED

same principal as $SCONO_x$, absorbing sulfur from the natural gas. The $SCOSO_x$ catalyst requires regeneration as well, and its regeneration is performed at the same time as $SCONO_x$, and with the same dilute hydrogen gas. The $SCONO_x$ system is capable of obtaining 90% NO_x reduction (to 1.5 ppmvd) and 80-85% VOC reduction.

$SCONO_x$ technology has been installed in a handful of facilities throughout the United States, and there have been significant operational and maintenance difficulties with its operation. $SCONO_x$ has not been implemented on any LM-6000 natural gas fired combustion turbines. For purposes of this analysis the technology will be considered technically feasible for NO_x emissions removal although significant issues remain unanswered regarding its reliability. $SCONO_x$ will be evaluated at 1.5 ppmvd NO_x.

Environmental Impacts

SCR as a control device presents a negative environmental impact due to the released ammonia during its operation. This process is known as ammonia slip. Higher NO_x control associated with an SCR system corresponds to higher overall ammonia emissions associated with ammonia slip. A 2.0 ppmvd (3-hr average) NO_x SCR system would remove an additional 10.46 tons of NO_x annually over a comparable 5.0 ppmvd (3-hr average) NO_x SCR system for the LM-6000 turbine discussed herein. However, this additional NO_x control is offset by an increase in ammonia emissions of 6.53 tons. An additional environmental impact associated with using SCR comes from ammonia transportation and storage. Ammonia is considered a toxic chemical substance (TCS) and in the event of spill or fire, presents an enormous environmental liability in the form of air, soil and groundwater contamination, and employee injuries. Any SCR system will incorporate these additional impacts to some extent regardless of final NO_x control efficiency.

The $SCONO_x$ does not use ammonia as a reducing agent, hence eliminating ammonia slip. Based solely on elimination of ammonia slip, $SCONO_x$ has the least environmental impact and is the optimum control technology.

Energy Impacts

There are additional power requirements associated with SCR operation due to running the pumps electrical motors associated with the system. The $SCONO_x$ system also requires an additional electrical demand associated with the operating the system. For purposes of this analysis the two additional energy impacts will be considered offsetting. Therefore, energy impact will not be a deciding factor in NO_x BACT determination.

Economic Impacts

The economic impacts analysis is based on the cost effectiveness of each technology per ton of removed pollutant. The maximum cost effectiveness threshold for NO_x accepted by DAQEM is $16,000-$18,000 per ton removed. Table V-A-1 summarizes the cost effectiveness for the three technically feasible technologies. The cost effectiveness of 2.0 ppmvd (3-hr average) SCR is comparable to that of 5.0 ppmvd (3-hr average) with 2.0 ppmvd (3-hr average) being slightly more cost effective at approximately $18,121 per ton reduced. The 1.5 SCONOx has a significantly higher

PROPOSED

cost effectiveness value of $36,345. The incremental cost between the 5 and 2 ppmvd (3-hr average) SCR systems is only $6,214 while the next higher control, $SCONO_x$, has an incremental cost of $874,650. Each of these additional control technologies exceed the generally accepted DAQEM economic thresholds for NO_x reduction however, the SCONOx system vastly exceeds these thresholds. The SCONOx system would require an annual investment of over 1.1 million dollars to reduce NO_x emissions 1.75 tons from that of a 2.0 ppmvd (3-hr average) SCR system annually.

Based on the information presented above, the technologies were evaluated:

Table V-A-1: Summary of Top-Down Results for NO_x

	Emissions			Economic Impacts			Energy Impacts	Environ. Impacts
Control Option	Rate	Reduction	Capital Cost	Annualized Cost	Cost	Incremental Cost	Increase over Baseline	Adverse Impact to Environment
	tons/yr	tons/yr	$	$	$/ton	$/ton	--	--
1.5 ppmvd SCONOx with DLN	5.23	81.98	9,911,667	2,979.45	36,345	874,650	Offsetting	Yes
2.0 ppmvd SCR with DLN	6.98	80.23	4,718,475	1,453,889	18,121	6,214	Offsetting	Yes
5.0 ppmvd SCR with DLN	17.44	69.77	4,608,925	1,388,860	19,907	--	Offsetting	Yes
25 ppmvd DLN (baseline)	87.21	--	--	--	--	--	--	--

Notes:
1. Rate is the predicted PTE associated with the control option.
2. Reduction is the quantity of emissions reduced over baseline.
3. Capital Cost is the installed capital cost relative to baseline per turbine.
4. Annualized Cost is the capital, direct & indirect cost of purchasing, operating and maintaining the proposed control option per turbine.
5. Cost Effectiveness = Annualized Cost / Emission Reduction.

B. BACT Analysis

<u>NO_X</u>
After eliminating technically infeasible options, evaluating the remaining technologies for environmental and economic impacts, and reviewing similar facilities for emission control technologies, DAQEM has determined that SCR with a 2.0 ppmvd (3-hr average) NO_X limit at 15 percent oxygen meets BACT for this application.

<u>PM_{10}</u>
The Saguaro facility is considered a minor source for PM_{10} in a serious nonattainment area. Based on AQR Section 12.1.1, this source type is required to meet the emission control for the Best Available Control Technology. The combustion of natural gas

PROPOSED

discharges insignificant amounts of ash or particulate matter (PM). Natural gas PM emissions originate from its noncombustible components, additive mercaptan, ambient air particulates used in the combustion process, and incomplete combustion. Search of the BACT/RACT/LAER Clearinghouse database indicated Good Combustion Practices (GCP) as the widely used "technique" in reducing PM_{10} emissions. GCP's are based on the comprehensive operational and maintenance plan with routine and periodic adjustments and checks, and optimal stoichiometric (fuel/air) ratio. Saguaro will utilize GCP as a BACT for PM_{10} emissions.
Given that high-efficiency drift eliminators and TDS control are both technically feasible control options for the Saguaro cooling tower cell, BACT for PM_{10} is satisfied through operation of the cooling tower with the high-efficiency drift eliminator (0.0006% drift) and a TDS limitation of 3,800 mg/L.

VOC
According to the AQR Section 12.2.11, Saguaro is required to implement BACT for Volatile Organic Compounds (VOCs) emissions. VOCs emissions originate from the incomplete combustion of natural gas. They are easily vaporized due to high vapor pressure. A CO oxidation catalyst will be utilized as a means of control for VOC emissions. In addition to CO removal, the CO catalyst is capable of reducing VOC emissions as well. VOC emissions can be reduced by practicing good combustion practices and maintaining a constant combustion chamber temperature. With the combination of the aforementioned technologies, Saguaro is anticipating exhaust VOC emissions to be 2.0 ppmvd (3-hr average) at 15 percent oxygen. This level of control coincides with the VOC levels found in the RACT/BACT/LAER Clearinghouse.

SO_x
Based on thorough research of the RACT/BACT/LAER Clearinghouse, common practices such as low sulfur content of natural gas and CO oxidation catalyst contribute to the reduction of SO_x emissions. Natural gas will be provided by a Southwest Gas Corporation (SWG) pipeline. Exclusive use of pipeline quality natural gas and good combustion practices will satisfy BACT requirements for SO_x emissions.

NH_3
Ammonia emissions from an SCR system are referred to as "Ammonia Slip". SCR uses ammonia as a reducing agent for NO_x emissions. Ammonia slip occurs when excess ammonia is injected into the process, thereby allowing a fraction of un-reacted ammonia to escape into the atmosphere. Ammonia is not considered a criteria pollutant, however, the RACT/BACT/LAER Clearinghouse lists 10.0 ppmvd (3-hr average) as the BACT for Ammonia Slip when used in conjunction with a NO_x control of 2.5 ppmvd (3-hr average) or lower (see Table 2). Saguaro Power Company will comply with this standard by installing a SCR system with 10.0 ppmvd (3-hr average) Ammonia Slip. With this action, ammonia's BACT requirements will be met.

PROPOSED

D. CO BACT Analysis

When the Saguaro facility applied for permit modification the facility was a major source for carbon monoxide in the serious nonattainment area, Air Quality Regulations required emission controls which are designed for the Lowest Achievable Emission Rate (LAER). Since CO was the only LAER pollutant, its emission controls became paramount on selecting control technologies. In October 2010, the US EPA designated Las Vegas Valley as attainment area for CO, however, the source decided to use originally proposed emission controls. This modification reduces the facility's CO Potential to Emit (PTE) below the major source threshold of 100 tons per year *[AQR 12.5].*

Carbon monoxide is formed by incomplete combustion of carbon-rich fuels. 2.0 ppmvd (3-hr average) CO LAER for the LM-6000 was based on consultation with DAQEM and research of the BACT/RACT/LAER Clearinghouse database for large simple cycle natural gas combustion turbines (>25MW). In addition, Saguaro solicited bids from a variety of vendors in order to identify the lowest achievable rate of CO control. Each of these methods identified 2.0 ppmvd (3-hr average) CO as the lowest achievable rate for this application. Saguaro will achieve this emission limit with DLN combustion controls and a CO oxidation catalyst. The research conducted did not identify a means of controlling CO emissions to a greater degree.

An Oxidation Catalyst is an add-on control placed in the exhaust stream following the combustion turbine. Oxidation Catalysts are primarily made of noble metals such as palladium or platinum, which is deposited on an alumina support. The effectiveness of the oxidation catalyst depends on fuel quality and load fluctuations. In order for an oxidation catalyst to be effective, the temperature of the exhaust gas must reach and remain above approximately 600°F.

During the combustion cycle DLN will reduce CO emissions to 25 ppmvd. Since the combustion turbine is directly connected to the Oxidation Catalyst, exhaust gas flow will be directed through the catalyst prior to being released into environment. The Oxidation Catalyst will operate at approximately 90.0% removal efficiency, which results in 2.0 ppmvd (3-hr average) or lower for the CO concentration. A 2.0 ppmvd (3-hr average) CO emission rate as measured over a 3-hour average, utilizing an oxidation catalyst, was the lowest emission rate identified during this analysis; therefore 2.0 ppmvd (3-hour average) can be considered LAER for this application.

The existing turbines (EUs: A01 and A02) will be also equipped with a new Oxidation Catalyst which will lower CO emission limit from 10 ppm to 2.0 ppm. Finally, the Nebraska boiler (EU: A06) will be equipped an Oxidation Catalyst to complete CO control. The CO emission limit for Nebraska boiler (EU: A06) will be lowered from 400 ppm to 2.0 ppm.

PROPOSED

VI. INCREMENT

Saguaro Power is a major source in Hydrographic Area 212 (Las Vegas Valley). Permitted emission units include five turbine generators, two starter engines, two boilers, one cooling tower and other equipment. Since minor source baseline dates for NO_X (October 21, 1988) and SO_2 (June 29, 1979) have been triggered, Prevention of Significant Deterioration (PSD) increment analysis is required. DAQEM modeled the source using AERMOD to track the 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) National Elevation Dataset (NED) terrain data was used to calculate elevations. Table 1 presents the results of the modeling.

Table VI-1: 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	48.84[1]	679114	3990413
SO_2	24-hour	31.84[1]	679114	3990413
SO_2	Annual	0.22	679136	3990509
NO_X	Annual	5.31	679136	3990509

[1]Modeled High 2nd High Concentration

Table VI-1 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.

PROPOSED

E. 40 CFR Subparts Db, Dc, GG, and KKKK Streamlining Demonstration

Table V-E-1: Streamlining Demonstration

Regulation (40 CFR)	Regulatory Standard	Permit Limit	Value Comparison				Averaging Period Comparison		
			Relevant Heat Input or Load Level[1]	Standard Value, in Units of 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?
60.4320 (KKKK)	25 ppmvd NO_x @15% O_2 (natural gas)	2.0 ppmvd NO_x @15% O_2 (natural gas)	N/A	25	10.0	Yes	4 hours	4 hours	Yes
60.4330 (KKKK)	0.90 lbs SO_2/MWh (39.6 lbs/hr) SO_x @15% O_2 (natural gas)	27 lbs/hr SO_x @15% O_2 (natural gas)	N/A	327	0.27	Yes	4 hours	4 hours	Yes
60.4330 (KKKK)	0.060 lbs SO_2/MMBtu (0.15% of S by weight)	0.05% of S by weight	N/A	0.15	0.05	Yes	N/A	N/A	N/A
60.332 (GG)	75 ppmvd NO_x @15% O_2 (natural gas)	10 ppmvd NO_x @15% O_2 (natural gas)	N/A	75(1)	10.0	Yes	4 hours	4 hours	Yes
60.333 (GG)	150 ppmvd (326 lbs/hr) SO_x @15% O_2 (natural gas)	27 lbs/hr SO_x @15% O_2 (natural gas)	N/A	326	0.27	Yes	4 hours	4 hours	Yes
60.333 (GG)	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
60.43b (Db)	20% Opacity	20% Opacity	N/A	20	20	Yes	60-minute period, excepting 6	60-minute period, excepting 6	Yes

PROPOSED

Regulation (40 CFR)	Regulatory Standard	Permit Limit	Value Comparison				Averaging Period Comparison		
			Relevant Heat Input or Load Level[1]	Standard Value, in Units of 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?
							minutes	minutes	
60.44b (Db)	0.20 lb NOx per MMBtu (192 ppm NOx @ 15% O_2)	12 ppm NOx @ 15% O_2	N/A	192	12	Yes	30-day rolling	3 hours	Yes
60.42c (Dc)	SO_2 Standards Not Applicable for Natural Gas	0.05 lb/hr, Natural Gas	N/A	N/A	0.05 lbs/hr	Yes	N/A	N/A	N/A
60.43c (Dc)	PM Standards Not Applicable for Natural Gas	0.43 lb/hr, Natural Gas	N/A	N/A	0.43 lbs/hr	Yes	N/A	N/A	N/A

[1]The 60.332.NOx standard is a formula; the value (75 ppmvd) is the minimum possible value of the standard for any emission unit.
Note: The formula used: EF =Cd * Cf * Fd * 20.9/(20.9 - %O2) and E = EF*HI.

where:
EF = emission rate (lb/MMBtu);
Cd = emission concentration (ppmvd);
Cf for NO_x = 1.194 E-07 (lb NOx/dscf ppm);
Fd = 8,710 dscf/MMBtu, dry basis F factor for O2 dilution for natural gas;
%O_2 = 15% (the oxygen volume at the stated limit;
E = mass emission rate (lb/hr); and
HI = heat input (MMBtu/hr).

PROPOSED

VII. PUBLIC NOTICE

NOTICE OF PROPOSED ACTION

NOTICE IS HEREBY GIVEN that the Clark County Department of Air Quality and Environmental Management (DAQEM) received an application for an Authority to Construct (ATC) permit for a stationary source of regulated air pollutants on December 30, 2008. The source is located at 8000 west Lake Mead Parkway, Henderson, NV 89015. The Control Officer has reviewed the application and determined that the proposed operation of the stationary source can comply with the Clark County Air Quality Regulations (AQR) by applying the best available control technology (BACT) and/or lowest achievable emission rate (LAER) for all regulated pollutants.

This notice announces the 30-day public comment period, commencing Thursday October 14, 2010, ending on Friday November 12, 2010 and is being issued pursuant to Nevada Revised Statute 445 and the AQR.

Saguaro Power Company, Inc., has applied for a modification the Authority to Construct (ATC) permit for a power generation facility in the Las Vegas Valley (Saguaro Power Company, Source: 393). The source is a major source of NO_X and CO and a minor source for PM_{10}, SO_x, VOC, and HAP. The source is located in the Las Vegas Valley airshed, hydrographic basin 212. Hydrographic basin 212 is nonattainment for PM_{10} and ozone, and PSD for all other regulated air pollutants. The modification requests the addition of three 44.2 MW each General Electric (GE) LM-6000 simple cycle combustion turbines, ammonia storage and injection units, and additional fourth cell on the existing cooling tower. Existing sources of regulated air pollutants (emission units) of the source include two 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. There are also two auxiliary boilers that are used to provide continuous steam supply. In addition, the source operates a cooling tower, two diesel fired turbine starter engines, a fuel oil storage tank, and an ammonia storage and injection system. Each turbine, boiler and cooling tower will be permitted to operate up to 24 hours per day and 8,760 hours per year. Best available control technology (BACT) for pollution control includes low-NOx burners, steam injection, and selective catalytic reduction (SCR) for the gas turbines, low-NOx burners with flue gas recirculation and CO oxidation system for turbines and boilers, and drift eliminators with 0.0006 percent drift for the cooling tower.

The maximum potential to emit of regulated air pollutants due to the operation of this source will be as follows:

	PM_{10}	NO_x	CO	SO_x	VOC	HAP
Source Potential to Emit (PTE) Tons per year	**50.65**	**120.18**	**18.84**	**9.68**	**19.12**	**9.84**

The technical support document (TSD), which describes the process, discusses compliance with relevant regulations, presents emission calculations, air quality impacts, and the proposed permit are available for public inspection at DAQEM, 500 S. Grand Central Parkway, Las Vegas, Nevada 89155, telephone (702) 455-5942 or the Clark County website: http://www.accessclarkcounty.com/depts/daqem/aq/pages/permits_notices.aspx. The TSD, and the proposed permit with enforceable conditions, will be mailed to interested persons upon request. Additional documentation may be requested by contacting Tina Gingras, Assistant Director, DAQEM or Richard D. Beckstead, Permitting Manager, DAQEM. Any fees associated with this request will be billed at a cost consistent with DAQEM policy and NRS 239.

Any person may submit written or oral comments to the Control Officer at the address given above. All comments must be received by Tuesday November 9, 2010 at 5:00 p.m., the close of this 30-day notice. The written comments will be retained and considered prior to the final determination by the Control Officer. A public hearing will be held on the proposed issuance of this permit if a request is made during the public comment period.

VIII. PERMITING HISTORY

1. The previous permit was issued on March 19, 2008.
2. The source submitted request for ATC on December 30, 2008.
3. The pre-construction ammonia monitoring was accepted on July 2, 2009.

PROPOSED

4. The permit and TSD were drafted and submitted for review on February 3, 2010.

PROPOSED

ATTACHMENTS

Calculation sheets are attached.

EU#:	A05		Emission Factor (lb/mmBtu)	Potential Emissions lb/hr	lb/day	ton/yr
Make:	Indeck/Volcano	PM10	0.0075	1.87	44.82	8.18
Model:		NOx	0.0146	3.64	87.25	15.92
S/N:		CO	0.0009	0.22	5.38	0.98
249.0	mmBtu/hr	SOx	0.0006	0.15	3.59	0.65
24.0	hr/day	VOC	0.0054	1.34	32.27	5.89
8760	hr/yr	HAP	1.900E-03	0.47	11.35	2.07
BACT:		%O2				
12	ppm NOx	3.0				
1	ppm CO	3.0				
Fuel:	Natural Gas					

EU#:	A01 and A02	Emission Factor (lb/mmBtu)	Potential Emissions lb/hr	lb/day	ton/yr
Make:	GE Turbine	PM10	0.0056	2.50	59.97	11.87
Model:		NOx	0.0340	15.20	364.75	72.19
S/N:		CO	0.0020	0.90	21.56	4.27
447.0	mmBtu/hr	SOx	0.0006	0.27	6.48	1.28
24.0	hr/day	VOC	0.0021	0.92	22.10	4.37
9500	hr/yr	HAP	1.030E-03	0.46	11.05	2.19
BACT:		%Oxygen				
10	ppm NOx	15.0				
10	ppm CO	15.0				
Fuel:	Natural Gas					

EU#:	A11, A12, A13	Emission Factor (lb/mmBtu)	Potential Emissions lb/hr	lb/day	ton/yr
Make:	GE	PM10	0.0109	3.99	95.75	28.41
Model:	LM6000	NOx	0.00803	2.94	70.54	20.93
S/N:	TBD	CO	0.00489	1.79	42.95	12.75
366.0	mmBtu/hr	SOx	0.0029	1.05	25.21	7.48
24.0	hr/day	VOC	0.0028	1.02	24.51	7.27
14245	hr/yr	HAP	1.030E-03	0.38	9.05	2.69
BACT:		%Oxygen				
2	ppm NOx	15.0				
2	ppm CO	15.0				
Fuel:	Natural Gas					

EU#:	A06	Emission Factor (lb/mmBtu)	Potential Emissions lb/hr	lb/day	ton/yr
Make:	Nationwide	PM10	0.0051	0.43	10.30	1.29
Model:	NOS 2A/S-55	NOx	0.0366	3.11	74.66	9.33
S/N:	032-88	CO	0.0015	0.13	3.06	0.38
85.0	mmBtu/hr	SOx	0.0006	0.05	1.22	0.15
24.0	hr/day	VOC	0.0054	0.46	11.02	1.38
6000	hr/yr	HAP	1.900E-03	0.16	3.88	0.48
BACT:		%Oxygen				
30	ppm NOx	3.0				
2	ppm CO	3.0				
Fuel:	Natural Gas					

EU	Description	Drift Loss %	Flow Rate (gal/min)	TDS (mg/l)	Hours of Operation hr/day	hr/yr	PM10 Emissions lb/hr	lb/day	ton/yr
A10	controlled tower	0.001%	30666	3800	24	8760	0.16	3.95	0.72
							0.16	**3.95**	**0.72**

PROPOSED