**TECHNICAL SUPPORT DOCUMENT**
**Table of Contents**

**Permit Number V99-017**
Date: October 26, 2006

TECHNICAL SUPPORT DOCUMENT

Permit Number V99-017
October 26, 2006

## 1. IDENTIFYING INFORMATION

| | |
|---|---|
| Facility Name: | Mesquite Power, LLC |
| Address: | 37625 West Elliot Road |
| City, State, Zip: | Arlington, AZ 85322 |
| Date Application Received: | The Title V permit renewal application was received from Mesquite Power, LLC on October 24, 2005. Mesquite Power submitted on October 31, 2005 a significant permit revision application to their existing Title V permit. The significant permit revision application supersedes a previously submitted minor permit revision application dated October 27, 2005. MCAQD has processed the Title V permit renewal application and the significant permit revision together. |

## 2. INTRODUCTION

This is a support document intended to provide additional information associated with the issuance of a significant permit revision and a Title V air quality permit renewal to Mesquite Generating Station. However, this Technical Support Document (TSD) is not part of the Permit and is not a legally enforceable document.

The Mesquite Power production facility is a major source for nitrogen oxides (NOx), carbon monoxide (CO), particulate matter less than 10 microns ($PM_{10}$), and volatile organic compounds (VOC) pollutants because the potential to emit these pollutants exceeds 100 tons per year.

### 2.1 Major Source Status with Regard to Ozone:

#### 2.1.1 1-Hour Standard

On April 21, 2004, the State submitted the One-Hour Ozone Redesignation Request and Maintenance Plan for the Maricopa County Nonattainment Area (assumed to include the Phoenix metropolitan nonattainment area). On March 21, 2005, EPA proposed to approve Arizona's request to redesignate the Phoenix metropolitan 1-hour ozone nonattainment area from nonattainment to attainment (see 70 FR 13425), and gave final approval of the redesignation on June 14, 2005 with an effective date of June 14, 2005 (see 70 FR 34362).

The 1-hour standard was revoked effective June 15, 2005 for all areas in Arizona (see 40 CFR 81.303 as amended by 70 FR 44470 - 44478) and no longer applies.

2.1.2 8-Hour Standard

On July 18, 1997 (62 FR 38856), EPA revised the ozone national ambient air quality standard (NAAQS) to establish an 8-hour standard; however, in order to ensure an effective transition to the new 8-hour standard, EPA also retained the 1-hour NAAQS for the area until such time as it determines that the area meets the 1-hour standard. See revised 40 CFR 50.9 at 62 FR 38894 and the above discussion regarding the status of the 1-hour standard for the Phoenix metropolitan 1-hour ozone nonattainment area. As a result of the actions described above, the 8-hour standard has replaced the 1-hour standard for ozone in the Maricopa County non-attainment area.

Mesquite Power, LLC is located in an area that is outside of the area that has been designated as basic nonattainment for the 8-hour standard (see July 1, 2004 version of 40 CFR 81.303).

MCAPCR Rule 240 §210.2 (5/7/03 version) states that "Any stationary source located in an attainment or unclassifiable area that emits, or has the potential to emit, 100 tons per year or more of any conventional air pollutant if the source is classified as a Categorical Source, or 250 tons per year or more of any pollutant subject to regulation under the Act if the source is not classified as a Categorical Source." Mesquite Power, LLC is classified as a categorical source and has the potential to emit greater than 100 tons of VOC and NOx emissions. Thus, the facility is a major source for VOC and NOx emissions.

2.2 Major Source Status with Regard to Remaining Criteria Pollutants:

Based on the July 1, 2005 version of 40 CFR 81.303, Mesquite Power, LLC is located in an area designated as unclassified/attainment with respect to National Ambient Air Quality Standards (NAAQS). This includes carbon monoxide (CO), sulfur dioxide ($SO_2$), nitrogen dioxide ($NO_2$), particulate matter less than 10 microns ($PM_{10}$) and particulate matter with a nominal aerodynamic diameter smaller than or equal to 2.5 microns ($PM_{2.5}$). The physical location is approximately 15 miles west of the Particulate Matter less than 10 microns (PM10) nonattainment area boundary and approximately 25 miles west of the CO and ozone nonattainment boundaries.

It should be noted that EPA has recently deleted Arizona attainment status designations (attainment, unclassifiable and nonattainment) affected by the original NAAQS for particulate matter measured as TSP (On June 3, 1993 EPA published a final rulemaking action revising the prevention of significant deterioration particulate matter increments, so that the increments are measured in terms of $PM_{10}$. Section 107(d)(4)(B) of the Clean Air Act authorizes EPA to eliminate all area TSP designations once the increments for $PM_{10}$ become effective).

Based on the above listed designations, the major source definitions of the MCAPCR, and the Mesquite Power facility's potential to emit (as limited by permit condition and PTE for $SO_2$), the Mesquite Power, LLC facility is a major source of CO and $PM_{10}$.

2.3 Major Source Status with Regard to Hazardous Air Pollutants (HAPs):

Mesquite estimates that emission rates of hazardous air pollutants (HAPs) are below the major threshold of 10 tpy for any individual HAP or 25 tons per year for any combination of HAPs with emission rates of:

12.6 tons per year – Total HAPs
4.5 tons per year – Highest Individual HAP (formaldehyde)

However county emission estimates indicate that the facility may be a major source of HAPs. Testing is required by the permit to determine the status.

## 3. PERMITTING HISTORY

Mesquite began operating at its location under permit V99-017 and is currently authorized to operate under that permit. The following timeline presents a summary of the history on file:

**April 21, 2001:** Title V/PSD permit was issued to Mesquite Generating Station. Mesquite Generating Station was a new facility and was required to install BACT which included a selective catalytic reduction and an oxidation catalyst at the facility. Emission rates of NOx, CO, PM10, and VOC were all estimated to be greater than the applicable PSD thresholds.

**February 11, 2002** Mesquite Generating Station provided notice of the start of construction stated “as of December 17, 2001”.

**May 6, 2003** This modification included requests to eliminate the ISO correction requirement for NOx Continuous Emissions Monitoring (CEM) data, remove the condition to install a flue gas measurement device, and clarify that the CEM system for measuring NOx emissions will be subject to the 40 CFR 75 requirements and the CEM system for measuring CO emissions will be subject to the 40 CFR 60 requirements.

**July 7, 2003** The purpose of these minor modifications (includes minor modifications 4-18-03-01 and 6-25-03-01) was to revise the definitions of Startup and Shutdown based on the turbine achieving "Mode 6" operation. Mode 6 operation indicates that the Low NOx burner systems are functional and the turbine is in normal operations. Ammonia injection will be initiated prior to achieving Mode 6 and all other systems affecting emission controls will be operational at this point. Achieving Mode 6 is a more accurate indication of the earliest point when the combustion turbine system can reliably operate in compliance with the emission limits. Prior to these modifications, the startup/shutdown SU/SD definitions were based on an operating load 60% of the rated nameplate generating capacity and SCR catalyst temperature above or below 600 ˚F.

Incorporating the Mode 6 condition as the SU/SD definitions was expected to maximize the periods that the facility must meet the more restrictive "normal" operating limits. Emission limits during "normal" operations are significantly lower than the startup and shutdown limits of this permit.

Other administrative changes were requested by the Permittee in these minor modifications, due to 40 CFR 60 Subparts Da and GG revisions since the issuance of this permit. The Permittee requested that the affected sections of the permit be revised to the current requirements of the Subparts.

**June 8, 2004:** A significant permit revision was approved in order to increase the allowable emissions for NOx, CO and VOC during SU/SD. The original permit included allowable emissions during periods of SU/SD based on estimates from the manufacturer. After the original Title V permit was issued these estimates were found to be underestimated. This modification changed SU/SD emissions in two ways. It changed the allowable emissions from a pound per hour per turbine basis to a pound per event per block (2 combustion turbines). The modification also changed the allowable annual emissions. The original allowable hourly SU/SD emissions are found in Table 1. Table 2 outlines the new adjusted limits.

Mesquite's annual allowable NOx emissions were increased to 408 tons per year (tpy) from 369 tpy. This increase was 39 tpy. Because the increase was just below the threshold for a major modification, the County imposed a 365-day rolling emission limit for NOx. Mesquite's annual allowable CO emissions were increased to 384 tpy from 359 tpy. This increase was 25 tpy. Mesquite's annual allowable VOC emissions were increased to 295 tpy from 259 tpy. This increase was 36 tpy.

**Table 1:**

| **Hourly Emission Limits During Startup or Shutdown** | | | | | |
|---|---|---|---|---|---|
| **(pounds per hour)** | **$NO_x$** | **CO** | **$PM_{10}$** | **$SO_2$** | **VOC** |
| GE – Combined Cycle System #1 | 26.1 | 19.9 | 18 | 1 | 1.9 |
| GE – Combined Cycle System #2 | 26.1 | 19.9 | 18 | 1 | 1.9 |
| GE – Combined Cycle System #3 | 26.1 | 19.9 | 18 | 1 | 1.9 |
| GE – Combined Cycle System #4 | 26.1 | 19.9 | 18 | 1 | 1.9 |

**Table 2:**

| **Device** | **$NO_x$ (lb/ event)** | **CO (lb/ event)** | **$PM_{10}$ (lb/hr)** | **$SO_2$ (lb/hr)** | **VOC (lb/ event)** |
|---|---|---|---|---|---|
| GE – Combined Cycle System #1 and #2 Combined during **Extended** Startup | 920 | 260 | 36 | 2 | 200 |
| GE – Combined Cycle System #3 and #4 Combined during **Extended** Startup | 920 | 260 | 36 | 2 | 200 |

| **Device** | **$NO_x$ (lb/ event)** | **CO (lb/ event)** | **$PM_{10}$ (lb/hr)** | **$SO_2$ (lb/hr)** | **VOC (lb/ event)** |
|---|---|---|---|---|---|
| GE – Combined Cycle System #1 and #2 Combined during **Regular** Startup | 362 | 108 | 36 | 2 | 84 |
| GE – Combined Cycle System #3 and #4 Combined during **Regular** Startup | 362 | 108 | 36 | 2 | 84 |
| GE – Combined Cycle System #1 and #2 Combined during **Shutdown** | 138 | 45 | 36 | 2 | 34 |
| GE – Combined Cycle System #1 and #2 Combined during **Shutdown** | 138 | 45 | 36 | 2 | 34 |

## 4. REVISIONS MADE TO EXISTING PERMIT CONDITIONS

In their significant revision permit application, Mesquite requested various changes to their existing permit conditions. This section includes a regulatory analysis of each requested change.

### 4.1 Include limits for tuning and testing procedures under the startup and shutdown emission limit table

Requested Change:

Mesquite requested that their permit include specific limits which apply during testing and tuning activities. The previous permit included no specifications for these activities. These activities require that the combined cycle system be maintained at low loads where control systems do not operate effectively and emission rates of NOx, CO, and VOCs, are therefore higher than emission rates associated with normal operation.

Analysis:

The manufacturer of the combustion turbines (GE) recommends that the tuning procedure be conducted twice per year. This procedure is necessary to address changes in ambient conditions, fuel conditions and normal component wear and to ensure efficient operation of the facility. During the procedure, the turbine is placed at various load levels and adjustments are made to optimize efficiency. The procedure generally lasts 5 hours.

Like the DLN tuning procedure, the testing procedure requires that the combustion turbine be placed in varying modes of operation. This 7-hour test is required by the Western Electricity Coordinating Council to maintain the facility's generator certification. One of the four combustion turbine generators (CTGs) will be tested at a time. This testing procedure is expected to be required every five years.

The permit application included emission calculations for tuning and testing procedures based on manufacturer-supplied data. The calculations included an assumption of no CO or NOx emission control at loads of 55% or less. Emission rates presented in the permit application are as follows:

| Event | NOx (lb/hr) | CO (lb/hr) | VOC (lb/hr) |
|---|---|---|---|
| Tuning | 300.0 | 1000.0 | 200.0 |
| Testing | 330.0 | 1050.0 | 200.0 |

The applicant used these emission rates in reevaluating the facility's impact on ambient air quality. The ambient air quality modeling analysis is discussed further in Section 22 of this TSD. The analysis indicated that the significance levels would not be exceeded.

Conclusion:

These events are conducted on an infrequent basis and are required to maintain efficient operation of the plant. The new permit therefore contains the requested limits which apply to the combined cycle systems, except permit has tuning and testing combined. Further, the permit contains the following additional requirements intended to address the ambient air quality analysis and ensure appropriate management of these events:

- Notification of each tuning or testing in writing event at least 24 hours prior to the event
- Only one combined cycle system may be tuned or tested at a given time
- No more than one combined cycle system can be operated in startup mode while any other system is undergoing tuning or testing activities that are subject to the higher emission limits for tuning and testing.

4.2 Increase the allowable start up and shut down emission limits (pounds per event) NOx and CO and remove the hourly startup/shutdown (SU/SD) emission limit for CO.

Requested Change:

Mesquite requested increases in the CO and NOx permit emission limits that apply during startup and shutdown events. In addition, Mesquite requested removal of the 260 pound-per-hour limit included in the notes of the SU/SD emission limit table (note 2, Table 3 of the previous permit). It is important to note that the Permittee did not request any increases in annual emission limits or the SU/SD limits that apply to PM10, SO2, or VOC.

There are two reasons for the request:

- The original permit included SU/SD NOx and CO limits that were based on flawed data for similar units provided by the turbine manufacturer. Only limited actual operating data was available at the time these limits were established. The flawed emission data has required numerous facilities to revise their permit limits.

- GE (the turbine manufacturer) has recently required a maintenance change to the startup procedure which is expected to cause an increase in NOx and CO startup emissions for the entire fleet of GE 7F turbines.

Background:

MCAQD has issued several Prevention of Significant Deterioration (PSD) permits for new power plants over the last five years. These permits included BACT limits for SU/SD events. Since issuance of their permits, many permittees have submitted renewal and revision applications which included requests to increase the limits for SU/SD emissions and increase the allowable hours of SU/SD operation.

The initial Title V/PSD permits were issued recognizing that associated control systems do not operate effectively (if at all) during SU/SD events due to the associated low exhaust temperature. Therefore, emissions limits for normal operation could not be applied during SU/SD events. Instead, MCAQD included in the permits, specific SU/SD limits which were established using manufacturer's specifications submitted by the applicant.

Many of the newly-constructed power plants in Maricopa County (since 2000) have modified the SU/SD limits because the initial manufacturer's data had underestimated these emissions. This resulted in an inability to comply with the permit limits. There is no indication that any of the applicants had intentionally acted to misrepresent or conceal any data in their original application. Currently, MCAQD is reviewing one other request from a power plant to increase SU/SD limits and limits on the allowable SU/SD hours.

Mesquite was granted a permit revision to adjust the allowable SU/SD limits in 2004 but the plant has not been able to meet the adjusted limits. The facility was the subject of a recent enforcement action (2006) in which they were required to operate under alternative limits until this renewal permit is issued.

In reviewing the requested permit revisions, County staff reviewed EPA's BACT policy. According to the November 19, 1987, memo from Gary McCutchen and Michael Trutna, "any time a permit limit founded in BACT is being considered for revision, a corresponding reevaluation (or reopening) of the original BACT determination is necessary." They explain that this "is necessary even if the permit limit is exceeded by less than a 'significant' amount."

If a source is faced with re-evaluating BACT due to faulty data, errors, or incorrect assumptions in the application, EPA expects the source, prior to any revision of BACT limits, to investigate and report to the permitting agency all available options to reduce emissions to a lower (if not the permitted) level. If compliance with the permit cannot be reasonably achieved, a re-evaluation may be warranted. If this is the case, the revision must address the BACT evaluation and all other PSD requirements (e.g., protection of National Ambient Air Quality Standards, increments, monitoring, etc.).

As directed by EPA guidance, Mesquite and County staff analyzed the following to determine the appropriate SU/SD emission limits and enforcement mechanisms:

1. Original BACT analysis and proposed SU/SD emission and operational limits
2. Protection of National Ambient Air Quality Standards
3. Monitoring needed to determine compliance with SU/SD limits and to ensure compliance with annual emission limits

Analysis:

In order to support the requested increases, Mesquite was required to submit the following:

- Emission data and calculations as well as proposed alternative BACT limits for SU/SD events
- Analysis of SU/SD emission and operational limits for similar facilities
- Report of available options for reducing emissions during SU/SD events, including control options and procedures to be used to minimize emissions during these events (startup, shutdown, malfunction plan)
- Re-evaluation of ambient air quality impacts and other PSD analyses
- Demonstration that annual limits can be met with the increased limits

1. Review of Original BACT Analysis and Proposed SU/SD Limits:

The table below indicates the current and proposed SU/SD emission limits for NOx, CO, and VOC. According to the application, the proposed SU/SD limits are based on CEMS data for CO and NOx and the proposed VOC limits are based on the 200 lb VOC per event limit from the previous permit as well as conservative engineering judgment.

| Pollutant | Currently Permitted Extended Startup (lb/event/ block) | Currently Permitted Regular Startup (lb/event/ block) | Currently Permitted Shutdown (lb/event/ block) | Proposed Startup (lb/hr/ combined cycle system) | Proposed Shutdown (lb/hr/ combined cycle system) |
|---|---|---|---|---|---|
| NOx | 920 | 362 | 138 | 250 | 200 |
| CO | 260 | 108 | 45 | 260 | 100 |
| VOC | 200 | 84 | 34 | 100 | 34 |

The previous SU/SD limits were in terms of pounds-per-event-per-block, but the new permit will contain pound-per-hour-per-combined-cycle limits and a limit on the length of time the higher startup limits apply. In order to support the new limits, the County required Mesquite to propose emission limits in terms of pounds-per-hour-per-combined cycle system and to propose an estimate of the startup duration. The change in emission limit terms was done to improve enforceability. The CEMS provides data for each combined cycle system stack on a per-hour basis; therefore, data conversion to a per-event-per-block basis will no longer be required and inspectors will more easily be able to determine whether the limits are met.

The Permittee submitted actual emissions data to support the revised limits. The highest emission rates for NOx and CO are presented below:

| Event | NOx Emission Rate (lb/hr) | CO Emission Rate (lb/hr) |
|---|---|---|
| Startup | 213 | 267 |
| Shutdown | 198 | 88 |

Mesquite also submitted an estimate of the startup duration for a regular and an extended start. These timeframes have been used to specify the length of time that the higher startup limits can apply.

The applicant submitted a review of startup duration limits in permits issued to similar facilities. Appendix C includes the complete table of results from the permit application. A sampling of the startup limits for similar power plants (GE 7F turbines) with similar controls is as follows:

| Facility | NOx Startup Limit | CO Startup Limit |
|---|---|---|
| Tesla Power Plant | 416 lb/event/turbine | 1181 lb/event/turbine |
| Santan | 227 lb/hr/turbine | 760 lb/hr/turbine |
| Gila Bend | 102 lb/hr/turbine | 594 lb/hr/turbine |
| Los Medanos (cold start) | 600 lb/event/turbine | 2514 lb/event/turbine |
| Elk Hills | 200 lb/hr/turbine (2 turbines) | 1800 lb/hr/turbine (2 turbines) |
| Mesquite (proposed) | 250 lb/hr/combined cycle system | 260 lb/hr/combined cycle system |

The proposed NOx and CO limits for Mesquite are comparable to those included in permits for similar facilities. In the case of CO, the proposed emission limit is significantly lower than the CO startup limit for similar facilities. In many cases, the emission limit is in terms of pounds-per-event. Without the exact duration of each event, it is difficult to compare the proposed pound-per-hour limits to the pounds-per-event limits.

A further review of SU/SD operational limits conducted by County staff for similar facilities is summarized below:

| Facility | Short-term Startup Duration Limit | Definition of Startup |
|---|---|---|
| La Paz Generating (ADEQ) | 4.2 hours (250 minutes) where startup ends at 75% load | Start of operation to 75% load |
| Harquahala | 10hrs/day | Start of operation to turbine exhaust temperature (prior to control) of 600F and load of 75% |
| Panda | 10 hrs/day | Start of operation to turbine exhaust temperature (prior to control) of 600F and load of 60% |

| | | |
|---|---|---|
| Redhawk | 10 hrs/day | Initial start to 60% load |
| Bowie (ADEQ) | 4.25 hrs/start | Start of operation to 50% load |
| Gila Bend | 10 hrs/day | |
| Kyrene | 8 hrs/day | |
| San Joaquin Valley Energy Center (California) | 3 hrs/start | |
| Diamond Wanapa (EPA) (Oregon) | Cold Start – 3.5 hours<br>Warm Start – 2.75 hours<br>Hot Start – 2 hours | First fuel to 50% capacity |

In their permit application, Mesquite requested the following limits on the duration of startup events:

Extended start, 10 hours
Regular start, 8 hours

Where an extended start is one in which the steam turbine reheat bowl temperature is at a lower temperature prior to the start. This is sometimes called a "cold start". The duration of an extended is significantly longer than that of a regular start where the equipment is still "warm". Data presented by Mesquite indicates that the majority of starts can be completed within 8 hours for an extended start and 5 hours for a regular start.

The revised permit contains a limit on the amount of time that the higher startup emissions may apply. The permit includes limits of:

8 hours for an extended start with two events per calendar year that may exceed 8 hours but are not longer than 10 hours

5 hours for a regular start with two events per calendar year that are greater than 5 hours but not more than 8 hours

The County determined that limiting the applicable duration of shutdown limits was not necessary because the duration is very short.

The permit application described the various technologies and procedures Mesquite considered to control SU/SD emissions from the combustion turbines at the plant. Technologies included the following in order from most to least effective (top down).

- Catalyst Control (SCR for NOx, Oxidation Catalyst for CO) with Good Engineering Practices
- Preheater (to reduce startup duration)
- Good Engineering Practices

The Mesquite plant already uses catalyst control and good engineering practices for NOx and CO emission reduction. However, the control effectiveness is lowered significantly during startup and shutdown events because reduced exhaust gas temperatures during these events limits the effectiveness of the catalyst. The rate at which the exhaust temperature can be increased is not controlled by the operator. Good engineering practices are used to bring control systems on-line.

Mesquite also considered the option of adding more catalyst material to improve control during SU/SD events. There is only a limited quantity of space available in the

Heat Recovery Steam Generator (HRSG) for catalyst addition. In addition, adding more catalyst would only slightly improve removal during SU/SD because, as mentioned, effectiveness is driven by exhaust gas temperature. Adding a substantial quantity of catalyst would be required to significantly improve removal but this would require installation of a new HRSG; this is clearly beyond cost effective levels. Further, additional catalyst would increase the backpressure causing lower efficiency of the power plant and an increase in fuel use. The net effect of this would be a per-megawatt increase in emission rates.

Another option was to begin ammonia injection into the Selective Catalytic Reduction units (NOx control) at a lower exhaust temperature. This would not be effective as ammonia requires elevated temperatures to advance the ammonia NOx catalytic reaction. In addition, this would cause an increase in ammonia slip which causes formation of secondary particulate matter. The current permit already requires injection of ammonia as soon as the appropriate exhaust temperature is reached.

Mesquite also considered the use of a pre-heater which would be expected to reduce the duration of startup times. However, like any fuel-burning unit, a pre-heater would require installation of additional emission sources, thus reducing any additional environmental benefit from the pre-heater.

The County has determined that good engineering practices are the best approach to minimizing emissions due to startup and shutdown events. Mesquite submitted procedures used to minimize emissions due to these events. The procedures and practices include:

- maintaining equipment according to manufacturer's recommendations
- manufacturer's "resident engineer" working on-site
- beginning ammonia injection to the SCR system as soon as the acceptable exhaust temperature is reached
- utilize the control system automatic shutdown sequence to decrease the load at the maximum rate
- Periodic borescope inspections of the combustion hardware
- Dry low NOx tuning and the use of a continuous dynamics monitoring system to maintain optimal efficiency

Mesquite is required to maintain a startup, shutdown, and malfunction plan for the facility to document good engineering practices and to ensure they are followed.

2. Protection of National Ambient Air Quality Standards

   Mesquite submitted an ambient air quality impact analysis to support the requested increases in NOx and CO emission rates during SU/SD events. The analysis is discussed in detail in Section 22 of this document. Results of the analysis indicate that the proposed emission limit for CO is below the significance levels set by the USEPA. Operational restrictions have been added to the permit in order to ensure that the significance levels will not be exceeded.

3. Monitoring needed to determine compliance with SU/SD limits and to ensure compliance with annual emission limits

As mentioned previously, Permittee has not requested any increases in annual limits. However, increases in short-term limits have the potential to cause an exceedance of the annual limits. The Permittee, therefore, submitted emission calculations to demonstrate that the annual limits would be met. The emission calculations indicated emission rates of 204 tons NOx per year, 191.8 tons CO per year, and 74.5 tons VOC per year (although VOC was not increased). These rates are equal to or less than the maximum allowed ton-per-year emission rates.

The applicant proposes to use CEMS data to ensure that the NOx and CO limits will be met. In order to ensure that the CEMS data accounts for all SU/SD emissions and CEMS downtime, the permit requires Mesquite to use the 40 CFR 75 Subpart D, Missing Data Substitution procedures to estimate NOx emissions for any period during which NOx CEMS data is not available or is not valid.

In the case of CO CEMS downtime, Mesquite must either use the missing data procedures required for NOx or must assume that the CO emission rate was equal to the applicable emission limit (startup, shutdown, testing/tuning, or normal operation) when calculating annual emission rates of CO.

VOC, SO2 and PM10 are not monitored by a CEMS. Therefore, Mesquite must assume that the emission rate of these pollutants during any startup, shutdown, testing, or tuning event was equal to the applicable emission limit when determining annual emissions of these pollutants. Mesquite may use a rate other than the applicable SU/SD limit for if they demonstrate that an alternative rate is more representative.

<u>Conclusion:</u>
The applicant has submitted sufficient data to support their requested increases in SU/SD emission limits. The following permit restrictions have been imposed in order to ensure that emissions during startup events are minimized and the revised limits do not result in an exceedance of the annual emission limits:

- Startup definition based on operating “mode”, operating percent of rated capacity, and temperature of SCR catalyst region
- A stipulation that startup limits apply only for a specified period of time with a different duration depending on the type of start (regular or extended) as described previously
- A requirement to use Part 75, Subpart D, Missing Data Substitution procedures or the applicable hourly emission limit in order to compute and report annual NOx emission rates
- A requirement to account for CO emissions during any CEMS downtime event, including a requirement to use either Part 75, Subpart D, Missing Data Substitution procedures or to assume the emission rate was equal to the CO emission limit during the downtime event.
- A requirement to use the emission limit value for startup, shutdown, testing, and tuning events, when computing annual VOC, SO2, and PM10 emission rates (an alternative calculation can be used if it is demonstrated to be more representative)
- A requirement to develop and comply with a SU/SD plan

4.3 Remove the limit on the annual number of SU/SD hours allowed:

Requested Change:
The Permittee has requested that the annual limit on the number of SU/SD hours (1400 hours per year) be removed and replaced with an annual permit limit compliance demonstration which relies on NOx and CO CEMS data.

Analysis:
The limit on the annual number of SU/SD hours was included in the original permit issued under the federal Prevention of Significant Deterioration (PSD) regulations. According to the Technical Support Document (TSD) for this permit (Section IV of TSD dated October 3, 2000), the annual pollutant emission limits were based on calculations which included 700 hours per year of startup or shutdown for each combined cycle system (1400 hours per year per block). The intent of the limit on the hours of SU/SD per year was to ensure that Mesquite would comply with the annual pollutant emission limits. Therefore, in removing the limits on SU/SD hours, the County must ensure that all annual limits remain federally enforceable (i.e., legally and practically enforceable).

The 1400 hour-per-year limit in the previous permit is not as restrictive as the annual NOx emission limit in the previous permit. This is because there is no restriction on the type of startup. The highest possible ton-per-year emission rate under the 1400 hour restriction (using the permit limits of 920 lb/extended start/block and 22.2 lb NOx/hr/combined cycle system for normal operation) is 274 tons of NOx per year for each combined cycle system, but the annual NOx limit is 204 tons per year.
Calculations of NOx emissions associated with this demonstration are as follows:

Startup emissions for one block (two Combined Cycle Systems #1/2 or #5/6) =
1400 hr/yr x 920 lb NOx/extended start ÷ 5.8 hr/event x 1/2000 ton/lb =
111 ton NOx/yr for each block

Normal operating emissions for one block =
(8760 hr/yr – 1400 hr/yr) x 2 x 22.2 lb NOx/hr x 1/2000 ton/lb =
163 ton NOx/yr for each block

Total for each block = 274 ton NOx/yr
Limit for each block = 204 ton NOx/yr

The annual NOx limit is therefore the more restrictive permit condition.

The permit must contain sufficient enforcement mechanisms to ensure that this annual limit will continue to be met. EPA's potential to emit policies speak directly to enforceability of annual limits and are, therefore, relevant to the SU/SD issue. EPA's policy entitled "Limiting Potential to Emit in New Source Permitting" of June 13, 1989, provides excellent guidance in ensuring that permit conditions effectively limit a source's potential to emit. The policy describes various options for limiting potential to emit. It generally prohibits blanket emission limits (e.g., ton/yr) but provides an exception if the permit agency determines that setting operating parameters for control equipment is infeasible in a particular situation (this is the case in SU/SD events). In this case, "short term emission limits (e.g., lbs per hour) would be sufficient to limit potential to emit, provided that such limits reflect operation of the control equipment, and the permit includes requirements to install, maintain, and operate a continuous emission monitoring (CEM) system," and retain related data.

According to a February 24, 1992, memo from John Rasnic, EPA "allows the use of long-term rolling averages in cases where the source experiences substantial and unpredictable annual variations in production." Many power plants experience such variations, even though there is a seasonal trend. The memo restricts any long term average to an annual average rolled at least every month. Where a rolling average is warranted, EPA suggests that a 365-day average allows for short term enforceability of limits while allowing for consideration of long-term data. The 365-day rolling average has been imposed in the case of NOx and CO.

<u>Conclusion</u>:
The limit on the annual number of SU/SD event-hours per year is being replaced with a pound-per-hour emission rate during each event and a limit on the duration of startup limits. In addition, CEMS compliance data will be used to provide sufficient assurance that annual limits will continue to be met.

The revised permit includes the following:
- Limitation on the length of time that the higher startup emission limits can apply (i.e., limit on the duration of startup limits)
- 365-day rolling annual average emission calculations for both NOx and CO (previous permit only required this for NOx)
- Requirement to account for CO and NOx emissions that occur during CEMS downtime
- Requirement to account for VOC, PM10, and SO2 emissions during SU/SD/testing/tuning
- Requirement to develop and comply with the startup, shutdown, and malfunction plan

In addition to these changes, the requirement to track annual hours of operation in each mode has been removed as it is no longer needed to enforce the annual limits.

4.4 Revise the differentiation between a regular and an extended start

<u>Requested Change:</u>
Permittee has requested that the differentiation between a regular and an extended start be revised.

<u>Analysis:</u>
According to the previous permit, an extended start is one in which the system has not reached mode 6 operation in the 72 hours prior to initiating the startup sequence and a regular start is one in which Mode 6 has been reached in the 72 hours prior to initiating startup. Permittee requests that this language be changed to indicate that an extended start is one in which the steam turbine reheat bowl is at a temperature of $400^{o}$F or less prior to initiating the start-up sequence and a regular start is one in which this temperature is above $400^{o}$F prior to such initiation. Permittee submitted actual data (refer to submittal in Attachment 1) which indicates that the new method of differentiation would require the facility to comply with the shorter duration limits associated with a regular startup more frequently than would be the case under the previous differentiation. The data (5/19/03 to 12/11/05) indicate that of 178 starts, 9

would have to meet extended start limits and 26 would have to meet regular start limits under the new differentiation. This means that more starts would have to meet the shorter duration limits for a regular start. Therefore, the proposed change will result in more stringent environmental control.

Conclusion:
Because this change is expected to result in more stringent emission control, the change has been approved. In order to enforce this new differentiation, the permit requires Mesquite to monitor and record the steam turbine reheat bowl temperature prior to each startup.

4.5 Additional Requested Changes

The Title V permit renewal application also includes the requested changes presented in the following table:

| Previous Permit Condition | Requested change | Response |
|---|---|---|
| **General Conditions** | | |
| 4.B | Remove reference to the compliance certification form supplied or approved by the Control Officer. | Current boilerplate General Conditions are included in the new permit. |
| 4.B and 16.C | Replace reference to "semiannual monitoring report" with "semiannual compliance report". | Current boilerplate General Conditions are included in the new permit. |
| 6.D | Revise regulatory citation "40 CFR Subpart G" to "'40 CFR 82". | The boilerplate conditions have been updated and the regulatory citation corrected. |
| 10 | Remove "Excess Emissions" condition as, according to County, and Rule 140, Section 103, it does not apply to PSD sources. | Current boilerplate General Conditions are included in the new permit. |
| 16.E | This condition requires emission estimates upon request. Permittee requests that this be removed as it is already provided for in Condition 16.A, Annual Emission Inventory Report. | Current boilerplate General Conditions are included in the new permit. Also, the conditions are not the same; one requires an annual emission statement while the other (16.E) does not specify a time-frame. |
| 16.F.1.a.1 and 2 | Verbal guidance from County staff has allowed notification within 1 business day and reports within 3 business days. Permittee requests that this be revised. | County rule 140, Section 500 specifically states that the verbal/faxed report is required within 24 hours following knowledge of the excess emission and the written report is due within 72 hours after the first report. Mesquite is required to strictly adhere to these timeframes. |

| Previous Permit Condition | Requested change | Response |
|---|---|---|
| **Specific Conditions** | Revise device numbering system. Combined cycle system #3 and #4 is now combined cycle system #5 and #6. | Revised device numbering system has been included in the new permit. |
| 18, Table 3 | Revise startup and shutdown limits as described in the permit revision application. | Refer to Section 4 of this document. |
| 18, Table 5 | Amend Table 5 for the CTGs to indicate that the NOx emission value for CTGs is based on a 4-hour rolling average. | The limit is directly from 40 CFR Subpart GG. The monitoring section (60.334(j)(1)(iii)(A )) states, "An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average $NO_X$ concentration exceeds the applicable emission limit in §60.332(a)(1) or (2)." The language from 60.334(j)(1)(iii)(A) has been inserted into the permit as requested. |
| 18, Table 5 | Amend Table to include the NOx standard of 1.6 lb/MW-hr for the duct burners (40 CFR 60.44Da(d)(1)). | The requested change has been incorporated into the permit. |
| 18, Table 5, footnote 3 | Amend footnote to identify NSPS Subpart Da, 60.44(d)(1) as the regulatory basis for the 1.6 lb/MW-hr limit and to specify the NOx limits for duct burners are based on a 30-day rolling average. | The permit refers to the appropriate regulatory basis for the limit as requested and the appropriate averaging period has been included. |
| 18, Table 5, footnote 3 | Amend footnote to specify the SO2 limit for duct burners is based on a 30-day rolling average. | This requested change is consistent with Subpart Da and has been incorporated into the permit. |
| 18, Table 5, footnote 3 | Amend the regulatory citations at the bottom of Table 3 to be consistent with the latest revision of 40 CFR 60, Subpart Da. The format has been changed from 60.44a(d)(1) to 60.44Da(d)(1). Update all Subpart Da citations. | Permit includes updated rule references and formats as requested. |
| 18.A.2, Note (i) | Remove this condition which indicates that Part 75 monitoring requirements are used to determine compliance with Subpart Da. Subpart Da does not require CEMS monitoring for duct burners. In addition, a stringency analysis would demonstrate that the 2.5 ppm stack NOx limit (PSD) is much more restrictive than either of the Subpart Da NOx limits. If this condition is not removed, it should be amended to clarify that the Subpart Da limits and monitoring are applied on the total stack emissions and are based on a 30-day rolling average of only duct burner operating days (duct | Reference to duct burner operating days has been included as requested. |

| Previous Permit Condition | Requested change | Response |
|---|---|---|
| | burners operating from 12 a.m. to Midnight). | |
| 18.A.2, Note j | This condition references a requirement that no longer applies due to revisions in the federal regulation. Please revise this condition to reference 40 CFR 60.335(b). | Requested change is acceptable and the permit includes updated rule references. |
| 18.A.2, Note l | Propose that this condition be revised to read: "VOC and PM-10 emissions … using the results of the prior annual reference method testing or the emission rates shown in Table 3." These are more accurate and conservative representations of the VOC and PM10 emissions. | The new permit allows approved performance test data, the emission methodology from the permit application, or an alternative emission calculation if the alternative demonstrated to the satisfaction of the Control Officer and the Administrator to be more representative of emissions. |
| 18.A.3 | Please remove this condition. Off-site SO2 modeling has shown compliance with the NAAQS. Plant has no means of monitoring or mitigating ground-level SO2 concentrations. | Because this permit condition is in the SIP, it must be retained in the permit as an applicable requirement. |
| 18.A.5(c) | In the third line of this condition, replace "facility" with "duct burner" as this requirement is from Subpart Da and is only applicable to the duct burners. | Requested change has been incorporated into the permit. |
| 19.G.9 | Please remove this condition. The condition was satisfied during original commissioning. | This condition required a RATA, linearity check, etc. within 90 days after commencement of operation. The condition has been satisfied. Annual RATA and bias tests per 40 CFR Part 75 as well as other data quality checks are required by the permit. |
| 20.E | Please remove this condition. Pursuant to 40 CFR Subpart Da (60.49(o)), the owner or operator of a duct burner is not required to install or operate a continuous emissions monitoring system to measure NOx emissions. | The previous permit condition states: "The NOx CEMS must obtain valid data for at least 18 of every 24 hours in at least 22 of every 30 consecutive days of operation." This requirement is required to satisfy Rule 210, Section 302.1.c.2. Note that this requirement has also been applied to the CO CEMS in order to meet the compliance assurance monitoring requirements for VOCs under 40 CFR §64.6. |
| 20.L | Conditions L, M, and O are redundant. Remove reference to Combined Cycle Systems as these are | The section on visible emission monitoring has been completely re- |

| Previous Permit Condition | Requested change | Response |
|---|---|---|
| | addressed in Condition M. Rewrite as: "L) The Permittee shall monthly conduct a facility walk-through and observe visible emissions from the diesel fueled fire water pump engine. The Permittee shall log the visual observations, including the date and time when that reading was taken, results of the reading, name of the person who took the reading, and any other related information." | written. |
| 20.M | Propose to replace the existing language with: "The Permittee shall monitor for compliance with the particulate matter emissions limits of the permit by taking a visual emission observation of the stack emissions from each Combined Cycle System during each week of operation that the equipment was used more than 10 hours." | See comment above. |
| 20.O | Apply this condition to both CCS and FW pump engine. Re-write as: "If emissions are visible from either the diesel fired firewater pump engine or the Combined Cycle Systems during observations conducted per Conditions 20.L or M, the Permittee shall obtain an opacity reading conducted in accordance with 40 CFR 60 Appendix A, Method 9 by a certified VE reader. This reading shall be taken within 3 operating days of the visible emission and taken thereafter weekly for each week when operations occur until there are no visible emissions. If the condition causing the visible emissions is eliminated before 3 days have passed, and no emissions are visible, the Permittee shall not be required to conduct the certified reading. The Control Officer may require additional emissions testing by other approved Reference Methods such as 40 CFR 60, Appendix A, Method 5 and Method 202 to demonstrate compliance with the particulate matter emissions limits of these Permit Conditions.<br><br>For purposes of this condition, a certified VE reader shall mean an individual who, at the time the reading is taken, is certified according to the County Rule Appendix C, Section 3.4. | See comment above. |
| 20.Q | Reference to 40 CFR 60.48c(i) is not applicable. Please remove this reference. | 40 CFR 60.48 (40 CFR 60 Subpart Dc) applies to smaller steam generating units. The reference has |

| Previous Permit Condition | Requested change | Response |
|---|---|---|
| | | been changed to 60.51Da and 60.52Da of 40 CFR 60 Subpart Da. |
| 21.A | References to 40 CFR 60.48c(a) and 60.49b(a) are not applicable. Please remove these references. | References have been changed to reflect correct regulation. |
| 21.B | Please remove this condition. All citations are erroneous. The section pertaining to reporting is 40 CFR Subpart Da, 60.51 (a) et. al., instead of 60.49a(a). Duct burner emissions can not be quantified separately from the gas turbine. In addition, CEM monitoring is not required for duct burners under Subpart Da. If the condition cannot be removed, it must be clarified to identify what NOx emissions must be reported, the averaging basis, etc. | All rule references have been updated. The current version of Subpart Da has been included in the permit. |
| 21.D.1. | | |
| 22.A.1 | Remove second sentence regarding fees for stack testing. County has revised regulations to eliminate these fees. | Current rule quotation will be used. |
| 22.B Table 7 | Remove third test condition in Table 7 (Each Combined Cycle System when Operating with Duct Burners OFF and 95% to 105% of nameplate capacity of the Combustion Turbine…). County has repeatedly approved eliminating this test condition via the test protocols as this condition is less stringent than the first test condition (Duct Burners ON and 95% to 105% of nameplate capacity of the Combined Cycle System). | The current standard testing conditions have been included in the new permit. |
| 23.B | Please remove this condition. The condition was satisfied upon completion of commissioning. | Recommended change has been made. |
| 24 | Please remove this condition. Mesquite Power does not engage in surface coating operations at this site. | Requested change has been made. |
| 27.C, D, and E | Several dust generating activities should be added to the permit renewal if possible. These include: unpaved parking areas, material loading/piles, and routine landscape activities. | Current boiler plate conditions have been included. |
| 31 | Please remove this condition. Mesquite Power does not use or apply cutback or emulsified asphalt. | Requested change has been made. |
| 32 | Remove this condition as Mesquite does not have any operations subject to Rule 330. | Requested change has been made. |

### 4.6 County-required Changes

In addition to the requested changes, the new permit contains the following additions:

| Change | Basis |
|---|---|
| Inspection of the SCR system and oxidation catalyst system is required to be completed at least every 18 calendar months. Also, other important requirements from the Operation and Maintenance plans have been placed in the permit. They are:<br>Analyze a sample of the catalyst within 30 days following inspection, operating data, or emission rate data that indicate that the catalyst may not be functioning properly; and<br>The maximum temperature of the catalyst shall not exceed 850$^{o}$F as measured at the SCR inlet. | This requirement is from the SCR and oxidation catalyst system operation and maintenance plan and is needed to ensure that controls are properly maintained |
| Permittee is now permitted to maintain a tariff agreement to shows that the sulfur content of the natural gas used in the combustion turbines meets the definition of natural gas in 40 CFR 60 Subpart GG (20 grains or less per 100 scf) | This requirement allows Permittee to demonstrate compliance with 40 CFR §60.333(b) and avoid the need to conduct daily fuel sulfur content monitoring under §60.334(i)(2). This allowance is provided for in §60.334(h)(3) (for gaseous fuel). |
| Reference has been made to the compliance testing procedures for PM10 and ammonia emission limits in Table 5. | Table 5 of the previous permit did not specify an averaging time for the PM10 limits and specified a 24-hour average for ammonia. The new permit includes a three-hour average for PM10 and includes no change to the ammonia averaging period. However for both PM10 and ammonia, the new permit specifies that compliance is determined through the required performance test which is based on the average of three one-hour (minimum) test runs. |
| Previous permit condition 19.G.9 has been replaced with more specific CEMS requirements from Parts 60 and 75. The condition required certification of the CEMS with the following: 1) relative accuracy test audit (RATA), 2) linearity check, 3) cylinder gas audit (CGA), 4) bias check, 5) 7-day calibration error check, and 6) cycle time check. | The previous permit condition referred to certification of the CEMS but did not specify that certification requirements only apply to the NOx CEMS under §75.20. There is no specific certification requirement for the CO CEMS. The CO CEMS is, however, required to comply with 40 CFR §60.13, Appendix B Performance Specification 4 and Appendix F Quality Assurance Procedures. The facility is also required to conduct a performance evaluation of the CO CEMS during each performance test (or within 30 days following the test). This change simply updates the current regulatory requirements for the plant. |
| References to “installation” of equipment and startup notifications have been removed. | The facility is not being constructed or modified under this permit and installation requirements are not needed. |

| | |
|---|---|
| Updates of applicable regulations have been included in the permit. | Updating the permit with current regulatory requirements is a primary goal of the permit renewal program. |
| Permit conditions for wipe cleaning in Permit Condition 29 have been incorporated into the solvent cleaning section. | Rule 331, Solvent Cleaning includes requirements for wipe cleaning. |
| Mesquite is required to collect valid CO CEMS data for 18 of 24 hours and 22 of 30 days. | This is required under 40 CFR §64.6 to meet the Compliance Assurance Monitoring requirements for VOCs. |
| The previous permit (condition 19.G.1) stated that in the case of a conflict between Part 60 and Part 75 requirements, Part 75 would govern. | This has been revised to state that the most stringent governs. |
| PM10 and SO2 emission limits which apply during startup, shutdown, testing and tuning events are being re-cast to be consistent with the per combined cycle system-based limits of the new permit (rather than the per block-based limits of the previous permit). | The emission limit values for PM10 and SO2 are the same as they were in the previous permit but because the permittee is not allowed to startup more than one combined cycle system at a time (of the four systems), the emission limit is equivalent. |
| Performance testing is being required for formaldehyde and hexane. | These pollutants are required to be tested in order to verify the major source status of the facility. |

## 5. SOURCE DESCRIPTION

The Mesquite Generating Station provides electricity to the grid for sale on the open market. The plant is a natural gas-fired combined cycle power plant with two power blocks. Each block includes two GE 7FE combustion turbines driving electrical generators (CTG), two heat recovery steam generators (HRSGs), and one steam turbine. The exhaust from the combustion turbine is routed through the HRSG to generate steam, making this configuration a combined cycle system (CCS). The CCS consists of one combustion turbine with the associated HRSG system. Each HRSG is equipped with a duct burner (DB) rated at 593 million British Thermal Units (Btus) per hour, to enable the generation of additional steam. Steam produced in the HRSG is routed to the steam turbine generator (STG). This configuration of two combined cycle systems with one steam turbine generator is referred to as a power block as depicted below:

<u>One Power Block</u>

CTG → HRSG/DB → STG

CTG → HRSG/DB → STG

Mesquite operates two of these power blocks. The CTGs are each rated at 180 megawatts (MW) and the two STGs are rated at approximately 290 MW each. Only the combustion turbines and duct burner portions of the power block consume fuel; they are, therefore, the primary sources of air pollution at the facility.

The plant uses dry low-NOx burners and selective catalytic reduction (SCR) for the control of NOx emissions. Oxidation catalysts are used to control CO and, to a lesser extent, VOC emissions. Only pipeline quality natural gas with a maximum sulfur content of 5 grains of total sulfur per 100 standard cubic foot (per tariff agreement) is used to fuel the CTGs and duct burners.

Mesquite maintains continuous emission monitoring systems (CEMS) for measuring CO and NOx outlet concentration and emission rates of the combined cycle systems. Oxygen is the diluent used in the NOx CEMS.

Support Equipment: Two mechanical draft cooling towers provide heat rejection for the steam cycle. Each cooling tower is comprised of 11 cells and is equipped with high efficiency drift eliminators. One 348 horsepower (HP) diesel-fired compression ignition engine drives an emergency fire-water pump.

Miscellaneous insignificant and trivial activities are also conducted at the facility. The site uses one remote reservoir solvent cleaner for maintenance. The liquid surface area is less than one square foot and therefore this qualifies as insignificant under Appendix D of Maricopa County Air Pollution Control Rules and Regulations.

The Mesquite Generating Station is located in Arlington, Arizona, Maricopa County. The 276-acre site is approximately 40 miles west of Phoenix and 8 miles south of the Interstate 10 freeway.

## 6. REGULATED ACTIVITIES

The power production operation consists of the following regulated activities/equipment:

- Four General Electric 7FA Combustion Turbines equipped with dry low-NOx burners. The turbines are fueled only by pipeline quality natural gas and equipped with dry low-NOx burners.

- Four supplementary fired Heat Recovery Steam Generators HRSGs each equipped with duct burners. The duct burners are fueled only by pipeline quality natural gas.

- The four combustion turbine/DB/HRSG systems drive two steam turbines in a two-on-one configuration as described in Section 5. The steam turbines themselves are not sources of air pollution.

- Each combined cycle system (which includes one combustion turbine and one DB/HRSG) is equipped with a selective catalytic control system to reduce emissions of NOx

- Each combined cycle system is equipped with an oxidizing catalyst system to reduce emissions of CO. Note that the oxidizing catalyst also reduces emissions of VOCs, although the system was designed for CO removal.

- Each combined cycle system is equipped with a continuous emission monitoring system (CEMS) for NOx and CO measurement

Regulated support equipment includes:

- Two mechanical draft cooling towers equipped with drift eliminators and a continuous cooling water conductivity monitoring system. Each cooling tower consists of eleven cells and has a cooling water circulating rate of 163,050 gallons per minute
- One 348-HP fire water pump engine, fueled only by diesel fuel

## 7. ALTERNATIVE OPERATING SCENARIOS

The permit application identifies only one operating scenario as described in Sections 5 and 6 of this document.

## 8. SUMMARY OF POTENTIAL TO EMIT

Table 8.1 presents the allowable annual emission rates for the regulated pollutants emitted at the source. These limits are federally enforceable; therefore, the allowable emission limits establish the facility's potential to emit.

| **Table 8.1** | **Summary of Potential to Emit (Tons per year)** | | | | |
|---|---|---|---|---|---|
| **Device** | **$NO_x$** | **CO** | **$PM_{10}$** | **$SO_2$** | **VOC** |
| GE – Combined Cycle Systems #1 #2 Combined | 204.0 | 191.8 | 253.2 | 17.6 | 147.5 |
| GE – Combined Cycle System #5 and $6 Combined | 204.0 | 191.8 | 253.2 | 17.6 | 147.5 |
| Cooling Tower #1 | NA | NA | 16.89 | NA | NA |
| Cooling Tower #2 | NA | NA | 16.89 | NA | NA |
| **Total PTE for GE Combined Cycle Systems #1, #2, #5 and #6 and Cooling Towers as in Permit Table 1** | **408.0** | **384.0** | **540** | **35.0** | **295.0** |
| Fire Water Pump Engine | 0.15 | 0.03 | 0.004 | 0.01 | 0.01 |

## 9. EMISSION LIMIT SUMMARY

9.1 Annual Emission Limits – Permit Table 18.1:
Rolling 365-day Average Emission Limit for NOx and CO
Rolling 12-month Average Emission Limits for $PM_{10}$, $SO_2$, and VOC
(Tons per year)

| **Device** | **$NO_x$** | **CO** | **$PM_{10}$** | **$SO_2$** | **VOC** |
|---|---|---|---|---|---|
| GE – Combined Cycle System #1 #2 Combined | 204.0 | 191.8 | 253.2 | 17.6 | 147.5 |
| GE – Combined Cycle System #5 and $6 Combined | 204.0 | 191.8 | 253.2 | 17.6 | 147.5 |
| Cooling Tower #1 | NA | NA | 16.89 | NA | NA |
| Cooling Tower #2 | NA | NA | 16.89 | NA | NA |
| Total for GE Combined Cycle Systems #1, #2, #5 and #6 and Cooling Towers | 408.0 | 384.0 | 540 | 35.0 | 295.0 |

There have been no increases in annual emission limits as compared to the previous permit.

In the case of NOx, the 365-day rolling average was established in the previous permit in order for the permittee to avoid the requirement to obtain a permit for a major modification. Refer to Technical Support Document for Significant Revision dated June 8, 2004, included in Appendix B of this TSD.

9.2 Combined Cycle System Emission Limits During Normal Operation:

Table 18.2a: Hourly Emission Limits for Combined Cycle Systems During Periods When Combined Cycle System Operates in Condition Other than Startup, Tuning, Testing, or Shutdown (pounds per hour):

| Device | $NO_x$ | CO | $PM_{10}$ | $SO_2$ | VOC |
|---|---|---|---|---|---|
| GE – Combined Cycle System #1 | 22.2 | 21.6 | 30.4 | 2.1 | 16.6 |
| GE – Combined Cycle System #2 | 22.2 | 21.6 | 30.4 | 2.1 | 16.6 |
| GE – Combined Cycle System #5 | 22.2 | 21.6 | 30.4 | 2.1 | 16.6 |
| GE – Combined Cycle System #6 | 22.2 | 21.6 | 30.4 | 2.1 | 16.6 |

These limits are the same as those included in the previous permit.

Table 18.2b: Additional Combined Cycle System Limits:

| Device | $NO_x$ | CO | $PM_{10}$ Solids (Filterable Alone) | $PM_{10}$ Total (Filterable plus Condensable) | VOC | $SO_2$ | Ammonia |
|---|---|---|---|---|---|---|---|
| Each Combined Cycle System Exhaust | 2.5 ppmv 3-hour rolling average | 4.0 ppmv 3-hour rolling average | 0.0063 lb/MMBtu (3-hour average) | 0.0128 lb/MMBtu (3-hour average) | 5.2 ppmv 3-hour average | NS | 10 ppmv 3-hour average |

The averaging time for PM10 in Table 2b was not specified in the previous permit, but this permit includes a 3-hour average. This averaging time is consistent with the NSPS compliance demonstration requirement of 60.8(f) which specifies that test results are based on the arithmetic mean of three 1-hour test runs.

The limits included in Tables 18.2a and 18.2b were established in previous permits, including the original major source Prevention of Significant Deterioration permit.

9.3 Combined Cycle System Limits during Startup, Shutdown, Tuning, and Testing

Table 18.2d: Combined Cycle System Emission Limits During Periods of Startup or Shutdown, Tuning, and Testing

| Device | $NO_x$ (lb/hr) | CO (lb/hr) | $PM_{10}$ (lb/hr) | $SO_2$ (lb/hr) | VOC (lb/hr) |
|---|---|---|---|---|---|
| GE – Combined Cycle System #1 during Startup | 250.0 | 260.0 | 36.0 | 2.0 | 100.0 |
| GE – Combined Cycle System #1 during Shutdown | 200 | 100.0 | 36.0 | 2.0 | 34.0 |
| GE – Combined Cycle System #1 during Tuning/Testing | 330.0 | 1050.0 | 36.0 | 2.0 | 200.0 |

9.4 New Source Performance Standards

Table 18.2c of the permit includes the applicable emission limits from 40 CFR 60 Subparts Da for the duct burners and GG for the combustion turbines (New Source Performance Standards). The requirements of these standards are discussed further in Section 12 of this document. The SO2 emission limit for the duct burners shown in the table was revised (compared to the last permit) to match the language in NSPS Subpart Da §60.42Da. Also language specifying that compliance with the SO2 limit is based on a 30-day rolling average basis was added as per NSPS Subpart Da 60.43Da(b).

9.5 Cooling Tower Limits

Table 18.3: Hourly Emission Limits for Cooling Towers (pounds per hour)

| **Device** | **$NO_x$** | **CO** | **$PM_{10}$** | **$SO_2$** | **VOC** |
|---|---|---|---|---|---|
| Cooling Tower #1 | NA | NA | 3.86 | NA | NA |
| Cooling Tower #2 | NA | NA | 3.86 | NA | NA |

$PM_{10}$ emissions from the Cooling Towers are calculated according to the equation presented in Permit Condition 18.C.

9.6 Off Site Sulfur Dioxide Limits

Table 18.4 of the permit includes sulfur dioxide concentration limits which apply “at any place beyond the premises.” The limits are as follows:

| Concentration of Sulfur Dioxide (micrograms per cubic meter) | Averaging Time (hours) |
|---|---|
| 850 | 1 |
| 250 | 24 |
| 120 | 72 |

These limits were taken directly from the previous permit which referenced SIP Rule 32F as the basis of the limits. The limit on fuel sulfur content is used to enforce these limits.

9.7 Particulate Matter Limits

The following particulate matter limit from Permit Condition18.E applies to any emission unit with a heat input rate of 4200 million Btu per hour:

$$E = 1.02\ Q^{0.769}$$

where:
E= the maximum allowable particulate emissions rate in pounds-mass per hour.
Q= the heat input in million Btu per hour.

This limit is from the previous permit and is based on ARS §49-106, State Rule R18-2-719.C.1 (R9-3-519.C.1) and SIP Rule 31H.1.a.

9.8 Opacity Limits

Opacity limits in the permit (Permit Condition 18.F) are as follows:

- The facility as a whole is limited to 20% opacity based on County Rule 300 and 40 CFR §60.42Da(b)
- SIP Rule 30 (federally enforceable) includes a limit of 40%.
- Rule 324 includes a 20% opacity limit for the fire water pump engine.

## 10. EMISSIONS BY POLLUTANT

This section addresses emissions of each pollutant. Calculations of potential to emit for the combined cycle systems were based on the following assumptions:

- 12 extended starts/yr lasting 5.8 hours
- 208 regular starts/yr lasting 2.5 hours
- 220 shutdowns/yr lasting 0.5 hours
- 4 tuning events/yr lasting 5 hours and
- 2 testing events/yr lasting 7 hours

In addition, the calculations include 52 hours per year of fire water pump operation.

### 10.1 Nitrogen Oxides (NOx)

| Process | Emission Calculation Methodology | Estimated NOx (ton/yr) | NOx Limit (ton/yr) |
|---|---|---|---|
| Four Combined Cycle Systems | Manufacturer-supplied data | 408 | 408 |
| Fire Water Pump | Manufacturer-supplied data | 0.15 | None |
| Total | | 408.15 | None |

### 10.2 Carbon Monoxide (CO)

| Process | Emission Calculation Methodology | Estimated CO (ton/yr) | CO Limit (ton/yr) |
|---|---|---|---|
| Four Combined Cycle Systems | Manufacturer-supplied data | 384 | 384 |
| Fire Water Pump | Manufacturer-supplied data | 0.03 | None |
| Total | | 384.03 | None |

### 10.3 Particulate Matter Less than 10 Microns (PM10)

| Process | Emission Calculation Methodology | Estimated PM10 (ton/yr) | PM10 Limit (ton/yr) |
|---|---|---|---|
| Four Combined Cycle Systems | Manufacturer-supplied data | 506.4 | 506.4 |
| Two Cooling Towers | Calculated from the equation presented in Permit Condition 18 | 33.8 | 33.8 |
| Total Combined Cycle Systems and Cooling Towers | | 539.8 | 540 |
| Fire Water Pump | Manufacturer-supplied data | 0.004 | None |

In order to compute the emission rate from the cooling towers, the specified equation in the permit was used as follows:

PM10= water circulation rate x total dissolved solids x 3.45 x $10^{-9}$

where,

Water circulation rate = 163,050 gallons per minute and

Total dissolved solids = 30,000 ppm

10.4 Sulfur Dioxide (SO2)

| Process | Emission Calculation Methodology | Estimated SO2 (ton/yr) | SO2 Limit (ton/yr) |
|---|---|---|---|
| Four Combined Cycle Systems | Manufacturer-supplied data and AP42 | 35 | 35 |
| Fire Water Pump | Manufacturer-supplied data | 0.01 | None |
| Total | | 35.01 | None |

10.5 Volatile Organic Compounds (VOC)

| Process | Emission Calculation Methodology | Estimated VOC (ton/yr) | VOC Limit (ton/yr) |
|---|---|---|---|
| Four Combined Cycle Systems | Manufacturer-supplied data | 295 | 295 |
| Fire Water Pump | Manufacturer-supplied data | 0.01 | None |
| Total | | 295.01 | None |

10.6 Hazardous Air Pollutants (HAPs)

According to calculations conducted by Mesquite and by the County (see details in the next two sections), the potential emission rates of the highest HAPs are as follows (over 500 lb/year):

Formaldehyde = 12.3 tpy (calculated by County)
Hexane = 10.5 tpy (calculated by County)
Toluene = 2.89 tpy
Xylene = 1.41 tpy
Acetaldehyde = 0.88 tpy
Ethylbenzene = 0.70 tpy
Propylene oxide = 0.64 tpy
Benzene = 0.279 tpy

10.6.1 HAPs – Calculated by Mesquite

| Process | Emission Calculation Methodology | Total Estimated HAPs (ton/yr) | Maximum Individual Estimated HAP (ton/yr) | HAP Limit(s) |
|---|---|---|---|---|
| Four Combined Cycle Systems | HAP Emissions based on AP42, Sections 1.3 (combustion turbines) and Section 1.4 (duct burners), except as follows:<br>Formaldehyde emission rate based on performance test for similar turbine<br>Hexane emission rate based on manufacturer guarantee for unburned hydrocarbons and estimated destruction | 12.6 | 4.5 (formaldehyde)<br><br>1.06 (Hexane) | None |

| | | | | |
|---|---|---|---|---|
| | removal efficiency for the duct burner | | | |
| Fire Water Pump | AP42 section 3.3 ($2.58 \times 10^{-3}$ lb propylene/MMBtu) | 0.00044 | 0.000176 (propylene) | None |

10.6.2 HAPs - Calculated by the County

| Process | Emission Calculation Methodology | Formaldehyde Emission Factor | Estimated Formaldehyde Estimated Emission Rate1 |
|---|---|---|---|
| Four Combustion Turbines | Background document for AP42, Stationary Gas Turbines Table 3.4-1 for oxidizing catalyst control | $3.6 \times 10^{-4}$ lb/MMBtu | 12.2 tons per year |
| Four Duct Burners | Table 1.4-3 of AP42 | 0.075 lb/$10^6$ scf ($7.4\times10^{-5}$ lb/MMBtu) | 0.09 tons per year |
| Total | | | 12.3 tons per year |

1 Emissions were calculated using the rated capacity of each combustion turbine (1929 MMBtu/hr) and each duct burner (593 MMBtu/hr) and assuming a heating value of 1020 Btu per cubic foot of natural gas. For duct burners, the CO catalyst is assumed to provide 88% removal. The following equation was then used to compute the emission rates:
Emission Rate (ton/yr) = Rated capacity (MMBtu/hr) x Emission Factor (lb Formaldehyde/MMBtu) x 8760 (hr/yr) x 1/2000 (ton/lb)

| Process | Emission Calculation Methodology | Hexane Emission Factor | Estimated Hexane Estimated Emission Rate1 |
|---|---|---|---|
| Four Combustion Turbines | CATEF emission factor from the California Air Resources Board database. | 0.25 lb/$10^6$ scf (0.000245 lb/MMBtu) | 8.3 tons per year |
| Four Duct Burners | Table 1.4-3 of AP42 | 1.8 lb/$10^6$ scf (0.00176 lb/MMBtu) | 2.2 tons per year |
| Total | | | 10.5 tons per year |

1 Emissions were calculated using the rated capacity of each combustion turbine (1929 MMBtu/hr) and each duct burner (593 MMBtu/hr) and assuming a heating value of 1020 Btu per cubic foot of natural gas. The following equation was then used to compute the emission rate:
Emission Rate (ton/yr) = Rated capacity (MMBtu/hr) x Emission Factor (lb Hexane/MMBtu) x 8760 (hr/yr) x 1/2000 (ton/lb)

10.7 Sulfuric Acid

Sulfuric acid ($H_2SO_4$) emissions were estimated by the Permittee as follows:
Tons $H_2SO_4$ per year = 35 x 0.16 x 0.65 x (98 lb/lbmole)/(64 lb/lbmole)

| Data | Units and Assumptions |
|---|---|
| 35 tons $SO_2$ per year | Combined cycle system limit of SO2 |
| 16 | Percent oxidation to $SO_3$ |
| 7.0 | Calculated tons $SO_3$ per year |
| 65% | Conversion of $SO_3$ to $H_2SO_4$ |
| 5.6 | Calculated tons $H_2SO_4$ per year |

10.8 CEMS Data Review:

As part of the county's review of the permit application, staff analyzed actual power block NOx and CO emission data for 2005, from the facility's annual emission inventory report.

| NOx (ton/year) | CO (ton/year) |
|---|---|
| 210 | 22 |

## 11. OPERATIONAL LIMITATIONS

11.1 Fuel Sulfur Content Limits

Fuel and sulfur content limits are as follows:

- Natural gas only in all devices except the fire water pump engine; sulfur content limit of 0.003 grains sulfur per dry standard cubic foot
- Diesel fuel only is to be used in the fire water pump engine; sulfur content of 0.05 percent sulfur by weight

These limits are from the previous permit implemented as part of the new source review process.

This natural gas sulfur content limit is in addition to the sulfur dioxide and sulfur content limits of 40 CFR 60, Subpart GG which applies to the combustion turbine portion of the combined cycle system. Subpart GG limits sulfur dioxide emissions to 0.015 % by volume at 15% oxygen (§60.333(a)) or the facility may limit fuel sulfur content to 0.8% sulfur by weight (8000 ppmw) (§60.333(b)).

11.2 Startup, Shutdown, Tuning, and Testing Operational Requirements for the Combined Cycle Systems

The permittee requested various changes which affect startup, shutdown, tuning, and testing activities at the site. These changes are described in detail in section 4 of this document.

11.3 Cooling Towers

Operational limits for the cooling towers are as follows:

1) The cooling towers are to be maintained with high efficiency drift eliminators certified by the cooling tower vendor to achieve less than 0.0005 percent drift.
2) The TDS content of the cooling water in the cooling tower shall not contain more than 30,000 milligrams per liter (mg/l) TDS.

11.4 Fire Water Pump Engine
The fire water pump engine is to be used only for emergencies or maintenance; fuel restrictions also apply as described previously.

11.5 Selective Catalytic Reduction (SCR) Air Pollution Control System
The following requirements apply to the SCR system:

- Mesquite is required to develop, implement, and comply with an operation and maintenance (O&M) plan for the SCR systems used to control NOx emissions from each combined cycle system.
- The SCR control system shall not inject ammonia into the SCR system when the inlet temperature to the catalyst is less than that specified in the O&M Plan.
- Inspect the catalyst for deformation, dust accumulation, plugging, or dust erosion and inspect the reactor seals to ensure their integrity at least every 14 operating months.

11.5 Oxidizing Catalyst Air Pollution Control System
Similar to the SCR systems, the permittee is required to develop, implement, and comply with an O&M plan for the oxidizing catalyst CO control systems. This permit requires that the Permittee inspect the upstream face of the catalyst and check for debris at least every 14 operating months.

## 12. APPLICABLE REQUIREMENTS

12.1 NEW SOURCE PERFORMANCE STANDARDS (NSPS) 40 CFR 60 SUBPART DA

a. DISCUSSION

Subpart Da applies only to the duct burner portion of the four heat recovery steam generating units. Subpart Da includes specific compliance demonstration procedures for NOx emissions from duct burners in §60.48Da(k). These procedures have been incorporated into the permit. Further, because the facility uses only natural gas, continuous opacity monitoring and continuous SO2 emission monitoring is not required.

This regulation was last revised by the USEPA on February 27, 2006. The latest version of Subpart Da has been included in the permit. Certain requirements in Subpart Da do not apply, including the mercury limits for coal-fired plants. In addition, the Commercial Demonstration Permit requirements of 40 CFR §60.47Da do not apply. Finally, the new version includes some additional requirements for facilities constructed after February 28, 2005; these new requirements do not apply because the facility was constructed prior to this date.

b. EMISSION LIMITATIONS AND STANDARDS

The following emission limitations apply to the facility:

- Particulates: 40 CFR §60.42Da(a)(1) 0.03 lb PM per million Btu heat input. No averaging period is given in this section.
- Opacity: 40 CFR §60.42Da(b) 20 percent opacity limit (6-minute average) except for one 6-minute period per hour of not more than 27 percent opacity.
- Sulfur dioxide: 40 CFR §60.43Da(b) (2) provides a limit of 0.20 lb SOx emitted per million Btu heat input with 0% reduction of potential combustion concentration. This is based on a 30-day rolling average (§60.43Da(g)). The

alternative emission limit of 0.80 lb SOx emitted per million Btu heat input and 90% reduction of potential combustion (§60.43Da(b)(1)) does not apply in this case because Mesquite has no fuel pre-treatment or control equipment to reduce SOx emissions.

- Nitrogen oxides: 40 CFR §60.44Da(d)(1) limits NOx emissions from units constructed between 7/9/97, and 2/28/05, to 1.6 lbs NOx per megawatt-hour gross energy output. Compliance is based on a 30-day rolling average except as provided in §60.48Da(k), which allows compliance to be determined using the average of three one-hour test runs or on a 30-day rolling average basis.

The emission limitations for PM, NOx, and SO2 in Subpart Da are much less stringent than those established under the Best Available Control Technology (BACT) requirements as shown in the following table:

| **Pollutant** | **Subpart Da Equivalent Emission Limit Calculation (lb/hr)**[1] | **Permit Limit** | **Comments**[2] |
|---|---|---|---|
| PM for Subpart Da PM10 for the Permit | 0.03 lb/MMBtu x 593 MMBtu/hr = **17.8 lb PM/hr for each duct burner** | 30.4 lb PM10/hr for turbine and duct burner combined Limit equivalent to **14.2 lb PM/hr for each duct burner** | The permit limit applies to the turbine and duct burner combined; Subpart Da only applies to the duct burner. Also, PM10 is a fraction of PM emissions. Assuming the permitted PM10 emissions are proportional to the heat input (MMBtu/hr) rating, the permit limit for the duct burner alone would be: 30.4 x 593/(593+1923) = 7.2 lb PM10/hr. Assuming that PM10 is about half of PM, this is estimated to be equivalent to 7.2 lbPM10/hr x 2 = 14.2 lb PM/hr which is less than the Subpart Da limit. |
| SO2 | 0.2 lb/MMBtu for Permittee this is 0.2 lb/MMBtu x 593 MMBtu/hr = **118.6 lb SO2/hr for each duct burner** | **2.1 lb SO2/hr** for each turbine and duct burner combined | The Subpart Da limit is much higher than the permit limit. Note that the permit limit applies to the combustion turbine and duct burner combined. |
| NOx | 1.6 lb/megawatt hr gross energy output from steam generator. Assuming that each duct burner generates 160.5 megawatts, the NOx limit would be 1.6 lb /megawatt-hr x 160.5 megawatts = **256.8 lb** | **22.2 lb NOx/hr** for combustion turbine and duct burner combined | The Subpart Da limit is much higher than the permit limit. Note that the permit limit applies to the combustion turbine and duct burner combined. Because two steam generating units supply steam to each steam turbine (rated at 321 megawatts), each steam generating unit gross energy output rating is assumed to be equal to half of the steam turbine rating, or 160.5 megawatts. |

| | | | |
|---|---|---|---|
| | **NOx/hr for each duct burner** | | |

[1] The emission limits of Subpart Da for PM and SO2 are in terms of pounds emitted per MMBtu heat input; because emission calculations and other permit limits are in terms of pounds emitted per hour and tons emitted per year, these Subpart Da limits were converted to pounds per hour rates for comparison purposes. Similarly, an equivalent emission limit for NOx was computed from the Subpart Da NOx limit.
[2] Duct burner rating = 593 MMBtu/hr; Turbine rating = 1923 MMBtu/hr

c. EMISSIONS CALCULATIONS

The permit application included a summary of overall pollutant emission rates from the combined cycle system as a whole based on manufacturer data. Duct burner emissions were not presented separately because the exhaust from the duct burner is combined with exhaust from the associated turbine, but Subpart Da applies only to the duct burner portion. Therefore, AP42 Table 1.4-4 for natural gas combustion was used to estimate emission rates for each of the four duct burners as follows (control efficiencies have been applied where appropriate, see note 1):

| Pollutant | AP42 Emission Factor (lb/MMBtu) | AP42 Emission Rate Estimate[1,2] (lb/hr) | Subpart Da Limit in Equivalent Pounds-per-hour |
|---|---|---|---|
| NOx | 0.19 lb NOx/MMBtu | 16.9 lb NOx/hr (SCR control 85%) | 256.8 lb NOx/hr |
| CO | 0.08 lb CO/MMBtu | 11.9 lb CO/hr (oxidizing catalyst control 75%) | NA |
| VOC | 0.0054 lb VOC/MMBtu | 2.9 lb VOC/hr (oxidizing catalyst control 10%) | NA |
| PM | 0.0074 lb PM/MMBtu | 4.4 lb PM/hr | 17.8 lb PM/hr |
| SO2 | 0.00059 lb SO2/MMBtu | 0.35 lb SO2/hr | 118.6 lb SO2/hr |

[1] Assumptions:

- Each duct burner is rated at 593 MMBtu/hr
- Electrical output of each duct burner is 160.5 megawatts
- Natural gas heating value is 1020 Btu/scf
- Selective catalytic reduction is 85% efficient for NOx removal (AP42 Section 1.4.4)
- Oxidation catalyst is 75% efficient for CO and 10% for VOCs (PSD permit application dated February 2000, pp. 5-16 and 5-23)

[2] Sample Calculation:

AP42 Emission rate lb/hr =
Emission factor (lb/MMBtu) x Heat Input (593 MMBtu/hr)

d. OPERATIONAL REQUIREMENTS/COMPLIANCE PROVISIONS

The following “Compliance Provisions”(§60.48Da) have been incorporated into the permit.

- §60.48Da(c): Particulate matter and NOx emission standards apply at all times except during periods of startup, shutdown, or malfunction.

- §60.48Da(e): Compliance with SOx limits under §60.43Da and NOx limits under §60.44Da is based on the average emission rate for 30 successive "boiler" operating days. The standard also says, "A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards." This requirement has been included in the permit by indicating that the SO2 and NOx emission limits for the duct burners are based on a 30-day rolling average (or one-hour average in the case of NOx, as allowed by §60.48Da(k)).
- §60.48Da(g): Compliance is determined by calculating the average of all hourly emission rates for SOx and NOx for the 30 successive boiler operating days (except for data obtained during periods of startup, shutdown (NOx only), or emergency conditions (SOx only)). For particulate matter, compliance with the daily average emission limit is determined by calculating the average of all hourly emission rates for each operating day. This requirement has been included in the permit by indicating the averaging times applicable to each regulated pollutant.
- §60.48Da(k): This section provides specific compliance provisions for duct burners used in combined cycle systems which are subject to the NOx limit of §60.44Da(d)(1). Emissions can be determined on a 30-day rolling average basis or a 1-hour average basis. This section also addresses duct burners which utilize a common steam turbine, as is the case at Mesquite. It allows the NOx emissions from the affected duct burners to be combined or the facility may propose an alternative method for apportioning the gross energy output from the steam turbine for each of the affected duct burners. 40 CFR §48Da(k) has been included in the permit in its entirety.

e. MONITORING/RECORDKEEPING

40 CFR Subpart Da emission monitoring requirements (§60.49Da(o)): This section provides an exemption from the following NOx monitoring requirements for the duct burners:

- CEM system for NOx
- wattmeter
- steam flow, temperature, and pressure meters
- continuous exhaust flow monitors

Monitoring under 40 CFR 60 Subpart GG and 40 CFR 75, and to meet requirements of the New Source Review Permit is however required.

40 CFR §60.49Da(b) provides an exemption for natural gas units from the requirement to continuously monitor SO2 emissions.

Continuous opacity monitoring is also not required for natural gas fired units per 40 CFR §60.49Da(a) and (u)(2).

f. REPORTING

Excess emission and monitoring system performance reports are due semiannually for each 6-month period and are to be postmarked by the 30th day following the end of each 6-month period.

g. TESTING
Initial testing for Subpart Da was completed following issuance of the previous permit. If the control officer determines that re-testing is required, the testing procedures in 40 CFR §60.50Da must be followed.

12.2 NSPS Subpart GG, Standards of Performance for Stationary Gas Turbines

a. DISCUSSION
Subpart GG, applies to stationary gas turbines with a peak input of 10 million BTU per hour or more. Mesquite operates four combined cycle systems each with two 1,730-million Btu/hr gas turbines for a total of four units subject to Subpart GG. There is a common stack which receives exhaust from both gas turbines (subject to Subpart GG) and both duct burners (subject to Subpart Da), for each of the four combined cycle systems.

The latest version of Subpart GG, including the most recent changes made on February 24, 2006, has been included in the permit.

b. EMISSION LIMITATIONS AND STANDARDS

- NOx (§60.332) – Emission limit calculated according to the following equation:
  STD = 0.0075 x (14.4/Y) + F
  Where STD is the allowable ISO corrected NOx concentration (% by volume at 15% oxygen, dry basis)
  Y = manufacturers rated heat rate at rated load (kilojoules per watt hour)
  F is an optional allowance for fuel-bound nitrogen.
  This limit (which is a minimum of 75 ppmv at 15% oxygen, dry basis) is much higher than the limit which was established in the New Source Review permit (2.5 ppmv at 15% oxygen).
- SOx (§60.333) – Emission limit of 0.015 percent SOx by volume at 15 percent oxygen and on a dry basis or fuel (natural gas) limited to total sulfur content of 0.8 percent by weight (8000 ppmw). As in the case of NOx, the original New Source Review permit includes a fuel sulfur content limit which is lower than that specified by Subpart GG.

c. EMISSIONS CALCULATIONS

NOx:

| Subpart GG Emission Limit | Permit Limit |
|---|---|
| Limit = 0.0075 x (14.4/Y)+F (percent by volume, dry 15% oxygen)<br><br>75 ppmvd is the | 2.5 ppmvd |

| | |
|---|---|
| lowest possible limit, assuming F=0 and Y = 14.4 (max)) | |

SO2:
The sulfur content limit of §60.333(b) is 8000 ppmw. The permit limit of 0.003 grains per dry standard cubic foot is equivalent to 10.7 ppmw which is well within the limit included in 60.333(b). The conversion from grains per dry standard cubic foot to ppmw is as follows:

0.003 gr/dscf x (0.068% / 0.2 gr/scf) = 0.00102 % weight or 10.7 ppmw
(conversion factor from definition of natural gas in 40 CFR 60, Subpart GG)

Permittee uses only natural gas. According to 40 CFR §60.331(u), natural gas contains no more than 680 ppmw which is much higher than the permit limit and is also below the sulfur content limit of Subpart GG (§60.333(b)).

d. OPERATIONAL REQUIREMENTS/COMPLIANCE PROVISIONS

The operational requirements and compliance provisions of 40 CFR Subpart GG are discussed in Sections 12.2.b and e.

e. MONITORING/RECORDKEEPING
Monitoring requirements are specified by §60.334(c), (h), (i), and (j). A NOx CEMS meeting the requirements of Part 75 is used to demonstrate compliance with the NOx limits of §60.332. CEM data must be reduced to hourly averages as per §60.13(h). According to §60.334 (b)(3)(iii), a NOx CEMS installed for purposes of compliance with 40 CFR Part 75, can be used to meet the requirements of Subpart GG, except that the missing data substitution method is not required to identifying excess emissions. Instead missing data are reported as monitor downtime.

Fuel sulfur content monitoring: According to §60.334(h)(1) and (3) Permittee may elect not to monitor the total sulfur content of the natural gas if it is demonstrated to meet the definition of natural gas (0.2 grains sulfur per standard cubic foot). The sulfur content can be demonstrated through a fuel supplier agreement (contract, tariff sheet, etc.) specifying that the sulfur content is 20.0 grains per 100 standard cubic feet or less. Permittee has a tariff agreement with the fuel supplier which specifies no more than 5 grains of total sulfur per 100 standard cubic feet of natural gas. This agreement satisfies the monitoring requirement of §60.334(h)(3) and a requirement to maintain the agreement has been included in the permit. Note that the previous New Source Review Permit contains a limit of 0.003 grains per dry standard cubic foot; quarterly monitoring and recordkeeping associated with the New Source Review sulfur content limit has been incorporated into this permit.

Nitrogen content of fuel (§60.334(h)(2)) - This section includes monitoring methods required to account for fuel-bound nitrogen in determining compliance with the NOx emission limit of 40 CFR 60, Subpart GG. Monitoring for nitrogen content is only required if an allowance is taken for fuel bound nitrogen in determining compliance with the NOx limit of §60.332.

f. REPORTING

Excess emissions must be reported in accordance with §60.334(j)(1)(iii) as follows: NOx - An hour of excess emissions is any operating hour in which the four-hour rolling average NOx concentration exceeds the applicable NOx limit in Subpart GG. As mentioned previously, the permit includes a more stringent emission concentration and averaging period.

NOx Monitor Downtime – Permittee must report any unit operating hour in which sufficient data are not obtained to validate the hour for NOx and/or diluent.

Ambient Conditions - If the Permittee does not use the worst-case ISO correction factor as specified in §60.334(b)(3)(ii), then the ambient conditions at the time of the excess emission period must be reported (temperature, pressure, and humidity).

SOx – Subpart GG (§60.334(j)(2)) defines a period of excess emission to be reported if there is an exceedance of the fuel sulfur content limit. Because the Subpart GG limit is much higher than the New Source Review permit limit, only documentation showing that the fuel meets the definition of natural gas is required to be kept on site.

g. TESTING

Testing under Subpart GG was completed initially following issuance of the previous permit. If testing is required again, the procedures of 40 CFR §60.335(a), (b), and (c) must be followed.

According to §60.335 the following test methods are required:

Method 20
ASTM D6522 or
Methods 7E and 3 or 3A to determine NOx and diluent concentration

The performance test must be performed within +/- 5 percent at 30, 50, 75 and 90-100 percent of peak load or at four evenly-spaced load points in the normal operating range, including the minimum point in the operating range and 90-100 percent of peak load.

§60.335(b)(3) allows testing of the combustion turbine either before or after the duct burner. If the sampling location is after the duct burner, the applicable NOx limit must still be met.

If Permittee elects to claim an emission allowance for fuel bound nitrogen, then concurrently with each test run, a fuel sample must be collected analyzed. §60.335(b)(9) describes the requirements for testing fuel bound nitrogen.

If a NOx CEMS is installed and certified, performance tests may be done in the following manner:

- Conduct a minimum of 9 reference method runs, with a minimum run time per run of 21 minutes at a single load level between 90 and 100 percent of peak (or the highest physically achievable) load.

- Use the test data to both demonstrate compliance with the applicable NOx emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

Compliance with the fuel sulfur content limit is demonstrated through the tariff agreement. Fuel sulfur content is, however, required to demonstrate compliance with the lower fuel sulfur content limit included in the permit.

12.3 NSPS Subpart A, General Provisions

a. DISCUSSION

This standard includes general provisions that apply to any facility subject to a New Source Performance Standard (NSPS). These general requirements address many items, including performance tests, monitoring requirements, control devices, and reports. Mesquite is subject to two NSPSs, Subparts Da and GG as described previously.

The Monitoring Requirements of Subpart A (40 CFR §60.13) were revised since issuance of the last Title V permit (revision dated August 27, 2001).

b. EMISSION LIMITATIONS AND STANDARDS

This standard includes no emission limitations or emission standards.

c. EMISSIONS CALCULATIONS

This standard does not address specific pollutants and therefore emission calculations related to this requirement are not required.

d. OPERATIONAL REQUIREMENTS

Operational requirements of Subpart A include the following:

- Properly operate and maintain process equipment and control systems
- Properly operate and maintain monitoring systems

e. MONITORING/RECORDKEEPING

Monitoring and recordkeeping provisions include:

- Startup, shutdown, and malfunction records
- Monitoring device records
- Performance testing records
- Performance evaluation records for CO
- Comply with applicable performance specifications under 40 CFR 60 Appendix B for continuous monitoring systems, and quality assurance/quality control requirements of 40 CFR 60 Appendix F
- CEMS general operating requirements (e.g., monitor calibration, minimum sampling frequency, etc.)

The monitoring and recordkeeping requirements which apply to NOx CEMS under 40 CFR Part 75 are used to meet the requirements of 40 CFR 60 Subparts GG and Da except that data reported shall not include periods of missing data.

f. REPORTING

Notification requirements include:

- Notice of any change that may increase emission rates
- Notification of startup

- Excess emission reports

g. TESTING
This standard outlines general requirements for performance testing including:
- Initial performance test
- Testing notification
- Test conditions and facilities
- Number of test runs

12.4 County Rule 324, Stationary Internal Combustion Engines (Fire Water Pump Engine)

a. DISCUSSION
This rule was adopted on October 22, 2003; it was therefore not included in the previous permit. This standard applies to the operation of the 348-horsepower engine used for pumping fire water in an emergency. The engine uses #2 diesel fuel. Under Rule 324 §104.7, emergency fire water pumps are only subject to Sections 301, 303, 502.1, and 502.4.

b. EMISSION LIMITATIONS AND STANDARDS
This standard includes the following requirements which have been incorporated into the permit:
Fuel sulfur content limit of 0.05% in Section 301
20% opacity limit in Section 303

c. EMISSIONS CALCULATIONS
The applicable limits have been included in the permit; emission calculations are not applicable.

d. OPERATIONAL REQUIREMENTS
Refer to Section b, above.

e. MONITORING/RECORDKEEPING
Recordkeeping provisions of Sections 502.1 and 502.4 include:
- Engine data records (engine combustion type, manufacturer, model, rated brake horsepower, serial number and location)
- Annual hours of operation
- Explanation of use

f. REPORTING
- This standard includes no reporting requirements for the fire water pump engine.

g. TESTING
Reference Method 9 is used to determine opacity.

12.5 County Rule 320, Odors and Gaseous Air Contaminants

a. DISCUSSION
This regulation includes generic requirements for limiting odors and air contaminants. The revised standard of July 2, 2003, has been incorporated into the permit.

b. EMISSION LIMITATIONS AND STANDARDS

This standard includes the following requirements which have been incorporated into the permit:
Material containment requirement (i.e., prevent evaporation of materials)
Limit fuel sulfur content to less than 0.05% by weight

c. EMISSIONS CALCULATIONS
The applicable limits have been included in the permit; emission calculations are not applicable.

d. OPERATIONAL REQUIREMENTS
Refer to Section b, above.

e. MONITORING/RECORDKEEPING
None included in Rule 320.

f. REPORTING
None included in Rule 320.

g. TESTING
None included in Rule 320.

12.6 County Rule 300 and SIP Rule 30, General Visible Emissions/Opacity Limits

a. DISCUSSION
These regulations include generic requirements for visible emissions and opacity (refer to the non-applicable requirements section for additional discussion on Rule 300 applicability). County Rule 300 is locally enforceable only. There have been no changes to Rule 300 since issuance of the last Title V permit. Rule 300 was last revised on February 2, 2001.

b. EMISSION LIMITATIONS AND STANDARDS
County Rule 300 – 20% opacity
SIP Rule 30 – 40% opacity

c. EMISSIONS CALCULATIONS
The applicable limits have been included in the permit; emission calculations are not applicable.

d. OPERATIONAL REQUIREMENTS
The permittee is only permitted to use natural gas in the combined cycle systems. Natural gas is associated with lower particulate matter emission rates and lower opacity.

e. MONITORING/RECORDKEEPING
Permittee is required to conduct a visible emissions observation of the cooling towers and combined cycle systems each week. In addition, permittee is required to conduct a monthly visible emissions observation of the fire water pump engine. If visible emissions are noted during any observation, opacity must be determined per EPA Reference Method 9 until no visible emissions are observed for a two-week period.

f. REPORTING

Reports of visible emissions observations, Method 9 readings and any deviations from the opacity and monitoring requirements are required to be submitted on a semiannual basis.

g. TESTING
Method 9 testing is required if visible emissions are observed.

12.7 SIP Rule 31.H – General Particulate Matter Limit

a. DISCUSSION
This regulation includes the process weight rate equation for fuel combustion.

b. EMISSION LIMITATIONS AND STANDARDS
The equation in SIP Rule 31.H which is used to determine the emission limit is as follows:

$E = 1.02\ Q^{0.769}$

where:
E= the maximum allowable particulate emissions rate in pounds-mass per hour.
Q= the heat input in million Btu per hour.

c. EMISSIONS CALCULATIONS
Using this equation and a heat input rate of 2516 million Btu per hour for each combined cycle system (1923 MMBtu for the turbine and 593 MMBtu/hr for the duct burner), the following emission limit is calculated using the equation in section b:

E = 1.02(2516)0.769
= 420 lb PM/hr for each combined cycle system

Emission calculations presented in the permit application indicate an emission rate of PM10 of 30.4 lb PM10/hr (which is the same as the permit limit). If it is assumed that the emission rate of PM is twice the rate of PM10, the calculated emission rate would be 60.8 lb PM per hour. This is well below the limit derived using the equation of SIP Rule 31.H.

d. OPERATIONAL REQUIREMENTS
None included.

e. MONITORING/RECORDKEEPING
None included.

f. REPORTING
None included.

g. TESTING
Testing for PM10 conducted according to Permit Condition 22 is intended to provide sufficient compliance demonstration.

12.8 SIP Rule 32F – Off-site Sulfur Dioxide Emission Limits

The fuel sulfur content limit is intended to limit the emissions of sulfur dioxide and therefore off-site emission impacts.

12.9 Acid Rain Program

Mesquite is subject to the federal Acid Rain Program. As required, the permittee submitted the Acid Rain Permit renewal on March 10, 2006. The submittal included the forms required by the USEPA. The permit incorporates the required acid rain permit. The following is a summary of the regulations under the Acid Rain Program that apply to Mesquite:

| 40 CFR Part | Title |
|---|---|
| 72 | Permits regulation |
| 73 | Sulfur dioxide allowance system |
| 75 | Continuous emission monitoring |
| 77 | Excess emissions<br>(includes procedures for the facility and EPA to follow in case of an exceedance of an applicable emission allowance; also addresses penalties) |
| 78 | Appeal procedures for Acid Rain Program<br>(applies only in the case of an appeal) |

12.10 Support Operations

This permit addresses the following support operations which are not discussed in detail in this document:

County Rule 310, Dust Generating Operations
County Rule 312, Abrasive Blasting
County Rule 315, Spray Coating
County Rule 331, Solvent Cleaning
County Rule 335, Architectural Coating

## 13. POTENTIALLY APPLICABLE REQUIREMENTS

Refer to section 14.

## 14. NONAPPLICABLE REQUIREMENTS

14.1 The following portions of NSPS 40 CFR 60, Subpart Da do not apply:

a. The nitrogen oxide limit included in §60.44Da(a) (0.2 lb/MMBtu), does not apply to the Mesquite steam generating units any longer because they are subject to §60.44Da(d)(1) (1.6 lb/megawatt hour gross energy output) instead. §60.44Da(a) applies to owners or operators subject to 40 CFR 60 Subpart Da, "except as provided under" §60.44Da(d).

b. The NSPS Standard of Performance for Electric Utility Steam Generating Units for Which Construction Commenced after September 18, 1978 (40 CFR 60 Subpart Da) applies to the heat recovery steam generators. However, the Standard for Mercury, included in 40 CFR §60.45 Da, applies only to coal fired units and, therefore, does not apply to the steam generating units at this facility.

c. 40 CFR §60.49Da(b) provides an exemption from SO2 continuous emission monitoring for gas-fired units. Also 40 CFR §60.49Da(a) provides an exemption from opacity monitoring requirements for gas-fired units. Finally, §60.49(o) exempts duct burners from the requirement to maintain a CEM system for NOx, a wattmeter, meters to measure steam flow, temperature, and pressure, and an exhaust flow monitoring system.

14.2 County Rule 323 applies to each stationary gas turbine with a heat input at peak load equal to or greater than 2.9 Megawatts (MW) and each steam generating unit that has a maximum design rated heat input capacity of greater than 10 million Btu per hour or 2.9 MW. However, Rule 323, Section 103.7, provides an exemption for combustion equipment used in power plant operations for the purpose of supplying greater than one-third of the electricity to any utility power distribution system for sale. Mesquite operates a power plant for the purpose of providing electricity to a distribution system. Therefore Mesquite is exempt from Rule 323.

14.3 County Rule 300 includes general opacity limitations (20%). The rule applies to visible emissions from sources for which no source-specific opacity requirements apply. Therefore Rule 300 only applies to sources other than the fire water pump which is subject to Rule 324, the heat recovery steam generating units (duct burners) subject to NSPS opacity requirements (40 CFR 60.42Da(b)), and dust generating activities subject to Rule 310 and 310.01.

14.4 County Rule 322 applies to power plant operations for which construction commenced prior to May 10, 1996 (Section 102). This power plant was constructed after that date and is, therefore, exempt from Rule 322.

14.5 40 CFR 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants (HAPs) for Stationary Combustion Turbines applies to stationary combustion turbines located at a major source of HAP emissions (40 CFR §63.6085). According to §63.690(b)(4), existing combustion turbines (i.e., constructed prior to January 14, 2003) do not have to meet the requirements of Subpart YYYY.

14.6 On February 18, 2005, EPA proposed a regulation which will apply to new combustion turbines (40 CFR 60 Subpart KKKK). According to the proposal, the regulation will apply to affected facilities which commence construction, modification or reconstruction after February 18, 2005. Because Mesquite Generating Station was constructed prior to this date and has not been re-constructed or “modified” after that date, 40 CFR 60 Subpart KKKK does not apply.

14.7 40 CFR Part 76, acid rain nitrogen oxides emission reduction program: This program only applies to coal-fired units. Because Mesquite is gas-fired, Part 76 does not apply.

14.8 40 CFR Part 74 includes provisions for opting into the sulfur dioxide program under the Acid Rain program and does not apply to Mesquite.

14.9 County Rule 245, Continuous Source Emission Monitoring, does not apply to any source which is subject to a New Source Performance Standard (Section 306.1) and therefore does not apply to Mesquite.

## 15. STREAMLINING

No regulatory requirements have been streamlined; some reporting and monitoring requirements have been combined.

## 16. TESTING

County Rule 200 Section 309 has granted the Control Officer the authority to require emissions testing if other sources of information are determined to be inadequate and certain other findings are made. The Control Officer has determined that the information available is not adequate. In addition, the Control Officer has determined that:

a. The facility emits NOx, CO, PM10, VOC and HAPs. The USEPA has determined that exposure to this pollutant can adversely affect human health. NOx and CO emissions are verified through the CEMS and QA/AC programs.
b. The test methods to be used are described in Permit Condition 22. These test methods are EPA approved test methods and have been shown to produce scientifically acceptable results. Test methods for specific HAPs to be tested are included in the permit.
c. All test methods in the permit have been shown to be technically feasible.
d. All test methods in the permit have been shown to be reasonably accurate
e. After examining the estimated cost of the test, the Department believes that the cost of a stack-sampling test of the control device performance is reasonable to determine the effectiveness of the control device, to establish a base line of emissions, to avoid potential fines, to establish parametric monitoring, to demonstrate adequacy of a maintenance program on equipment or controls, to provide emissions rate information for possible future PSD/NSR modeling requirements and to establish emissions rate information for environmental justices purposes.

## 17. PERMIT SHIELD

A permit shield was granted in the previous permit and has been included in this permit for specific applicable requirements. In addition to more generic requirements, the permit shield applies to:

Rule 300, Visible Emissions
Rule 310, Open Fugitive Dust Sources
Rule 312, Abrasive Blasting
Rule 315, Spray Coating Operations
Rule 320, Odors and Gaseous Air Contaminants
Rule 331, Solvent Cleaning
Rule 335, Architectural Coatings
Rule 360, New Source Performance Standards: Subparts A, Da, and GG
Rule 324, Stationary Internal Combustion Engines
Rule 600, Emergency Episodes

## 18. PREVIOUSLY ISSUED PERMIT CONDITIONS

Refer to Section 4 of this document for a detailed discussion of the changes made to the previous permit conditions.

## 19. COMPLIANCE ASSURANCE MONITORING (CAM) APPLICABILITY

The previous Title V permit indicated that 40 CFR 64, Compliance Assurance Monitoring, would not apply to the facility. However, the permit application, page 5-6, indicates that §64.3 does apply.

40 CFR Part 64 applies to each pollutant-specific emissions unit at a major source if the unit satisfies all of the following:

- The unit is subject to an emission standard for the pollutant other than an exempted emission limit or standard under 40 CFR §64.2(b)(1)
- The unit uses a control device to achieve compliance
- The unit has a pre-control potential to emit of 100% of the major source threshold

Detailed review of 40 CFR 64 indicates that the CAM requirements do not apply to CO or NOx emissions at Mesquite. Because these pollutants qualify for the exemption described in 40 CFR §64.2(b)(1)(vi) exempts units where the permit specifies a continuous compliance determination method, including a CEMS. Because a CEMS is required to monitor both CO and NOx emissions, these pollutants are exempt from CAM.

The facility is, however, subject to CAM for VOC emissions because uncontrolled VOC emissions from each combine cycle system exceed the 100 ton-per-year major source threshold at 108 tons per year and the facility uses a control system to meet all VOC limits in the permit except for those limits that apply during startup, shutdown, testing, and tuning. The facility uses an oxidizing catalyst designed to control CO emissions but this system also removes VOC emissions by approximately 10%, according to the emission calculations. Because the oxidizing catalyst is designed to remove CO and the CO CEMS provides assurance that the oxidizing catalyst is functioning properly, Mesquite has proposed that compliance assurance with all VOC emission limits (except those that apply to startup, shutdown, testing, or tuning) be achieved through the CO CEMS requirements.

40 CFR §64.4(c) requires submittal of CO CEMS data taken at the time of the last VOC emission test. Mesquite submitted the required data which is summarized below:

Date of last test June 22 and 23, 2006
VOC emission rate determined during the test:
Unit #1 = 1.24 lb VOC per hour
Unit #2 = 1.15 lb VOC per hour
VOC emission limit = 16.6 lb VOC per hour
These emission rates are from the most recent test report. At the time of this TSD, the County had not completed a final review of the test data.

Highest CO emission rate from Unit #1 during the test = 1.08 lb CO per hour
Highest CO emission rate from Unit #2 during the test = 4.18 lb CO per hour
CO emission limit = 21.6 lb CO per hour

The permit requires Mesquite to collect and record CO CEMS data during each VOC emission test.

According to 40 CFR §64.6(c), the permit must specify
:

| 40 CFR §64.6 Requirement | Permit Requirement |
|---|---|
| Indicator(s) to be monitored | CO Emission Rate |
| Device(s) to be used to measure the indicator(s) | CO CEMS |
| Performance requirements established to satisfy §64.3(b) (Performance Criteria) or (d) (Special Criteria for the use of Continuous Emission, Opacity, or Predictive Monitoring Systems). According to §64.3(d), the use of a CEMS that satisfies 40 CFR §60.13, Appendix B is deemed | The CO CEMS must be operated according to 40 CFR §60.13, Appendix B and therefore, the system meets the performance criteria. However, because the CO CEMS does not directly VOC |

| | |
|---|---|
| to satisfy the general design criteria required by §64.3(a) and (b). | emissions, the permit defines an excursion of the VOC limit as any CO emission limit exceedance. |
| Means by which an exceedance or excursion is defined. The permit must specify the level at which an exceedance or excursion will be deemed to occur, including the appropriate averaging period associated with such exceedance or excursion. For defining an excursion from an indicator range, the permit may either include the specific values at which an excursion shall occur or the specific procedures that will be used to establish that value or condition. If the latter, the permit shall specify appropriate notice procedures for the operator to notify the permitting authority upon any establishment or re-establishment of the value. | Exceedance of the CO emission limit is an excursion of the VOC emission limit. |
| Obligation to conduct the monitoring and fulfill the other obligations specified in 40 CFR §§64.7 through 64.9. | Permit requires 40 CFR §64.7 to 64.9 to be followed. |
| If appropriate a minimum data availability requirement for valid data collection for each averaging period and if appropriate a minimum data availability requirement for the averaging periods in a reporting period. | 40 CFR §60.13 and the permit require a sampling cycle every 15 minutes. The Permit imposes minimum of 18 of 24 hours of CO CEMS operation. |
| Compliance schedule | A compliance schedule is not required because the permit does not require any new monitoring equipment or systems. |

## 20. COMPLIANCE PLAN

The facility is operating under an order of abatement by consent (OAC Number TV-002-06-HMK). Issuance of this permit signifies the expiration of the effective period of the order.

## 21. HAP IMPACT ANALYSIS

This renewal permit does not include any proposed increase in HAPs. Impact of HAPs was addressed in the previous permit. The modeled impacts were compared to the most recent version (1999) of the annual and short term (1-hour and 24-hour) Arizona Ambient Air Quality Guidelines (AAAQGs) as published by ADEQ. The model results provided indicated maximum impacts ranging from about 46 percent to much less than one percent of the AAAQGs.

The original HAP impact analysis addressed hexane and formaldehyde. However, estimates by County staff indicate that emissions of these pollutants may be higher than that presented in the permit application. The impact of these pollutants was, therefore, re-evaluated. The table below shows the impact predicted using the county's emission estimates. Note that the impact is still well within the AAAQGs for these pollutants.

**Deleted:** ¶

| |
|---|
| Hexane<br>Mesquite Emission Estimate (per January 2001 Title V permit TSD data): 0.000845lb/hr<br>24- hour impact (per January 2001 Title V permit TSD data): 6.98 E-04 µg/m3<br>1-hour impact (per January 2001 Title V permit TSD data): 2.84E-03 µg/m3<br><br>Annual hours of operation per year = 5525 hr/yr, based on Mesquite's application dated 10-27-05<br><br>County Emission Estimate = 10.5 ton/yr x 2000 lb/ton x 1/(5525 hr/yr) = 3.80 lb/hr<br>24-hour County-estimated impact = 6.98 E-04 x (3.8/0.000845) = 3.13 µg/m3<br>1-hour County-estimated impact: 2.84 E-03 x (3.80/0.000845) = 12.77 µg/m3<br><br>24-hour AAAQG: 7.90 µg/m3<br>1-hour AAAQG: 25 µg/m3 |
| Formaldehyde<br>Mesquite Emission Estimate(per January 2001 Title V permit TSD data): 0.487 lb/hr<br>24- hour impact(per January 2001 Title V permit TSD data): 0.402 µg/m3<br>1-hour impact(per January 2001 Title V permit TSD data): 1.63µg/m3<br><br>County Emission Estimate: 12.3 ton/yr x 2000 lb/ton x 1/(5525 hr/yr) = 4.45 lb/hr<br>24-hour County-estimated impact: 0.402 x (4.45/0.487) = 3.67 µg/m3<br>1-hour County-estimated impact: 1.63 x (4.45/0.487) = 14.9 µg/m3<br><br>24-hour AAAQG: 1400 µg/m3<br>1-hour AAAQG: 5400 µg/m3 |

For the complete set of information regarding the HAP impact analysis completed for the initial Title V permit, see the TSD from the initial Title V permit (dated January 2001).

## 22. AMBIENT AIR QUALITY IMPACT ANALYSIS

In the application for their significant permit revision (dated December 14, 2005) Mesquite submitted an ambient air quality modeling analysis for carbon monoxide (CO). The analysis provided by Mesquite did not address nitrogen oxides (NOx). This is appropriate because the facility did not request an increase in annual NOx emission rates and NOx ambient impacts are only provided in terms of an annual average. However, ozone which is formed by a reaction between NOx and VOC does have a one-hour standard. In the original Prevention of Significant Deterioration (PSD) permit application, impacts of NOx on the nearby ozone non-attainment area were considered (as required by County Rule 240.308.1(e)(2)). This ozone impact analysis is discussed in the second portion of this evaluation.

The Class I significant impact level is one microgram of CO per cubic meter (24-hour average) if the facility is within 100 kilometers of a Class I area. The nearest Class I area, Superstition Wilderness Area, is 127 kilometers from the site. Therefore, the Class I Significant Impact Level does not apply.

Carbon Monoxide Analysis

Modeling was performed using the Industrial Source Complex Short-Term (ISCST3 Version 02035) dispersion model to determine if the proposed revisions would exceed the Significant Impact Levels (SIL) for CO (40 CFR 51.165(b)(2)). The impact was also compared to the National Ambient Air Quality Standard for CO.

One-hour CO Standard: The following operating scenarios were addressed in the modeling analysis for the one-hour carbon monoxide standard.

1. Startup:

The modeled emission rate for startup was 250 lb/hr for each of the four combustion turbines (total of 1000 lb/hr). This assumes that all four combined cycle systems (i.e., total of four turbines) would be in startup mode at the same time. Because the turbines share a common starting system which allows startup of only one turbine at a time, the assumption of 250 lb/hr for all four turbines is very conservative. The original analysis predicted an impact of 1450 micrograms per cubic meter ($\mu g/m^3$).

2. Testing:

Mesquite assumes that only one turbine would be subject to testing at a time, while the other three would be in normal operation. Therefore, the analysis was based on 1000 lb CO/hour for one turbine and 21.6 lb CO/hr for the other three turbines for a total of 1065 lb CO/hr. This is very conservative because, according to data submitted by Mesquite, emission rates during testing are not expected to exceed 1000 lb CO/hr. The original analysis predicted an impact of 1008 $\mu g/m^3$.

The final permit limits and restrictions reflect higher total emission rates than were used in the original modeling analysis. In the case of startup, the impact is 4% higher using an emission rate of 260 pounds CO per hour for each of the four turbines. In the case of testing the permit reflects one combined cycle system in testing at 1050 pounds CO per hour, one units in startup mode at 260 pounds CO per hour, and two units in normal operation at 21.6 pounds CO per hour each for a total of 1353.2 pounds CO per hour. The impact during a testing event is therefore approximately 27% higher than that predicted in the original analysis.

Using these higher rates, the results of the original modeling analysis presented in the permit application have been revised to reflect the higher limits using the following equations:

New Predicted Impact for startup (micrograms(μg)/m$^3$) = Original startup impact (μg/m$^3$) x 1.04

and

New Predicted Impact for test (μg/m$^3$) = Original test impact (μg/m$^3$) x 1.27

Eight-hour CO Standard: The following operating scenarios were addressed in the modeling analysis for the eight-hour carbon monoxide standard.

1. Startup:

The modeled emission rate for startup was 39.5 pounds CO per hour for each of the four combustion turbines for total of 158 pounds CO per hour. The emission rate should have included two units in startup mode at 260 pounds CO per hour each and two in normal operation at 21.6 pounds CO per hour each, for a total of 565 pounds CO per hour. This value is 3.57 times higher than the emission rate used in the original modeling analysis. The original analysis predicted an impact of 97 μg/m$^3$. The impact predicted using the higher emission rate is, therefore 347 μg/m$^3$.

2. Testing:

The modeled emission rate for testing included one unit emitting at 480 pounds CO per hour and three emitting at the normal rate of 21.6 pounds CO per hour for a total of 545 pounds CO per hour. The emission rate should have included one unit undergoing testing at 1050 pounds CO per hour, one in startup at 260 pounds CO per hour, and two in normal operation at 21.6 pounds CO per hour each for a total of 1353.2 pounds CO per hour. This value is 2.48 times higher than the emission rate used in the original modeling analysis. The originally predicted impact was 127 μg/m$^3$. The impact predicted using the correct emission rate is 315 μg/m$^3$.

The final results of the ambient air quality impact analysis are presented in the following table. Results have been adjusted as described previously. Based on the analysis and information presented by Mesquite, the Class II Significant Impact Level will not be exceeded. Therefore, according to the USEPA's New Source Review Workshop Manual, the results of this analysis is accepted by the EPA as the required air quality analysis (NAAQS and PSD increments) for CO. In addition, the modeling analysis indicates that the pre-construction monitoring threshold is not exceeded.

| **Comparison of Modeled Impact to National Ambient Air Quality Standard (SIL), Significant Impact Level, and Monitoring Threshold** | **1-hour impact CO (micrograms/cubic meter)** | **8-hour impact CO (micrograms/cubic meter)** |
|---|---|---|
| Startup | 1508 | 346 |
| Testing | 1281 | 315 |
| **Class II Significant Impact Level (40 CFR 51.165(b)(2)) (Rule 240 Section 308.1(2))** | **2,000** | **500** |
| **Maximum percent of Class II Significant Impact Level** | **75% (Startup)** | **73% (Testing)** |

| | | |
|---|---|---|
| **Ambient Air Quality Preconstruction Monitoring Threshold (Rule 240 Sect. 507 (575 mg/m3))** | **NA** | **575*** |
| **National Ambient Air Quality Standard** | **40,000** | **10,000** |

*County Rule 240 Section 507.1 provides a level of 575 milligrams per cubic meter but the EPA's New Source Review Workshop manual indicates a level of 575 micrograms per cubic meter.

Ozone Impact Analysis

As part of the original issuance of the PSD permit, the County required that Mesquite conduct an analysis of the impact NOx and VOC emissions from the facility would have on the ozone non-attainment area (refer to Photochemical Modeling Impact Report of July 24, 2000). In this analysis, Mesquite used an emission rate of 94.4 pounds of NOx per hour, reflecting emission estimates for four turbines operating under base load conditions. Emission estimates of NOx during startup, shutdown, tuning, or testing activities were not considered in the analysis. According to the July 24, 2000, report, the increase in the ozone peak was found to be within the numerical "noise" level of the Urban Airshed Model used in the analysis. The increase in ozone was found to be 0.01459 parts per billion over the 1999 baseline peak. The analysis predicted no new exceedances of the ozone 1-hour standard.

Appendix A Technical Support Document
(Ambient Air Quality Impact Report/Engineering Analysis)
for Original Title V Permit (dated January 2001)

**Ambient Air Quality Impact Report/Engineering Analysis**
Mesquite Generating Station (Mesquite)
Prevention of Significant Deterioration,

# Title IV, and Title V Permit Number V99-017
# January 23, 2001

---

## I. APPLICANT

Mesquite Power, LLC
101 Ash Street
San Diego, CA 92101

## II. PROJECT LOCATION

The Mesquite Generating Station (MGS) will be located in the unincorporated community of Arlington, Arizona, in the county of Maricopa. The site is located approximately 40 miles west of Phoenix and approximately eight miles south of Interstate 10. The 276 acre site is situated approximately two miles south of the existing Palo Verde Nuclear Generating Station (PVNGS). The approximate legal description of the site is the west half of Section 15, Township 1 South, Range 6 West of the Gila and Salt River Base and Meridian, Maricopa County, Arizona, excepting the east half of the Northeast quarter of the Northwest quarter of said Section 15. The site is located at approximately 112$^o$ 20’ 40’’ West longitude and 33$^o$ 20’ 40” North latitude. The site elevation is 890 feet above mean sea level (msl).

MGS is a proposed new natural gas-fired combined cycle merchant power plant with two power blocks, each rated at a maximum of 650 megawatts (MW) electric (nominal), for a maximum total at the site of 1,300 MW at design ambient conditions. Only natural gas fuel will be used for the combined cycle systems. MGS will be owned and operated by Mesquite Power, LLC (“Mesquite”). The project is classified as Standard Industrial Classification (SIC) Code 4911 and North American Industrial Classification System (NAICS) 221112, Fossil-Fuel Electric Power Generation.

With respect to the National Ambient Air Quality Standards (NAAQS), portions of Maricopa County are designated as serious nonattainment for $PM_{10}$, CO, and ozone (since the 182(f) waiver is not implemented in Maricopa County for New Source Review purposes, both of the precursor pollutants $NO_x$ and VOC are regulated by the County for ozone NAAQS purposes). The County is designated as attainment/unclassified for $SO_2$, $NO_2$, and lead. The proposed MGS site is located in an attainment area approximately 15 miles west of the $PM_{10}$ nonattainment area boundary and approximately 25 miles west of the CO and ozone nonattainment boundary.

The Maricopa County Environmental Services Department (MCESD) has been delegated primary responsibility for the Prevention of Significant (PSD) program in the County, and therefore, the project comes under the jurisdiction of MCESD. Since MGS is a major source in an attainment area, it is subject to the requirements of the PSD, Title IV and Title V regulatory programs.

## III. PROJECT DESCRIPTION

Mesquite initially filed a combined PSD and Title V Air Quality Permit Application for the MGS project on February 15, 2000. Supplements to the Application were submitted through September 2000 to reflect changes and corrections to the original application. The application was submitted pursuant to MCESD Rules 200, 210 and 240.

The major MGS components with the potential for air emissions are listed in Table 3-1. The MGS will use either four General Electric 7FA or four Westinghouse 501F natural gas-fired combustion turbines operating in combined-cycle mode with four supplementary fired, three-pressure Heat Recovery Steam Generators (HRSGs) and two steam turbine generators. Steam generation in each of the HRSGs will be augmented with a supplementary natural gas fired duct burner. Each HRSG will also be outfitted with a Selective Catalytic Reduction (SCR) system to reduce the emissions of $NO_x$ and an Oxidizing Catalyst system to reduce the emissions of CO and VOCs.

**Table 3-1**
**Mesquite Generating Station Major Emitting Equipment**

| | |
|---|---|
| **Four Combined Cycle Systems (System #1, System #2, System #3, System #4) and two steam turbines with electrical generators.** | |
| | **Each Combined Cycle System consists of the following:** |
| a. | General Electric 7FA or Westinghouse 501F combustion turbine operating in combined-cycle mode with a nominal rating of 170 megawatts electric without duct firing and 180 megawatts electric with duct firing and fueled by pipeline quality natural gas only. |
| b. | Supplementary fired, three-pressure Heat Recovery Steam Generator (HRSG) with duct burners. The duct burners have a maximum heat input of 592.6 mmBtu/hr (HHV) and are fueled by pipeline quality natural gas only. |
| c. | Selective Catalytic Reduction (SCR) nitrogen oxides emissions control system capable of treating the entire exhaust of the Combustion Turbine and duct burner combined. |
| d. | Oxidation Catalyst carbon monoxide and volatile organic compound emissions control system capable of treating the entire exhaust of the Combustion Turbine and duct burner combined. |
| e. | Continuous emissions monitor (CEM) system that records oxides of nitrogen ($NO_x$), carbon monoxide (CO), and oxygen ($O_2$) content of the System exhaust. |
| f. | An exhaust stack with height 170 feet above plant grade and inside diameter of 18 feet. |
| **Wet Cooling Towers** | |
| a. | Two twelve-cell wet cooling towers, with each cooling tower rated at 163,050 gallons per minute recirculation rate (326,100 gallons per minute total for both cooling towers) and height 45 feet above plant grade. |
| b. | Continuous cooling water conductivity monitoring system. |
| c. | Drift eliminators on each cooling tower. |
| **Emergency Diesel Engine** | |
| a. | One 348-horsepower engine firing No. 2 distillate fuel oil to drive the emergency fire water pump. |

For some emission calculations and permit limits involving emissions in terms of heat input rate (e.g. pounds per million Btu), the heat input rate in terms of million Btu per hour (mmBtu/hr) is required. The heat input rate is a function of the heat content of the fuel (e.g., higher heating value or lower heating value, and the temperature and load conditions, among other variables). For purposes of assessing emissions in terms of mmBtu, a higher heating value (HHV) of 1,020 Btu per standard cubic foot of natural gas has been assumed. Using this heating value and the amount of natural gas that will be combusted in the Combustion Turbines during 100% load and 73 degrees Fahrenheit (annual average temperature at the site), the Combustion Turbines will each combust a maximum of approximately 1,923 mmBtu/hr at full load. Likewise, at full load the duct burners will combust a maximum of approximately 593 mmBtu/hr.

## IV. EMISSIONS FROM THE PROJECT

Tables 4-1 through 4-5 display the proposed maximum permit limits (potential to emit, or PTE) <u>with</u> pollution controls from the MGS systems for the criteria pollutants. The emission estimates shown in the table are based on vendor guarantees, Mesquite's experience with other similar power plants, and a BACT analysis. The annual emission rates shown in Table 4-1 include up to 700 hours per year and less than 10 hours per day of operation for each Combined Cycle System in startup or shutdown mode. Estimated emissions from the emergency engine are provided in Table 4-6. The hourly emission rates in Table 4-2 are the maximum emission rates under any combination of full load and ambient temperature conditions. The emission rates in Table 4-3 reflect emissions during startup and shutdown, and Table 4-5 contains additional specific limits that affect emissions. Table 4-4 contains the cooling tower emission limits. In addition to the limits shown in the tables, the fuel sulfur content is limited to less than 0.003 grains per dry standard cubic foot in natural gas and 0.05 percent by weight in the diesel fuel. Cooling Tower total dissolved solids is limited to 30,000 milligrams per liter (mg/l).

The emission limits for $NO_x$ and CO are three hour rolling averages calculated from continuous monitors. The averaging times for $PM_{10}$ and VOC are consistent with the stack emissions testing methods (3 one-hour averages). The ammonia injection rate is a 24-hour rolling average. $SO_2$ emissions are determined from fuel sulfur monitoring, normally conducted quarterly, but more frequently as required by the Permit.

**Table 4-1**

**Rolling 12-month Average Emission Limits**

| Rolling 12-month Average Emission Limits (tons per year) | | | | | |
|---|---|---|---|---|---|
| **Device** | **$NO_x$** | **CO** | **$PM_{10}$** | **$SO_2$** | **VOC** |
| GE – Combined Cycle System #1 | 92.4 | 89.8 | 126.6 | 8.8 | 64.8 |
| GE – Combined Cycle System #2 | 92.4 | 89.8 | 126.6 | 8.8 | 64.8 |
| GE – Combined Cycle System #3 | 92.4 | 89.8 | 126.6 | 8.8 | 64.8 |
| GE – Combined Cycle System #4 | 92.4 | 89.8 | 126.6 | 8.8 | 64.8 |
| WH – Combined Cycle System #1 | 98.6 | 95.9 | 118.7 | 9.3 | 67.0 |
| WH – Combined Cycle System #2 | 98.6 | 95.9 | 118.7 | 9.3 | 67.0 |
| WH – Combined Cycle System #3 | 98.6 | 95.9 | 118.7 | 9.3 | 67.0 |
| WH – Combined Cycle System #4 | 98.6 | 95.9 | 118.7 | 9.3 | 67.0 |
| Cooling Tower #1 | NA | NA | 16.89 | NA | NA |
| Cooling Tower #2 | NA | NA | 16.89 | NA | NA |

**Table 4-2**
**Hourly Emission Limits During Periods When Combined Cycle System Operates in Condition Other than Startup or Shutdown**

| Hourly Emission Limits During Periods When Combined Cycle System Operates in Condition Other than Startup or Shutdown (pounds per hour) | | | | | |
|---|---|---|---|---|---|
| **Device** | **$NO_x$** | **CO** | **$PM_{10}$** | **$SO_2$** | **VOC** |
| GE – Combined Cycle System #1 | 22.2 | 21.6 | 30.4 | 2.1 | 16.6 |
| GE – Combined Cycle System #2 | 22.2 | 21.6 | 30.4 | 2.1 | 16.6 |
| GE – Combined Cycle System #3 | 22.2 | 21.6 | 30.4 | 2.1 | 16.6 |
| GE – Combined Cycle System #4 | 22.2 | 21.6 | 30.4 | 2.1 | 16.6 |
| WH – Combined Cycle System #1 | 23.6 | 23.0 | 28.8 | 2.2 | 16.1 |
| WH – Combined Cycle System #2 | 23.6 | 23.0 | 28.8 | 2.2 | 16.1 |
| WH – Combined Cycle System #3 | 23.6 | 23.0 | 28.8 | 2.2 | 16.1 |
| WH – Combined Cycle System #4 | 23.6 | 23.0 | 28.8 | 2.2 | 16.1 |

**Table 4-3**
**Hourly Emission Limits During Periods of Startup or Shutdown**

| Hourly Emission Limits During Startup or Shutdown (pounds per hour) | | | | | |
|---|---|---|---|---|---|
| **Device** | **$NO_x$** | **CO** | **$PM_{10}$** | **$SO_2$** | **VOC** |
| GE – Combined Cycle System #1 | 26.1 | 19.9 | 18.0 | 1.0 | 1.9 |
| GE – Combined Cycle System #2 | 26.1 | 19.9 | 18.0 | 1.0 | 1.9 |
| GE – Combined Cycle System #3 | 26.1 | 19.9 | 18.0 | 1.0 | 1.9 |
| GE – Combined Cycle System #4 | 26.1 | 19.9 | 18.0 | 1.0 | 1.9 |
| WH – Combined Cycle System #1 | 88.2 | 28.3 | 13.7 | 1.2 | 3.7 |
| WH – Combined Cycle System #2 | 88.2 | 28.3 | 13.7 | 1.2 | 3.7 |
| WH – Combined Cycle System #3 | 88.2 | 28.3 | 13.7 | 1.2 | 3.7 |
| WH – Combined Cycle System #4 | 88.2 | 28.3 | 13.7 | 1.2 | 3.7 |

**Table 4-4**

**Hourly Emission Limits for Cooling Towers**

| Hourly Emission Limits (pounds per hour) | | | | | |
|---|---|---|---|---|---|
| **Device** | **$NO_x$** | **CO** | **$PM_{10}$** | **$SO_2$** | **VOC** |
| Cooling Tower #1 | NA | NA | 3.86 | NA | NA |
| Cooling Tower #2 | NA | NA | 3.86 | NA | NA |

NA means not applicable

**Table 4-5**

**Additional Concentration or Rate Emission Limits**

| | *Concentration and Rate Limits* | | | | | | |
|---|---|---|---|---|---|---|---|
| **Device** | **NOx** | **CO** | **$PM_{10}$ Solids (Filterable Alone)** | **$PM_{10}$ Total (Filterable plus Condensable )** | **VOC** | **$SO_2$** | **Other** |
| Each Combustion Turbine Exhaust when Operating in Conditions Other than Startup | Value determined by calculation[1] | NS | NS | NS | NS | 0.015 percent | NS |
| Each Duct Burner Exhaust | 0.2 lb/mmBtu | NS | 0.03 lb/mmBtu and 20% opacity | NS | NS | 0.8 lb/mm Btu or 0.2 lb/mm Btu | NS |
| Each Combined Cycle System Exhaust | 2.5 ppm 3-hour rolling average | 4.0 ppm 3-hour rolling average | 14.4 - 15.2 lb/hr | 28.8 – 30.4 lb/hr | 5.2 ppm 3-hour rolling average | NS | *Ammonia* 10 ppm 24-hour rolling average |

1 NSPS Subpart GG 60.332(a)(1)
NS means not specified

**Table 4-6**
**Emission Estimates for the Emergency Fire Water Pump Engine**

| | **Pounds per hour** | **Tons per year** |
|---|---|---|
| **$NO_x$** | 5.6 | 0.15 |
| **CO** | 1.0 | 0.30 |
| **VOC** | 0.3 | 0.01 |
| **$PM_{10}$** | 0.15 | 0.004 |
| **$SO_2$** | 0.54 | 0.01 |

## V. APPLICABILITY OF NEW SOURCE REVIEW

In order to trigger the applicability of Maricopa County Rule 240 New Source Review or Rule 210 Title V permit requirements the proposed project must meet the definition of a "major source." As shown in Table 5-1, the proposed Mesquite Generating Station is a major source for NOx, CO, PM10, and VOC because the potential to emit these pollutants exceeds 100 TPY. The applicability threshold for New Source Review is 100 TPY because fossil fuel-fired steam electric plants of more than 250 mmBtu/hr are included in the definition of categorical source in Maricopa County Rule 240, Section 202. Only the Prevention of Significant Deterioration (PSD) program is applicable due to the classification of the area as attainment/unclassifiable. The facility is also a major source for the purposes of Title V (as defined in Maricopa County Rule 100, Section 255).

**Table 5-1**

**Determination of Major Source and PSD Applicability**

| Pollutant | Annual Emissions (TPY) | Major Source Threshold (TPY) | Major Source? | Significance Level (TPY) | PSD Applicable? |
|---|---|---|---|---|---|
| $NO_x$ | 394.3 | 100 | Yes | 40 | Yes |
| CO | 383.7 | 100 | Yes | 100 | Yes |
| $SO_2$ | 37.3 | 100 | No | 40 | No |
| $PM_{10}$ | 540.1 | 100 | Yes | 15 | Yes |
| VOC | 268.1 | 100 | Yes | 40 | Yes |

PSD New Source Review requires an analysis of Best Available Control Technology (BACT) for those pollutants that exceed the applicable PSD trigger levels; an ambient air quality impacts analysis for increment consumption and National Ambient Air Quality Standards (NAAQS) for all criteria pollutants (whether or not they exceed thresholds); a visibility and other air quality related values (AQRVs) impact analysis for all criteria pollutants that could affect Class I Areas; and an "additional impacts analysis", including visibility, for non-Class I areas. MCESD rules also require an analysis of the impact of MGS on ozone concentrations in the nonattainment area. In addition to the PSD review for criteria pollutants, MCESD policy requests an air toxics ambient impact evaluation for those chemicals listed by the Arizona Department of Environmental Quality (ADEQ) under its draft Ambient Air Quality Guidelines (AAQGs) policy. Each of these elements will be discussed in the following sections.

## VI. BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

A "top down" analytical procedure is required to establish an emission limit that represents the most stringent control technique available, taking cost and other environmental factors into account. The procedure includes the following elements:

- Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation
- Eliminate the technically infeasible or unavailable technology options
- Rank the remaining control technologies by control effectiveness (cost and emissions reductions)
- Evaluate the most effective controls and select the most stringent technique based on energy, environmental and economic impacts.

Mesquite provided a detailed BACT analysis for each of the emitting units. That analysis was reviewed by MCESD and the results are summarized in the following subsections. Mesquite provided a thorough analysis of BACT for all emitting systems, including the diesel-fueled engine for the emergency fire water pump. The engine will be operated only for testing or for emergency situations. Therefore, good combustion control of modern engines was determined as BACT for the emergency fire water pump engine.

### A. $NO_x$ from the Combined Cycle Systems

In the combined cycle system, $NO_x$ is emitted from the combustion turbine and duct burners. Mesquite proposed an SCR system coupled with a dry low-$NO_x$ combustor and an emission limit after controls of 2.5 parts per million by volume corrected to 15% oxygen (2.5 ppm) on a rolling 3-hour average.

Emission reduction systems evaluated from most to least stringent were: SCONOx, SCR plus dry low-$NO_x$ combustor, XONON, SNCR and SCR plus water/steam injection or advanced low-$NO_x$ combustor. Only the SCONOx system could theoretically achieve emission levels lower than 2.5 ppm for the combined cycle systems proposed by Mesquite for MGS. The SCONOx system has not yet been installed on larger (i.e., over about 170 MW) systems, but beta tests of SCONOx on larger systems similar to MGS have been recently permitted.

Goal Line Technologies announced in December of 1999 that it would guarantee performance on large systems, although there still have not been any such systems installed and there remain significant concerns regarding operational reliability and validity of the guarantee on large systems. Since SCONOx has not been installed or demonstrated on larger systems, it is not considered a technically feasible option.

Nevertheless, Mesquite calculated the cost of SCONOx per ton of $NO_x$ removed as if SCONOx could be installed and meet an emission limit of 2.5 ppm on a 1-hour average basis. The cost per ton removed under this scenario was $12,943. This can be compared to the cost per ton removed of the next most stringent $NO_x$ control, SCR plus dry low-$NO_x$ combustor at 2.5 ppm, of $2,604 per ton removed, only one-fifth the cost. The lack of technical feasibility and the high cost per ton of $NO_x$ removed eliminated $SCONO_x$ as a viable BACT. Therefore, in-combustor $NO_x$ control consisting of dry-low $NO_x$ burners firing natural gas only, followed by post-combustion $NO_x$ control consisting of a selective catalytic reduction system to reduce $NO_x$ emissions to 2.5 ppmvd at 15 percent oxygen was considered BACT.

### B. CO from the Combined Cycle Systems

In the Combined Cycle Systems, CO is emitted from the combustion turbine and duct burners. Emission reduction systems evaluated from most to least stringent included an oxidation catalyst and good combustion control. An oxidation catalyst was evaluated in detail since it is technically feasible and MCESD is considering such requirements for some other facilities located in the Phoenix metropolitan area (i.e., within the CO nonattainment boundary that requires a Lowest Achievable Emission Rate, LAER, decision).

Mesquite calculated the cost per ton of CO removed with an oxidation catalyst to range between $1,185 and $1,868 per ton of CO removed, depending on the combined cycle system. Therefore, Mesquite selected oxidation catalyst with good combustion control, to achieve 4.0 ppm corrected to 15 percent oxygen on a 3-hour rolling average basis, as BACT for CO from the combined cycle systems.

### C. $PM_{10}$ from the Combined Cycle Systems

$PM_{10}$ emissions from natural gas-fired combined cycle systems are relatively small. In addition, no post-combustion control systems have been installed to control $PM_{10}$ from natural gas-fired units. Therefore, good combustion control is considered BACT for $PM_{10}$ from the Combined Cycle systems.

A dual emission limit was established for $PM_{10}$ from each combined cycle system of 14.4 pounds per hour (for the GE system) or 15.2 pounds per hour (for the Westinghouse system) for filterable (Method 5) particulate, and 28.8 pounds per hour (for the GE system) or 30.4 pounds per hour (for the Westinghouse system) for filterable plus condensable particulate combined (Method 5 and Method 202).

The dual emission limit was established to ensure that good combustion control commensurate with other similar permitted systems was maintained.

### D. $PM_{10}$ from the Cooling Tower

There is a potential for $PM_{10}$ emissions from condensation of water droplets that drift away from the cooling tower. There are two primary factors that control the amount of $PM_{10}$ from the cooling tower: maximum total dissolved solids (TDS) in the cooling tower water and droplet drift rate.

A droplet drift rate of 0.0005 percent resulting from installation of high efficiency drift eliminators on the cooling tower was concluded as BACT. This limit can be compared to USEPA assumed drift rates (in AP-42) of 0.02 percent. The permitted drift rate is based on vendor guarantees and is consistent with the most stringent limits listed in the RACT/BACT/LAER Clearinghouse (RBLC).

The second parameter affecting $PM_{10}$ from the cooling towers is TDS loading limits. The TDS is limited to 30,000 ppm (weight). This limit is a balance between the need to keep the TDS low and the need to minimize water usage (which forces the TDS higher). TDS is required to be monitored on a daily basis (through conductivity measurements) with monthly TDS laboratory analysis.

### E. VOC from the Combined Cycle Systems

Mesquite proposed good combustion control with catalyst oxidation as BACT; identical to the proposed BACT for CO. The permitted limit is 5.2 ppm at 15 percent oxygen for each of the combined cycle systems (10 % reduction in VOC emissions). The VOC limits proposed are consistent with the most stringent in the RBLC.

### F. $SO_2$ Emissions from the Combined Cycle Systems

Mesquite will use only natural gas fuel in the Combined Cycle Systems and Auxiliary Boiler. The sulfur content of the natural gas will be limited to 0.3 grains per 100 standard cubic feet, consistent with pipeline quality natural gas. The sulfur content will be monitored on a custom schedule acceptable to the USEPA and MCESD as described in the Permit.

Although $SO_2$ is not emitted in levels above BACT thresholds, the sulfur content limits on natural gas fuel and the use of natural gas only is consistent with BACT for $SO_2$.

### G. $PM_{10}$ and $SO_2$ from the Diesel-Fueled Engine

To aid in particulate and $SO_2$ control from the diesel-fueled engine, sulfur content in the diesel fuel will be limited to 0.05% by weight and verified by the fuel supplier.

### H. Additional Pollutants

As part of the BACT analysis, pollutants in addition to the criteria pollutants were examined. In none of the BACT decision cases were non-criteria pollutant emissions relevant for the BACT decision except for the SCR systems, which uses ammonia to control $NO_x$ emissions. Some of the ammonia used in the SCR systems will be emitted unreacted from the system. This is termed “ammonia slip.” The unreacted ammonia in the SCR exhaust has the potential to react downstream of the SCR or in the atmosphere with $SO_2$ in the exhaust to create additional particulate matter.

Ammonia slip is permitted at a maximum of 10 ppm in the exhaust. This level will be confirmed through required annual stack testing and a requirement that whenever the ammonia injection rate associated with 10 ppm ammonia slip is exceeded, additional stack testing to confirm that the 10 ppm limit is still being met is required. The AAAQG analysis showed that ambient ammonia concentrations would be less than 46 percent and 18 percent of the 1-hour and 24-hour Arizona Ambient Air Quality Guidelines (AAAQGs), respectively.

The 10 ppm ammonia slip level is consistent with the best operating systems. In addition, since the amount of sulfur in the pipeline quality natural gas is relatively low and since only natural gas fuel is used, resultant $PM_{10}$ emissions from ammonia reacting with the $SO_2$ will be relatively low.

Since there is not continuous emission monitoring system for ammonia, the ammonia slip limit will be met by establishing an ammonia injection rate above which source testing will be required to confirm that the ammonia slip limit is being met.

## VII. CRITERIA POLLUTANT AIR QUALITY IMPACTS IN ATTAINMENT AREAS

### A. Existing Ambient Air Quality Conditions

The National Ambient Air Quality Standards (NAAQS) are regulated pollutant limits designed to protect human health and the environment. The primary and secondary NAAQS for the criteria pollutants are provided in Table 5-1. National primary ambient air quality standards define levels of air quality which the EPA Administrator judges are necessary, with an adequate margin of safety, to protect the public health.

National secondary ambient air quality standards define levels of air quality which the Administrator judges necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant

**Table 5-1**
**National Ambient Air Quality Standards (40 CFR 50.4-50.12)**
**(micrograms per cubic meter)**

| Pollutant | 1-hour Average | | 3-hour Average | | 8-hour Average | | 24 hour Average | | Annual Average | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Primary | Secondary | Primary | Secondary | Primary | Secondary | Primary | Secondary | Primary | Secondary |
| $SO_2$ | | | | 1,300 | | | 365 | | 80 | |
| $PM_{10}$ | | | | | | | 150 | 150 | 50 | 50 |
| $NO_2$ | | | | | | | | | 100 | 100 |
| CO | 40,000 | | | | 10,000 | | | | | |
| Pb | | | | | | | | | 1.5[a] | |

[a] Lead NAAQS is a calendar quarter averaging time

The portion of Maricopa County where the proposed project is located is currently classified as attainment for all criteria pollutants. Mesquite first analyzed the ambient air quality impacts of MGS and compared those impacts to the Significant Impact Levels (SILs). If the impacts were below the SILs, the analysis proceeded to the “Additional Impacts Analysis.” This is the case since, by definition of the SILs, if the impacts are less than the SILs the source would not cause or contribute to a violation of a national ambient air quality standard (40 CFR 51.165(b)(2)). The SILs are shown in Table 7-2.

**Table 7-2**
**Significant Impact Levels (40 CFR 51.165(b)(2))**
**(micrograms per cubic meter)**

| Pollutant | 1-hour Average | 3-hour Average | 8-hour Average | 24 hour Average | Annual Average |
|---|---|---|---|---|---|
| $SO_2$ | | 25 | | 5 | 1 |

| | | | | | |
|---|---|---|---|---|---|
| $PM_{10}$ | | | | 5 | 1 |
| $NO_2$ | | | | | 1 |
| CO | 2000 | | 500 | | |

In addition, if the impact of the facility is less than the SILs, the impacts will also be less than the PSD increments. The Class I increments are shown in Table 7-3, and the Class II increments in Table 7-4.

**Table 7-3**
**PSD Class I Increments (40 CFR 51.166(c)**
**(micrograms per cubic meter)**

| Pollutant | 3-hour Average | 24 hour Average | Annual Average |
|---|---|---|---|
| $SO_2$ | 25 | 5 | 2 |
| $PM_{10}$ | | 8 | 4 |
| NO | | | 2.5 |

**Table 7-4**
**PSD Class II Increments (40 CFR 51.166(c)**
**(micrograms per cubic meter)**

| Pollutant | 3-hour Average | 24 hour Average | Annual Average |
|---|---|---|---|
| $SO_2$ | 512 | 91 | 20 |
| $PM_{10}$ | | 30 | 17 |
| $NO_2$ | | | 25 |

If the impacts are greater than the SILs, then the impacts of MGS would have to be added to a representative background ambient air quality value and/or pre-construction monitoring would be required if the impacts were greater than the monitoring thresholds of 40 CFR 52.21(i)(8)(i).

## B. Climate and Meteorological Conditions

The air quality modeling analysis relies on five years of the most recent, readily available meteorological data (surface observations) from the Palo Verde Nuclear Generating Station (PVNGS). The meteorological station at PVNGS measures winds at 10 and 60 meters above ground level and meets or exceeds the Nuclear Regulatory Commissions (NRC) requirements for monitoring instrument specifications, calibrations, and data capture. The NRC requirements are more stringent than PSD requirements, and thus the PVNGS data are useable for the MGS impacts analysis. PVNGS is at the same elevation as MGS and is located about 2 miles north of MGS, with no intervening high terrain. Therefore, the PVNGS data are representative of MGS plume dispersion and transport.

The PVNGS five-year data set consisted of observations from 1994 through 1998. These data were combined with upper air data from the Tucson, Arizona National Weather Service upper air station. The USEPA standard methodology for determining mixing heights and processing the meteorological data suitable for input to ISC3 was used to process the Tucson and PVNGS data. USEPA guidance was used for missing data substitutions.

### C. GEP Stack Height Analysis

USEPA procedures for determining Good Engineering Practice (GEP) stack height were used to evaluate the proposed stack heights. The GEP stack heights were found to be 225 feet for the Combined Cycle Systems, 52.5 feet for Cooling Tower Cells 1-3 and 13-23, 115 feet for Cooling Tower Cells 4-11, 176.6 feet for Cooling Tower Cell 12, 177.2 feet for Cooling Tower Cell 24 and 205 feet for the diesel fire pump. Mesquite proposed stack heights of 170 feet for the Combined Cycle Systems, 10 feet for the cooling tower, and 1 foot for the diesel fire pump. All of the proposed stack heights are within GEP, and the proposed stack heights were used in the modeling analysis.

### D. Dispersion Modeling Procedures

The ambient air quality impact analysis was conducted in accordance with approved Air Quality Modeling Protocols. The protocols document the model selection, GEP analysis methodology, selection of the receptor network, and interactive sources.

The modeling analysis has several different modeling grids, these are:

- 12-50 kilometer (km) grid
  The 12-50 km grid is used to ensure that the model predicted maximum ground-level impacts and the extent of any significant impacts from the facility will be captured. The receptor spacing in this grid is 2,000 meters (m) from 12 to 20 km, 5,000 m from 20 to 40 km, and 10,000 m from 40 to 50 km. Receptor elevations were determined by Digital Elevation Map (DEM). For a more detailed discussion of the elevation selection procedures refer to the addendum to the Mesquite Generating Station modeling protocol.
- 10-km grid with elevated terrain points
  The 10-km grid is used with the 12-50 km grid to determine all maximum impact values and the extent of any significant impacts. The receptor spacing in this grid is 100 m from the fenceline to 1 km, 500 m from 1 to 5 km, and 1,000 m from 5 to 10 km. Additional receptors were placed on selected elevated terrain points that might not be accurately represented with normal grid spacing alone. The elevation for the normal grid spacing receptors was determined by DEMs. For a more detailed discussion of the elevation selection refer to the addendum to the Mesquite Generating Station modeling protocol. The additional receptor elevations were determined by selecting the higher elevation from a visual inspection of 7.5 minute topography maps and DEMs.
- Class I Areas
  There are three Class I areas evaluated in the modeling analysis. They are the Superstition Wilderness Area, Pine Mountain Wilderness Area, and Mazatzal Wilderness Area; all three of these areas are located over 100 km away from the

facility. These Class I areas were modeled by putting receptors on a single point in the area, this single point was selected to be closest boundary of the area to the facility. The receptors were placed at this closest point in the horizontal with a 100-ft spacing in the vertical. This vertical stacking, which ranges from the lowest elevation to the highest elevation found in that Class I area, was done to ensure the maximum impact in the area was captured.

- Sensitive Areas

  There are eight sensitive areas (i.e., six Class II areas and two Indian Reservations) evaluated in the modeling analysis. These areas were selected for inclusion in the analysis per the request of the Mr. Pete Lahm representing the Federal Land Manager. Mr. Lahm asked that all sensitive areas within 50 km be evaluated. The Class II areas are Hummingbird Springs Wilderness Area, Big Horn Mountains Wilderness Area, Eagletail Mountains Wilderness Area, Signal Mountain Wilderness Area, Woolsey Peak Wilderness Area, and North Maricopa Mountains Wilderness Area. The Indian Reservations include the Gila River and Gila Bend Reservations. These sensitive areas were modeled by placing receptors along the closest boundary of each area to the facility. The receptors were placed along this closest boundary with varying spacing in the horizontal (determined by the length of the closest boundary of each area) and a 100-ft spacing in the vertical. This vertical stacking, which ranges from the lowest elevation to the highest elevation found in that sensitive area, was done to ensure the maximum impact in the area was captured.

- Nonattainment Areas

  There are two nonattainment areas included in the modeling analysis (Maricopa PM and CO/Ozone). These nonattainment areas were modeled by placing receptors along the closest boundary of each area to the facility. The receptors were placed along this closest boundary with 10-km spacing in the horizontal and a 100-ft spacing in the vertical. This vertical stacking, which ranges from the lowest elevation to the highest elevation found in that non-attainment area, was done to ensure the maximum impact in the area was captured.

### E. Stack Emissions Characteristics Used in the Models

Ambient air quality impacts are a function of not only the magnitude of the emission rate (e.g., pounds per hour) but also the emitting characteristics (e.g., exit temperature, exhaust flow rate, etc.) Merchant power plants tend to operate at variable load conditions and, therefore, variable emitting characteristics. The ISCST3 air dispersion model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, duct firing, and ambient temperatures (17°F, 59°F, 73°F, and 122°F). This was accomplished by representing each Combined-cycle combustion turbine (CCCT) proposed operating load range (i.e., General Electric (GE) 100, 75, and 50 percent loads; Westinghouse (WES) 100, 85, and 70 percent loads as well as duct fired and steam injection scenarios) with a representative set of stack parameters and pollutant emission rates that were conservatively selected from the turbine performance data contained in Appendix C of the Mesquite Generating Station Air Permit Application to produce the worst-case plume dispersion conditions (i.e., lowest exhaust temperature and exit velocity and the highest emission rate) and thus highest model predicted concentrations. This process is referred to as enveloping and was performed for each turbine type (i.e., independent sets of "worst-case" numbers were developed for both GE and WES).

Although this analysis was performed for both the GE and Westinghouse turbines, MGS notified the Department during the preparation of responses to public comments that MGS had contracted for the GE turbines and no longer needed the Westinghouse units in the proposed permit; the Westinghouse units were subsequently removed from the proposed permit. The modeling analysis showing that the facility meets all applicable requirements is still valid since it is based upon the worst case for either type of turbine. The references to the Westinghouse turbines were removed from the permit, but information concerning their emission rates remains in this report to maintain the historical record of the information used in processing the application.

The representative stack parameters and emission rates for each load and operating scenario were considered in the analysis via a detailed spreadsheet. This spreadsheet was used in determining the load based representative emissions and stack parameters from the turbine performance data contained in Appendix C of the Mesquite Generating Station Air Permit Application. The Mesquite Generating Station was enveloped by assuming that the CCCTs will operate simultaneously under a given load condition (i.e., 100, 75, 50, etc.) along with the diesel fire pump operating at 100 percent load for 52 hours per year. Emission rates and stack parameters were enveloped by obtaining the "worst-case" emission rates and stack parameters (i.e., lowest exit velocity, lowest exit temperature, and highest emission rate) for each load and pollutant over the four ambient temperatures (i.e., 17°F, 59°F, 73°F, and 122°F).

For pollutants with annual averaging periods (i.e., $NO_x$, and $PM/PM_{10}$), emission rates and stack parameters were enveloped such that the "worst-case" values, taking into account the various operating scenarios (i.e., evaporative cooling only, evaporative cooling with duct firing, and evaporative cooling with duct firing and steam injection) at the annual average temperature (73°F) and 100% load on the combustion turbine (CT), were calculated. These values were developed by selecting "worst-case" values (i.e., lowest exit velocity, lowest exit temperature, and highest emission rate) over all possible scenarios occurring at 73°F and 100% load on the CT.

Worst-case stack parameters were developed for each load by taking the lowest exit temperature and the lowest exit velocity over the four ambient temperatures. The combination of these parameters results in the enveloped stack parameters for each load.

For the diesel fire water pump, the emission rates and stack parameters at 100 percent load were used.

## F. Modeling Results

The results from modeling all five years of meteorological data indicate that the emissions from the proposed project exceeded the SILs for annual average $NO_2$ and 24-hour and annual average $PM_{10}$ concentrations. The maximum impact points were near the project site at locations from three km to six km northeast to north-northwest of the plant site.

**Table 7-5**
**Maximum Ambient Air Quality Impacts for Criteria Pollutants[a]**

| Pollutant | 1-hour Average | 3-hour Average | 8-hour Average | 24 hour Average | Annual Average |
|---|---|---|---|---|---|
| ***MAXIMUM IMPACTS OF MGS*** | | | | | |
| $SO_2$[b] | | N/A | | N/A | N/A |
| $PM_{10}$ | | | | 21.03µg/m$^3$ [c] | 3.95µg/m$^3$ |
| $NO_2$ | | | | | 2.39µg/m$^3$ |
| CO | 479.69µg/m$^3$ | | 35.12µg/m$^3$ | | |
| ***MAXIMUM IMPACTS COMPARED TO SILs*** | | | | | |
| $SO_2$[b] | | N/A | | N/A | N/A |
| $PM_{10}$ | | | | 421% | 395% |
| $NO_2$ | | | | | 239% |
| CO | 24% | | 7% | | |
| ***MAXIMUM IMPACTS COMPARED TO CLASS II INCREMENTS*** | | | | | |
| $SO_2$[b] | | N/A | | N/A | N/A |
| $PM_{10}$ | | | | 70% | 23% |
| $NO_2$ | | | | | 10% |

[a] Maximum impact of either a GE or Westinghouse Turbine setup
[b] $SO_2$ impacts were determined to be insignificant during screening level analysis
[c] $PM_{10}$ 24-hour impacts was the high sixth-high impact over the five years of analysis
µg/m$^3$ means micrograms per cubic meter
N/A means not applicable

All maximum impact concentrations are well below the Class II increments. The impacts at the Class II areas and two Indian communities were much lower than the SILs.

All impacts were below the pre-construction monitoring thresholds as well.

The results of the NAAQS and PSD Increment Consumption Analyses showed violations of the NAAQS and PSD Increment Consumption for annual average NOx impacts. The analysis provided by Mesquite showed that MGS would have an insignificant contribution to these exceedances. Therefore, MCESD will identify the sources with significant contributions to the exceedances and work with these sources to eliminate the modelled exceedances.

## VIII. AIR TOXICS IMPACT ANALYSIS

The potential of the facility to cause exceedances of the Arizona Ambient Air Quality Guidelines (AAAQGs) was evaluated by determining AAAQG compound emissions and inputting the emission rates into the worst case ambient impact scenario. AAAQG compound emission rates were obtained from the California Air Toxics emissions database (CATEF) and the USEPA emission factors in AP-42 for lead and other metal emissions (since CATEF does not include metal emission factors for gas turbines). The modeled impacts were compared to the most recent version (1999) of the annual and short term (1-hour and 24-hour) AAAQGs as published by ADEQ.

The model results provided in Table 8-1 indicated maximum impacts ranging from about 46 percent to much less than one percent of the AAAQGs.

**Table 8-1**
**Annual and Short Term AAAQG Analysis for MGS**

| Pollutant | CAS Number | Emission Rate (lb/h) | Annual Impact (μg/m$^3$)[a] | Annual AAAQG (μg/m$^3$)[b] | 24 hour Impact (μg/m$^3$)[a] | 24 hour AAAQG (μg/m$^3$)[b] | 1 hour Impact (μg/m$^3$)[a] | 1 hour AAAQG (μg/m$^3$)[b] |
|---|---|---|---|---|---|---|---|---|
| Acetaldehyde | 75-07-0 | 1.07E-01 | 1.20E-02 | 4.50E-01 | 8.87E-02 | 1.70E+02 | 3.61E-01 | 6.30E+02 |
| Acrolein | 107-02-8 | 3.20E-02 | - | - | 2.65E-02 | 2.00E+00 | 1.07E-01 | 6.30E+00 |
| Ammonia | 7664-41-7 | 3.12E+01 | - | - | 2.58E+01 | 1.40E+02 | 1.05E+02 | 2.30E+02 |
| Arsenic | 7440-38-2 | 4.45E-04 | 4.99E-05 | 2.30E-04 | 3.67E-04 | 1.60E-02 | 1.49E-03 | 6.00E-02 |
| Barium | 7440-39-3 | 9.79E-03 | - | - | 8.08E-03 | 4.00E+00 | 3.28E-02 | 1.50E+01 |
| Benzene | 71-43-2 | 4.67E-03 | 5.24E-04 | 1.20E-01 | 3.86E-03 | 4.40E+01 | 1.57E-02 | 1.70E+02 |
| Benz(a)anthracene | 56-55-3 | 8.03E-06 | 9.00E-07 | 4.80E-03 | 6.63E-06 | 1.60E+00 | 2.69E-05 | 6.00E+00 |
| Benzo(a)pyrene | 50-32-8 | 1.03E-06 | 1.15E-07 | 4.80E-04 | 8.51E-07 | 1.80E-01 | 3.46E-06 | 6.70E-01 |
| Beryllium | 7440-41-7 | 2.67E-05 | 2.99E-06 | 4.20E-04 | 2.20E-05 | 1.60E-02 | 8.96E-05 | 6.00E-02 |
| 1,3-Butadiene | 106-99-0 | 2.76E-04 | 3.09E-05 | 3.60E-03 | 2.28E-04 | 1.30E+00 | 9.26E-04 | 5.00E+00 |
| Cadmium | 7440-43-9 | 2.45E-03 | 2.74E-04 | 5.60E-04 | 2.02E-03 | 2.00E-01 | 8.21E-03 | 7.70E-01 |
| Chromium | 7440-47-3 | 3.11E-03 | - | - | 2.57E-03 | 4.00E+00 | 1.04E-02 | 1.50E+01 |
| Cobalt | 7440-48-4 | 1.87E-04 | - | - | - | - | - | - |
| Copper | 7440-50-8 | 1.89E-03 | - | - | 1.56E-03 | 7.90E-01 | 6.34E-03 | 3.00E+00 |
| Dibenz(a,h)anthracene | 53-70-3 | 6.74E-06 | 7.56E-07 | 4.80E-04 | 5.57E-06 | 1.80E-01 | 2.26E-05 | 6.70E-01 |
| Ethylbenzene | 100-41-4 | 2.17E-02 | - | - | 1.79E-02 | 3.50E+03 | 7.27E-02 | 4.50E+03 |
| Formaldehyde | 50-00-0 | 1.88E-01 | 2.11E-02 | 7.60E-02 | 1.55E-01 | 1.60E+01 | 6.31E-01 | 2.50E+01 |
| Hexane | 110-54-3 | 4.87E-01 | - | - | 4.02E-01 | 1.40E+03 | 1.63E+00 | 5.40E+03 |
| Manganese | 7439-96-5 | 8.45E-04 | - | - | 6.98E-04 | 7.90E+00 | 2.84E-03 | 2.50E+01 |
| Mercury | 7439-97-6 | 5.78E-04 | - | - | 4.78E-04 | 4.00E-01 | 1.94E-03 | 1.50E+00 |
| 2-Methylchloranthrene | 56-49-5 | 1.13E-05 | - | - | - | - | - | - |
| Naphthalene | 91-20-3 | 2.06E-03 | - | - | 1.70E-03 | 4.00E+02 | 6.91E-03 | 6.30E+02 |
| Nickel | 7440-02-0 | 4.67E-03 | 5.24E-04 | 2.10E-03 | 3.86E-03 | 1.20E-01 | 1.57E-02 | 4.50E-01 |
| Propylene Oxide | 75-56-9 | 9.96E-02 | 1.12E-02 | 2.70E-01 | 8.23E-02 | 9.80E+01 | 3.34E-01 | 3.70E+02 |
| Selenium | 7782-49-2 | 5.34E-05 | - | - | 4.41E-05 | 1.60E+00 | 1.79E-04 | 6.00E+00 |
| Toluene | 108-88-3 | 1.31E-01 | - | - | 1.09E-01 | 3.00E+03 | 4.41E-01 | 4.40E+03 |
| Vanadium | 7440-62-2 | 5.12E-03 | - | - | 4.23E-03 | 4.00E-01 | 1.72E-02 | 1.50E+00 |
| Xylene (Total) | 1330-20-7 | 4.29E-02 | - | - | 3.55E-02 | 3.50E+03 | 1.44E-01 | 5.40E+03 |

[a] Derived by multiplying the nominal 1 g/s annual, 24 hour, or 1 hour impact by the emission rate (g/s) of each pollutant.
Nominal 1 g/s: annual impact = 0.8893 (μg/m$^3$)
24 hour impact = 6.54986 (μg/m$^3$)
1 hour impact = 26.61199 (μg/m$^3$)
Example calculation: acetaldehyde emission rate of 1.07E-01 lb/h * (453.59 g/lb / 3600 s/h) = 1.35E-02 g/s
1.35E-02 * annual 1 g/s impact of 0.8893 (μg/m$^3$)
= annual acetaldehyde impact 1.20E-02 μg/m$^3$

[b] Obtained from draft guidance document *Arizona Ambient Air Quality Guidelines (AAAQGs)* 1999 Update.

## IX. URBAN AIRSHED MODELING

MCESD Rule 240.308.1(e)(2) states that any major source of $NO_x$ or VOCs located within 50 kilometers of the nonattainment area boundary shall be presumed to contribute to violations of the ozone standard in the nonattainment area unless it can be shown because of physical terrain, meteorology, or other physical factors the source is not expected to contribute to violations.

Mesquite analyzed the potential of MGS to contribute to ozone violations in the nonattainment area in a report dated July 24, 2000. This report presented an approach that consisted of conducting Urban Airshed Modeling (UAM) (among other analyses) that evaluated the combined impact of the proposed Pinnacle West Redhawk generating station, the proposed Arlington Valley Energy Project (AVEP), and the proposed MGS.

Although ozone impacts from all three facilities are generally slightly higher than those predicted for the Redhawk and AVEP facilities, the increase in the ozone peak is insignificantly small since it is within the numerical noise level of the UAM. Cumulative emissions from all three facilities will produce an ozone peak of 0.166614 parts per million (ppm). This represents an increase of 0.01459 parts per billion (ppb) over the 1999 baseline peak, which is slightly lower than the increase from just Redhawk and AVEP together. Thus, MGS emissions will not add significantly to the regional ozone peak. The results show that ozone increases from all three facilities will occur in areas with low ozone concentrations near the western boundary of the UAM modeling grid. A maximum ozone increase of 5.28 ppb was predicted to occur in areas of low ozone concentrations. Highest increases in daily ozone maxima were predicted to be 1.78 ppb in areas of low ozone and 0.113 ppb in areas of elevated ozone. These ozone increases are slightly higher than those predicted for the Redhawk facility alone or the combination of Redhawk and AVEP.

The analysis showed that Redhawk, AVEP and MGS combined would not cause any new exceedances of the ozone 1-hour standard nor exacerbations of existing exceedances of this standard.

## X. ADDITIONAL IMPACT ANALYSIS

### A. Visibility Impacts

The PSD regulations require that PSD permit applications address the potential impairment to visibility in Class I areas. Class I areas are national or regional areas of special natural, scenic, recreational, or historic value for which the PSD regulations provide special protection. The nearest Class I areas to MGS are the Superstition, Pine Mountain, and Mazatzal Wilderness Areas about 130 km (75 miles) east to northeast of the site. These Wilderness Areas are so distant that visibility impacts from MGS are not likely.

However there are eight additional “sensitive” areas (i.e. six Class II Wilderness areas and two Indian Reservations) within close proximity of the site. Although not required by PSD regulations, Mesquite analyzed the potential visibility impact on these nearby areas. Mesquite used a Level II analysis with the VISCREEN plume visibility model. VISCREEN is known to yield highly conservative results (i.e., over-predict impacts). Mesquite compared the VISCREEN results to Class I area criteria, even though Class II criteria, which do not exist, would likely be significantly less stringent than the Class I criteria. This combination of conservatism resulted in plume contrast values during worst case conditions (worst case meteorology coupled with worst case emissions) which indicated two of the eight "sensitive" areas, Signal Mountain and Woolsey Peak, exceeded two of the four visual screening criteria by small margins. These exceedances were subsequently disproved based on sun angle geometry in accordance with EPA guidance.

In summary, MGS will not likely have a visibility impact on the Class I areas, the nearby Class II Wilderness areas, nor the nearby Native American communities (since they are located farther away from the site than the Class II Wilderness areas modeled).

### *B. Nitrate Deposition and Impact*

Although not required by PSD regulations, Mesquite analyzed the potential for nitrate deposition (both dry and wet) at the "sensitive" areas (i.e. Class II Wilderness areas and Indian Reservations) within close proximity of the site. A maximum deposition of less than 0.11 kilograms per hectare per year was estimated. A maximum concentration of nitric acid of approximately 11,000 micrograms per square meter per second was estimated. There are no criterion for acceptable acid deposition values, but MGS is not anticipated to significantly contribute to nitrate deposition and impact.

## C. Growth Analysis

MGS will employ approximately 300 personnel during the construction phase and will employ approximately 25 to 30 personnel on a permanent basis. MGS hopes to hire from the local communities where possible, and there should be no substantial increase in community growth or need for additional infrastructure. Therefore, it is not anticipated that the project will result in an increase in secondary air emissions associated with growth.

## D. Soils and Vegetation Analysis

The NAAQS have been established to protect public health and welfare from any adverse effects of criteria pollutants. This includes impacts on soil and vegetation. Comparing the ambient air quality impacts from the proposed project in Table 7-5 with the NAAQS values in Table 7-1 is it apparent that the project will have predicted impacts well below all NAAQS. Therefore, it can be concluded that no adverse effects on soils and vegetation are expected.

# XI. ENDANGERED SPECIES ACT

Mesquite has consulted with US Fish and Wildlife Service (USFWS), the Arizona Department of Game and Fish (ADGF), and the Arizona Department of Agriculture (ADA) to determine if endangered species could be adversely affected by MGS. In addition, Mesquite conducted literature reviews, database searches, and field evaluations. The results of these reviews indicated that the construction and operation of MGS is not expected to impact threatened, endangered, or special status plants and animals identified by the USFWS, AGFD, and ADA. In accordance with EPA's delegation agreement with Maricopa County, the proposed permit will not be issued until the FWS has determined that the project will not adversely affect any endangered species.

# XII. REGULATORY STREAMLINING

### A. Applicable Requirements

The proposed project is subject to applicable New Source Performance Standards (NSPS) that contain requirements less stringent than the requirements established in the proposed permit for MGS. The permit conditions are drafted to incorporate the most stringent requirements. The main requirements that have been streamlined are as follows:

*1. 40 CFR Subpart GG $NO_x$ Emission Limit*

40 CFR 60.332(a)(1) limits emissions of $NO_x$ from the combustion turbine to 75 ppm by volume corrected to 15 percent oxygen. At MGS, the $NO_x$ emissions are limited to 2.5 ppm by volume corrected to 15 percent oxygen. Therefore the MGS permit limits are more stringent than the Subpart GG limits.

### B. Non-Applicable Requirements

The proposed permit contains a section indicating that certain regulations are not applicable to MGS. There are, obviously, a very large set of regulations that do not apply to MGS, but the permit calls out a few specifically in order to avoid future confusion. The rationale for the conclusion that the noted regulations are not applicable is as follows:

1. CAA Section 112(g), *Case by Case MACT* and 40 CFR Part 63, *NESHAPs for Major Sources of HAPs*

   MGS is not a major Federal HAPs source, with total HAPs emissions of 20.1 tons per year and no one HAP greater than 10 tons per year.

2. 40 CFR 60 Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971*

   Subpart D applies to steam generating units over 250 mmBtu/hr that are not electric generating units. MGS is an electric generating station, so Subpart D does not apply.

3. 40 CFR 60 Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*

   Subpart Db applies to steam generating units over 100 mmBtu/hr that are not subject to Subpart Da. The duct burners are the only “steam generating units” rated at over 100 mmBtu/hr, but the duct burners are rated at over 250 mmBtu/hr and are subject to Subpart Da. Units subject to Subpart Da are not subject to Db.

4. 40 CFR 64, *Compliance Assurance Monitoring (CAM)*

   The CAM rule applies only to pollutant-specific emission units that meet all of the following three criteria:
   1) pre-control emissions for the unit are greater than major source thresholds (100

tons per year in the case of MGS);
2) the emission unit is subject to an emission limit or standard other than one that is exempt under CAM; and
3) the emission unit uses an active control device to meet the emission limit.

A specific exemption to the CAM requirements is made for emission units that are required by a permit to have a continuous compliance determination method such as a Continuous Emissions Monitoring System (CEMS).

The only emission units at MGS with pre-control emissions over 100 tons per year are the $NO_x$, CO and $PM_{10}$ emissions from the Combined Cycle Systems and the $PM_{10}$ emissions from the cooling towers. $NO_x$ from the combustion turbines is controlled by SCR and CO from the combustion turbines is controlled by the oxidation catalyst; thus making these emissions potentially subject to CAM. However, since the Permit requires CEMS for NOx and CO emissions from these units, CAM does not apply for these compounds. The $PM_{10}$ emissions from the combustion turbines are not directed to a control device, therefore these emissions are not subject to CAM. The cooling towers employ drift eliminators but the $PM_{10}$ emissions from these units are not subject to CAM since the drift eliminators are an integral part of the equipment and not an active control device. Therefore, overall, CAM does not apply to MGS.

5. 40 CFR 75.17, *Affected Units Exhausting through a Common Stack*

MGS uses four separate stacks for the four Combined Cycle Systems, so this provision does not apply.

6. Maricopa County Rule 245 – *Continuous Monitoring Requirements*

Continuous monitoring requirements for various sources, including fossil fuel-fired steam generators, are contained in Rule 245. However, per Section 306.1 of Rule 245, sources subject to a Federal New Source Performance Standard (NSPS) are exempt from the requirements in Rule 245. The Combustion Turbines and Duct Burners are subject to NSPS. Thus, the monitoring requirements of Rule 245 are not applicable and are effectively subsumed by the NSPS requirements.

7. Maricopa County Rule 370 – *Hazardous Air Pollutants (HAPs)*

The Federal HAPs program is only applicable to major sources of HAPs. MGS is not a major source of HAPs, so these regulations do not apply.

The State of Arizona has also adopted a State HAPs program under A.R.S. Section 429.06. The applicability thresholds for the State HAPs program are 2.5 TPY or more of any combination of HAPs or 1.0 TPY or more of a single HAP. The State HAPs program will only be effective once the Arizona DEQ adopts implementing regulations; under A.R.S. Section 49-480.04 Maricopa County will be required to implement the State HAPs program in Maricopa County at that time. Hence, currently there is no applicable State HAPs program. Moreover, the exemption for electric utility steam generating units also applies to the State HAPs program.

In absence of the State HAPs program, Maricopa County requests that facilities model HAP emissions to show compliance with a set of Arizona Ambient Air Quality Guidelines (AAAQG). Modeling was voluntarily submitted for the MGS facility. As discussed in Section VIII, the results demonstrate that the potential project HAP emissions do not exceed the AAAQG.

## C. Other Applicable Requirements

1. Maricopa County Rule 270 – *Performance Testing*

   Rule 270 contains performance and compliance testing requirements and establishes requirements for testing criteria, conditions, and reporting of test results. The Rule 270 performance testing requirements are specified in the permit.

2. Maricopa County Rule 300 – *Opacity Regulations*

   Requirements for visible emissions are established in Rule 300. Opacity is to be 20% or less with a few exceptions (start-up, shutdown, or unavoidable combustion irregularities not exceeding three minutes as in Section 302.1). Opacity requirements are contained in the permit, and EPA Reference Method 9 is to be used to determine opacity when required. The proposed combined cycle units will only combust natural gas, which is a clean burning fuel, and such equipment rarely, if ever, exceeds 20% opacity. As a result, no continuous monitoring for opacity is required.

3. Maricopa County Rule 304 and 311, State Rule R18-2-719.c.1, and SIP Rule 31(H) – *Particulate Matter*

   Rule 311 contains PM emission limits for process industries, and since MGS is not a "process industry", the rule is not applicable. However, Section 304 of the rule and SIP Rule 31(H) include limitations for fuel burning operations that are applicable. An equation to calculate maximum allowable PM emissions is provided in Section 304.1 for equipment with a heat input rating of 4200 mmBtu/hr or less. The BACT PM emission limits from the combined cycle units will be much less than this limit, and therefore it is effectively subsumed.

   State Rule R18-2-719.c.1 applies to diesel fired fuel burning equipment that is not subject to NSPS. Therefore, the requirements of this rule are applicable only to the emergency fire water pump engine. The emission limits are based on the same equation as for SIP Rule 31(H).

4. Maricopa County Rule 320 – *Odors and Gaseous Air Contaminants*

Sections 306 and 308 of Rule 320 contain $SO_2$ and $NO_x$ limitations for electrical power plants, respectively. Requirements for $SO_2$ in Sections 306.1 - 306.4 only apply to equipment burning oil, and are therefore not applicable to the proposed MGS. The applicable $NO_x$ requirement at Rule 320, Section 308.1 for gaseous fossil fuel is 0.2 lb/mmBtu (3-hour average, as $NO_2$). The MGS permit limit for $NO_x$ is 2.5 ppmv for a 3-hour average, and is well below the Rule 320 limitation.

*5.* Maricopa County Rule 360 and 40 CFR Part 60 – *New Source Performance Standards (NSPS)*

Federal authority for NSPS requirements (delineated in 40 CFR Part 60) has been delegated to Maricopa County in County Rule 360. County Rule 360 adopts the federal standards of performance in Section 301.

*6.* 40 CFR Part 68 and Federal Clean Air Act Section 112(r)(1) -- *Accidental Releases of Toxic Chemicals*

Chemical accidental release prevention requirements have been established in 40 CFR Part 68. Applicability is determined by comparing the amount of a listed substance at a facility to its threshold quantity. MGS will use ammonia associated with the SCR NOx control system. Ammonia is regulated by 40 CFR Part 68. If MGS has more than 10,000 pounds of anhydrous ammonia in a single process or more than 20,000 pounds of 20 percent aqueous ammonia in a single process, the risk management planning requirements would be triggered. In such a case, the Permit requires submittal of a Risk Management Plan as required by 40 CFR Part 68. If MGS uses less than 20 percent aqueous ammonia solution, no Risk Management Plan will be required since less than 20 percent aqueous ammonia is inherently safer with respect to accidental releases and is exempt from 40 CFR Part 68.

Regardless of the requirement for a Risk Management Plan, under Section 112(r)(1) of the Federal Clean Air Act, MGS has a general duty to identify, prevent, and minimize the consequences of an accidental release of toxic chemicals.

## XIII. TITLE IV APPLICABILITY

MGS is subject to the acid rain provisions of the Clean Air Act. The permitted emission limits, monitoring, recordkeeping, reporting and other requirements of the Permit include the acid rain provisions of 40 CFR Parts 72, 73 and 75 that apply to MGS. The proposed Permit serves as a combined PSD, Title V, and Title IV acid rain permit. MGS's Acid Rain Permit application is incorporated by reference into the proposed Permit.

MGS holds no $SO_2$ allocations since it is a new plant, however, MGS will have to obtain sufficient $SO_2$ emission allowances as of the allowance transfer deadline not less than the previous year's actual $SO_2$ emissions as required by the Acid Rain Program. Since the Acid Rain Program $NO_x$ emissions limits apply only to coal-fired units, there are no Acid Rain Program $NO_x$ limits for MGS (40 CFR 76.1) .

## XIV. MONITORING AND COMPLIANCE DEMONSTRATION PROCEDURES

MGS will install SCR on each of the Combined Cycle Systems to control $NO_x$ emissions. As part of the Acid Rain Program requirements, continuous emissions monitors (CEMS) for $NO_x$ are required, and the CEMS will meet the requirements in 40 CFR Part 75.

In order to demonstrate compliance with emission limitations for other pollutants, additional monitoring requirements are specified in the permit. In addition to the $NO_x$ CEMS, CEMS for CO (as well as an $O_2$ diluent gas monitor) will be required on each Combined Cycle System. Natural gas flow meters are also required as part of the Acid Rain Program and will be installed on each fuel line to monitor the unit-specific fuel flow to the combustion turbines and duct burners. These monitors will be installed, certified, and operated in accordance with applicable provisions of 40 CFR Parts 60 (Appendices B and F) and 40 CFR Part 75. For VOC and $PM_{10}$, monitored fuel usage in conjunction with emission factors contained in the Permit Application (unless more representative rates can be demonstrated to the Control Officer) will be used to determine emissions. $PM_{10}$ emissions from the cooling towers will be calculated using the total dissolved solids (TDS) concentration in the cooling water as determined through monthly testing.

$PM_{10}$ compliance monitoring will also include a provision to perform a visible emissions observation of the stack emissions from each emission unit each week of operation during which that equipment was used more than 10 hours. If emissions are visible, the MGS shall obtain an opacity reading conducted in accordance with EPA Reference Method 9 by certified reader within 3 operating days (unless the visible emissions are remedied prior to the 3 days). If opacity exceeds 15% the Control Officer may require emissions testing by other EPA approved Reference Method such as Reference Method 5 to demonstrate compliance with the particulate matter emission limits of these Permit Conditions.

$SO_2$ emissions will be determined using the sulfur content in the fuel and fuel usage data. Sulfur content of the fuel will be determined through fuel sulfur content testing according to a “custom” fuel testing schedule that is approved as part of the permit.

As provided in Maricopa County Rule 270, performance testing will be required for $NO_x$, CO, VOC, and $PM_{10}$ to demonstrate compliance. Testing will be performed at full load and at reduced load conditions. Initial testing will also be performed for ammonia at full load. Testing is performed annually for $PM_{10}$ and VOC, and every five years for $NO_x$ and CO. However, a RATA is required annually for the $NO_x$ and CO monitors. Ammonia testing is required initially and at least every five years unless the ammonia trigger rate is exceeded, in which case testing is required within 90 days of the exceedance.

## XV. CONCLUSION AND PROPOSED ACTION

Based on the information supplied by Mesquite, and on the analyses conducted by the Maricopa County Environmental Services Department, MCESD has determined that the proposed Mesquite Generating Station Project will employ BACT, will not cause or contribute to a violation of any federal ambient air quality standard, will not cause any applicable PSD increment to be exceeded, will not cause any AAAQG to be exceeded, and will not cause additional adverse air quality impacts.

Therefore, MCESD proposes to issue to Mesquite Energy, LLC an Air Quality Permit which will serve as an Authority to Construct and operate the Mesquite Generating Station, subject to the attached permit conditions.

Appendix B Technical Support Document for Significant Revision S03-003

**Technical Support Document**

Significant Revision S03-003

Mesquite Generating Station (Mesquite)

Title V Permit Number V99-017

---

## I. APPLICANT

Mesquite Power, LLC
101 Ash Street
San Diego, CA 92101

## II. PROJECT LOCATION

The Mesquite Generating Station (MGS) is located in the unincorporated community of Arlington, Arizona, in the county of Maricopa. The site is located approximately 40 miles west of Phoenix and approximately eight miles south of Interstate 10. The 276 acre site is situated approximately two miles south of the existing Palo Verde Nuclear Generating Station (PVNGS). The approximate legal description of the site is the west half of Section 15, Township 1 South, Range 6 West of the Gila and Salt River Base and Meridian, Maricopa County, Arizona, excepting the east half of the Northeast quarter of the Northwest quarter of said Section 15. The site is located at approximately 112$^{o}$ 20' 40'' West longitude and 33$^{o}$ 20' 40" North latitude. The site elevation is 890 feet above mean sea level (msl).

MGS is an existing natural gas-fired combined cycle merchant power plant with two power blocks, each rated at a maximum of 650 megawatts (MW) electric (nominal), for a maximum total at the site of 1,300 MW at design ambient conditions. Only natural gas fuel is used for the combined cycle systems. MGS is owned and operated by Mesquite Power, LLC ("Mesquite"). The project is classified as Standard Industrial Classification (SIC) Code 4911 and North American Industrial Classification System (NAICS) 221112, Fossil-Fuel Electric Power Generation.

With respect to the National Ambient Air Quality Standards (NAAQS), portions of Maricopa County are designated as serious nonattainment for particulate matter <10 microns ($PM_{10}$), carbon monoxide (CO), and ozone (since the 182(f) waiver is not implemented in Maricopa County for New Source Review purposes, both of the precursor pollutants nitrogen oxides ($NO_x$) and volatile organic compounds (VOC) are regulated by the County for ozone NAAQS purposes). The County is designated as attainment/unclassified for $SO_2$, $NO_2$, and lead. The proposed MGS site is located in an attainment area approximately 15 miles west of the $PM_{10}$ nonattainment area boundary and approximately 25 miles west of the CO and ozone nonattainment boundary.

The Maricopa County Environmental Services Department (MCESD) has been delegated primary responsibility for the Prevention of Significant (PSD) program in the County, and therefore, the project comes under the jurisdiction of MCESD. Since MGS is a major source in an attainment area, it is subject to the requirements of the PSD, Title IV and Title V regulatory programs.

## III. PROJECT DESCRIPTION

Mesquite initially received a combined PSD and Title V Air Quality Permit on February 8, 2001. The permit was subsequently modified through Minor Modifications 12-16-02-03, 4-18-03-01, and 6-25-03-01.

This proposed Significant Permit Revision is to change the allowable emissions during periods of startup and shutdown. The Revision is required because of recent operational data that indicates such emissions can be considerably greater than the current permit limits. The initial permit SU/SD emission limits were based on theoretical/engineering estimates supplied by the manufacturer. The emission limits contained in this proposed Significant Revision, however, are based on actual performance data at MGS.

The major MGS components with the potential for air emissions are listed in Table 3-1. The MGS uses four General Electric 7FA natural gas-fired combustion turbines (CTGs) operating in combined-cycle mode with four supplementary fired Heat Recovery Steam Generators (HRSGs) and two steam turbine generators. Steam generation in each of the HRSGs is augmented with a supplementary natural gas fired duct burner. Each HRSG is outfitted with a Selective Catalytic Reduction (SCR) system to reduce the emissions of $NO_x$ and an Oxidizing Catalyst system to reduce the emissions of CO and VOCs.

**Table 3-1**
**Mesquite Generating Station Major Emitting Equipment**

| **Four Combined Cycle Systems (System #1, System #2, System #~~3, System #4~~ #5 and #6) and two steam turbines with electrical generators.** | |
|---|---|
| | **Each Combined Cycle System consists of the following:** |
| a. | General Electric 7FA combustion turbine operating in combined-cycle mode with a nominal rating of 170 megawatts electric without duct firing and 180 megawatts electric with duct firing and fueled by pipeline quality natural gas only. |
| b. | Supplementary fired, three-pressure Heat Recovery Steam Generator (HRSG) with duct burners. The duct burners have a maximum heat input of 592.6 mmBtu/hr (HHV) and are fueled by pipeline quality natural gas only. |
| c. | Selective Catalytic Reduction (SCR) nitrogen oxides emissions control system capable of treating the entire exhaust of the Combustion Turbine and duct burner combined. |
| d. | Oxidation Catalyst carbon monoxide and volatile organic compound emissions control system capable of treating the entire exhaust of the Combustion Turbine and duct burner combined. |
| e. | Continuous emissions monitor (CEM) system that records oxides of nitrogen ($NO_x$), carbon monoxide (CO), and oxygen ($O_2$) content of the System exhaust. |
| f. | An exhaust stack with height 170 feet above plant grade and inside diameter of 18 feet. |
| **Wet Cooling Towers** | |
| a. | Two twelve-cell wet cooling towers, with each cooling tower rated at 163,050 gallons per minute recirculation rate (326,100 gallons per minute total for both cooling towers) and height 45 feet above plant grade. |
| b. | Continuous cooling water conductivity monitoring system. |
| c. | Drift eliminators on each cooling tower. |
| **Emergency Diesel Engine** | |
| a. | One 348-horsepower engine firing No. 2 distillate fuel oil to drive the emergency fire water pump. |

## IV. EMISSIONS FROM THE PROJECT

This proposed Significant Revision revises SU/SD emissions only for $NO_x$, CO, and VOC. Emissions of $SO_2$ and $PM_{10}$ are not affected by this Revision, as those emissions are not affected by the SCR and Oxidation Catalyst ramp up temperatures and control efficiency problems during startup and shutdown.

Tables 4-1 shows the proposed emission limits in tons per year (tpy). Table 4-2 compares the currently permitted to the proposed emission limits. Table 4-3 shows the derivation of the proposed emissions in Tables 4-1 and 4-2.

**Table 4-1**

**Rolling 365-day Average Emission Limit for NOx**

**Rolling 12-month Average Emission Limits for CO, $PM_{10}$, $SO_2$, and VOC**

(Tons per Year)

| Device | $NO_x$ | CO | $PM_{10}$ | $SO_2$ | VOC |
|---|---|---|---|---|---|
| GE – Combined Cycle System #1 #2 Combined | 204.0 | 191.8 | 253.2 | 17.6 | 147.5 |
| GE – Combined Cycle System **~~#3 and #4~~ #5 and#6** Combined | 204.0 | 191.8 | 253.2 | 17.6 | 147.5 |
| Subtotal for Combined Cycle Systems #1, #2, **~~#3, and #4~~ #5, and #6** | 408 | 384 | 506 | 35 | 295 |
| Cooling Tower #1 | NA | NA | 16.89 | NA | NA |
| Cooling Tower #2 | NA | NA | 16.89 | NA | NA |
| Subtotal for Cooling Towers #1 and #2 | NA | NA | 34 | NA | NA |
| FACILITY TOTAL EMISSIONS | 408 | 384 | 540 | 35 | 295 |

**Table 4-2**
**Comparison of Currently Permitted with Proposed Rolling 12-month Average Emission Limits (tpy)**

| Device | $NO_x$ | CO | $PM_{10}$ | $SO_2$ | VOC |
|---|---|---|---|---|---|
| Currently Permitted Total for GE Combined Cycle Systems #1, #2, **~~#3, and #4~~ #5, and #6** | 369 | 359 | 506 | 35 | 259 |
| PROPOSED Total for GE Combined Cycle Systems #1, #2, **~~#3, and #4,~~ #5 and #6** | 408 | 384 | 506 | 35 | 295 |
| Total for Cooling Towers | NA | NA | 34 | NA | NA |
| | | | | | |
| Currently Permitted FACILITY TOTAL EMISSIONS | 369 | 359 | 540 | 35 | 259 |
| PROPOSED FACILITY TOTAL | 408 | 384 | 540 | 35 | 295 |

| | | | | | |
|---|---|---|---|---|---|
| EMISSIONS | | | | | |
| PROPOSED INCREASE IN EMISSIONS | 39 | 25 | 0 | 0 | 36 |

Note: No change is proposed for the cooling towers or the $PM_{10}$ or $SO_2$ limits.

**Table 4-3**
**Derivation of Proposed Revised Emission Limits for One Power Block**
**(Note a)**

| Operation Scenario | Duration (hr/event) (Note b) | Estimated Frequency (events/yr) (Note b) | Estimated Total Duration (hrs/yr) | $NO_x$ (lb/ event) | $NO_x$ (tpy) | CO (lb/ event) | CO (tpy) | VOC (lb/ event) | VOC (tpy) |
|---|---|---|---|---|---|---|---|---|---|
| Extended Start | 5.8 | 12 | 70 | 920 | 5.5 | 260 | 1.6 | 200 | 1.2 |
| Regular Start | 2.5 | 208 | 520 | 362 | 37.6 | 108 | 11.2 | 84 | 8.7 |
| Shutdown | 0.5 | 220 | 110 | 138 | 15.2 | 45 | 5.0 | 34 | 3.7 |
| Normal Operations (Note c) | | | 8060 | 44.4 | 178.9 | 43.2 | 174.1 | 33.2 | 133.8 |
| **Totals** | | **220** | **8760** | | **237.3** | | **191.8** | | **147.5** |

Notes:

a. MSG consists of two power blocks (one power block is 2 CTGs, 2 HRSGs, and one Steam Turbine Generator.
b. Durations and Frequency are used for emission calculation purposes and are not permit limits.
c. Normal emission values reflect maximum emissions during conditions other than startup or shutdown.
d. An Extended start is one in which the combined cycle system has not be reached Mode 6 operation in the 72 hours prior to initiating the startup sequence. A regular start is one in which the combined cycle system has reached Mode 6 operation during the 72 hours prior to initiating the startup sequence (i.e., a startup after a failed start where the turbine does not get fully up to temperature could still be considered an extended start).
e. The NOx estimated emissions are 237.3 tons per year. Mesquite's original request of 237.3 tons per year per Power Block has been adjusted to 204.0 tons per year. This change adjusts their proposed annual emission net increase from 106 tons per year to 39. This modification remains a Title V significant permit revision because there is a relaxation of the permitted SU/SD emissions. The permit no longer has PSD applicability so long as the Permittee does not exceed the new 365-day rolling NOx emission limitation.

## V. APPLICABILITY OF NEW SOURCE REVIEW

Since the facility emission increases are less than the significant modification thresholds, the requested change is not a Significant Revision to the existing permit. Table 5-1 shows the proposed emission increases and the significant modification thresholds.

**Table 5-1**

**Determination of Major Source and PSD Applicability**

| Pollutant | Proposed Annual Emissions Increase (tpy) | Significance Level (tpy) |
|---|---|---|
| $NO_x$ | 39 | 40 |
| CO | 25 | 100 |
| $SO_2$ | 0 | 40 |
| $PM_{10}$ | 0 | 15 |
| VOC | 36 | 40 |

The NOx annual emission increase is 39 tons. Since this number is very close to the PSD significance level the annual emission limit calculation has changed from a 12-month rolling average to a 365-day rolling average. So long as this limit is not exceeded, PSD will not be applicable to this revision.

## VI. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

For this proposed Title V Significant Revision, the permit emission limits for NOx and VOC are being adjusted. $NO_x$ emissions are being increased to 39 tons which are below the significance thresholds. Since this limit was accepted by Mesquite Power, a PSD significant permit revision is not required. However, at anytime the 365-day rolling average limit for NOx is exceeded, PSD/NSR requirements will be applicable to the source. This will include a BACT/LAER analysis of emissions during regular operation and operation during start up and shut down. These requirements can be found in the 40 CFR 52.21 (r)(4).

## VII. CRITERIA POLLUTANT AIR QUALITY IMPACTS IN ATTAINMENT AREAS

A combination of quantitative and qualitative ambient impact analyses were used to assess the impact of this proposed Significant Revision. The modelling techniques were the same for this Significant Revision as for the original permit application. Consequently, the same modelling protocol was used. The only changes in the impact analyses were the emission changes and an update to the emissions from nearby sources. Only $NO_x$ and CO were quantitatively assessed (modelled) since there are no changes in $PM_{10}$ or $SO_2$ emissions, and the increase in VOC emissions were assessed qualitatively.

The same five years of meteorological data were used in this analysis as in the initial application (1994 – 1998 Palo Verde Nuclear Generating Station 10-meter and 60-meter surface data coupled with Tucson upper air data).

## A. Existing Ambient Air Quality Conditions

The National Ambient Air Quality Standards (NAAQS) are regulated pollutant limits designed to protect human health and the environment. The primary and secondary NAAQS for the relevant criteria pollutants (CO and $NO_x$) are provided in Table 7-1. National primary ambient air quality standards define levels of air quality which the EPA Administrator judges are necessary, with an adequate margin of safety, to protect the public health. National secondary ambient air quality standards define levels of air quality which the Administrator judges necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.

**Table 7-1**
**National Ambient Air Quality Standards (40 CFR 50.4-50.12)**
**(micrograms per cubic meter)**

| Pollutant | 1-hour Average | 8-hour Average | Annual Average |
|---|---|---|---|
| $NO_2$ | -- | -- | 100 |
| CO | 40,000 | 10,000 | -- |

The portion of Maricopa County where the proposed project is located is currently classified as attainment for all criteria pollutants. MGS first analyzed the ambient air quality impacts of the proposed emissions and compared those impacts to the Significant Impact Levels (SILs). If the impacts were below the SILs, the analysis proceeded to the "Additional Impacts Analysis." This is the case since, by definition of the SILs, if the impacts are less than the SILs the source would not cause or contribute to a violation of a national ambient air quality standard (40 CFR 51.165(b)(2)). The SILs for the relevant pollutants are shown in Table 7-2.

**Table 7-2**
**Significant Impact Levels (40 CFR 51.165(b)(2))**
**(micrograms per cubic meter)**

| Pollutant | 1-hour Average | 8-hour Average | Annual Average |
|---|---|---|---|
| $NO_2$ | | | 1 |
| CO | 2000 | 500 | |

In addition, if the impact of the facility is less than the SILs, the impacts will also be less than the PSD increments. The Class I and Class II increments are shown in Table 7-3. (Note that there are no PSD increments for CO).

**Table 7-3**
**PSD Class I and II Increments (40 CFR 51.166(c)**
**(micrograms per cubic meter)**

| Pollutant | Area Type | Annual Average |
|---|---|---|
| $NO_2$ | Class I | 2.5 |
| $NO_2$ | Class II | 25 |

If the impacts are greater than the SILs, then the impacts of MGS would have to be added to a representative background ambient air quality value and combined with impacts from other nearby sources. In addition, if the impacts are greater than the monitoring thresholds of 40 CFR 52.21(i)(8)(i), pre-construction monitoring would be required; however, the impacts associated with this Significant Revision are less than the monitoring thresholds.

### B. GEP Stack Height Analysis

The proposed Significant Revision does not change Good Engineering Practice (GEP) stack heights, and all of the stack heights were previously determined to be within GEP.

### C. Modeling Results

As shown in Table 7-4, the results from modeling all five years of meteorological data indicate that the proposed emissions cause an exceedance of the SIL for only annual average $NO_2$.

**Table 7-4**
**Maximum Ambient Air Quality Impacts of MGS Alone**
**for Relevant Criteria Pollutants**

| Pollutant | 1-hour Average | 8-hour Average | Annual Average |
|---|---|---|---|
| ***MAXIMUM IMPACTS OF MGS*** | | | |
| $NO_2$ | | | 2.28 $\mu g/m^3$ |
| CO | 757 $\mu g/m^3$ | 54 $\mu g/m^3$ | |
| ***MAXIMUM IMPACTS COMPARED TO SILs*** | | | |
| $NO_2$ | | | 228 % |
| CO | 38 % | 11 % | |
| ***MAXIMUM IMPACTS COMPARED TO CLASS II INCREMENTS*** | | | |
| $NO_2$ | | | 9 % |

Note: A conversion percentage of 75% NO to $NO_2$ was assumed, however the conclusions at this stage of the analysis would not change if 100% was assumed (i.e., the impacts are still greater than the SIL, and the SIL circle would not change (since it is driven by an isolated hill, see text).

The SIL analysis indicated that the annual $NO_2$ SIL was exceeded. The distance to which concentrations dropped below the SIL was 1.3 km. Therefore a combined impact analysis was conducted with all $NO_2$ sources (termed "nearby" sources) located within 52 km of MGS. Note that although the distance to which the MGS impacts drop below the SIL is 1.3 km, the impact point is an isolated hill, and all of the concentrations between the fenceline and the hill are less than the SIL.

The combined impacts analysis began by obtaining from the MCESD a list of all sources within 52 km of MGS and the associated emission rates of $NO_x$ from those sources. The sources were then screened by evaluating the emission rate compared to the distance from MGS. The screening methodology used the SCREEN3 model, conservatively assuming a ground level release. For a set of emission rates (1, 5, 10, 15, 20, 25, and 41 tons per year) the distance at which the impacts of the hypothetical ground level source is less than 1 ug/m$^3$ was determined. A set of hypothetical impact areas for each class of source was then determined. Then for each nearby source, a hypothetical impact distance was determined (based on the distance). Finally, if the nearby source was located further from MGS than 1.3 km (i.e., the SIL circle of MGS) plus the hypothetical impact distance of the source, the source was eliminated from further consideration. The result of this screening was that 8 nearby sources were explicitly modeled for combined impacts with MGS. The eight sources were PVNGS, AVEF I, AVEF II, Pinnacle West, Harquahala Generating Station, Panda Gila River Generating Station, Gila Compressor Station, and Gila Bend Power Generating Station.

The source inventory was separated into two separate inventories; one inventory included MGS plus all 8 nearby sources (NAAQS Inventory), while the second inventory contained all sources in the NAAQS inventory except the Gila Compressor Station (Increment Inventory). The Gila Compressor Station was excluded from the Increment Inventory because this facility was installed prior to the $NO_2$ baseline date. No modifications have been made to the Gila Compressor Station since the baseline date; therefore this source does not consume increment. The results of the increment impact analysis using the Increment Inventory are shown in Table 7-5. There is no exceedance of the Class II PSD increment associated with the proposed Significant Revision.

**Table 7-5**
**Maximum Ambient Air Quality Impacts of MGS**
**Plus Nearby Sources (within 52 km) for $NO_2$**

| **Pollutant** | **Annual Average** |
|---|---|
| ***MAXIMUM IMPACTS OF MGS Plus NEARBY SOURCES*** | |
| $NO_2$ | 4.2 µg/m$^3$ |
| ***MAXIMUM IMPACTS COMPARED TO CLASS II INCREMENTS*** | |
| $NO_2$ | 17 % |

Note: A conversion percentage of 75% NO to $NO_2$ was assumed, however the conclusions at this stage of the analysis would not change if 100% was assumed (i.e., the impacts are still less than the increments.

The results of the NAAQS analysis using the NAAQS Inventory are provided in Table 7-6. The background annual average $NO_2$ concentration in the area was assumed to be 34 µg/m$^3$ based on an Arizona Department of Air Quality (ADEQ) monitoring station peak 24-hour value. The peak 24-hour value was assumed to represent the annual average since the ADEQ station did not have a complete year of available data. This is an extremely conservative assumption. If the modeled combined impact of MGS plus 8 nearby sources of 41.3 µg/m$^3$ is added to the assumed background, the total is 75.3 µg/m$^3$, less than the NAAQS of 100 µg/m$^3$. At the maximum impact point, located about 12 km southeast of MGS, approximately 98% of the impact is related to the Gila Compressor Station. The contribution of the Gila Compressor station within the MGS impact area (i.e., within 1.3 km of MGS) is less than 1 ug/m$^3$.

**Table 7-6**
**Maximum Ambient Air Quality Impacts of MGS**

**Plus Nearby Sources (within 52 km) for $NO_2$**

| **Pollutant** | **$NO_2$ Annual Average concentration** |
|---|---|
| ***MAXIMUM IMPACTS OF MGS Plus NEARBY SOURCES*** | 4.1.3 $\mu g/m^3$ |
| ***BACKGROUND CONCENTRATION*** | 34 $\mu g/m^3$ |
| ***TOTAL MAXIMUM IMPACT*** | 75.3 $\mu g/m^3$ |
| ***MAXIMUM IMPACTS COMPARED TO NAAQS*** | 75.3 % |

Note: A conversion percentage of 75% NO to $NO_2$ was assumed, however the conclusions at this stage of the analysis would not change if 100% was assumed (i.e., the impacts are still less than the NAAQS.

The background annual average $NO_2$ concentration in the area was assumed to be 34 ug/m$^3$ based on an Arizona Department of Air Quality (ADEQ) monitoring station peak 24-hour value. The peak 24-hour value was assumed to represent the annual average since the ADEQ station did not have a complete year of available data. This is an extremely conservative assumption.

## VIII. AIR TOXICS IMPACT ANALYSIS

The proposed emissions increases are related only to the criteria pollutants. Since no credit was taken for possible emission reduction of air toxics from the oxidation catalyst in the original permit application and impact analysis, and since the proposed change is not primarily related to the oxidation catalyst, there is no change in permitted or previously modeled air toxics impacts. Therefore, air toxics were not evaluated as part of this Significant Permit Revision.

## IX. URBAN AIRSHED MODELING

MCESD Rule 240.308.1(e)(2) states that any major source of $NO_x$ or VOCs located within 50 kilometers of the nonattainment area boundary shall be presumed to contribute to violations of the ozone standard in the nonattainment area unless it can be shown because of physical terrain, meteorology, or other physical factors the source is not expected to contribute to violations.

Mesquite qualitatively analyzed the potential of MGS to contribute to ozone violations in the nonattainment area by evaluating the previous urban airshed modeling. The modeling submitted with the initial application indicated that the contribution of MGS to the nonattainment area was insignificantly small. Likewise, the proposed increase of this Significant Revision will be even less.

## X. ADDITIONAL IMPACT ANALYSIS

### A. PSD Class I and Visibility Impacts

The potential impact of MGS on the nearest Class I areas was qualitatively assessed by comparing the emissions of MGS to the emissions of AVEF and evaluating the impacts of AVEF. This comparison is valid since both facilities used the same meteorological data set for the modeling and have essentially the same exhaust and stack parameters. AVEF emissions are greater than MGS, and it was shown in the AVEF permit application that AVEF would not have a significant impact on the Class I areas (all impacts are well below significance thresholds, including Class I increments). Therefore, MGS would also not have a significant impact since MGS and AVEF are located less than 12 km apart. The nearest Class I areas to MGS are the Superstition, Pine Mountain, and Mazatzal Wilderness Areas about 130 km (75 miles) east to northeast of the site.

### B. Growth Analysis

The proposed emission increase does not change employment at MGS.

### C. Soils and Vegetation Analysis

When impacts are less than the SILs, and the source is more than 10 km from a Class I area, no analysis on soils and vegetation is required per USEPA Guidance ("A Screening Procedure for Impacts of Air Pollution Sources on Plants, Soils, and Animals." EPA-450/2-81-078). Although the $NO_2$ impacts were greater than the SILs, this occurred only 1.3 km from MGS on two isolated high terrain points. At all remaining receptors, the impacts were below the SILs. Therefore, the proposed emissions increase will not cause an adverse impact on soils and vegetation.

## XI. ENDANGERED SPECIES ACT

Since the proposed change does not change the footprint of the MGS facility nor change its operations, a new consultation with the US Fish and Wildlife Service (USFWS) and the Arizona Department of Game and Fish (ADGF) was not required. Such a consultation was conducted prior to issuing the first MGS permit.

## XII. REGULATORY STREAMLINING

There are no regulatory streamlining changes included in this Significant Revision.

## XIII. TITLE IV APPLICABILITY

MGS is subject to the acid rain provisions of the Clean Air Act, however, the proposed change does not affect the MGS Acid Rain Program.

## XIV. MONITORING AND COMPLIANCE DEMONSTRATION PROCEDURES

The proposed change does not affect monitoring or compliance requirements in the existing permit.

## XV. CONCLUSION AND PROPOSED ACTION

Based on the information supplied by Mesquite, and on the analyses conducted by the Maricopa County Environmental Services Department, MCESD has determined that the proposed Significant Revision will not cause or contribute to a violation of any federal ambient air quality standard, will not cause any applicable PSD increment to be exceeded, will not cause any Arizona Ambient Air Quality Guideline value to be exceeded, and will not cause additional adverse air quality impacts.

Therefore, MCESD proposes to issue to Mesquite Energy, LLC the requested Significant Revision to the existing Air Quality Permit, subject to the attached permit conditions.

Appendix C
Startup and Shutdown Emission Limits for Various
Maricopa County, California and Other Power Facilities

**Startup and Shutdown Emission Limits for**
**Various Maricopa County, California and Other Power Facilities**

| Facility | Location | Equipment | Condition | (Units) Averaging Period | $NO_x$ | CO | Estimated lb/event for two turbines (1) NOx | Estimated lb/event for two turbines (1) CO | Other limits and Comments | Reference |
|---|---|---|---|---|---|---|---|---|---|---|
| Mesquite Generating Station | Maricopa County, Arizona | Four GE 7FA turbines with SCR and Oxidation Catalyst | Extended Startup (Per Power Block – 2 CT Combined) | (lb/event) | 920 | 500 | 920 | 500 | Emissions based on the October 2005 Application) | Mesquite Power, November 2005 |
| | | | Regular Startup (Per Power Block – 2 CT Combined) | (lb/event) | 565 | 320 | 565 | 320 | | |
| | | | Shutdown (Per Power Block – 2 CT Combined) | (lb/event) | 275 | 105 | 275 | 105 | | |
| Arlington Valley Energy Facility | Maricopa County, Arizona | Two GE 7FA turbines with SCR | Startup (Per Power Block – 2 CT Combined) | (lb/event) | 799 | 2484 | 799 | 2484 | Max CO = 2520 lb/hr/power block during SU/SD; Max 1,050 hours/year/ power block during SU/SD | Mesquite Power, November 2005 |
| | | | Shutdown (Per Power Block – 2 CT Combined) | (lb/event) | 124 | 712 | 124 | 712 | | |

| Facility | Location | Equipment | Condition | (Units) Averaging Period | $NO_x$ | CO | Estimated lb/event for two turbines (1) NOx | CO | Other limits and Comments | Reference |
|---|---|---|---|---|---|---|---|---|---|---|
| Harquahala Generating Station | Maricopa County, Arizona | Westinghouse 501G turbines with SCR and Oxidation Catalyst | Startup – Cold (per turbine) | (lb/event) | 461 | 3000 | 922 | 6000 | Max 700 hours/year/turbine and 10 hours/day in SU/SD | Mesquite Power, November 2005 |
| | | | Startup – Warm (per turbine) | (lb/event) | 304 | 2600 | 608 | 5200 | | |
| High Desert Power Project | Victorville, California | Three Westinghouse 501F turbines with SCR and Oxidation Catalyst | Startup – Cold (per power block) | (lb/event) | 549 | 10623 | 366 | 7082 | CEC Order Approving a Petition to modify air quality conditions of regarding startup and other requirements. October 2004 | |
| | | | Startup – Warm (per power block) | (lb/event) | 504 | 10788 | 336 | 7192 | | |
| | | | Startup – Hot (per power block) | (lb/event) | 414 | 11187 | 276 | 7458 | | |
| | | | Shutdown (per power block) | (lb/event) | 291 | 717 | 194 | 478 | | |
| Delta Energy Center | Pittsburgh, California | Three Westinghouse 501F turbines with SCR | Gas turbine startup | (lb / event / turbine) | 240 | 2514 | 480 | 5028 | CEC Order Approving a Petition to Amend Start-Up and Tuning Emissions, September 8, 2004. Note: only one turbine can be in startup or tuning at a time. | CEC amendment, September 8, 2004. |
| | | | Steam turbine cold startup or combustor tuning | (lb / event / turbine) | 300 | 9750 | 600 | 19500 | | |
| | | | Shutdown | (lb / event / turbine) | 80 | 902 | 160 | 1804 | | |

| Facility | Location | Equipment | Condition | (Units) Averaging Period | $NO_x$ | CO | Estimated lb/event for two turbines (1) NOx | CO | Other limits and Comments | Reference |
|---|---|---|---|---|---|---|---|---|---|---|
| Blythe Energy Project | Riverside County, California | Two Siemens-Westinghouse V84.3 turbines with SCR | Startup or Shutdown (Per Power Block – 2 CT Combined) | (lb/event) | 376 | 3600 | 376 | 3600 | CEC Order Approving a Petition to Modify Air Quality Permit, March 30, 2005; PSD Permit SE-03-01, issued by EPA on 11/16/2004. | |
| Moss Landing Power Plant Project | Monterey County, California | Four GE 7FA turbines with SCR | Gas turbine startup | (lb / event / turbine) | 320 | 3068 | 640 | 6136 | CEC Staff Analysis of Proposed Project Modification: Request to Modify Air Emissions During Startup and Tuning, December 23, 2003.<br>Note: only one turbine can be in tuning mode at a time. | |
| | | | Steam turbine cold startup or combustor tuning | (lb / event / turbine) | 480 | 5412 | 960 | 10824 | | |
| | | | Shutdown | (lb / event / turbine) | 160 | 1804 | 320 | 3608 | | |
| Tesla Power Plant Project | Alameda County, California | Four GE 7FA turbines with SCR and Oxidation Catalyst | Startup (per turbine) | (lb / event / turbine) | 416 | 1181 | 831 | 2361 | CEC Decision June 16, 2004 | |
| Santan Generating Station | Maricopa County, Arizona | GE 7FA turbines with SCR and Oxidation Catalyst | Startup (Per Turbine) | (lb/hr) 1-hour avg. | 227.1 | 760.2 | | | | Mesquite Power, November 2005 |

| Facility | Location | Equipment | Condition | (Units) Averaging Period | $NO_x$ | CO | Estimated lb/event for two turbines (1) NOx | Estimated lb/event for two turbines (1) CO | Other limits and Comments | Reference |
|---|---|---|---|---|---|---|---|---|---|---|
| Gila Bend Power Station | Maricopa County, Arizona | GE 7FA turbines with SCR and Oxidation Catalyst | Startup (Per Turbine) | (lb/hr)1-hour avg. | 102.5 | 594 | | | Max 600 hours/year/turbine and 10 hours/day in SU | Mesquite Power, November 2005 |
| Redhawk Pinnacle West | Maricopa County, Arizona | Four GE 7FA turbines with SCR | SU/SD | (lb/hr) | 338 | 870 | | | Max 1277.5 hours/year/turbine and 10 hours/day in SU | Mesquite Power, November 2005 |
| Kyrene Generating Station | Maricopa County, Arizona | GE 7FA turbines with SCR | SU/SD | (lb/hr)1-hour avg. | 162 | 760.2 | | | Max 250 hours/year/CT and 8 hours/day in SU/SD | Mesquite Power, November 2005 |
| APS West Phoenix | Maricopa County, Arizona | GE 7FA turbines with SCR and Oxidation Catalyst | Startup | (lb/hr)1-hour avg. | 169 | 870 | | | n/a | Mesquite Power, November 2005 |
| Panda Gila River | Maricopa County, Arizona | GE 7FA turbines with SCR and Oxidation Catalyst | Startup | (lb/hr)1-hour avg. | 230 | 100 | | | Max 600 hrs/year/turbine | Mesquite Power, November 2005 |

| Facility | Location | Equipment | Condition | (Units) Averaging Period | $NO_x$ | CO | Estimated lb/event for two turbines (1) NOx | CO | Other limits and Comments | Reference |
|---|---|---|---|---|---|---|---|---|---|---|
| Magnolia Power Project | Burbank, California | GE 7FA turbine with SCR and Oxidation Catalyst | Cold Start-up (1turbine) | lb/event | NA | 500 | | 1000 | CEC Final Commissions Decision. March 2003 | |
| | | | Warm Start-up (1 turbine) | lb/event | NA | 300 | | 600 | | |
| | | | Hot Start-up (1 turbine) | lb/event | NA | 285 | | 570 | | |
| | | | Shutdown (1 turbine) | lb/event | NA | 120 | | 240 | | |
| Los Medanos Pittsburgh) Energy Center | Pittsburgh, California | Two GE 7FA turbines with SCR and Oxidation Catalyst | Startup (1 turbine) | (lb / event / turbine) | 240 | 2514 | 480 | 5028 | CEC staff Assessment, Ammendment Request #7. April 2004. No more than 1 turbine may startup at any time. | |
| | | | Cold startup or combustor tuning (1 turbine) | (lb / event / turbine) | 600 | 2514 | 1200 | 5028 | | |
| Mountain View Power Project | San Bernardino, California | Four GE 7FA turbines with SCR and Oxidation Catalyst | Startup (Per Turbine) | lb/hr (3-hour rolling average), 4-hour maximum duration | 160 | NA | | | CEC Order Approving a Petition to modify air quality conditions of certification. September 2004 | |

| Facility | Location | Equipment | Condition | (Units) Averaging Period | $NO_x$ | CO | | Estimated lb/event for two turbines (1) NOx | CO | Other limits and Comments | Reference |
|---|---|---|---|---|---|---|---|---|---|---|---|
| San Joaquin Valley Energy Center | San Joaquin, Fresno County, California | Three Siemens – Westinghouse 501FD turbines with SCR and Oxidation Catalyst | Startup (per turbine) 3 hour average | lb/hr | 80 | 902 | # | | | CEC Final Commission Decision, January 2004. Maximum durations are 3 hours for startup and 1 hour for shutdown. | |
| El Segundo Power Plant Project | El Segundo, Los Angeles County, California | Two GE 7FA turbines with SCR and Oxidation Catalyst | Startup (per turbine) | lb/hr | 80 | NA | | | | CEC Final Commission Decision, February 2005. NIOTE, this facility has not been built. | |
| Elk Hills Power | Kern County, California | Two GE 7FA turbines with SCR and Oxidation Catalyst | Startup (Two turbines) | lb/hr | 400 | 3600 | | 800 | 3600 | CEC Commission order approving project modification July 23,2003; Draft PSD Permit Dec. 2005 | |
| **FLORIDA** | | | | | | | | | | | |
| FP&L Turkey Point Fossil Plant | Miami-Dade County, FL | Four GE PG7241 FA with SCR | | | | | | | | No startup limits | PSD Permit |

| Facility | Location | Equipment | Condition | (Units) Averaging Period | $NO_x$ | CO | Estimated lb/event for two turbines (1) NOx | CO | Other limits and Comments | Reference |
|---|---|---|---|---|---|---|---|---|---|---|
| Treasure Coast Energy Center | St. Lucie County, FL | One GE PG7241FA with SCR | | | | | | | No startup limits | PSD Permit |
| Florida P&L West County Energy Center | Palm Beach County, FL | Four GE F class or three G class with SCR | | | | | | | No startup limits | PSD Permit |
| El Paso Broward Energy Center | Broward County, FL | One GE PG7241FA with SCR | | | | | | | No startup limits | PSD Permit |
| **MASSACHUSETTS** | | | | | | | | | | |
| IDC Bellingham | Bellingham, MA | Two GE 7FA with SCR | | | | | | | No startup limits | PSD Permit |
| Mystic Station | Everett, MA | Two MHI 501G with SCR and CO catalyst | | | | | | | No startup limits | PSD Permit |
| Fore River Station | Weymouth, MA | Two MHI 501G with SCR and CO catalyst | | | | | | | No startup limits | PSD Permit |

| Facility | Location | Equipment | Condition | (Units)<br>Averaging Period | $NO_x$ | CO | Estimated lb/event for two turbines (1)<br>NOx | <br>CO | Other limits and Comments | Reference |
|---|---|---|---|---|---|---|---|---|---|---|
| **Utah** | | | | | | | | | | |
| Lake Side Power Plant | Utah County, Utah | Two Siemens-Westinghouse 501F with SCR and CO catalyst | | | | | | | No startup limits. | PSD Permit, January 6, 2005. |
| **Arkansas** | | | | | | | | | | |
| Kgen Hot springs | Malvern, Arkansas | Four GE 7FA with HRSG and duct burners with SCR | | | | | | | No start-up emisions limits, limited to 4 hour start and use per-heater | Draft PSD permit 11/07/2005 |

(1) Estimated emissions for two turbines are being provided for comparisons purposes to the two turbines at Mesquite. The estimates ar+C48e not intended to imply actual permit limits. Only lb/event comparisons were provided as facilities with lb/hr restrictions may require different durations for start-up that are not known at this time.

Attachment 1 Letter from Sempra Global for Mesquite Power dated February 14, 2006

[illegible]
Permitting Manager
101 Ash Street, [illegible]
San Diego, CA [illegible]
Tel: [illegible]
Fax: [illegible]
[illegible]@SempraGlobal.com

February 14, 2006

Mr. Jack Dallal
Maricopa County Air Quality Department
1001 N. Central Avenue, Suite 150
Phoenix, AZ 85004-1942

**RE: Mesquite Power Title V Renewal and Significant Permit Revision Applications**

Dear Mr. Dallal:

This letter responds to your request dated February 2, 2006 for additional information and clarification in order to continue with the processing of Mesquite Power Title V Permit renewal and Significant Permit revision applications. Your requests are copied below with the response following.

Request 1:

The calculation of annual emission rates in Table 3-4 of the permit application includes 734 hours per year of startup, shutdown, testing, and tuning events and 3,235 hours per year of "time off-line". The time off-line represents a significant quantity of time during which there are estimated to be no emissions (37% of the time). The application states that the time off-line represents the "total estimated hours off-line associated with tuning and testing events and prior to each start." Please provide the backup data used to estimate this time off-line. This should include documentation of the time required to prepare the units for startup including physical and operational constraints. It is interesting to note that the documentation associated with permit revision #S03-003 does not account for time off-line (refer to Technical Support Document of June 8, 2004).

Response 1:

The information provided in Table 3-4 is an example operating scenario. The time-off line was calculated in a simplistic and conservative manner. The operating scenario assumes 12 extended starts and 208 regular starts. Based on the current permitted definition of start-up an extended start occurs when the power block has been offline for 72 hours or more. A regular start occurs when the power block has been offline for less than 72 hours. The time-offline in Table 3-4 can be approximately estimated by assuming downtime of 72 hours for 12 events and approximately 12 hours for 208 events. This results in an estimate of (12*72+208*12) 3360 hours of total off-line time or 38% off-line time. Table 3-4 assumed 3,235 hours off-line or 34% in order to account for a few starts that would occur with less than 12 hours downtime in between operation. The determination of the 12 hours off-line for most regular starts is based on the assumption that if a unit is taken offline in the evening it would be placed back on-line the following morning. It is acknowledged that Permit

Revision #S03-003 did not account for any downtime between starts which is an extremely conservative assumption and not physically possible.

As noted above, Table 3-4 is an example operating scenario. A variety of regular starts, extended starts, shutdowns, maintenance operations, time off-line and time in operation could be accomplished under the current permitted annual limits. Mesquite Power monitors emissions under all types of operations using a CEMs and fuel flowrate, providing Maricopa County with defensible emissions estimates on an annual basis to assure ongoing compliance with permitted annual limits.

Request 2:
Please provide a correlation between the current differentiation between regular and extended starts (Mode 6 basis) and the proposed differentiation (steam turbine reheat bowl temperature).

Response 2:
Attachment 1 contains data that shows the current differentiation between regular and extended starts and how the starts would be defined under the current steam turbine reheat bowl temperature.

Request 3:
Please provide actual startup and shutdown data from the continuous emission monitors. The information prepared by Marilyn Teague and submitted by e-mail to Kate Graf on December 30, 2005, should suffice (it needs to be submitted as part of the permit application).

Response 3:
Attachment 2 contains the actual start-up shutdown data from the continuous emission monitors and shows the requested start-up/shutdown emissions on a per event per turbine basis.

Per your request, these responses have been provided within 15 calendar days of receipt of your letter. Should you have any additional questions regarding the applications, please call me at 619-696-1824. We look forward to working with you on this revision.

Sincerely,

Joan A. Heredia
Permitting Manager

Cc: Project File
Marilyn Teague, Sempra Global
John Sowers, Mesquite Power

Enclosures

ATTACHMENT 1

| NOx / CO | Ext S/U | Reg S/U |
|---|---|---|
| Block 1 | 27 | 74 |
| Actual Extended S/U's | 12 | 2 |
| Actual Regular S/U's | 15 | 72 |
| | | |
| Block 2 | 27 | 52 |
| Actual Extended S/U's | 16 | 7 |
| Actual Regular S/U's | 11 | 45 |
| | | |
| Total | **54** | **126** |
| Actual Ext S/U | **28** | **9** |
| Actual Reg S/U | **26** | **117** |
| | | |
| Percent of more restrictive limits | **48.1%** | |
| Percent of less restrictive limits | **7.1%** | |

**NOx EXTENDED STARTS BASED ON TIME OFFLINE**

| Unit | Date | ST Reheat Bowl Temp 1 | Revised Start Type Based on Bowl Temp | | |
|---|---|---|---|---|---|
| BLOCK 1 | | MQ1S3_TT_RHBLI1 | | | |
| CT-1 | 5/19/2003 18:00 | 177.17 | Ext | | |
| CT-1 | 6/16/2003 3:00 | 1033.25 | Reg | | |
| CT-1 | 8/3/2003 11:00 | 289.90 | Ext | | |
| CT-1 | 9/4/2003 1:00 | 285.90 | Ext | | |
| CT-1 | 10/18/2003 17:00 | 109.00 | Ext | | |
| CT-1 | 5/24/2004 23:00 | 88.56 | Ext | | |
| CT-1 | 6/1/2004 0:00 | 1012.42 | Reg | | |
| CT-1 | 11/6/2004 4:00 | 654.93 | Reg | | |
| CT-1 | 12/7/2004 7:00 | 73.56 | Ext | | |
| CT-1 | 1/23/2005 14:00 | 1008.82 | Reg | | |
| CT-1 | 1/25/2005 23:00 | 994.38 | Reg | | |
| CT-1 | 5/4/2005 12:00 | 624.27 | Reg | | |
| CT-1 | 6/21/2005 2:00 | 1023.17 | Reg | | |
| CT-2 | 5/19/2003 19:00 | 176.15 | Ext | | |
| CT-2 | 6/9/2003 3:00 | 1031.63 | Reg | | |
| CT-2 | 8/4/2003 4:00 | 1028.78 | Reg | | |
| CT-2 | 9/4/2003 3:00 | 279.30 | Ext | | |
| CT-2 | 10/20/2003 12:00 | 1025.30 | Reg | | |
| CT-2 | 10/21/2003 3:00 | 1022.52 | Reg | | |
| CT-2 | 5/26/2004 4:00 | 1030.84 | Reg | | |
| CT-2 | 11/5/2004 12:00 | 279.70 | Ext | | |
| CT-2 | 11/6/2004 2:00 | 275.06 | Ext | | |
| CT-2 | 12/7/2004 15:00 | 832.22 | Reg | | |
| CT-2 | 1/23/2005 7:00 | 60.66 | Ext | | |
| CT-2 | 5/4/2005 12:00 | 624.27 | Reg | | |
| CT-2 | 5/23/2005 2:00 | 808.60 | Reg | | |
| CT-2 | 6/20/2005 6:00 | 128.79 | Ext | | |
| | | 27 | | 12 | Ext |
| | | | | 15 | Reg |
| BLOCK 2 | | | | | |
| CT-5 | 11/8/2003 10:00 | 65.87 | Ext | | |
| CT-5 | 11/17/2003 11:00 | 193.01 | Ext | | |
| CT-5 | 11/29/2003 12:00 | 1019.43 | Reg | | |
| CT-5 | 12/22/2003 9:00 | 258.89 | Ext | | |
| CT-5 | 1/1/2004 21:00 | 90.55 | Ext | | |
| CT-5 | 5/10/2004 2:00 | 251.71 | Ext | | |
| CT-5 | 12/7/2004 18:00 | 53.65 | Ext | | |
| CT-5 | 1/23/2005 8:00 | 61.58 | Ext | | |
| CT-5 | 5/8/2005 9:00 | 794.22 | Reg | | |
| CT-5 | 5/16/2005 5:00 | 616.38 | Reg | | |
| CT-5 | 5/23/2005 3:00 | 695.39 | Reg | | |
| CT-5 | 6/20/2005 9:00 | 123.97 | Ext | | |

| | | | | | |
|---|---|---|---|---|---|
| CT-6 | 11/8/2003 9:00 | 65.44 | Ext | | |
| CT-6 | 11/19/2003 11:00 | 142.64 | Ext | | |
| CT-6 | 11/24/2003 17:00 | 162.84 | Ext | | |
| CT-6 | 12/22/2003 2:00 | 285.86 | Ext | | |
| CT-6 | 1/1/2004 23:00 | 90.98 | Ext | | |
| CT-6 | 5/10/2004 0:00 | 257.22 | Ext | | |
| CT-6 | 12/7/2004 14:00 | 53.65 | Ext | | |
| CT-6 | 1/23/2005 14:00 | 969.66 | Reg | | |
| CT-6 | 1/25/2005 23:00 | 996.50 | Reg | | |
| CT-6 | 5/8/2005 6:00 | 351.78 | Ext | | |
| CT-6 | 5/23/2005 3:00 | 695.39 | Reg | | |
| CT-6 | 6/20/2005 16:00 | 1029.56 | Reg | | |
| CT-6 | 6/21/2005 3:00 | 1026.11 | Reg | | |
| CT-6 | 12/11/2005 9:00 | 1009.47 | Reg | | |
| CT-6 | 12/11/2005 15:00 | 1024.27 | Reg | | |
| | | 27 | | 16 | Ext |
| | | | | 11 | Reg |

**NOx REGULAR START BASED ON TIME OFFLINE**

| Unit | Date | ST Reheat Bowl Temp 1 | Revised Start Type based on Bowl Temp |
|---|---|---|---|
| BLOCK 1 | | MQ1S3_TT_RHBLH | |
| CT-1 | 5/13/2003 0:00 | 1009.75 | Reg |
| CT-1 | 5/23/2003 5:00 | 1013.59 | Reg |
| CT-1 | 5/27/2003 4:00 | 504.98 | Reg |
| CT-1 | 5/28/2003 5:00 | 1018.61 | Reg |
| CT-1 | 5/30/2003 16:00 | 665.43 | Reg |
| CT-1 | 6/4/2003 2:00 | 998.60 | Reg |
| CT-1 | 6/30/2003 2:00 | 526.45 | Reg |
| CT-1 | 8/10/2003 11:00 | 632.46 | Reg |
| CT-1 | 8/10/2003 17:00 | 593.33 | Reg |
| CT-1 | 8/11/2003 2:00 | 531.80 | Reg |
| CT-1 | 8/23/2003 20:00 | 1027.34 | Reg |
| CT-1 | 9/24/2003 17:00 | 1020.92 | Reg |
| CT-1 | 10/20/2003 2:00 | 136.82 | Ext |
| CT-1 | 10/22/2003 3:00 | 983.42 | Reg |
| CT-1 | 10/25/2003 5:00 | 1018.70 | Reg |
| CT-1 | 10/26/2003 23:00 | 1030.45 | Reg |
| CT-1 | 10/28/2003 17:00 | 1023.14 | Reg |
| CT-1 | 10/29/2003 9:00 | 1014.89 | Reg |
| CT-1 | 10/29/2003 20:00 | 1013.60 | Reg |
| CT-1 | 10/30/2003 23:00 | 1025.84 | Reg |
| CT-1 | 11/2/2003 20:00 | 1014.98 | Reg |
| CT-1 | 11/8/2003 3:00 | 1004.14 | Reg |
| CT-1 | 11/15/2003 7:00 | 1034.54 | Reg |
| CT-1 | 1/28/2004 4:00 | 1006.98 | Reg |
| CT-1 | 1/29/2004 1:00 | 1003.79 | Reg |
| CT-1 | 6/14/2004 5:00 | 1032.28 | Reg |
| CT-1 | 8/30/2004 3:00 | 1015.25 | Reg |
| CT-1 | 10/25/2004 4:00 | 1009.13 | Reg |
| CT-1 | 10/29/2004 18:00 | 680.09 | Reg |
| CT-1 | 10/30/2004 11:00 | 633.06 | Reg |
| CT-1 | 11/10/2004 1:00 | 949.42 | Reg |
| CT-1 | 3/10/2005 9:00 | 1009.50 | Reg |
| CT-1 | 3/10/2005 12:00 | 1015.20 | Reg |
| CT-1 | 3/12/2005 5:00 | 1023.32 | Reg |
| CT-1 | 4/17/2005 3:00 | 1033.06 | Reg |
| CT-1 | 5/22/2005 23:00 | 418.76 | Ext |
| CT-1 | 5/27/2005 4:00 | 1032.81 | Reg |
| CT-1 | 5/27/2005 10:00 | 978.85 | Reg |
| CT-1 | 5/29/2005 10:00 | 841.09 | Reg |
| CT-1 | 5/30/2005 8:00 | 603.52 | Reg |
| CT-1 | 7/18/2005 18:00 | 656.41 | Reg |
| CT-1 | 7/19/2005 3:00 | 578.12 | Reg |

| | | | | | |
|---|---|---|---|---|---|
| CT-1 | 7/20/2005 2:00 | 843.50 | Reg | | |
| CT-1 | 12/17/2005 16:00 | 1011.51 | Reg | | |
| CT-2 | 5/20/2003 10:00 | 1011.36 | Reg | | |
| CT-2 | 5/22/2003 5:00 | 1016.64 | Reg | | |
| CT-2 | 5/24/2003 5:00 | 1023.57 | Reg | | |
| CT-2 | 5/27/2003 5:00 | 499.45 | Reg | | |
| CT-2 | 5/30/2003 18:00 | 647.20 | Reg | | |
| CT-2 | 6/30/2003 4:00 | 513.38 | Reg | | |
| CT-2 | 7/28/2003 21:00 | 1016.37 | Reg | | |
| CT-2 | 7/30/2003 18:00 | 745.69 | Reg | | |
| CT-2 | 8/11/2003 5:00 | 960.67 | Reg | | |
| CT-2 | 8/13/2003 3:00 | 1024.84 | Reg | | |
| CT-2 | 8/25/2003 4:00 | 1021.19 | Reg | | |
| CT-2 | 9/24/2003 18:00 | 1008.14 | Reg | | |
| CT-2 | 10/22/2003 5:00 | 952.03 | Reg | | |
| CT-2 | 11/11/2003 11:00 | 1014.50 | Reg | | |
| CT-2 | 12/14/2003 19:00 | 1025.84 | Reg | | |
| CT-2 | 1/12/2004 4:00 | 1021.44 | Reg | | |
| CT-2 | 1/19/2004 1:00 | 998.57 | Reg | | |
| CT-2 | 3/2/2004 23:00 | 1014.18 | Reg | | |
| CT-2 | 3/4/2004 17:00 | 1017.54 | Reg | | |
| CT-2 | 5/30/2004 15:00 | 484.02 | Reg | | |
| CT-2 | 5/31/2004 0:00 | 429.93 | Reg | | |
| CT-2 | 7/6/2004 13:00 | 1030.34 | Reg | | |
| CT-2 | 7/21/2004 11:00 | 1033.27 | Reg | | |
| CT-2 | 11/9/2004 23:00 | 991.33 | Reg | | |
| CT-2 | 3/23/2005 1:00 | 1029.60 | Reg | | |
| CT-2 | 5/27/2005 12:00 | 929.08 | Reg | | |
| CT-2 | 5/28/2005 5:00 | 1015.69 | Reg | | |
| CT-2 | 5/31/2005 3:00 | 1022.72 | Reg | | |
| CT-2 | 7/18/2005 20:00 | 638.26 | Reg | | |
| CT-2 | 7/20/2005 0:00 | 430.73 | Reg | | |
| | | 72 | | 2 | Ext |
| | | | | 70 | Reg |
| BLOCK 2 | | | | | |
| CT-5 | 11/9/2003 9:00 | 238.17 | Ext | | |
| CT-5 | 11/10/2003 8:00 | 833.88 | Reg | | |
| CT-5 | 11/10/2003 15:00 | 1016.37 | Reg | | |
| CT-5 | 11/10/2003 22:00 | 982.77 | Reg | | |
| CT-5 | 11/11/2003 14:00 | 1022.63 | Reg | | |
| CT-5 | 11/12/2003 13:00 | 687.77 | Reg | | |
| CT-5 | 11/17/2003 18:00 | 183.56 | Ext | | |
| CT-5 | 11/19/2003 9:00 | 144.26 | Ext | | |
| CT-5 | 11/22/2003 7:00 | 241.46 | Ext | | |
| CT-5 | 11/24/2003 8:00 | 164.51 | Ext | | |
| CT-5 | 11/25/2003 10:00 | 712.14 | Reg | | |
| CT-5 | 1/2/2004 4:00 | 188.91 | Ext | | |
| CT-5 | 1/3/2004 13:00 | 1024.51 | Reg | | |
| CT-5 | 3/11/2004 13:00 | 1022.45 | Reg | | |
| CT-5 | 3/17/2004 2:00 | 1017.65 | Reg | | |
| CT-5 | 4/9/2004 18:00 | 992.71 | Reg | | |

| | | | | | |
|---|---|---|---|---|---|
| CT-5 | 4/20/2004 3:00 | 1031.99 | Reg | | |
| CT-5 | 5/23/2004 11:00 | 447.43 | Reg | | |
| CT-5 | 6/7/2004 3:00 | 589.36 | Reg | | |
| CT-5 | 6/7/2004 17:00 | 1027.33 | Reg | | |
| CT-5 | 6/9/2004 5:00 | 647.20 | Reg | | |
| CT-5 | 6/14/2004 5:00 | 1032.77 | Reg | | |
| CT-5 | 7/2/2004 8:00 | 1004.14 | Reg | | |
| CT-5 | 11/1/2004 14:00 | 940.04 | Reg | | |
| CT-5 | 3/14/2005 5:00 | 1019.03 | Reg | | |
| CT-5 | 7/28/2005 6:00 | 1037.96 | Reg | | |
| CT-5 | 12/22/2005 21:00 | 1015.84 | Reg | | |
| CT-5 | 12/24/2005 23:00 | 1004.04 | Reg | | |
| CT-6 | 11/9/2003 7:00 | 246.86 | Ext | | |
| CT-6 | 11/10/2003 7:00 | 852.79 | Reg | | |
| CT-6 | 11/26/2003 9:00 | 910.81 | Reg | | |
| CT-6 | 12/14/2003 19:00 | 1035.75 | Reg | | |
| CT-6 | 1/2/2004 13:00 | 485.40 | Reg | | |
| CT-6 | 5/23/2004 13:00 | 483.14 | Reg | | |
| CT-6 | 6/7/2004 4:00 | 581.90 | Reg | | |
| CT-6 | 6/9/2004 7:00 | 629.61 | Reg | | |
| CT-6 | 6/23/2004 2:00 | 1000.67 | Reg | | |
| CT-6 | 7/1/2004 9:00 | 877.85 | Reg | | |
| CT-6 | 7/1/2004 10:00 | 861.54 | Reg | | |
| CT-6 | 10/25/2004 5:00 | 1009.82 | Reg | | |
| CT-6 | 11/1/2004 15:00 | 933.10 | Reg | | |
| CT-6 | 3/17/2005 2:00 | 1031.71 | Reg | | |
| CT-6 | 4/17/2005 3:00 | 1033.73 | Reg | | |
| CT-6 | 5/2/2005 3:00 | 1019.01 | Reg | | |
| CT-6 | 5/16/2005 3:00 | 634.31 | Reg | | |
| CT-6 | 5/27/2005 4:00 | 1033.13 | Reg | | |
| CT-6 | 5/28/2005 5:00 | 1033.22 | Reg | | |
| CT-6 | 5/29/2005 11:00 | 1025.83 | Reg | | |
| CT-6 | 5/30/2005 22:00 | 1034.69 | Reg | | |
| CT-6 | 7/27/2005 13:00 | 1037.96 | Reg | | |
| CT-6 | 7/27/2005 17:00 | 1037.96 | Reg | | |
| CT-6 | 7/28/2005 3:00 | 1037.96 | Reg | | |
| | | 52 | | 7 | Ext |
| | | | | 45 | Reg |

ATTACHMENT 2

**NOx** **EXTENDED START**

| Unit | Date | Lbs/Event | Exceed Proposed Limit | Exceed Proposed Limit |
|---|---|---|---|---|
| CT-1 | 5/24/2004 23:00 | 903.8 | YES | YES |
| CT-6 | 11/8/2003 5:00 | 871.2 | | YES |
| CT-5 | 1/23/2005 8:00 | 660.7 | | |
| CT-1 | 12/7/2004 7:00 | 650.0 | | |
| CT-5 | 11/8/2003 10:00 | 583.0 | | |
| CT-2 | 5/19/2003 19:00 | 570.9 | | |
| CT-6 | 11/24/2003 17:00 | 507.0 | | |
| CT-1 | 5/4/2005 12:00 | 492.6 | | |
| CT-2 | 10/21/2003 3:00 | 393.7 | | |
| CT-6 | 5/10/2004 0:00 | 395.5 | | |
| CT-1 | [illegible] | 350.4 | | |
| CT-6 | 12/7/2004 14:00 | 357.9 | | |
| CT-6 | 1/1/2004 23:00 | 311.4 | | |
| CT-2 | 11/5/2004 12:00 | 310.9 | | |
| CT-5 | 5/10/2004 2:00 | 308.4 | | |
| CT-5 | 12/22/2003 9:00 | 308.3 | | |
| CT-5 | 6/20/2005 9:00 | 301.8 | | |
| CT-6 | 5/8/2005 6:00 | 295.4 | | |
| CT-5 | 5/23/2005 3:00 | 290.0 | | |
| CT-2 | 11/6/2004 2:00 | 287.4 | | |
| CT-2 | 9/4/2003 3:00 | 273.5 | | |
| CT-2 | 6/20/2005 6:00 | 233.5 | | |
| CT-1 | 8/3/2003 11:00 | 220.3 | | |
| CT-6 | 12/22/2003 2:00 | 217.2 | | |
| CT-5 | 11/29/2003 12:00 | 214.6 | | |
| CT-5 | 5/16/2005 5:00 | 213.7 | | |
| CT-2 | 1/23/2005 7:00 | 212.0 | | |

| # Events | Average Top 10 | % Margin | Average Plus % Margin | Proposed Limit | Proposed Lb/Event/ Block | Current Lb/Event/ Block |
|---|---|---|---|---|---|---|
| 55 | 581.0 | 25 | 726.3 | 730 | 920 | 920 |
| Average 262.2 | Average 2nd - 11th 526.4 | 25 | 658.0 | 660 | | |
| Average Top 20 447.1 | | | | | | |

**NOx** **REGULAR START**

| Unit | Date | Lbs/Event | Exceed Proposed Limit | Exceed Proposed Limit | # Events | Average Top 10 | % Margin | Average Plus % Margin | Proposed Limit | Proposed Lb/Event/ Block | Current Lb/Event/ Block |
|---|---|---|---|---|---|---|---|---|---|---|---|
| CT-1 | 10/20/2003 2:00 | 717.8 | YES | YES | 126 | 418.2 | 30 | 543.7 | 545 | 565 | 382 |
| CT-6 | 11/6/2003 7:00 | 512.6 | | YES | | | | | | | |
| CT-6 | 11/26/2003 10:00 | 488.4 | | | | | | | | | |
| CT-5 | 11/19/2003 9:00 | 450.2 | | | | | | | | | |
| CT-1 | 8/30/2003 18:00 | 413.1 | | | | | | | | | |
| CT-5 | 11/12/2003 13:00 | 363.2 | | | | | | | | | |
| CT-2 | 8/31/2004 0:00 | 349.6 | | | | | | | | | |
| CT-5 | 6/7/2004 3:00 | 301.2 | | | | | | | | | |
| CT-5 | 6/9/2004 5:00 | 295.7 | | | | | | | | | |
| CT-2 | 5/27/2003 5:00 | 291.0 | | | | | | | | | |
| CT-2 | 5/30/2004 15:00 | 290.1 | | | | | | | | | |
| CT-1 | 5/22/2005 23:00 | 271.0 | | | | | | | | | |
| CT-5 | 11/24/2003 8:00 | 269.4 | | | | | | | | | |
| CT-5 | 11/9/2003 9:00 | 267.3 | | | | | | | | | |
| CT-5 | 11/10/2003 8:00 | 267.3 | | | | | | | | | |
| CT-5 | 11/22/2003 7:00 | 257.5 | | | | | | | | | |
| CT-2 | 5/22/2003 5:00 | 252.3 | | | | | | | | | |
| CT-5 | 5/23/2004 11:00 | 244.1 | | | | | | | | | |
| CT-6 | 11/26/2003 9:00 | 242.4 | | | | | | | | | |
| CT-6 | 5/23/2004 13:00 | 241.4 | | | | | | | | | |
| CT-1 | 10/29/2003 17:00 | 232.9 | | | | | | | | | |
| CT-6 | 1/2/2004 13:00 | 232.1 | | | | | | | | | |
| CT-6 | 6/7/2004 4:00 | 227.2 | | | | | | | | | |
| CT-2 | 7/18/2005 20:00 | 218.3 | | | | | | | | | |
| CT-2 | 8/13/2003 3:00 | 208.7 | | | | | | | | | |
| CT-1 | 6/30/2003 2:00 | 206.2 | | | | | | | | | |
| CT-6 | 7/27/2005 13:00 | 198.4 | | | | | | | | | |

| Average | Average 2nd - 11th | % Margin | Average Plus % Margin | Proposed Limit |
|---|---|---|---|---|
| 151.8 | 374.5 | 30 | 486.9 | 490 |

| Average Top 20 |
|---|
| 338.7 |

**NOx** **SHUTDOWN**

| Unit | Date | Lbs/Event | Exceed Proposed Limit | Exceed Proposed Limit |
|---|---|---|---|---|
| CT-2 | 10/25/2003 6:00 | 342.2 | YES | YES |
| CT-2 | 10/21/2003 23:00 | 322.6 | YES | YES |
| CT-1 | 10/21/2003 23:00 | 308.5 | | YES |
| CT-5 | 11/9/2003 12:00 | 273.2 | | |
| CT-1 | 6/9/2003 10:00 | 244.9 | | |
| CT-2 | 6/9/2003 10:00 | 227.1 | | |
| CT-5 | 11/6/2003 19:00 | 215.6 | | |
| CT-1 | 10/25/2003 7:00 | 186.1 | | |
| CT-5 | 5/21/2004 0:00 | 179.7 | | |
| CT-2 | 6/6/2003 0:00 | 173.0 | | |
| CT-6 | 5/21/2004 0:00 | 161.5 | | |
| CT-5 | 9/7/2004 9:00 | 147.8 | | |
| CT-2 | 5/2/2004 23:00 | 131.4 | | |
| CT-1 | 9/10/2004 13:00 | 128.1 | | |
| CT-5 | 11/11/2003 10:00 | 114.4 | | |
| CT-5 | 11/13/2003 15:00 | 113.9 | | |
| CT-1 | 6/18/2003 22:00 | 86.4 | | |
| CT-2 | 6/18/2003 22:00 | 85.8 | | |
| CT-2 | 6/17/2003 22:00 | 83.2 | | |
| CT-5 | 11/2/2004 1:00 | 74.8 | | |
| CT-1 | 8/24/2003 0:00 | 72.5 | | |
| CT-1 | 6/9/2003 22:00 | 71.6 | | |
| CT-1 | 6/16/2003 22:00 | 71.6 | | |
| CT-2 | 6/9/2003 22:00 | 71.3 | | |
| CT-1 | 6/10/2003 22:00 | 71.0 | | |
| CT-1 | 12/1/2003 13:00 | 70.9 | | |
| CT-2 | 6/10/2003 22:00 | 70.8 | | |

| # Events | Average Top 10 | % Margin | Average Plus % Margin | Proposed Limit | Proposed Lb/Event/ Block | Current Lb/Event/ Block |
|---|---|---|---|---|---|---|
| 174 | 247.3 | 25 | 309.1 | 310 | 275 | 138 |
| Average 41.8 | Average 2nd - 11th 229.2 | 25 | 286.5 | 290 | | |
| Average Top 20 180.0 | | | | | | |

**CO** **EXTENDED START**

| Unit | Date | Lbs/Event | Exceed Proposed Limit | Exceed Proposed Limit |
|---|---|---|---|---|
| CT-1 | 12/7/2004 7:00 | 326.3 | | |
| CT-6 | 12/7/2004 14:00 | 312.0 | | |
| CT-5 | 12/7/2004 18:00 | 311.2 | | |
| CT-5 | 1/23/2005 8:00 | 309.6 | | |
| CT-6 | 1/1/2004 23:00 | 300.6 | | |
| CT-5 | 12/22/2003 9:00 | 283.7 | | |
| CT-2 | 1/23/2005 7:00 | 256.8 | | |
| CT-1 | 5/4/2005 6:00 | 249.9 | | |
| CT-6 | 1/25/2005 23:00 | 243.4 | | |
| CT-2 | 5/23/2005 2:00 | 242.6 | | |
| CT-1 | [illegible] | [illegible] | | |
| CT-6 | 5/10/2004 0:00 | 237.1 | | |
| CT-6 | 5/8/2005 6:00 | 227.7 | | |
| CT-1 | 1/25/2005 23:00 | 226.9 | | |
| CT-5 | 5/23/2005 3:00 | 223.8 | | |
| CT-6 | 11/24/2003 17:00 | 217.7 | | |
| CT-1 | 11/6/2004 4:00 | 213.3 | | |
| CT-6 | 12/22/2003 2:00 | 211.8 | | |
| CT-6 | 12/11/2005 9:00 | 209.3 | | |
| CT-6 | 11/8/2003 9:00 | 209.2 | | |
| CT-2 | 9/4/2003 3:00 | 206.9 | | |
| CT-2 | 6/20/2005 6:00 | 203.8 | | |
| CT-5 | 11/8/2003 10:00 | 192.9 | | |
| CT-1 | 5/19/2003 18:00 | 190.2 | | |
| CT-5 | 1/1/2004 21:00 | 182.1 | | |
| CT-6 | 6/21/2005 3:00 | 181.4 | | |
| CT-2 | 5/4/2005 12:00 | 176.4 | | |

| # Events | Average Top 10 | % Margin | Average Plus % Margin | Proposed Limit | Proposed Lb/Event/ Block | Current Lb/Event/ Block |
|---|---|---|---|---|---|---|
| 55 | 283.6 | 25 | 354.5 | 355 | 500 | 260 |
| Average 171.1 | Average 2nd - 11th 274.9 | 25 | 343.7 | 345 | | |
| Average Top 20 252.6 | | | | | | |

**CO** **REGULAR START**

| Unit | Date | Lbs/Event | Exceed Proposed Limit | Exceed Proposed Limit |
|---|---|---|---|---|
| CT-6 | 11/26/2003 9:00 | 192.0 | | |
| CT-6 | 5/23/2004 13:00 | 175.1 | | |
| CT-5 | 11/25/2003 10:00 | 173.8 | | |
| CT-1 | 8/10/2003 11:00 | 163.2 | | |
| CT-2 | 7/18/2005 20:00 | 161.2 | | |
| CT-5 | 8/7/2004 3:00 | 159.4 | | |
| CT-6 | 6/23/2004 2:00 | 157.9 | | |
| CT-6 | 3/17/2005 2:00 | 155.3 | | |
| CT-5 | 5/9/2004 5:00 | 152.9 | | |
| CT-1 | 5/22/2005 23:00 | 149.8 | | |
| CT-1 | 10/20/2003 2:00 | 147.5 | | |
| CT-5 | 1/3/2004 13:00 | 139.4 | | |
| CT-6 | 11/9/2003 7:00 | 135.8 | | |
| CT-5 | 11/19/2003 9:00 | 133.0 | | |
| CT-1 | 11/2/2003 20:00 | 132.5 | | |
| CT-6 | 5/7/2004 4:00 | 132.5 | | |
| CT-1 | 6/30/2003 2:00 | 129.1 | | |
| CT-5 | 11/24/2003 8:00 | 124.1 | | |
| CT-1 | 5/30/2003 16:00 | 116.6 | | |
| CT-1 | 6/14/2004 5:00 | 115.5 | | |
| CT-2 | 5/31/2005 3:00 | 107.8 | | |
| CT-5 | 5/23/2004 11:00 | 107.3 | | |
| CT-5 | 7/28/2005 6:00 | 107.1 | | |
| CT-2 | 5/27/2003 5:00 | 106.7 | | |
| CT-5 | 6/14/2004 5:00 | 102.8 | | |
| CT-6 | 10/25/2004 5:00 | 101.0 | | |
| CT-5 | 11/22/2003 7:00 | 96.3 | | |

| # Events | Average Top 10 | % Margin | Average Plus % Margin | Proposed Limit | Proposed Lb/Event/ Block | Current Lb/Event/ Block |
|---|---|---|---|---|---|---|
| 123 | 164.0 | 30 | 213.2 | 215 | 320 | 108 |
| Average 60.7 | Average 2nd - 11th 159.5 | 30 | 207.4 | 210 | | |
| Average Top 20 147.3 | | | | | | |

**CO** **SHUTDOWN**

| Unit | Date | Lbs/Event | Exceed Proposed Limit | Exceed Proposed Limit | # Events | Average Top 10 | % Margin | Average Plus % Margin | Proposed Limit | Proposed Lb/Event/ Block | Current Lb/Event/ Block |
|---|---|---|---|---|---|---|---|---|---|---|---|
| CT-6 | 5/21/2004 0:00 | 157.9 | YES | YES | 152 | 76.0 | 25 | 95.0 | 95 | 105 | 45 |
| CT-6 | 5/21/2004 0:00 | 113.5 | YES | YES | | | | | | | |
| CT-2 | 10/25/2003 6:00 | 85.6 | | YES | | Average 2nd - 11th | | | | | |
| CT-5 | 11/9/2003 19:00 | 84.5 | | YES | Average | | | | | | |
| CT-5 | 6/7/2004 9:00 | 59.6 | | | 10.5 | 64.3 | 25 | 80.4 | 80 | | |
| CT-1 | 10/25/2003 7:00 | 56.1 | | | | | | | | | |
| CT-1 | 8/24/2003 0:00 | 55.2 | | | Average | | | | | | |
| CT-1 | 10/21/2003 23:00 | 52.6 | | | Top 20 | | | | | | |
| CT-2 | 10/21/2003 23:00 | 50.8 | | | 49.3 | | | | | | |
| CT-2 | 8/4/2003 0:00 | 42.3 | | | | | | | | | |
| CT-2 | 1/2/2004 23:00 | 40.6 | | | | | | | | | |
| CT-6 | 11/6/2003 12:00 | 34.4 | | | | | | | | | |
| CT-5 | 11/11/2003 10:00 | 30.6 | | | | | | | | | |
| CT-5 | 11/13/2003 15:00 | 30.3 | | | | | | | | | |
| CT-5 | 1/2/2004 1:00 | 20.0 | | | | | | | | | |
| CT-5 | 12/18/2003 0:00 | 18.2 | | | | | | | | | |
| CT-5 | 11/13/2003 20:00 | 15.5 | | | | | | | | | |
| CT-2 | 5/13/2003 1:00 | 13.6 | | | | | | | | | |
| CT-2 | 9/11/2005 23:00 | 12.2 | | | | | | | | | |
| CT-1 | 5/13/2003 2:00 | 10.5 | | | | | | | | | |
| CT-2 | 6/18/2003 22:00 | 10.4 | | | | | | | | | |
| CT-2 | 6/17/2003 22:00 | 10.3 | | | | | | | | | |
| CT-2 | 10/3/2003 23:00 | 10.2 | | | | | | | | | |
| CT-1 | 5/28/2003 23:00 | 9.9 | | | | | | | | | |
| CT-6 | 12/7/2005 10:00 | 9.4 | | | | | | | | | |
| CT-6 | 3/14/2005 22:00 | 9.1 | | | | | | | | | |
| CT-1 | 6/9/2003 10:00 | 8.8 | | | | | | | | | |