COUNTY NOTICES PURSUANT TO A.R.S. § 49-112(A) or (B)

NOTICE OF PROPOSED RULEMAKING

Maricopa County Air Pollution Control Regulations
Rule 311 – Particulate Matter From Process Industries
Rule 320 – Odors and Gaseous Contaminants
Rule 322 – Power Plant Operations
Rule 323 – Fuel Burning Equipment From Industrial/Commercial/Institutional Sources

PREAMBLE

1. Rules Affected	**Rulemaking Action**
Rule 311	Amend
Rule 320	Amend
Rule 322	New Rule
Rule 323	New Rule

2. The specific authority for the rulemaking, including both the authorizing statute (general) and the statutes the rules are implementing (specific):

Authorizing statutes: A.R.S. §§ 49-112(A) and 49-479

Implementing statute: A.R.S. § 49-479

3. A list of all previous notices appearing in the Register addressing the proposed rule:

Notice of Rulemaking Docket Opening: 8 A.A.R. 4108, September 27, 2002

4. The name and address of agency personnel with whom persons may communicate regarding the rulemaking:

Name: Patricia P. Nelson or Jo Crumbaker, Air Quality Division

Address: 1001 N. Central Avenue, Suite # 695
Phoenix, AZ 85004

Telephone: (602) 506-6709 or 506-6705

Fax: (602) 506-6179

E-mail: pnelson@mail.maricopa.gov or jcrumbak@mail.maricopa.gov

5. An explanation of the rule, including the agency's reasons for initiating the rule:

Historically in the Maricopa County Rules and Regulations, there has not been a source specific rule to address fuel burning equipment from power plant operations and industrial, commercial or institutional (ICI) sources. Existing Rule 320, Odors and Gaseous Contaminants, contains a clause that addresses nitrogen oxide (NOx) and sulfur oxide (SOx) standards from only one type of power plants – steam plants. EPA had a State Implementation Plan (SIP) approvability issue with the SOx provisions in the former version of Rule 320 because the ambient air SOx limits were eliminated from the rule in the mid 1970s. Also the carbon monoxide (CO) standard in Rule 320 was limited to a general statement which said that CO shall be controlled by means of secondary combustion. EPA has also informed Maricopa County that existing Rule 311 is not Best Available Control Technology (BACT) for particulate matter with a nominal aerodynamic diameter smaller than or equal to 10 microns (PM 10) for major sources of fuel burning equipment.

Maricopa County is now proposing to correct these deficiencies in both existing Rules 311 and 320 by adopting two new rules which combine the different emission limitations from two different sources of fuel burning equipment from power plant operations (Rule 322) and Industrial Commercial/Institutional (ICI) Sources (Rule 323). Maricopa County will also protect the National Ambient Air Quality Standards (NAAQS) for carbon monoxide, ozone and particulate matter by adopting this rule package as well as protect the NAAQS for SOx by reducing the sulfur content in the fuels. By adopting Rules 322 and 323 Maricopa County will implement Best Available Control Technology (BACT).

The stakeholder process for Rule 322 involved the issuance of seven draft revisions and workshops to resolve issues with the utility companies and the public. The stakeholder process for Rule 323 involved five draft revisions and workshops to resolve issues from the various sources affected by docket was opened on September 5, 2002. The notice of proposed rulemaking is being issued on November 5, 2002.

Section-by-Section Explanation for the Amended or Proposed Rules

Rule 311

Subsection 102 – This proposed change amends the applicability clause for clarification.

Subsection 303 – This proposed change amends the Portland cement plant provisions to reflect New Source Performance Standards (NSPS)

Subsection 304 – This proposed change repeals the particulate standard that uses a formula based upon heat rating for fuel burning equipment.

Subsection 307 – This proposed change repeals the exemption for Portland cement plants with process weights in excess of 250,000lb/hr.

Subsection 503 - This proposed change amends the records retention time to reflect the current Maricopa County standard retention time of five years instead of three years.

Subsection 504 – This proposed change amends language used to reflect the current language that Maricopa County now uses in its rules to adopt test methods by reference.

Rule 320

Subsection 201 – This proposed change repeals the definition of fossil fuel fired steam generator because the term is not included in the text of proposed Rule 320.

Subsections 202 and 203 – This proposed change amends the definition of high and low sulfur oil by redefining the qualifier of 0.9% sulfur in the current rule to reflect a lower percentage of 0.05% in the proposed rule.

Subsection 305 – This proposed change amends the limit on SOx and sulfuric acid mist from sulfuric acid plants because there are no longer any sulfuric acid plants in Maricopa County.

Subsection 306.1-306.3 – This proposed change repeals the limitations on SOx from electrical power plants because these limitations will be addressed in proposed Rule 322.

Subsection 306.4 – This proposed change amends the word “Bureau” and replaces it with “Control Officer” since the Maricopa County Air Quality Agency is no longer called a Bureau.

Section 307 – This proposed change strikes the word “other” from the text.

Section 308 – This proposed change repeals the limitations on NOx from electrical power plants because they will be addressed in the new Rule 322.

Section 310 – This proposed change repeals the limitations on CO because they will be addressed in new Rules 322 and 323.

Section 311 – This proposed change repeals the exemptions on sulfuric acid plants because the section addressing sulfuric acid plants in subsection 305 is proposed to be repealed from the rule.

Rule 322

Maricopa County proposes to regulate existing combustion equipment at power plants for which construction commenced prior to May 1996 with proposed new Rule 322. The rule applies to electric utility steam generating units and co-generation units that have a heat input of equal to or greater than 100 MM Btu/hour and stationary turbines with a heat input at peak load of equal to or greater than 10 MM Btu/hour. Another condition of applicability is that these units must also supply more than 1/3 of their potential electric output capacity to a power distribution system for sale.

One commenter expressed concern that this rule would be more burdensome to older plants than to newer sources. Newer sources constructed after this date will have applied for or received Title V permits with even stricter operating conditions reflecting BACT or Lowest Achievable Emission Rate (LAER) than this proposed rule. The proposed rule sets limitations for NOx and CO in Section 300 by replacing the standards that will be repealed in current Rule 320. It uses the same year, 1972, that triggers applicability for compliance with the NOx standard in Rule 320. These combustion units are thus grandfathered under proposed Rule 322.

There are partial exemptions from meeting NOx and CO standards in Rule 322 for stationary gas turbines. These include turbines used for firefighting or flood control, used in the military at training facilities and engaged by manufacturers in research and development for testing purposes. There are also identical partial exemptions for combustion equipment fired with an emergency fuel that is normally fired with gas and for 36 hours per year per unit when burning emergency fuel for testing, reliability and maintenance purposes. In the initial draft, these partial exemptions were limited to only cogeneration steam units. At the request of a stakeholder, these exemptions have been extended to cover all combustion units.

The existing six power plants in Maricopa County affected by this proposed rule produced a total of 435 tons of PM10 and 63 tons of SOx according to the Maricopa County 2001 inventory. Proposed Rule 322 sets BACT for PM by mandating the use of natural gas as the fuel or a fuel that meets a particulate matter standard of 0.007 lbs/ MM Btu except when burning emergency fuel. Particulate emissions depend upon the grade and sulfur content of the fuel. Heavier oils with higher ash and sulfur levels produce higher particulate matter emissions. Lighter oils have lower viscosities, which allow better atomization and the result is more complete combustion and less unburned fuel emitted as particulate. Proposed Rule 322 requires the use of low sulfur fuel (< 0.05% by weight of sulfur). The empirical correlation between particulate matter and oil sulfur content suggests a quantitative basis for curbing particulate emissions through fuel switching. Reducing the sulfur in fuel to a maximum sulfur content of 0.05% aids in the reduction of both PM and SOx. By adopting Rule 322, which mandates the use of fuels that meet a particulate standard of 0.007 lbs/ MM Btu, the County thereby limits the type of fuels that can be used to either natural gas or a fuel equivalent to natural gas in emission rate. This measure thus ensures not only a low particulate emission rate but also ensures a low SOx rate.

One commenter requested an extension in time to be able to use existing supplies of fuel oil with a sulfur content of >0.05% by weight. Maricopa County agreed to allow the use of this fuel for emergency purposes up until 1.5 years after adoption of the rule.

The proposed rule requires testing the temperature differential across the back of the burners in turbines to ensure good combustion practices. These provisions reflect the resolution of stakeholder concerns as to using the range of manufacturer specifications and the consequences of operating outside the temperatures specified in the rule. If the manufacturer recommends that the maximum temperature required to ensure good combustion is a different temperature, then proof of this alternative temperature differential may be submitted to the Control Officer.

The proposed rule also addresses PM emissions from cooling towers by establishing a maximum numerical limit of 20, obtained by multiplying the total dissolved solids (TDS) of water used in the cooling tower by the percentage of drift rate from cooling towers associated with this type of equipment. This proposed formula was developed by a stakeholder and evaluated by Maricopa County. This approach using both parameters in a formula to estimate PM emissions offers operational flexibility.

Opacity is limited to 20% except for fuel switching. Fuel switching is limited to 40% for any six (6) minute averaging period not to exceed one hour. Fuel switching will now only be allowed under emergency conditions. Fuel switching under emergency conditions often causes more combustion irregularities than planned fuel switching. A justification for this exemption, prepared by the power plants, has been submitted to EPA per the EPA memorandum of August 1999 *entitled State Implementation Plans (SIPS): Policy Regarding Excess Emissions During Malfunctions, Startup and Shutdown* submitted by Steven Herman and Robert Perciasepe.

Finally, in both this proposed rule and proposed Rule 323, commenters requested that both the 1990 and the 1998 versions of the ASTM test method, "Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluoresence Spectrometry" be included. These sources are already subject to the Acid Rain regulations in 40 CFR Part 75 that reference the 1990 version. Maricopa County agreed to this and is proposing to list both versions of the test method.

Rule 323

New Rule 323 proposes to address fuel burning equipment at ICI sources which includes boilers, cogeneration units, and indirect-fired process heaters with a heat input of greater than 10 MM Btu/hour. The rule also addresses stationary gas turbines with a heat input at peak load greater than 2.9 megawatts. Proposed standards include use of low sulfur oil (max 0.05% sulfur by weight), limits on CO and NOx and a requirement to tune the equipment every six months if the heat input is greater than 100 MM Btu/hr along with recordkeeping provisions.

Proposed Rule 323 requires the use of low sulfur fuel (< 0.05% by weight of sulfur). The empirical correlation between particulate matter and oil sulfur content suggests a quantitative basis for curbing particulate emissions through fuel switching. Reducing the sulfur in fuel to a maximum sulfur content of 0.05% aids in the reduction of both PM and SOx.

Proposed exemptions include direct-fired process heaters, reciprocating internal combustion equipment, combustion equipment associated with nuclear power plant operations, and combustion equipment which supplies greater than one-third of the electricity they generate to any utility power distribution system for sale. Partial exemptions for turbines include turbines used in fire fighting and flood control and military training facilities. Also exempted are steam generators that are fired with an emergency fuel that are normally fired with natural gas. Additionally there are exemptions for reliability and maintenance testing purposes up to 36 hrs. per unit per year.

One stakeholder questioned the logic for this rule and whether the proposed limits are reasonable. Maricopa County has proposed Rule 323 to apply to the combustion equipment that will no longer be regulated by Rules 320 and 311 because these sections are being repealed. As requested by the stakeholders, Maricopa County has proposed either option of meeting the NOx numerical standards in the rule or following a tune-up procedure in subsection 304.1 for combustion equipment with a heat input of greater than 10MM Btu/hr to 100 MM Btu/hr. The initial draft had proposed a tuning procedure that was considered onerous and expensive by stakeholders and internal engineering staff. The County located a simpler tuning procedure, now proposed in subsection 304.1, that was fully approved by EPA for New Jersey State, N.J.A.C. 7:27.19 (New Jersey Administrative Code). As a rule, a minimum of annual boiler tune-ups would minimize unburned carbon emissions from boilers. Tuning boilers to operate at low excess oxygen levels is a common method of limiting NOx emissions and increasing boiler efficiency. Care in the tuning process will ensure than an appropriate excess oxygen level is chosen to minimize particulate emissions and opacity without sacrificing low NOx emissions.

Emissions from oil-fired process heaters depend upon the grade and sulfur content of the oil fired if the process heater is fired with oil. Over 90 percent of process heaters in the U.S. burn natural gas or refinery gas according to a State And Territorial Air Pollution Administrators/Association Of Local And Air Pollution Control Officials (STAPPA/ALAPCO) document entitled *Controlling Particulate Matter Under the Clean Air Act: A Menu of Option* from July 1996. Therefore there are minimal costs to owners/operators using process heaters due to using natural gas.

Another commenter raised the question of whether their Combustion Management System (CMS) was considered an Emission Control System (ECS) and therefore subject to an Operations and Maintenance (O&M) Plan. The County concurred that a CMS is basically a process logic controller, not an ECS and is therefore not subject to an O&M Plan.

6. The time during which the County will accept written comments and the time and the place where oral comments may be made:

Formal written comments may be submitted from the time of the oral proceeding, December 12, 2002 until January 10, 2002 (30 days after the oral proceeding). Formal oral comments may be made at the oral proceeding on December 12, 2002.

7. Demonstration of compliance with A.R.S. § 49-112:

Under A.R.S. § 49-112(A), Maricopa County may adopt rules that are more stringent than or in addition to a provision of the state, provided that the rule is necessary to address a peculiar local condition; and if it is either necessary to prevent a significant threat to public health or the environment that results from a peculiar local condition and is technically and economically feasible; or if it is required under a federal statute or regulation, or authorized pursuant to an intergovernmental agreement with the federal government to enforce federal statutes or regulations if the county rule is equivalent to federal statutes or regulations; and if any fee adopted under the rule will not exceed the reasonable costs of the county to issue and administer that permit program. Maricopa County is in compliance with A.R.S. § 49-112(A) in that Maricopa County proposes to adopt revisions to Rules 311 and 320 and to adopt new Rules 322 and 323 that are more stringent than a provision of the state in order to address a peculiar local condition, the designation of Maricopa County as a serious non-attainment area for ozone, carbon monoxide and particulate matter at 10 microns. Maricopa County is the only ozone nonattainment county in Arizona.

8. A reference to any study relevant to the rule that the agency reviewed and either proposes to rely on in its evaluation or justification for the rule, or proposes not to rely on in its evaluation of or justification for the rule, where the public may obtain or review each study, all data underlying each study, and any analysis of the study and other supporting material:

Controlling Particulate Matter Under The Clean Air Act: A Menu Of Options, July 1996

State And Territorial Air Pollution Program Administrators/ Association of Local Air Pollution Control Officials (STAPPA/ALAPCO).

This document may be reviewed at Maricopa County Environmental Services Department, 1001 N. Central Avenue, Suite 695, Phoenix, AZ 85004.

This document may be obtained from STAPPA/ALAPCO, 444 North Capitol Street, NW, Suite 307, Washington, D.C. 20001 (telephone (202) 624-7864; fax (202) 624-7863).

EPA memorandum of September 20, 1999 titled *State Implementation Plans (SIPS): Policy Regarding Excess Emissions During Malfunctions, Startup and Shutdown*, submitted by Steven Herman and Robert Perciasepe.

This document may also be reviewed at Maricopa County Environmental Services Department, 1001 N. Central Avenue, Suite 695, Phoenix, AZ 85004. It may be obtained from the EPA Office of Air and Radiation and the EPA office of Enforcement and Compliance Assurance.

9. A showing of good cause why the rule is necessary to promote a statewide interest if the rule will diminish a previous grant of authority of a political subdivision of this state:

Not applicable

10. The preliminary summary of the economic, small business and consumer impact:

Maricopa County proposes to amend Rules 311 by deleting the fuel burning sections and amend Rule 320 by removing certain outdated standards that apply to NOx, SOx, and CO emitted from combustion equipment at power plants and ICI sources and replace these standards with new Rules 322 and 323. Both Rules 322 and 323 are source-specific rules.

Brief Summary of Costs

There will be no costs to the sources affected by Rules 311 and 320 by the proposed revisions to these rules because the revisions are basically only deletions of text. There will be some costs to the electric utilities affected by proposed Rule 322 because of the required usage of fuels that meet a particulate standard of 0.007 lbs/MM Btu and the usage of fuels with a sulfur content of less than 0.05%. There will be some costs to the industries affected by Rule 323 due to tuning procedure costs and the proposed usage of fuels with a sulfur content of less than 0.05%. There will be only small incremental costs to Maricopa County. This preliminary economic impact statement (EIS) was developed to estimate the impact of this rule. This impact statement, comprised of potential costs and benefits, represents an estimate. Maricopa County solicits input from sources that could be small businesses and organizations under this definition on the administrative and other costs required for compliance with the proposed rulemaking, and any other information relevant to the economic, small business and consumer impact statement.

Maricopa County Costs

Projected costs to Maricopa County Environmental Services Division are those that accrue for implementation and enforcement of the new standards. Although there are some small incremental costs due to this rulemaking such as administrative tasks, distribution costs and education of inspectors, Maricopa County does not intend to hire any additional employees to implement or enforce these rules.

Rules 311 and 320 Costs

There will be no costs to any agency or stakeholder anticipated from the repealing of sections from Rules 311 and 320.

Rule 322 Costs

Rule 322 affects existing power plants in Maricopa County. All of the boilers at these existing plants were constructed before May of 1972, the date when the NOx standards became applicable. Therefore there are no costs to the existing power plants from complying with the NOx emission standard. The 2001 emissions inventory reflects a total of 435 tons of PM10 emitted from the six existing power plants in Maricopa County and a total of 63 tons of SOx. The strategy for lowering PM emissions from combustion units by mandating use of natural gas is one of the least costly strategies because switching to different fuels is almost always possible at many units without equipment modifications.

Switching from other fuels to natural gas requires that natural gas be available onsite. Natural gas already is available to the power plants via pipeline so there should be no additional costs for delivery needs. In fact the utilities already are using natural gas. Natural gas (as of October 2002/year to date) used by electric utilities reflects an average cost of $4.85/ MM Btu from the Department of Energy (DOE) Energy Information Administration (EIA) web site. The same site shows the average cost of low sulfur fuel oils delivered to electric utilities in the Western region to be $4.67/ MM Btu. Currently according to Oil Prices Information Services (OPIS), the costs of low versus high sulfur oil is very minimal – less than one cent per gallon. Of course many scenarios affect oil and gas prices such as: energy policies of countries, crises in world economies, demographics, transportation costs, turbulence and military threats in the Middle East, supply and demand ratios, and temporary refinery shutdowns due to natural disasters such as hurricanes or floods. Thus while currently the prices of fuel oil are cheaper than the price of gas, the County realizes that prices are volatile and do fluctuate.

An added benefit of using natural gas is that natural gas usage lowers maintenance costs as compared to the usage of fuel oil because natural gas is cleaner than fuel oil. Another drawback to using fuel oil is that the presence of some metals such as vanadium cause corrosion of ferrous materials found in most boilers.

Due to Clean Air Act acid rain requirements and Title V monitoring requirements that the affected sources already comply with, the proposed recordkeeping and monitoring provisions will not significantly add financial burden to the affected sources.

Rule 323 Costs

Proposed Rule 323 affects fuel burning equipment at Industrial/Commercial/Institutional Sources including boilers, cogeneration units, and indirect-fired process heaters. An inventory of combustion units at these sources reflects only units below 100 MM Btu/hr. The requirement to tune these smaller units is expected to be the major cost accrued by this proposed rule. Costs for tune-ups range from $85 to $100 per unit and labor costs of $80 per hour. One to two hours of labor is expected for most of the units. The other costs expected from this proposed rule would be the costs of using low sulfur fuel. Most of the sources are already using the low sulfur fuel because high sulfur fuel (> 500 ppm sulfur) is in minimal supply in this area. If, in fact, a source is using high sulfur fuel and switches to low sulfur fuel, then the costs would be less than one cent per gallon based upon OPIS pricing. Minimal costs are expected to be accrued for proposed recordkeeping provisions according to the key stakeholders.

Rules impact reduction on small businesses

A.R.S. § 41-1055 requires Maricopa County to reduce the impact on small businesses by using certain methods when they are legal and feasible in meeting the statutory objectives of the rulemaking. A small business is defined in A.R.S. § 41-1001 as a “concern, including its affiliates, which is independently owned and operated, which is not dominant in its field and which employs fewer than one hundred full-time employees or which had gross annual receipts of less than four million dollars in its last fiscal year. For purposes of a specific rule, an agency may define small business to include more persons if it finds that such a definition is necessary to adapt the rule to the needs and problems of small businesses and organizations.” Rule 322 does not affect any small businesses. It only applies to power plant operations that sell more than 1/3 of their electricity and these utilities are large businesses. Rule 323 does apply to small businesses. The final economic, small business and consumer impact statement for this rule must contain a statement of probable impact of the rule on small businesses. This preliminary economic impact statement (EIS) was developed to estimate the impact of this rule. This impact statement, comprised of potential costs and benefits, represents an estimate. Maricopa County solicits input from sources that could be small businesses and organizations under this definition on the administrative and other costs required for compliance with the proposed rulemaking, and any other information relevant to the economic, small business and consumer impact statement.

11. <u>The time, place, and nature of the proceedings for the adoption, amendment, or repeal of the rules or, if no proceeding is scheduled, where, when, and how persons may request an oral proceeding on the proposed rules:</u>

Oral Proceeding Date:	December 12, 2002, 9:00 a.m.
Location:	Maricopa County Environmental Services Department 5th Floor Conference Room, #560 1001 N. Central Avenue Phoenix, AZ 85004
Nature:	Public hearing with the opportunity for formal comments on the record regarding the proposed rules and submittal of the rules to EPA as a revision to the State Implementation Plan (SIP).

Call (602) 506-0169 for current information. Please call (602) 506-6443 for special accommodations under the Americans with Disabilities Act.

12. <u>Any other matters prescribed by statute that are applicable to the specific agency or to any specific rules or class of rules:</u>

None

13. <u>Incorporations by reference and their location in the rules:</u>

<u>New incorporations by reference</u>	<u>Location</u>
ASTM Method # D1266-98	Rule 322, Section 504 Rule 323, Section 504
ASTM Method # D-2622-98	Rule 322, Section 504 Rule 323, Section 504

ASTM Method # D-2880-00	Rule 322, Section 504 Rule 323, Section 504
ASTM Method # D-4294-90 or 98	Rule 322, Section 504 Rule 323, Section 504
Standard Methods for the Examination of Water and Wastewater # 2540C	Rule 322, Section 504
Incorporations by reference updated to 7/1/01	Location
40 CFR Part 60 Appendix A	Rule 322, Section 504 Rule 323, Section 504

14. The full text of the rules follows:

RULE 311 – PARTICULATE MATTER FROM PROCESS INDUSTRIES

100 No change
101 No change
102 This rule shall apply to any affected operation which is not subject to ~~the provisions of Rule 316 of these Regulations~~ Rules 313, 316, 317, 319, 322, and 323 which regulate particulate matter from specific sources. All sources regulated by this rule shall also comply with Rule 310.
200 No change
201 No change
202 No change
203 No change
204 No change
205 No change
206 No change
207 No change
300 No change
301 No change
302 No change
303 **Limitations – Portland Cement Plants:** Portland cement plants shall be subject to the New Source Performance Standards (NSPS), 40 CFR60, Subpart F, referenced in Rule 360 of these Rules and Regulations.

~~**303.1** No person owning or operating a portland cement plant with a process weight rate in excess of 250,000 lbs/hr shall discharge or cause or allow the discharge of particulate matter emissions from any kiln into the ambient air which is in excess of 0.3 lbs/ton (0.15 kg per metric ton) of feed to the kiln, maximum two-hour average, or greater than ten percent opacity.~~

~~**303.2** No person owning or operating a portland cement plant shall discharge or cause or allow the discharge of particulate matter emissions from the clinker cooler into the ambient air in excess of 0.1 lb/ton (0.05 kg per metric ton) of feed to the kiln, maximum two hour average, or greater than ten percent opacity.~~

~~**303.3** No person owning or operating a portland cement plant shall discharge or cause or allow the discharge into the ambient air of particulate matter emissions from any affected facility, other than the kiln or clinker cooler, which is greater than ten percent opacity.~~

~~**304** **LIMITATIONS – FUEL BURNING EQUIPMENT:** No person shall discharge, cause or allow the discharge of particulate matter emissions, caused by combustion of fuel, from any fuel burning operation in excess of amounts calculated by the equations presented in Sections 304.1 and 304.2 of this rule.~~

~~**304.1** For equipment having a heat input rating of 4200 million btu/hr or less, the maximum allowable emissions (E) shall be determined by the following equation:~~

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

~~where:~~

~~E = The maximum allowable particulate emission rate in pounds-mass per hour, and~~

~~Q = The heat output in million BTU per hour.~~

~~**304.2**~~ ~~For equipment having a heat input rating greater than 4200 million BTU/hr, the maximum allowable emissions shall be determined by the following equation:~~

~~$E = 17.0\ Q^{0.432}$~~

~~where "E" and "Q" have the same meanings as in Section 304.1 of this rule.~~

~~**305**~~**304** **APPROVED EMISSION CONTROL SYSTEM REQUIRED:** For affected operations which may exceed the applicable standards set forth in Sections 301 through ~~304~~302 of this rule, an owner or operator may comply by installing and operating an approved emission control system.

~~**306**~~**305** Renumbered

~~**307**~~**306** **EXEMPTIONS:** The provisions of Section 301 of this rule shall not apply to incinerators or fuel burning equipment ~~facilities~~. ~~The provisions of Section 301 of this rule shall not apply to portland cement plants having process weights in excess of 250,000 lb/hr.~~

400 No change

401 No change

500 No change

501 No change

502 No change

503 RECORD RETENTION: Copies of reports, logs and supporting documentation required by the Control Officer shall be retained at least ~~three~~ five years. Records and information required by this rule shall also be retained for at least ~~three~~ five years.

504 TEST METHODS ADOPTED BY REFERENCE: The EPA ~~reference~~ test methods as they exist in the Code of Federal Regulations (CFR) (July 1, 2001), as listed below, are adopted by reference. These adoptions by reference include no future editions or amendments. Copies of test methods referenced in this Section are available at the Maricopa County Environmental Services Department, 1001 N. Central Avenue, Phoenix, AZ. 85004-1942. ~~in 40 CFR 60, Appendix A, shall be used to determine compliance with the pertinent standards prescribed in this section.~~ When more than one test method is permitted for a determination, an exceedance of the limits established in this rule determined by any of the applicable test methods constitutes a violation of this rule.

504.1 ~~Sample velocity and velocity traverse and selection of sample sites and sample traverses shall be determined according to~~ EPA Reference Method 1 ("Sample and Velocity Traverse for Stationary Sources"), 1a ("Sample and Velocity Traverses for Stationary Sources with Small Stacks and Ducts") (40 CFR 60, Appendix A).

504.2 ~~Velocity and volumetric flow rate shall be determined according to~~ EPA Reference Method 2 ("Determination of Stack Gas Velocity and Volumetric Flow Rate"), 2A ("Direct Measurement of Gas Volume Through Pipes and Small Ducts"), 2C ("Determination of Stack Gas Velocity and Volumetric Flow Rate in Small Stacks or Ducts") and 2D ("Measurement of Gas Volumetric Flow Rates in Small Pipes and Ducts") (40 CFR 60, Appendix A).

504.3 ~~Gas analysis shall be determined according to~~ EPA Reference Method 3. ("Gas Analysis for the Determination of Dry Molecular Weight"), 3A ("Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure)"), 3B ("Gas Analysis for the Determination of Emission Rate Correction Factor of Excess Air"), 3C ("Determination of Carbon Dioxide, Methane, Nitrogen and Oxygen from Stationary Sources") (40 CFR 60, Appendix A).

504.4 ~~Stack gas moisture shall be determined according to~~ EPA Reference Method 4 ("Determination of Moisture Content in Stack Gases") (40 CFR 60, Appendix A).

504.5 ~~Stack effluent concentration of particulate matter and associated moisture content shall be determined according to~~ EPA Reference Method 5 ("Determination of Particulate Emissions from Stationary Sources") (40 CFR 60, Appendix A) and possibly, if requested by the Control Officer, EPA Reference Method 202 ("Determination of Condensable Particulate Emissions from Stationary Sources") (40 CFR 51, Appendix M).

~~**504.6**~~ ~~Visible emissions shall be determined according to~~ EPA Reference Method 9 ("Visual Determination of the Opacity of Emissions from Stationary Sources") (40 CFR 60, Appendix A).

RULE 320 – ODORS AND GASEOUS AIR CONTAMINANTS

100 No change

101 No change

200 No change

~~**201 FOSSIL FUEL FIRED STEAM GENERATOR** - A furnace or boiler used in the process of burning fossil fuel for the primary purpose of producing steam by heat transfer.~~

~~202~~201 **HIGH SULFUR OIL -** Fuel oil containing ~~0.9~~0.05 percent or more by weight of sulfur.
~~203~~202 **LOW SULFUR OIL -** Fuel oil containing less than ~~0.9~~0.05 percent by weight of sulfur.
~~204~~203 **ODORS -** Smells, aromas or stenches commonly recognized as offensive, obnoxious or objectionable to a substantial part of a community.
~~205~~204 **REDUCTION -** Any heated process, including rendering, cooking, drying, dehydrating, digesting, evaporating and protein concentrating.
300 No change
301 No change
302 No change
303 No change
304 No change
~~305~~ ~~**LIMITATION - SULFUR DIOXIDE AND SULFURIC ACID MIST FROM SULFURIC ACID PLANTS:** No person shall emit or discharge into the atmosphere more than 4.0 pounds of sulfur dioxide or 0.15 pounds of sulfuric acid mist per ton of sulfuric acid produced (calculated as 100 percent H2SO4) maximum two hour average, from facilities that produce sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans or acid sludge.~~
~~306~~ ~~**LIMITATION SULFUR DIOXIDE FROM ELECTRICAL POWER PLANTS:** This section applies to facilities operated for the purpose of producing electric power with a resulting discharge of sulfur dioxide in the facility's effluent gases.~~

~~306.1~~ ~~Steam Plants Using Low Sulfur Oil After May 30, 1972: Existing steam power generating facilities which commenced construction or a major modification after May 30, 1972, shall not emit more than 0.8 pounds of sulfur dioxide, maximum three hour average, per million BTU heat input when low sulfur oil is fired.~~

~~306.2~~ ~~Steam Plants Using Low Sulfur Oil Prior to May 30, 1972: Existing steam power generating facilities which commenced construction or a major modification prior to May 30, 1972, shall not emit more than 1.0 pounds of sulfur dioxide, maximum three hour average, per million BTU heat input when low sulfur oil is fired.~~

~~306.3~~ ~~Steam Plants Using High Sulfur Oil: All existing steam power generating facilities which are subject to the provisions of this rule shall not emit more than 2.2 pounds of sulfur dioxide, maximum three hour average, per million BTU heat input when high sulfur oil is fired.~~

~~306.4~~305 **Permit Conditions - High Sulfur Oil:** Any permit issued for the operation of an existing source, or any renewal or modification of such a permit, shall include a condition prohibiting the use of high sulfur oil by the permittee. The applicant must demonstrate to the Control Officer that sufficient quantities of low sulfur oil are not available for use by the source and that it has adequate facilities and contingency plans to insure that the sulfur dioxide ambient air quality standards set forth in Rule 510 of these Regulations will not be violated. The terms of the permit may authorize the use of high sulfur oil under such conditions as are justified. In cases where the permittee is authorized to use high sulfur oil, it shall submit to the ~~Bureau~~ Control Officer monthly reports detailing its efforts to obtain low sulfur oil. When the conditions justifying the use of high sulfur oil no longer exist, the permit shall be modified accordingly.

~~307~~306 **LIMITATION - SULFUR FROM ~~OTHER~~ INDUSTRIES:** No person shall discharge into the atmosphere from any ~~other~~ industry, ~~not covered in other sections of this rule~~ reduced sulfur, which includes sulfur equivalent from all sulfur emissions including but not limited to sulfur dioxide, sulfur trioxide and sulfuric acid, in excess of ten percent of the sulfur entering the process as feed.

~~308~~ ~~**LIMITATION - NITROGEN OXIDES FROM ELECTRICAL POWER PLANTS:** This section applies to facilities operated for the purpose of producing electric power with a resulting discharge of nitrogen oxides.~~

~~308.1~~ ~~Steam Plants Using Gaseous Fossil Fuel: Existing steam power generating facilities which commenced construction or a major modification after May 30, 1972, shall not emit more than 0.2 pounds of nitrogen oxides, maximum three hour average, calculated as nitrogen dioxide, per million BTU heat input when gaseous fossil fuel is fired.~~

~~308.2~~ ~~Steam Plants Using Liquid Fossil Fuel: Existing steam power generating facilities which commenced construction or a major modification after May 30, 1972, shall not emit more than 0.3 pounds of nitrogen oxides, maximum three hour average, calculated as nitrogen dioxide, per million BTU heat input when liquid fossil fuel is fired.~~

~~309~~307 **Renumbered**
~~310~~ ~~**CARBON MONOXIDE:** The discharge of carbon monoxide emissions from any process source shall be effectively controlled by means of secondary combustion.~~
~~311~~ ~~**EXEMPTIONS:** Section 305 of this rule shall not apply to existing sources nor to metallurgical plants or other facilities where conversion to sulfuric acid is utilized as a means of controlling emissions to the atmosphere of sulfur dioxide or other compounds.~~

RULE 322 – POWER PLANT OPERATIONS

100 **GENERAL**

101 PURPOSE: To limit the discharge of nitrogen oxides, sulfur oxides, particulate matter and carbon monoxide emissions into the atmosphere from stationary fossil-fuel-fired equipment at existing power plants and existing cogeneration plants and to limit particulate matter emissions from cooling towers associated with this equipment.

102 APPLICABILITY: This rule applies to any of the following types of equipment that burn fossil fuel for which construction commenced prior to May 10,1996:

102.1 Each electric utility steam generating unit or cogeneration steam generating unit used to generate electric power that has a heat input of equal to or greater than 100 million (MM) Btu/hour (29 megawatts (MW)).

102.2 Each electric utility stationary gas turbine with a heat input at peak load equal to or greater than 10 MMBtu/hour (2.9 MW) based upon the lower heating value of the fuel.

102.3 Each cooling tower associated with the type of equipment listed in subsections 102.1 and 102.2

103 EXEMPTIONS: This rule shall not apply to the following types of equipment:

103.1 Combustion equipment associated with nuclear power plant operations.

103.2 Reciprocating internal combustion equipment.

104 PARTIAL EXEMPTIONS:

104.1 Stationary gas turbines that meet any of the following criteria listed below are exempt from Sections 304 and 305 and subsections 301.1, 306.4, 401.4, and 501.4 of this rule:

- **a.** Used for fire fighting; or
- **b.** Used for flood control; or
- **c.** Used in the military at military training facilities or military gas turbines for use in other than a garrison; or
- **d.** Engaged by manufacturers in research and development of equipment for either gas turbine emission control techniques or gas turbine efficiency improvements.

104.2 All equipment listed in Section 102 fired with an emergency fuel that is normally fired with natural gas is exempt from Sections 304 and 305 and subsections 301.1, 306.4, 401.4, and 501.4 of this rule.

104.3 All equipment listed in Section 102 shall be exempt from Sections 304 and 305 and subsections 301.1, 306.4, 401.4, and 501.4 of this rule for 36 cumulative hrs. of firing emergency fuel per year, per unit for testing, reliability, training, and maintenance purposes.

SECTION 200 - DEFINITIONS: For the purpose of this rule, the following definitions shall apply: See Rule 100 (General Provisions and Definitions) of these rules for definitions of terms that are used but not specifically defined in this rule.

201 COGENERATION STEAM GENERATING UNIT – A steam or hot water generating unit that simultaneously produces both electrical (or mechanical) and thermal energy (such as heat or steam) from the same primary energy source and supplies more than one-third of its potential electric output to any utility power distribution system for sale.

202 COMBINED CYCLE GAS TURBINE – A type of stationary gas turbine wherein heat from the turbine exhaust is recovered by a steam generating unit to make steam for use in a steam-electric turbine.

203 CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) – The total equipment required to sample and analyze emissions or process parameters such as opacity, nitrogen oxide and oxygen or carbon dioxide, and to provide a permanent data record.

204 COOLING TOWERS – Open water recirculating devices that use fans or natural draft to draw or force air through the device to cool water by evaporation and direct contact.

205 CORRECTIVE ACTION PLAN (CAP) - A methodical procedure that is used to evaluate and correct a turbine operational problem and that includes, at a minimum, improved preventative maintenance procedures, improved ECS operating practices, possible operational changes and progress reports.

206 DISTILLATE OIL – A petroleum fraction of fuel oil produced by distillation that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396-01, “Standard Specification for Fuel Oils.”

207 DRIFT – Water droplets, bubbles, and particulate matter that escape from cooling tower stacks.

208 DRIFT RATE – Percentage (%) of circulating water flow rate that passes through a high efficiency drift eliminator on a cooling tower.

209 ELECTRIC UTILITY STATIONARY GAS TURBINE – Any stationary gas turbine that is constructed for the purpose of supplying more than 1/3 of its potential electric output capacity to any utility power distribution system for sale. Both simple and combined cycle gas turbines are types of electric utility stationary gas turbine.

210 ELECTRIC UTILITY STEAM GENERATING UNIT – Any steam electric generating unit that uses fossil fuel and is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electric output to any utility power distribution system for sale.

211 EMERGENCY FUEL - Fuel fired only during circumstances such as natural gas emergency, natural gas curtailment, or breakdown of delivery system such as an unavoidable interruption of supply that makes it impossible to fire natural gas in the unit. Fuel is not considered emergency fuel if it is used to avoid either peak demand charges or high gas prices during on-peak price periods or due to a voluntary reduction in natural gas usage by the power company.

212 EMISSION CONTROL SYSTEM (ECS) – A system approved in writing by the Control Officer, designed and operated in accordance with good engineering practice to reduce emissions.

213 FOSSIL FUEL – Naturally occurring carbonaceous substances from the ground such as natural gas, petroleum, coal and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating energy.

214 FUEL SWITCHING STARTUP PROCESS – The act of changing from one type of fuel to a different type of fuel.

215 HEAT INPUT – Heat derived from the combustion of fuel, not including the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines and kilns.

216 HIGH EFFICIENCY DRIFT ELIMINATOR (HEDE) – Device used to remove drift from cooling tower exhaust air, thus reducing water loss by relying on rapid changes in velocity and direction of air-droplet mixtures by impaction on eliminator passage surfaces. A HEDE is not categorized as an emission control system but is an inherent part of the cooling towers' design requirements.

217 HIGHER HEATING VALUE (HHV) or GROSS HEATING VALUE – The amount of heat produced by the complete combustion of a unit quantity of fuel determined by a calorimeter wherein the combustion products are cooled to the temperature existing before combustion and all of the water vapor is condensed to liquid.

218 LOW SULFUR OIL – Fuel oil containing less than or equal to 0.05% by weight of sulfur.

219 LOWER HEATING VALUE (LHV) OR NET HEATING VALUE – The amount of heat produced by the complete combustion of a unit quantity of fuel determined by a calorimeter wherein the combustion products are cooled to the temperature existing before combustion and all of the water vapor remains as vapor and is not condensed to a liquid. The value is computed from the higher heating value by subtracting the water originally present as moisture and the water formed by combustion of the fuel.

220 NATURAL GAS CURTAILMENT - An interruption in natural gas service, such that the daily fuel needs of a combustion unit cannot be met with natural gas available due to one of the following reasons, beyond the control of the owner or operator:

- **a.** An unforseeable failure or malfunction, not resulting from an intentional act or omission that the governing state, federal or local agency finds to be due to an act of gross negligence on the part of the owner or operator; or
- **b.** A natural disaster; or
- **c.** The natural gas is curtailed pursuant to governing state, federal or local agency rules or orders; or
- **d.** The serving natural gas supplier provides notice to the owner or operator that, with forecasted natural gas supplies and demands, natural gas service is expected to be curtailed pursuant to governing state, federal or local agency rules or orders.

221 NITROGEN OXIDES (NOx) – Oxides of nitrogen calculated as equivalent nitrogen dioxide.

222 OPACITY – A condition of the ambient air, or any part thereof, in which an air contaminant partially or wholly obscures the view of an observer.

223 PARTICULATE MATTER EMISSIONS – Any and all particulate matter emitted to the ambient air as measured by applicable state and federal test methods.

224 PEAK LOAD – 100% of the manufacturer's design capacity of a gas turbine at 288° Kelvin, 60% relative humidity, and 101.3 kilopascals pressure (ISO standard day conditions).

225 POWER PLANT OPERATION – An operation whose purpose is to supply more than one-third of its potential electric output capacity to any utility power distribution system for sale.

226 RATED HEAT INPUT CAPACITY – The heat input capacity in million Btu/hr. a specified on the nameplate of the combustion unit. If the combustion unit has been altered or modified such that its maximum heat input is different than the heat input capacity on the name plate, the maximum heat input shall be considered the rated heat input capacity.

227 REGENERATIVE CYCLE GAS TURBINE – Any stationary gas turbine that recovers thermal energy from the exhaust gases and utilizes the thermal energy to preheat air prior to entering the combustion unit.

228 RESIDUAL OIL – The heavier oils that remain after the distillate oils and lighter hydrocarbons are distilled off in refinery operations. This includes crude oil or fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05% by weight, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396-01, "Standard Specifications for Fuel Oils."

229 SIMPLE CYCLE GAS TURBINE – Any stationary gas turbine that does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or that does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

230 STATIONARY GAS TURBINE – Any simple cycle gas turbine, regenerative gas turbine or any gas turbine portion of a combined cycle gas turbine that is not self propelled or that is attached to a foundation.

231 SULFUR OXIDES (SOx) – The sum of the oxides of sulfur emitted from the flue gas from a combustion unit that are directly dependent upon the amount of sulfur in the fuel used.

232 THIRTY DAY (30) ROLLING AVERAGE – An arithmetic mean or average of all hourly emission rates for 30 successive combustion equipment operating days and calculated by a CEMS every hour.

233 THREE (3) HOUR ROLLING AVERAGE – An arithmetic mean or average of the 180 most recent one-minute average values calculated by a CEMS every minute.

234 TOTAL DISSOLVED SOLIDS (TDS) – The amount of concentrated matter reported in milligrams/liter (mg/l) or parts per million (ppm) left after filtration of a well-mixed sample through a standard glass fiber filter. The filtrate is evaporated to dryness in a weighed dish and dried to constant weight at 180° C and the increase in dish weight represents the total dissolved solids.

235 UNCOMBINED WATER – Condensed water containing no more than analytical amounts of other chemical elements or compounds.

SECTION 300 – STANDARDS

301 LIMITATIONS – PARTICULATE MATTER:

301.1 **Fuel Type:** An owner or operator of any combustion equipment listed in Section 102 shall burn only natural gas except when firing emergency fuel per subsection 104.2 and 104.3 of this rule. An owner or operator may burn a fuel other than natural gas for non-emergency purposes providing that the fuel shall not cause to be discharged more than 0.007 lbs. of particulate matter per MMBtu heat input, demonstrated and documented through performance testing of this alternate fuel. This usage of different fuels other than natural gas shall be approved by the Control Officer prior to usage.

301.2 **Good Combustion Practices:** An owner or operator of any stationary gas turbine listed in subsection 102.2, regardless of fuel type, shall use operational practices recommended by the manufacturer and parametric monitoring to ensure good combustion control. In lieu of a manufacturers' recommended procedure to ensure good combustion practices, one of the following procedures may be used:

a. Monitor the maximum temperature differential across the combustion burners or at locations around the back end of the turbine, dependent upon the particular unit, to ensure no more than a 100° F difference using a thermocouple. If a valid maximum temperature differential of greater than 100° F is observed across the burners, investigation and corrective action shall be taken within three hours to reduce the temperature difference to 100° F or less; or

b. If the manufacturer recommends that the maximum numerical temperature differential to ensure good combustion is a temperature that is greater than 100° F, then proof of this maximum alternate temperature shall be submitted to the Control Officer. The procedure to measure the maximum temperature differential listed above in subsection 301.2a shall then be followed using the alternate recommended maximum temperature differential after approval by the Control Officer.

c. If the frequency of failure to meet the proper temperature differential of 100° F or to meet the alternate temperature differential recommended by the manufacturer reflects a pattern that the turbine is not being operated in a manner consistent with good combustion practices, then the Control Officer may require the owner or operator to submit a Corrective Action Plan (CAP).

301.3 **Cooling Towers:** An owner or operator of a cooling tower associated with applicable units listed in Section 102 shall:

a. Equip the cooling tower with a high efficiency drift eliminator (HEDE). The HEDE shall not be manufactured out of wood.

b. The concentration of Total Dissolved Solids (TDS) multiplied by the percentage of drift rate shall not exceed the maximum numerical limit of 20.

c. Visually inspect the HEDE for integrity on a monthly basis only if the HEDE can be viewed safely and does not require an owner or operator to walk into the tower. If the HEDE cannot be safely inspected monthly then subsection 301.3d shall apply.

d. Visually inspect the HEDE for integrity during a regularly scheduled outage when the cooling tower is not operating if it cannot be inspected on a monthly basis. This visual inspection shall be no less than once per year.

302 LIMITATIONS – OPACITY:

302.1 No person shall discharge into the ambient air from any single source of emissions any air contaminant, other than uncombined water, in excess of 20% opacity, except as provided in subsection 302.2.

302.2 Opacity may exceed the applicable limits established in subsection 302.1 for up to one hour during the start up of switching fuels; however, opacity shall not exceed 40% for any six (6) minute averaging period in this one hour period, provided the Control Officer finds that the owner or operator has, to the extent practicable, maintained and operated the source of emissions in a manner consistent with good air pollution control practices for minimizing emissions. The one hour period shall begin at the moment of startup of fuel switching.

302.3 Determination of whether good air pollution control practices are being used shall be based on information provided to the Control Officer upon request, which may include, but is not limited to, the following:

a. Monitoring results.

b. Opacity observations.
c. Review of operating and maintenance procedures.
d. Inspection of the source.

303 LIMITATIONS - SULFUR IN FUEL: An owner or operator of any applicable equipment listed in Section 102 that burns fuel oil alone or in combo with any other fuel as either emergency fuel or non-emergency fuel that meets the standards in subsection 301.1 shall use only low sulfur oil with one exception. Existing supplies in storage of any fuel oil and/or of any used fuel oil with sulfur content greater than 0.05% by weight may be used by the owner or operator until (1.5 years after adoption of rule) for emergency fuel. This usage shall be reported within 24 hours to the Control Officer, verbally along with the dates of usage. A written report shall follow within 48 hours of usage which shall include identification of the nature of the emergency and actual and expected dates of usage.

304 LIMITATIONS – NITROGEN OXIDES: No owner or operator of any applicable equipment listed in subsection 102.1 that commenced construction or a major modification after May 30, 1972 shall cause to be discharged into the atmosphere nitrogen oxides in excess of the following limits:

304.1 155 ppmv per MMBtu heat input, calculated as nitrogen dioxide when burning gaseous fossil fuel. During steady state operations, this test result using EPA Reference Method(s)7, shall be based upon the arithmetic mean of the results of three test runs. Each test run shall have a minimum sample time of one hour. If a Continuous Emission Monitoring System (CEMS) is used, the test result shall be based upon a 30-day rolling average.

304.2 230 ppmv per MMBtu calculated as nitrogen dioxide when burning liquid fossil fuel. During steady state operations, this test result using EPA Reference Method(s)7, shall be based upon the arithmetic mean of the results of three test runs. Each test run shall have a minimum sample time of one hour. If a CEMS is used, the test result shall be based upon a 30-day rolling average.

305 LIMITATIONS - CARBON MONOXIDE: No owner or operator of any equipment listed in Section 102 shall cause to be discharged into the atmosphere carbon monoxide (CO) measured in excess of 400 ppmv during steady state compliance source testing. This test result, using EPA Reference Method 10, shall be based upon the arithmetic mean of the results of three test runs. Each test run shall have a minimum sample time of one hour. The CO concentration shall be measured dry and corrected to 3% oxygen for electric utility steam generating units and cogeneration steam generating units. The CO concentration shall be measured dry and corrected to 15% oxygen for, stationary gas turbines.

306 REQUIREMENTS FOR AIR POLLUTION CONTROL EQUIPMENT AND ECS MONITORING EQUIPMENT:

306.1 Emission Control System Required: For affected operations which may exceed any of the applicable standards set forth in Section 300 of this rule, an owner or operator may comply by installing and operating an emission control system (ECS).

306.2 Providing and Maintaining ECS Monitoring Devices: No owner or operator required to use an approved ECS pursuant to this rule shall do so without first properly installing, operating, and maintaining in calibration and in good working order, devices for indicating temperatures, pressures, transfer rates, rates of flow, or other operating conditions necessary to determine if air pollution control equipment is functioning properly and is properly maintained as described in an approved O&M Plan.

306.3 Operation and Maintenance (O&M) Plan Required For ECS:

a. General Requirements: An owner or operator shall provide and maintain an O&M Plan for any ECS, any other emission processing equipment, and any ECS monitoring devices that are used pursuant to this rule or to an air pollution permit.
b. Approval by Control Officer: An owner or operator shall submit to the Control Officer for approval the O&M Plans of each ECS and each ECS monitoring device that is used pursuant to this rule.
c. Initial Plans: An owner or operator that is required to have an O&M Plan pursuant to this rule shall comply with all O&M Plans that the owner or operator has submitted for approval, but which have not yet been approved, unless notified by the Control Officer in writing. Once the initial plan has been approved in writing by the Control Officer, an owner or operator shall then comply with the approved plan.
d. Revisions to Plan: If revisions to the initial plan have been approved by the Control Officer in writing, an owner or operator shall comply with the revisions to the initial plan.
e. Control Officer Modifications to Plan: After discussion with the owner or operator, the Control Officer may modify the plan in writing prior to approval of the initial O&M plan. An owner or operator shall then comply with the plan that has been modified by the Control Officer.

306.4 Continuous Emission Monitoring Systems (CEMS):

a. An owner or operator of a combustion unit subject to Section 304 with a heat input of greater than 250 MMBtu/hr, regardless of fuel type, shall install, calibrate, maintain, and operate a CEMS for measuring nitrogen oxides and recording the output of the system. Where nitrogen oxide emissions are monitored by a CEMS, then a CEMS shall also be required for the measurement of either the oxygen or carbon dioxide content of the flue gases. All CEMS shall comply with the provisions in 40 CFR Subpart Da, Part 60, 60.47 (a).

b. An owner or operator of any affected unit listed above that requires a CEMS for nitrogen oxides that meets and is continuing to meet the requirements of 40 CFR Part 75 may use that CEMS to meet the requirements of subsection 306.4a of this rule.

307 EMERGENCY FUEL USE NOTIFICATION – An owner or operator of a unit that uses emergency fuel that is normally fired with natural gas shall notify the Control Officer verbally no later than 24 hours after declaration of the emergency that necessitates its use per subsection 104.2. This verbal report shall be followed by a written report within 48 hours of initial usage which shall also include identification of the nature of the emergency, initial dates of usage and the expected dates of usage.

SECTION 400 - ADMINISTRATIVE REQUIREMENTS

401 COMPLIANCE SCHEDULE

401.1 Operation and Maintenance (O&M) Plan: Any owner or operator employing an approved ECS on the effective date of this rule shall by (insert eight months after rule is adopted) file an O&M Plan with the Control Officer in accordance with subsection 306.3 of this rule.

401.2 Modifications to Existing ECS: Any owner or operator required to modify their ECS equipment or system by either reconstructing or adding on new equipment for compliance with this rule shall by (insert six months after rule is adopted) file a schedule for the modification with the Control Officer. The plan shall show how the ECS is to be used to achieve full compliance and shall specify dates for completing increments of progress. Any and all ECS(s) used to achieve such compliance shall be in operation by (insert 30 months after date of adoption of rule).

401.3 ECS Installation: An owner or operator required to install a new ECS to satisfy the requirements of this rule shall file a schedule for the installation of an ECS by (insert eight months after the rule is adopted). The plan shall show how the ECS is to be used to achieve full compliance and shall specify dates for completing increments of progress. Any and all ECS(s) used to achieve such compliance shall be in operation by (insert 36 months after adoption of rule).

401.4 CEMS Installation: An owner or operator required to install or modify a CEMS to satisfy the requirements of this rule shall file a schedule for the installation or modification of the CEMS by (insert eight months after the rule is adopted) and complete the installation of the CEMS by (insert 36 months after date of adoption of rule).

SECTION 500 - MONITORING AND RECORDS

501 RECORDKEEPING AND REPORTING: Any owner or operator subject to this rule shall comply with the requirements set forth in this section. Any records and data required by this section shall be kept on site at all times in a consistent and complete manner and be made available without delay to the Control Officer or his designee upon request. Records shall consist of the following information:

501.1 **Equipment Listed in Section 102:** Type of fuel used, amount of fuel used, amount of sulfur in the fuel if using liquid fuel, and the days and hours of operation.

501.2 **Cooling Towers:** Monthly gravimetric testing reports for TDS shall be recorded for six months in succession and thereafter quarterly reports shall be recorded. Results of the monthly or yearly visual inspection of the HEDE shall also be recorded. If the HEDE cannot be visually inspected monthly, then documentation of the physical configuration of the HEDE shall be submitted to the Control Officer to demonstrate that the HEDE cannot be inspected monthly.

501.3 **Emergency Fuel Usage:** Type and amount of emergency fuel used, dates and hours of operation using emergency fuel, nature of the emergency or reason for the use of emergency fuel as stated in subsections 104.2 and 104.3.

501.4 **Fuel Switching:** Duration of fuel switch including stop and start times and monthly totals for twelve-month log of hours of operation for testing, reliability and maintenance purposes per subsection 302.2.

501.5 **CEMS:** All CEMS measurements, results of CEMS performance evaluations, CEMS calibration checks, and adjustments and maintenance performed on these systems.

501.6 **Good Combustion Practices:** Measurements of the temperature differential across the burners of turbines per subsection 301.2, results of evaluation and of corrective action taken to reduce the temperature differential or a finding that the temperature differential returned to the range listed in subsection 301.2 a or b without any action by the owner or operator.

502 RECORDS RETENTION: Copies of reports, logs, and supporting documentation required by the Control Officer shall be retained for at least five years. Records and information required by this rule shall also be retained for at least five years.

503 COMPLIANCE DETERMINATION:

503.1 **Low Sulfur Oil Verification:**

a. An owner or operator shall submit fuel oil or liquid fuel receipts from the fuel supplier indicating the sulfur content of the fuel or verification that the oil used to generate electric power meets the 0.05% sulfur limit if requested by the Control Officer; or

b. If fuel receipts are not available then an owner or operator shall submit a statement of certification or proof of the sulfur content of the oil or liquid fuel from the supplier to the Control Officer; or

c. An owner or operator may elect to test the fuel for sulfur content in lieu of certification from the fuel supplier or fuel receipts.

503.2 **Drift Rate Verification:** An owner or operator shall submit design drift rate verification from the manufacturer of the HEDE used in the cooling towers to the Control Officer if proof of the design drift rate is requested by the Control Officer.

504 **TEST METHODS ADOPTED BY REFERENCE:** The EPA test methods as they exist in the Code of Federal Regulations (CFR) (July 1,2001), as listed below, are adopted by reference. These adoptions by reference include no future editions or amendments. Copies of test methods referenced in this Section are available at the Maricopa County Environmental Services Department, 1001 N. Central Avenue, Phoenix, AZ 85004-1942. The ASTM methods (1990, 1998 and 2000) and the Standard Methods listed below (1995) are also adopted by reference. When more than one test method as listed in subsections 504.10 through 504.13 is permitted for the same determination, an exceedance of the limits established in this rule determined by any of the applicable test methods constitutes a violation.

504.1 EPA Reference Methods 1 (“Sample and Velocity Traverses for Stationary Sources”), 1a (“Sample and Velocity Traverses for Stationary Sources with Small Stacks and Ducts”) (40 CFR 60, Appendix A).

504.2 EPA Reference Methods 2 (“Determination of Stack Gas Velocity and Volumetric Flow Rate”), 2A (“Direct Measurement of Gas Volume Through Pipes and Small Ducts”), 2C (“Determination of Stack Gas Velocity and Volumetric Flow Rate in Small Stacks or Ducts”) and 2D (“Measurement of Gas Volumetric Flow Rates in Small Pipes and Ducts”) (40 CFR 60, Appendix A).

504.3 EPA Reference Method 3 (“Gas Analysis for the Determination of Dry Molecular Weight”), 3A (“Determination of Oxygen and Carbon Dioxide Concentrations in Emissions From Stationary Sources (Instrumental Analyzer Procedure)”), 3B (“Gas Analysis for the Determination of Emission Rate Correction Factor of Excess Air”), 3C (“Determination of Carbon Dioxide, Methane, Nitrogen and Oxygen from Stationary Sources”) (40 CFR 60, Appendix A).

504.4 EPA Reference Method 4 (“Determination of Moisture Content in Stack Gases”) (40 CFR 60, Appendix A).

504.5 EPA Reference Method 5 (“Determination of Particulate Emissions from Stationary Sources”) (40 CFR 60, Appendix A) and possibly, if requested by the Control Officer, EPA Reference Method 202 (“Determination of Condensable Particulate Emissions from Stationary Sources”) (40 CFR 51, Appendix M).

504.6 EPA Reference Method 7 (“Determination of Nitrogen Oxide Emissions from Stationary Sources”), 7A (“Determination of Nitrogen Oxide Emissions from Stationary Sources”), 7B (“Determination of Nitrogen Oxide Emissions from Stationary Sources - Ultraviolet Spectrometry”), 7C (“Determination of Nitrogen Oxide Emissions from Stationary Sources - Alkaline-Permanganate Colorimetric Method”), 7D (“Determination of Nitrogen Oxide Emissions from Stationary Sources – Alkaline-Permanganate Chromatographic Method”), 7E (“Determination of Nitrogen Oxide Emissions from Stationary Sources – Instrumental Analyzer Method”) (40 CFR 60, Appendix A).

504.7 EPA Reference Method 9 (“Visual Determination of the Opacity of Emissions from Stationary Sources”) (40 CFR 60, Appendix A).

504.8 EPA Reference Method 10 (“Determination of Carbon Monoxide Emissions from Stationary Sources”) (40 CFR 60, Appendix A).

504.9 EPA Reference Method 20 (“Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines”) (40 CFR 60, Appendix A).

504.10 American Society of Testing Materials, ASTM Method #D2622-98, (“Standard Test Method for Sulfur in Petroleum Products by Wavelength Disperse X-Ray Fluorescence Spectrometry”), 1998.

504.11 American Society of Testing Materials, ASTM Method #D1266-98, (“Standard Test Method for Sulfur in Petroleum Products - Lamp Method”), 1998.

504.12 American Society of Testing Materials, AST Method #D2880-00, (“Standard Specification for Gas Turbine Fuel Oils”), 2000.

504.13 American Society of Testing Materials, ASTM Method #D4294-90 or 98 (“Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry”), 1990 or1998.

504.14 Standard Methods for the Examination of Water and Wastewater, (“Dissolved Solids Dried at 180° C, Method #2540C”), American Public Health Association, 19th edition, 1995.

RULE 323 – FUEL BURNING COMBUSTION EQUIPMENT FROM INDUSTRIAL-COMMERCIAL-INSTITUTIONAL (ICI) SOURCES

SECTION 100 – GENERAL

101 PURPOSE: To limit the discharge of nitrogen oxides, sulfur oxides, carbon monoxide and particulate matter emissions into the atmosphere from fuel burning combustion equipment at industrial and/or commercial and/or institutional (ICI) sources.

102 APPLICABILITY: This rule applies to any of the following types of ICI combustion equipment that burns either fossil fuels or alternative fuels:

102.1 Each steam generating unit that has a maximum design rated heat input capacity from fuels combusted in the generating unit of greater than 10 million (MM) Btu/hr (2.9 Megawatts (MW)).

102.2 Each stationary gas turbine with a heat input at peak load equal to or greater than 2.9 megawatts (MW).

102.3 Each cogeneration steam generating unit with a heat input of greater than 10 MMBtu/hr.

102.4 Each indirect-fired process heater with a heat input greater than 10 MMBtu/hr.

102.5 **NSPS & NESHAP:** In addition to this rule, facilities may be subject to New Source Performance Standards (NSPS) in Rule 360 and/or National Emission Standards for Hazardous Air Pollutants (NESHAP) in Rule 370 of these Rules and Regulations.

103 EXEMPTIONS: This rule shall not apply to the following types of equipment:

103.1 Incinerators, crematories or burn-off ovens,

103.2 Combustion equipment used in agricultural operations in the growing of crops or the raising of fowl or animals,

103.3 Dryers, cement and lime kilns,

103.4 Direct-fired process heaters,

103.5 Medical waste incinerators,

103.6 Reciprocating internal combustion equipment,

103.7 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,

103.8 Combustion equipment used for the generation of nuclear power, or

103.9 Water heaters used for the sole purpose of heating hot water for comfort or for radiant heat.

104 PARTIAL EXEMPTIONS:

104.1 Stationary gas turbines listed in subsection 102.2 that are used for any of the following reasons shall be exempt from Sections 304, 305 and subsections 301.1, 501.1 and 501.3 of this rule:

a. Used for firefighting, or

b. Used for flood control, or

c. Used at military training facilities other than a garrison facility, or

d. Engaged by manufacturers in research and the development of equipment for either gas turbine emission control techniques or gas turbine efficiency improvements, or

e. Fired with emergency fuel that is normally fired with natural gas, or

f. Testing, reliability, maintenance, training, and readiness purposes for a total of 36 hours per year per unit when firing any emergency fuel.

104.2 All steam generating units including cogeneration units and process heaters that are used for any of the following reasons shall be exempt from Sections 301, 304, 305 and subsections 501.1 and 501.3 of this rule:

a. Fired with an emergency fuel that is normally fired with natural gas or

b. Firing any emergency fuel for testing, reliability and maintenance purposes up to a maximum total of 36 hrs. per unit per year.

SECTION 200 - DEFINITIONS: For the purpose of this rule, the following definitions shall apply See Rule 100 (General Provisions and Definitions) of these rules for definitions of terms that are used but not specifically defined in this rule:

201 ALTERNATIVE FUELS – Substitutes for traditional oil-derived and fossil-fuel derived motor vehicle fuels including but not limited to biodiesel propane, ethanol or methanol.

202 COGENERATION STEAM GENERATING UNIT – A steam or hot water generating unit that simultaneously produces both electrical (or mechanical) and thermal energy (such as heat or steam) from the same primary energy source.

203 CORRECTIVE ACTION PLAN (CAP) – A methodical procedure that is used to evaluate and correct a turbine operational problem and that includes, at a minimum, improved preventative maintenance procedures, improved ECS operating practices, possible operational changes and progress reports.

204 DISTILLATE OIL – A petroleum fraction of fuel oil produced by distillation that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396-01, "Standard Specification for Fuel Oils."

205 EMERGENCY FUEL – Fuel fired by a gas combustion unit, normally fueled by natural gas, only during circumstances of unforeseen disruption or interruption in the supply of natural gas to a unit that normally runs on natural gas.

The inability to burn natural gas may be one of the following but is not limited to natural gas emergency, natural gas curtailment or breakdown of delivery system.

206 EMISSION CONTROL SYSTEM (ECS) - A system approved in writing by the Control Officer, designed and operated in accordance with good engineering practice to reduce emissions.

207 FOSSIL FUEL – Naturally occurring carbonaceous substances from the ground such as natural gas, petroleum, coal and any form of solid, liquid or gaseous fuel derived from such material for the purpose of creating energy.

208 HEAT INPUT – Heat derived from the combustion of fuel not including the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines and kilns.

209 LOW SULFUR OIL – Fuel oil containing less than or equal to 0.05% by weight of sulfur.

210 NATURAL GAS CURTAILMENT – A shortage in the supply of natural gas, due solely to limitations or restrictions in distribution pipelines by the utility supplying the gas and not due to the cost of natural gas.

211 NITROGEN OXIDES (NOx) – Oxides of nitrogen calculated as equivalent nitrogen dioxide.

212 OPACITY – A condition of the ambient air, or any part thereof, in which an air contaminant partially or wholly obscures the view of an observer.

213 PARTICULATE MATTER EMISSIONS - Any and all particulate matter emitted to the ambient air as measured by applicable state and federal test methods.

214 PEAK LOAD - 100% of the manufacturer's design capacity of a gas turbine at 288 Kelvin, 60% relative humidity, and 101.3 kilopascals pressure (ISO standard day conditions).

215 PROCESS HEATERS – An enclosed combustion device that uses controlled flame to transfer heat to a process fluid or a process material that is not a fluid or to heat transfer material for use in a process unit (not including the generation of steam). Process heaters may be either indirect or direct-fired, dependent upon whether the gases of combustion mix with and exhaust to the same stack or vent (direct-fired) with gases emanating from the process material or not (indirect-fired). Emissions from indirect-fired units consist entirely of products of combustion while emissions from direct-fired units are unique to the given process and may vary widely in any industrial process. A process heater is not an oven or kiln used for drying, curing, baking, cooking, calcining or vitrifying.

216 RATED HEAT INPUT CAPACITY - The heat input capacity in million Btu/hr. as specified on the nameplate of the combustion unit. If the combustion unit has been altered or modified so that its maximum heat input is different than the heat input capacity on the nameplate (design heat capacity), the maximum heat input shall be considered as the rated heat input capacity.

217 REGENERATIVE CYCLE GAS TURBINE – Any stationary gas turbine that recovers thermal energy from the exhaust gases and utilizes the thermal energy to preheat air prior to entering the combustor.

218 RESIDUAL OIL – The heavier oils that remain after the distillate oils and lighter hydrocarbons are distilled off in refinery operations. This includes crude oil or fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05% by weight, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396-01, "Standard Specifications for Fuel Oils".

219 SIMPLE CYCLE GAS TURBINE – Any stationary gas turbine that does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or that does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

220 STATIONARY GAS TURBINE – Any simple cycle gas turbine or regenerative gas turbine that is not self-propelled or that is attached to a foundation.

221 STEAM GENERATING UNIT - An external combustion unit or boiler fired by fossil fuel that is used to generate hot water or steam. The hot water or steam is then used as energy for driving another process or piece of equipment.

222 SULFUR OXIDES (SOx) - The sum of the oxides of sulfur emitted from the flue gas from a combustion unit that are directly dependent upon the amount of sulfur in the fuel used.

223 UNCOMBINED WATER – Condensed water containing no more than analytical trace amounts of other chemical elements or compounds.

224 WATER HEATER – A closed vessel in which water is heated by combustion of fuel and water is either withdrawn for use external to the vessel (at pressures not exceeding 160 psi with all controls and devices prevent water temperatures from exceeding 210° F) or used for radiant heat. Water heaters are usually no larger than MM BTU/hr as opposed to boilers, do not reach temperatures of 220° F and higher that boilers can reach and are not manufactured to meet boiler codes.

SECTION 300 - STANDARDS

301 LIMITATIONS - PARTICULATE MATTER:

301.1 Limitation: Liquid Fuels An owner or operator shall not discharge, cause or allow the discharge of particulate matter emissions, caused by combustion of non-gaseous liquid fuels or a blend of liquid fuels with other fuels in excess of 0.10 lbs. per MMBtu heat input from any combustion units listed in subsection 102.1,102.3 and 102.4 with either a rated heat input capacity or heat input of greater than 100 MM Btu/hr.

301.2 Good Combustion Practices: An owner or operator of a stationary gas turbine listed in subsection 102.2, regardless of fuel type or size, shall use operational practices recommended by the manufacturer and parametric monitoring that ensure good combustion control. In lieu of a manufacturer's recommended procedure to ensure good combustion practices, one of the following procedures may be used:

a. Monitor the maximum temperature differential across the combustion burners or at locations around the back end of the turbine, dependent upon the particular unit, to ensure no more than a 100° F difference using a thermocouple. If a valid maximum temperature differential of greater than 100° F is observed across the burners, investigation and corrective action shall be taken within three hours to either reduce the temperature difference to 100° F or less, or

b. If the manufacturer recommends that the maximum numerical temperature differential to ensure good combustion is a temperature that is greater than 100° F, then proof of this maximum alternate temperature shall be submitted to the Control Officer. The procedure to measure the maximum temperature differential listed above in subsection 301.2a shall then be followed using the alternate recommended maximum temperature differential after approval by the Control Officer.

c. If a repetitive pattern of failure to meet the proper temperature differential of 100° F or to meet the alternate temperature differential recommended by the manufacturer indicates that the turbine is not being operated in a manner consistent with good combustion practices, then the Control Officer may require the owner or operator to submit a Corrective Action Plan (CAP).

302 LIMITATIONS – OPACITY: No owner or operator shall discharge into the ambient air from any single source of emissions any air contaminant, other than uncombined water, in excess of 20% opacity.

303 LIMITATIONS - SULFUR IN FUEL:

303.1 An owner or operator of any applicable equipment listed in Section 102 that burns liquid fuel oil or a mixture or blend of fuel oil with any other fuels shall use only low sulfur oil with one exception.

303.2 Existing supplies in storage of the fuel with a sulfur content greater than 0.05% by weight may be used by the owner or operator until (insert 1.5 years after adoption of rule). This usage shall be reported to the Control Officer along with the dates of usage within 72 hours of usage in writing. In the case of continuous or recurring high sulfur fuel use, the notification requirements of this rule shall be satisfied if the source provides the required notification and includes in the notification an estimate of the time for which the high sulfur fuel will be used. High sulfur fuel use that occurs after the estimated time period as originally reported shall require additional notification pursuant to this subsection.

304 LIMITATIONS – NITROGEN OXIDES:

304.1 An owner or operator of any combustion equipment listed in Section 102 with a heat input of greater than 10 MMBtu/hr. to 100 MMBtu/hr, except gas turbines, shall comply either with a or b below:

a. Establish initial optimal baseline concentrations for NOx and CO utilizing the initial design burner specifications or manufacturer's recommendations to ensure good combustion practices. Tune the unit annually in accordance with good combustion practices or a manufacturer's procedure, if applicable, that will include the following at a minimum:

1. Inspect the burner system and clean and replace any components of the burner as necessary to minimize emissions of NOx and CO, and

2. Inspect the burner chamber for areas of impingement and remove if necessary, and

3. Inspect the flame pattern and make adjustments as necessary to optimize the flame pattern, and

4. Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly, and

5. Measure the NOx and the CO concentration of the effluent stream after each adjustment was made with a handheld portable monitor to ensure optimal baseline concentrations are maintained or

b. Limit nitrogen oxide emissions to no more than the following amounts:

1. 155 ppm per MMBtu heat input, calculated as nitrogen dioxide, when burning gaseous fuel. During steady state operations, this test result using EPA Reference Method(s) 7 shall be based upon the arithmetic mean of the results of three test runs. Each test run shall have a minimum sample run time of one hour.

2. 230 ppm per MMBtu heat input, calculated as nitrogen dioxide, when burning liquid fuel. During steady state operations, this test result using EPA Reference Method(s) 7 shall be based upon the arithmetic mean of the results of three test runs. Each test run shall have a minimum sample run time of one hour.

304.2 An owner or operator of any combustion equipment, listed in Section 102, with a heat input greater than 100 MMBtu/hr, shall:

a. Tune the equipment every six months with good combustion practices or a manufacturer's procedure that at a minimum includes the procedures listed in subsection 304.1a. and

b. Meet the NOx emission limits as stated in subsection 304.1b.

305 LIMITATIONS – CARBON MONOXIDE: No owner or operator of any equipment listed in Section 102 with a heat input greater than 100 MM Btu/hr shall cause to be discharged into the atmosphere, carbon monoxide (CO), measured in excess of 400 ppmv, during steady state source testing. This test result, using EPA Reference Method 10, shall be based upon the arithmetic mean of the results of three test runs. Each test run shall have a minimum sample time of one hour. For simple gas turbines, the CO shall be measured dry and corrected to 15% oxygen. For all other combustion equipment, the CO shall be measured dry and corrected to 3% oxygen.

306 REQUIREMENTS FOR AIR POLLUTION CONTROL EQUIPMENT AND ECS MONITORING EQUIPMENT:

306.1 Emission Control System Required: For affected operations which may exceed any of the applicable standards set forth in Sections 300 of this rule, an owner or operator may comply by installing and operating an emission control system (ECS).

306.2 Providing and Maintaining ECS Monitoring Devices: No owner or operator required to use an approved ECS pursuant to this rule shall do so without first providing properly installing, operating and maintaining in calibration and in good working order, devices for indicating temperatures, pressures, transfer rates, rates of flow, or other operating conditions necessary to determine if air pollution control equipment is functioning properly and is properly maintained as described in an approved O&M Plan.

306.3 Operation and Maintenance (O&M) Plan Required For ECS:

- **a. General Requirements:** An owner or operator shall provide and maintain an O&M Plan for any ECS, any other emission processing equipment, and any ECS monitoring devices that are used pursuant to this rule or to an air pollution permit.
- **b. Approval by Control Officer:** An owner or operator shall submit to the Control Officer for approval the O&M Plans of each ECS and each ECS monitoring device that is used pursuant to this rule.
- **c. Initial Plans:** An owner or operator that is required to have an O&M Plan pursuant to this rule shall comply with all O&M Plans that the owner or operator has submitted for approval, but which have not yet been approved, unless notified by the Control Officer in writing. Once the initial plan has been approved in writing by the Control Officer, an owner or operator shall comply with this approved plan.
- **d. Revisions to Plan:** If revisions to the initial plan have been approved by the Control Officer in writing, an owner or operator shall comply with the revisions to the initial plan.
- **e. Control Officer Modifications to Plan:** After discussion with the owner or operator, the Control Officer may modify the plan in writing prior to approval of the initial O&M plan. An owner or operator shall then comply with the plan that has been modified by the Control Officer.

SECTION 400 - ADMINISTRATIVE REQUIREMENTS

401 COMPLIANCE SCHEDULE

401.1 Operation and Maintenance (O&M) Plan: Any owner or operator employing an approved ECS on the effective date of this rule shall by (insert eight months after rule is adopted) file an O&M Plan with the Control Officer in accordance with subsection 306.3 of this rule.

401.2 Modifications to Existing ECS: Any owner or operator required to modify their ECS equipment or system by either reconstructing or adding on new equipment for compliance with this rule shall by (insert eight months after rule is adopted) file a schedule for the modification with the Control Officer. The plan shall show how the ECS is to be used to achieve full compliance and shall specify dates for completing increments of progress. Any and all ECS used to achieve such compliance shall be in operation by (Insert 24 months date of adoption of rule).

401.3 ECS Installation: An owner or operator required to install a new ECS for compliance with this rule shall by (insert eight months after rule is adopted) file a schedule for the installation with the Control Officer. The ECS shall then be installed and in compliance by (36 months after adoption of the rule).

SECTION 500 - MONITORING AND RECORDS

501 RECORDKEEPING AND REPORTING: An owner or operator subject to this rule shall comply with the requirements set forth in this section. Any records and data required by this section shall be kept on site at all times in a consistent and complete manner and be made available without delay to the Control Officer or his designee upon request. Records shall consist of the following information:

501.1 Equipment Listed In Section 102: Type of fuel used, amount of fuel used, amount of sulfur in the fuel if using liquid fuel, and the days and hours of operation.

501.2 Emergency Fuel Usage – Type of emergency fuel used, dates and hours of operation using emergency fuel, nature of the emergency or purpose for the use of emergency fuel as stated in subsections 104.1 and 104.2, and monthly totals for twelve-month log of hours of operation in the emergency mode.

501.3 Good Combustion Practice – Measurements of the temperature differential across the burners of turbines per subsection 301.2, results of evaluation and corrective action taken to reduce the temperature differential or a finding that the temperature differential returned to the range listed in subsection 301.2 a or b without any action by the owner or operator.

501.4 **Tuning Procedure** – Date that the procedure was performed on the particular unit and at a minimum: stack gas temperature, flame conditions, nature of the adjustment and results of the nitrogen oxide and carbon monoxide concentrations obtained by using a handheld monitor after each adjustment.

502 **RECORDS RETENTION:** Copies of reports, logs and supporting documentation required by the Control Officer shall be retained for at least five years. Records and information required by this rule shall also be retained for at least five years.

503 **COMPLIANCE DETERMINATION:**

503.1 **Low Sulfur Oil Verification:**

a. An owner or operator shall submit fuel oil receipts from the fuel supplier indicating the sulfur content of the fuel oil or verification that the fuel oil used meets the 0.05% sulfur limit if requested by the Control Officer, or

b. If fuel receipts are not available, an owner or operator shall submit a statement of certification or proof of the sulfur content of the fuel oil from the supplier to the Control Officer, or

c. An owner or operator may elect to test the fuel oil for sulfur content in lieu of certification from the fuel supplier or fuel receipts.

504 **TEST METHODS ADOPTED BY REFERENCE:** The EPA test methods as they exist in the Code of Federal Regulations (CFR) (July 1, 2001), as listed below, are adopted by reference. These adoptions by reference include no future editions or amendments. Copies of test methods referenced in this Section are available at the Maricopa County Environmental Services Department, 1001 N. Central Avenue, Phoenix, AZ 85004-1942. The ASTM methods (1990, 1992, 1998, and 2000) are also adopted by reference. When more than one test method as listed in subsection 504.10 to 504.13 is permitted for the same determination, an exceedance of the limits established in this rule determined by any one of the applicable test methods constitutes a violation

504.1 EPA Reference Methods 1 (“Sample and Velocity Traverses for Stationary Sources”), 1a (“Sample and Velocity Traverses for Stationary Sources with Small Stacks and Ducts”) (40 CFR 60, Appendix A).

504.2 EPA Reference Methods 2 (“Determination of Stack Gas Velocity and Volumetric Flow Rate”), 2A (“Direct Measurement of Gas Volume Through Pipes and Small Ducts”), 2C (“Determination of Stack Gas Velocity and Volumetric Flow Rate in Small Stacks or Ducts”) and 2D (“Measurement of Gas Volumetric Flow Rates in Small Pipes and Ducts”) (40 CFR 60, Appendix A).

504.3 EPA Reference Method 3 (“Gas Analysis for the Determination of Dry Molecular Weight”), 3A (“Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure)”), 3B (“Gas Analysis for the Determination of Emission Rate Correction Factor of Excess Air”), 3C (“Determination of Carbon Dioxide, Methane, Nitrogen and Oxygen from Stationary Sources”) (40 CFR 60, Appendix A).

504.4 EPA Reference Method 4 (“Determination of Moisture Content in Stack Gases”) (40 CFR 60, Appendix A).

504.5 EPA Reference Method 5 (“Determination of Particulate Emissions from Stationary Sources”) (40 CFR 60, Appendix A) and possibly, if requested by the Control Officer, EPA Reference Method 202 (“Determination of Condensable Particulate Emissions from Stationary Sources”) (40 CFR 51, Appendix M).

504.6 EPA Reference Method 7 (“Determination of Nitrogen Oxide Emissions from Stationary Sources”), 7A (“Determination of Nitrogen Oxide Emissions form Stationary Sources”), 7B (“Determination of Nitrogen Oxide Emissions from Stationary Sources – Ultraviolet Spectrometry”), 7C (“Determination of Nitrogen Oxide Emissions from Stationary Sources – Alkaline-Permanganate Colorimetric Method”), 7D (“Determination of Nitrogen Oxide Emissions from Stationary Sources – Alkaline – Permanganate Chromatographic Method”), 7E (“Determination of Nitrogen Oxide Emissions from Stationary Sources – Instrumental Analyzer Method“), (40 CFR 60, Appendix A).

504.7 EPA Reference Method 9 (“Visual Determination of the Opacity of Emissions from Stationary Sources”) (40 CFR 60, Appendix A).

504.8 EPA Reference Method 10, (“Determination of Carbon Monoxide from Stationary Sources”) (40 CFR 60, Appendix A).

504.9 EPA Reference Method 20 (“Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions From Stationary Gas Turbines”) (40 CFR 60, Appendix A).

504.10 American Society of Testing Materials, ASTM Method #D2622-92 or 98, (“Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry”), 1992 or1998.

504.11 American Society of Testing Materials, ASTM Method #D1266-98, (“Standard Test Method for Sulfur in Petroleum Products (Lamp Method)”), 1998.

504.12 American Society of Testing Materials, ASTM Method #D2880-00, (“Standard Specification for Gas Turbine Fuel Oils”), 2000.

504.13 American Society of Testing Materials, ASTM Method #D4294-90 or 98, (“Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy- Dispersive X-ray Fluorescence Spectrometry, 1990 or 1998.