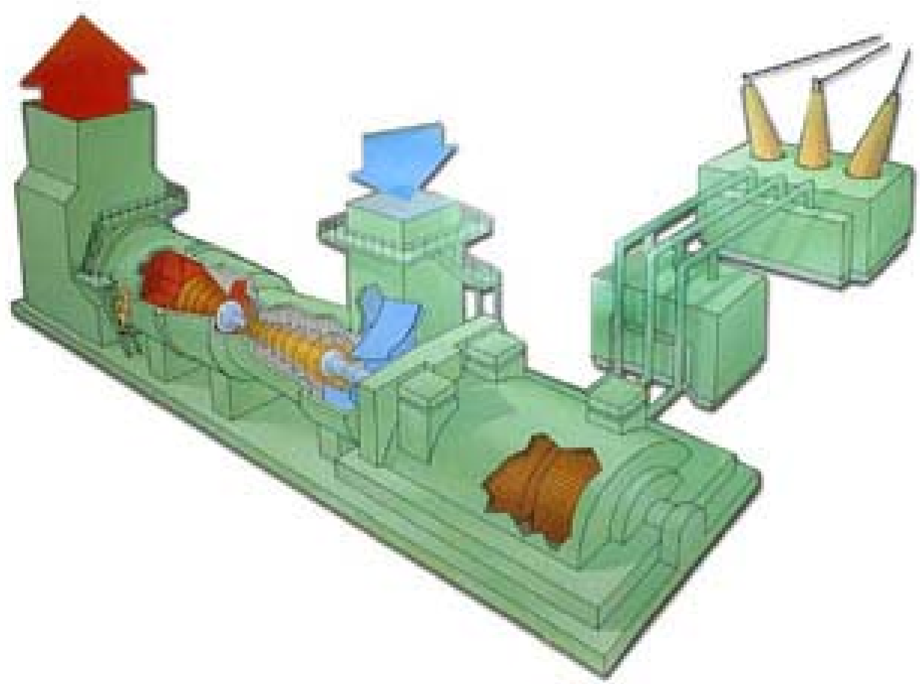
Bay Area Air Quality Management District

939 Ellis Street
San Francisco, CA 94109

Bay Area 2005 Ozone Strategy
Control Measure SS 14

BAAQMD Regulation 9, Rule 9:
Nitrogen Oxides from Stationary Gas Turbines



Staff Report
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REGULATION 9, RULE 9
Nitrogen Oxides from Stationary Gas Turbines

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I. EXECUTIVE SUMMARY

Staff of the Bay Area Air Quality Management District (BAAQMD or District) is proposing amendments to District Regulation 9, Rule 9: Nitrogen Oxides from Stationary Gas Turbines. The proposed amendments will require certain gas turbines in the Bay Area to be retrofitted with pollution control devices to reduce emissions of nitrogen oxides (NOx), one of the main contributors to ozone (smog) formation. Staff has developed these proposed amendments to implement Control Measure SS 14 in the Bay Area 2005 Ozone Strategy. The proposed amendments are expected to reduce NOx emissions from gas turbines by 0.43 tons per day, which combined with recent turbine shutdowns, is a reduction of approximately 10% from current levels.

The proposed amendments will:

- **Reduce NOx Emission Limits For Certain Classes Of Turbines.** Where turbines can feasibly be retrofitted to improve their NOx emissions performance, the proposed amendments lower the applicable NOx emissions limits to levels that can be achieved by the available retrofit technology.
- **Change the Way Turbine Size Is Measured To More Accurately Reflect Turbine Capacity.** The current rule measures turbine size by electrical generating capacity. This approach does not adequately account for other types of work produced by some turbines, such as steam or mechanical work. The proposed amendments classify turbines by heat input rate instead of electrical output in order to account for all of the work a turbine produces.
- **Provide "Output Based" NOx Emission Limits.** The proposed amendments specify alternative compliance standards based on the mass of NOx emitted per unit of work produced. These "output based" alternative standards will encourage energy efficiency, which supports efforts to reduce CO_2 emissions to address emissions related to global climate change.
- **Make Other Miscellaneous Changes to Improve Clarity and Enforceability.**

The proposed amendments are the culmination of a comprehensive rule development process that included dialog and visits with a large number of facilities, as well as two public workshops, in May and October 2006. Staff used the information gathered through this process to develop site-specific cost estimates for different types of NOx control retrofit projects, and validated them with equipment vendors. Staff assessed the impacts on each facility's capacity, thermal efficiency, and operating costs, and then developed the NOx emissions limit proposals by analyzing incremental cost-effectiveness of each of the technologies identified.

A socioeconomic analysis of the proposed amendments concludes that the amendments would not have significant economic impacts. An initial study of the proposed amendments conducted pursuant to the California Environmental Quality Act (CEQA) concludes that the rule amendments would not cause significant environmental impacts. Staff is proposing the approval of a CEQA negative declaration along with the proposed amendments.

II. BACKGROUND

A. Introduction

Ozone is the principal component of smog. Ozone is highly reactive, and at high concentrations near ground level can be harmful to public health. The Bay Area and neighboring regions are not yet in attainment with the State one-hour ozone standard, so further reductions in ozone precursors, nitrogen oxides (NOx) and reactive organic gases (ROG) are needed. Ozone forms when NOx chemically reacts with ROG. Ozone formation is higher in the summer when warm temperatures and strong sunlight facilitate the reaction.

The Bay Area 2005 Ozone Strategy continues on-going Bay Area efforts to reduce ozone precursors in order to assure that the region attains and maintains compliance with health-based ozone standards and to reduce transport to neighboring regions. The District is considering adopting amendments to Regulation 9, Rule 9 in connection with Control Measure SS-14 in the District's 2005 Ozone Strategy. In Control Measure SS-14, the District committed to evaluate emissions of NOx from stationary gas turbines and determine if recent advances in NOx emissions control technology could be implemented to further reduce NOx emissions from the stationary gas turbines in the Bay Area.

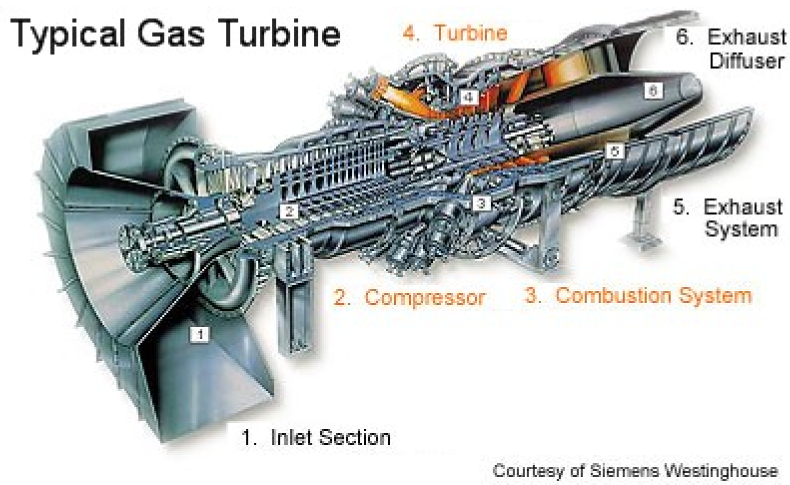
The Bay Area is also not in attainment for the California standards for particulate matter (both 10 microns in size and smaller [PM_{10}], and 2.5 microns and smaller [$PM_{2.5}$]). In the winter months, NOx and other pollutants react to produce secondary $PM_{2.5}$ in the form of nitrates. NOx reductions will have the added benefit of reducing secondary $PM_{2.5}$ formation.

B. Source Description

A gas turbine is an internal combustion engine that consists of a compressor, a combustor and a power turbine. The compressor provides pressurized air to the combustor where the fuel is burned. Hot exhaust gases enter the power turbine where the gases expand across the turbine blades, driving one or more shafts to power the compressor and an electric generator or other device. Stationary gas turbines are generally used to generate electricity, although some are designed to compress gases or pump water. Natural gas is the most common fuel, but gas turbines can burn refinery process gas, landfill or sewage digester waste gas, liquefied petroleum gas (LPG), and most liquid fuels.

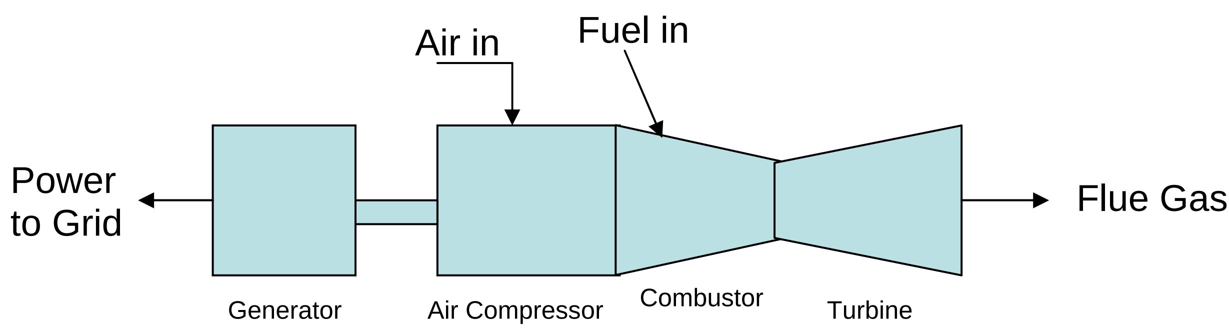
There are two major types of gas turbines. Industrial gas turbines, which evolved from aircraft jet engines, are generally more durable and powerful than aeroderivatives. Aeroderivatives are aircraft jet engines used in ground installations. Aeroderivatives are lightweight, compact and less powerful than industrial gas turbines. However, aeroderivatives operate at higher compression ratios and thus are more efficient than industrial gas turbines. Figure 1 shows a cutaway view of a typical gas turbine.

Figure 1



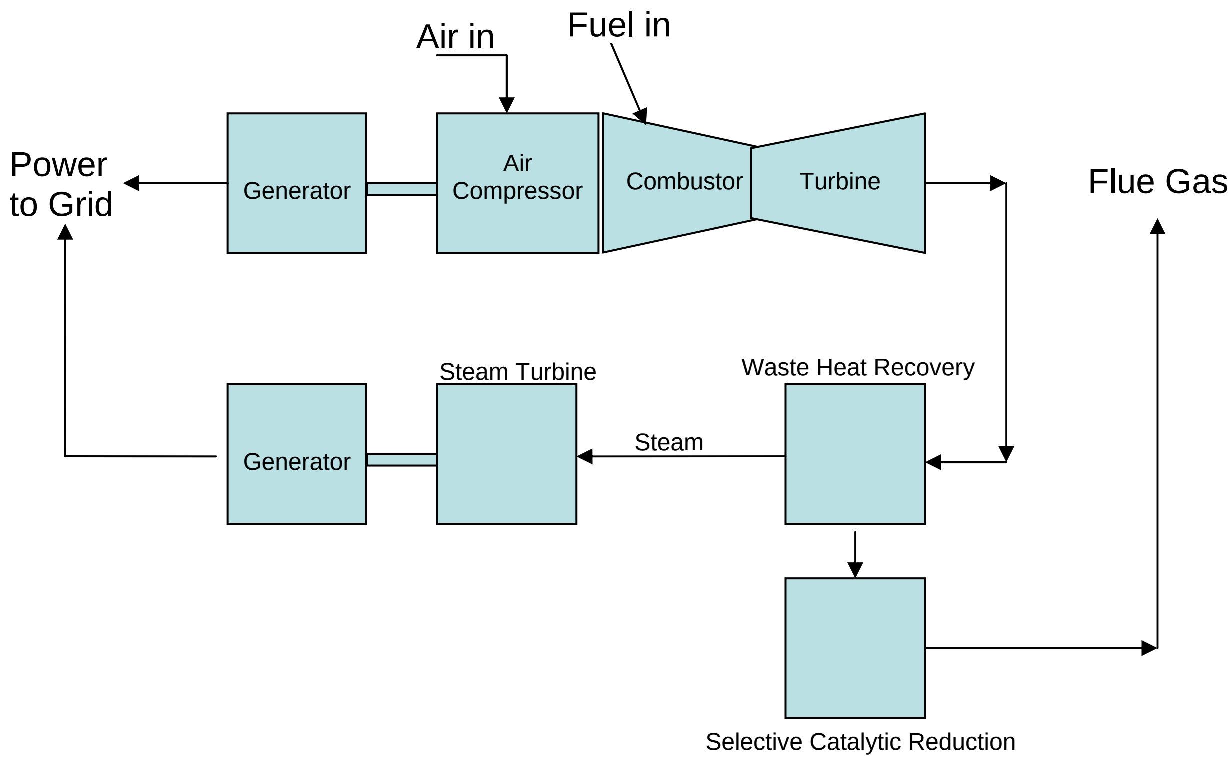
Gas turbines can be designed in two configurations. Simple cycle gas turbines do not recover secondary heat from the hot combustion gases for additional electrical or steam productivity, and therefore have a thermal efficiency between 25 and 41%. Simple cycle gas turbines have flue gas exhaust temperatures of 700 – 900°F. These gas turbines are generally used to supplement electricity during "peak" electrical demand periods, and are commonly referred to as "peaking" power turbines. Figure 2 is a schematic diagram of a simple cycle gas turbine.

Figure 2: Simple Cycle Gas Turbine



Combined cycle gas turbines recover the "waste heat" in the flue gas stream to produce additional electricity. Cogeneration gas turbines recover waste heat to produce steam for a wide variety of commercial uses. These plants have a thermal efficiency of 45 to 52% and flue gas exhaust temperatures of 300 – 500°F. These gas turbines are generally used for base load electrical generation. Figure 3 is a schematic diagram of a combined cycle gas turbine.

Figure 3: Combined Cycle Gas Turbine



There are 155 permitted turbines in the Bay Area. These units cover a wide range of sizes, fuels (natural gas, refinery or waste gas, or liquid fuels), operating configurations (simple cycle, cogeneration or combined cycle), operating modes (continuous, intermittent, or emergency standby), and existing NOx limits. These turbines currently emit an estimated 6.5 tons/day of NOx. These emissions were calculated based on a review of each permitted turbine's current fuel use, permit conditions, and source tests.

Ninety two of the 155 gas turbines operate continuously in a wide variety of applications. Forty three of these turbines are large, greater than 10 Megawatt (MW) capacity. Twenty one large gas turbines currently emit NOx below Best Available Retrofit Control Technology (BARCT) levels, as further described in Section IIIA. Another 10 large gas turbines are already equipped with NOx Selective Catalytic Reduction (SCR) systems. Thirteen are mid-sized turbines, ranging from 3 to 10 MW. Thirty six gas turbines are small, less than 3 MW, and do not generate enough NOx to be good candidates for any significant reductions beyond current requirements.

Of the continuously operating turbines, nine large and six mid-sized gas turbine power trains burn refinery fuel or waste gas as their primary fuel. Two large turbines burn diesel fuel. Refinery fuel gas, waste gas, and liquid fuels generate more NOx than natural gas, because it is more difficult to control turbine flame temperatures when burning a mixture of gases or liquids. There has been very little technology development effort to improve NOx performance from turbines burning gas or liquid mixtures, so options for significant improvements from these turbines are very limited.

Fifteen turbines operate intermittently as peaking power turbines. In spite of their low utilization, the largest of these intermittent use turbines may still be good candidates for NOx reductions. Forty eight turbines operate on a limited use basis, less than 877 hours per year. Eleven are used for testing and research, and 37 are used for standby/emergency power. Most of these turbines only operate a few hours each week, or are tested monthly.

A picture of a typical simple cycle gas turbine facility is shown in Figure 4.

Figure 4. Typical simple cycle gas turbine power generator

C. Current Retrofit Technology For Reducing NOx Emissions

There are two basic approaches for reducing NOx emissions: 1) minimize NOx generated during combustion; and 2) treat exhaust gases with various agents to reduce the NOx therein. The primary means for controlling generation of NOx emissions is to prevent NOx formation by cooling the flame temperature inside the combustion chamber in the gas turbine. In the earliest efforts to reduce combustion emissions, steam or water was injected into the combustor to absorb heat and cool the peak combustion temperature. A more recent approach is to regulate the flow of fuel into the combustor and thoroughly mix the fuel with the air using Dry Low NOx (DLN) combustion technology to reduce combustion temperatures. Most manufacturers have developed DLN technology for their new gas turbines, but offer retrofit DLN on only select models of their older gas turbines. A few manufacturers have incorporated catalysts into their combustor designs to achieve complete combustion at even lower flame temperatures.

The primary means to treat NOx emissions after they are created is by chemically reacting the NOx with ammonia or urea in the presence of a catalyst to convert the NOx back into nitrogen. This process is referred to as Selective Catalytic Reduction (SCR). This technology has demonstrated 90 - 95% effectiveness in reducing NOx.

D. Regulatory History

The 1988 California Clean Air Act (CCAA) set the state's overall air quality planning requirements. The CCAA requires the District to adopt BARCT for existing permitted stationary sources. The California Air Resources Board (ARB), in coordination with local air districts, developed a guidance document in 1992 entitled "Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for the Control of Oxides of Nitrogen from Stationary Gas Turbines" to aid local districts with the adoption of NOx regulations. The RACT/BARCT Guidelines included a suggested NOx control rule for air districts to use in developing their respective BARCT rules for the control of NOx from gas turbines. The District used this ARB guideline as a template for Regulation 9, Rule 9. Regulation 9, Rule 9 was adopted pursuant to the region's first plan prepared under the CCAA's ozone planning requirements, the Bay Area 1991 Clean Air Plan (CAP). Regulation 9, Rule 9 was adopted on May 5, 1993, and amended on September 21, 1994 to accommodate a delay in development of combustion technology necessary to meet the NOx standards. By January 1, 1997 all gas turbines subject to the regulation were required to be in compliance with all applicable standards.

E. Current Rule

The current rule sets NOx emission limits for various classes of turbines based on turbine size (measured by electrical generating capacity), with the largest turbines subject to the most stringent standards. The rule also provides slightly higher limits for turbines that burn refinery fuel gas or liquid fuel, because those fuels burn hotter and therefore generate more NOx. The standards in the current rule are summarized in Table 1:

Table 1: Current Regulation 9, Rule 9 Emissions Limits

Turbine Size	NOx Emission Limit (ppm)		
	Natural Gas	Refinery Fuel Gas	Oil
< 0.3 MW	Exempt	Exempt	Exempt
> 0.3MW and < 10MW	42	55	65
> 10MW, without SCR	15	15	42
> 10MW, with SCR	9	9	25

For turbines over 10 MW, the current rule also provides a credit for high thermal efficiency. More efficient units use less fuel, resulting in less total emissions. Turbines with a design efficiency of greater than 25% are allowed to adjust their emission limits to higher levels based on how efficient they are.

The current rule also provides separate emission standards for low-usage turbines, defined as turbines that operate less than 877 hours per year (approximately 10% of the time). These turbines must meet a 42 ppm NOx emission limit when burning natural gas and a 65 ppm limit when burning liquid fuel. Small low-usage turbines (less than 4 MW) are exempt from the rule.

Since the current rule was adopted, there have been improvements in turbine emission control devices. In 1999, ARB published "Guidance for Power Plant Siting and Best Available Control Technology" which identified possible controls for new, large (> 50 MW) power generating turbines. Other districts, including the South Coast AQMD and the San Joaquin Valley Unified Air Pollution Control District, have updated their gas turbine rules to reflect these developments. The Bay Area AQMD is similarly revisiting its rule through Control Measure SS-14 and these proposed amendments.

III. PROPOSED RULE AMENDMENTS

A. Introduction

The California Clean Air Act requires that the District adopt “every feasible measures” to reduce air pollution. *See* Health & Safety Code § 40914(b). In addition, California Health & Safety Code section 40919(a)(3) directs the District to require the use of Best Available Retrofit Control Technology (BARCT), which is defined as “the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source.” In accordance with these statutory mandates, staff has evaluated the NOx control technologies available for stationary gas turbines to determine the most stringent requirements that would be technically and economically feasible for each class of turbine in the Bay Area.

It is important to note that Regulation 9, Rule 9 and the proposed amendments address existing turbines already in use in the Bay Area. When new turbines are installed (or when existing turbines undergo a major modification), they are subject to the more stringent “Best Available Control Technology” (BACT) requirements of District Regulation 2, Rule 2. BACT emissions controls can now achieve less than 2–2.5 parts per million (ppm) NOx from combined cycle or cogeneration gas turbine trains, and less than 5 ppm NOx from simple cycle gas turbine configurations. The proposed amendments address technologies that can be used to retrofit existing turbines to improve their emissions performance. Retrofitting existing equipment is typically not as effective as incorporating NOx control technology directly into the design of new equipment. It is therefore not feasible to achieve the very low BACT emissions performance levels of new turbines with BARCT retrofit technology applied to existing turbines. As new units come on line and older units are retired, however, the Bay Area will move towards the lowest BACT levels at all turbines.

The retrofit control technology currently available for existing turbines includes improvements in water and steam injection methods, DLN combustion technology, and improvements in the performance of SCR catalysts that have occurred since this rule was last amended in 1994. (These technologies are described in more detail in Section II.C.

above.) Staff has evaluated which of these technologies are feasible for particular classes of turbines. The proposed amendments are based on the most effective technology feasible.

This section outlines what the proposed amendments will require for each class of turbine. The discussion addresses turbines in full-time use first, and then addresses limited-use turbines that operate less than 877 hours per year (10% of the time), which require special consideration because their limited usage means that they are not producing as much NOx even without retrofits. The other miscellaneous changes that would be made by the proposed amendments are described at the end of this section.

B. Turbines in Full-Time Use

The NOx emissions performance that can be feasibly achieved with retrofit controls depends on the size and application of the gas turbine. Small turbines generate less NOx, so control techniques for these turbines are very different than those for large combined cycle or cogeneration gas turbines. In addition, some units are distributed power generators located in space-constrained locations that may not physically have the room for large retrofit control systems. The proposed amendments therefore categorize turbines by size, with more stringent controls required for the larger units.

The proposed amendments also change the metric by which turbine size is measured in order to more accurately reflect the true capacity of each unit. Turbine size is currently measured in terms of megawatts (MW) of electrical generation. However, this approach does not reflect other types of energy generated by some turbines, such as steam or mechanical energy. Staff therefore proposes to use heat input instead of electrical generating capacity to determine turbine size. Heat input captures all types of energy generated by a turbine, and is also more directly related to emissions generated. Gas turbines and cogeneration or combined cycle facilities have widely different thermal efficiencies, which can create inconsistencies in the turbine categories. Staff has found that categorizing turbine size by heat input, commonly referred to as turbine heat input rating is a much more direct method. Turbine heat input for the gas turbine's nameplate rated output at standard conditions is a common design parameter, and characterizes turbine size directly. The proposed amendments contain a definition of turbine heat input rating, which would be measured in millions of British thermal units per hour (MMBtu/hr). (For ease of reference, this Staff Report will refer to turbine sizes by both heat input rating in MMBtu/hr and the approximate equivalent electrical generating capacity in MW.)

The proposed amendments for each class of turbines are set forth below, and are summarized in Table 2 at the end of the discussion.

<u>Very Small Gas Turbines</u>: The proposed amendments retain the current exemption for all gas turbines less than 5 MM Btu/hr turbine heat input rating (~ 0.3 MW equivalent). These gas turbines are not large enough to justify requiring NOx emissions controls.

Small Gas Turbines: For facilities with turbine heat input ratings from 5 to 50 MM Btu/hr. (~0.3 to 3.0 MW equivalent), staff is not proposing any changes to the existing emission limits. These units provide little opportunity for significant NOx reductions.

Mid-size Gas Turbines: For facilities with turbine heat input ratings from 50 to 150 MM Btu/hr (~3.0 to 10 MW equivalent), there are two types of retrofit control technology that are feasible: enhanced water or steam injection, and DLN combustion technology. The proposed amendments establish NOx emission limits based on the performance achievable by commercially available technologies for each make and model of turbine and for the type of fuel.

If water or steam injection enhancement technology is commercially available for a particular combination of turbine and fuel, the proposal reduces the NOx limit to 35 ppm. These enhancements are technically and economically feasible. Cost ranges from $7,000 to $19,000 per ton of NOx reduced.

If DLN combustion technology is commercially available for a particular combination of turbine and fuel, the proposal reduces the NOx limit to 25 ppm. This technology has a cost ranging from $15,000 to $18,000 per ton of NOx reduced.

If no retrofit technology is commercially available for the specific make and model of gas turbine, with its specific fuel, the proposal retains the NOx emission limit at 42 ppm.

The proposed amendments recognize that water or steam injection enhancements or DLN combustion technology systems are not available for all existing units and fuel combinations. Even some that are available may not meet the required emissions limit. The proposed amendments therefore include a definition of "commercially available" to make it clear when an operator must retrofit a turbine. The definition of "commercial availability" requires that the technology retrofit system be offered by at least one vendor, be guaranteed to achieve the required emission control performance for the specific make and model of turbine, and have been demonstrated in practice to achieve the required emissions control performance using a similar fuel composition.

Water/steam injection enhancements and DLN combustion technology may be developed in the future for some existing turbines in the Bay Area. The proposal requires that turbine operators retrofit a turbine if and when these technologies become commercially available for the particular type of turbine and type of fuel burned, and provides a mechanism for compliance in such situations. If and when these specific technologies become commercially available for a particular make and model of turbine and type of fuel, the District will make a determination that the technology is commercially available and will notify the operators of all such turbines within the District. If a facility cannot meet the more stringent NOx emissions limit, this notification will start the compliance timeline for planning, permitting, acquisition and installation of new equipment, including the requirement for an application for Authority to Construct within 18 months, and compliance within 36 months. Facilities will also be provided with an appeal process should they disagree that the new technology is in fact commercially available for their make and model of turbine. The proposed amendments also make clear that no turbine will be required to retrofit more than once, for example by installing enhanced water or steam injection if and when it becomes commercially available and then having to install DLN technology later if and when that technology becomes commercially available. Successive retrofits would be very costly and would not provide commensurate NOx-reduction benefits.

Large Gas Turbines: For facilities with turbine heat input ratings from 150 to 250 MM Btu/hr (~10 to 18 MW equivalent), the proposed amendments retain the current emissions standard of 15 ppm. These gas turbines already have enhanced water or steam injection or DLN combustion technology installed in order to achieve the existing 15 ppm NOx emission limit. The potential for further reduced NOx is limited, and the use of control technology such as SCR is costly. Accordingly, staff is not recommending additional control for this class of turbines at this time. Staff will continue to monitor developments in SCR and DLN technology and will consider further amendments if the situation changes.

Larger Gas Turbines: For facilities with turbine heat input ratings from 250 to 500 MM Btu/hr (~18 to 40 MW equivalent), staff proposes to lower the emission standard to 9 ppm. For facilities without an SCR system, this represents a reduction in NOx limits from 15 ppm to 9 ppm. (Facilities with an SCR system are already subject to the 9 ppm limit.) All six turbines in this category are already achieving 9 ppm NOx. The proposed amendments will lock in that level of performance and prevent backsliding. Staff considered a further reduction to 5 ppm, which would require installation of state-of-the-art DLN, a new SCR, or enhancements to the existing SCR. Since the NOx reductions from 9 ppm to 5 ppm are modest, however, staff is not recommending requiring additional reductions for this class of turbines at this time. As with the 150 to 250 MM Btu/hr turbines, staff will continue to monitor technological progress and will consider further amendments if the situation changes.

Largest Gas Turbines: For facilities with turbine heat input ratings greater than 500 MM Btu/hr (~40 MW plus), staff proposes an emissions standard of 5 ppm. For facilities without an SCR system, this represents a reduction in the NOx limit from 15 ppm to 5 ppm. For facilities with an existing SCR system, this proposal represents a reduction in the NOx limit from 9 ppm to 5 ppm. To comply with this limit, turbines in this size category will have to:

- enhance their SCR and ammonia injection system;
- install an SCR system; or
- install state-of-the-art DLN.

SCR systems and state-of-the-art DLN are very expensive, but for these largest gas turbines the NOx reductions are also significant. Costs range from $10,000 to $20,000 per ton of NOx reduced. For facilities that already have SCR systems, several facilities confirmed that additional ammonia injection reduced NOx emissions as required under the proposed amendments. Maintenance of ammonia injection equipment and SCR catalyst replacement may be required for some facilities.

<u>Emissions Limits For Turbines Burning Fuels Other Than Natural Gas:</u> Most gas turbines burn natural gas because it is readily available in most locations, it is the cleanest burning fuel and very consistent in quality and heating value. As a result, most of the low NOx research and development work for gas turbines has been focused on use of natural gas. However, some turbines do burn refinery process gas, landfill gas, or vaporized LPG. Each of these fuel sources has either a higher heating value, more variation in heating value, or both. These factors create hotter flames and generate more NOx in the combustion chamber. Gas turbines burning these fuels generate higher NOx, and have fewer retrofit technology options available. The proposed amendments therefore establish higher NOx emission limits for turbines burning these other fuels to reflect the fact that they cannot realistically meet the same limits as natural gas turbines.

The proposed amendments also broaden the definition of these other fuels beyond refinery process gas to include waste gas (generally landfill gas or sewage digester gas), LPG, and mixtures of any of these fuels with natural gas. They also provide for situations where gas turbines burn a mixture of fuels. This typically occurs in a refinery or at a landfill, where the normal fuel is refinery fuel gas or landfill waste gas, but can be supplemented with natural gas. This can also occur when natural gas may be supplemented by vaporized LPG. In these cases, the mixture of fuels will almost always burn with a higher flame temperature than natural gas alone, resulting in higher NOx emissions. The NOx emission limit for the mixture should therefore be the highest of the limits applicable to any of the fuels in the mixture.

The limits applicable to particular classes of turbine when burning different fuels are summarized below in Table 2. For turbines with a heat input rating between 5 and 150 MMBtu (~0.3 to 10 MW) that burn refinery process gas, Staff is proposing to reduce the NOx emissions limit from 55 ppm to 50 ppm, because several gas turbines that burn refinery process gas have steam injection enhancements available. These retrofit enhancements will reduce NOx generation by approximately 20%. This NOx reduction is technically and economically feasible. Staff proposes no changes to the NOx emissions limits for gas turbines burning liquid fuels. There are no gas turbines operating full time in the Bay Area burning liquid fuels.

<u>Alternative “Output Based” Emission Standards:</u> The current regulation’s emission limits are based on concentrations of NOx in turbine exhaust, expressed as parts per million (ppm). The proposed amendments continue to express the emissions limits in ppm, but also provide an alternative expression in terms of the mass of NOx emitted per unit of useful work generated by the turbine, quantified as pounds per megawatt-hour (lb/MW-hr). Turbine operators would be able to use either the concentration (ppm) limit or the mass (lb/MW-hr) limit to determine compliance.

Expressing emission limits in terms of pounds per megawatt-hour encourages energy efficiency as a preventive means to reduce emissions, because a more efficient turbine generating more megawatt-hours from a given amount of fuel will be rewarded with a higher effective NOx limit than a less-efficient turbine. The current rule attempts to achieve this result by allowing an upward adjustment in the ppm emission limits based on thermal efficiency, but the adjustment is available only for large turbines over 10 MW, and it requires an efficiency adjustment calculation comparing each turbine's thermal efficiency to a 25% efficiency benchmark. Using a lb/MW-hr standard improves on this approach because it incorporates energy-efficiency directly, without the need for an adjustment calculation, and because it extends the energy-efficiency benefits to all classes of turbines.

The Environmental Protection Agency (EPA) has encouraged this approach in its revised Standards of Performance for Stationary Combustion Turbines, which were published on July 6, 2006. (*See* 71 Fed. Reg. 38482 (July 6, 2006), to be codified at 40 C.F.R. pt. 60, subpt. KKKK.) EPA calls these limits "output based" emissions standards. EPA recommends basing the lb/MW-hr limits on 25% thermal efficiency for the less than 50 MM Btu/hr turbine category; 27% thermal efficiency for the 50 to 500 MM Btu/hr turbine categories, and 44% thermal efficiency for the greater than 500 MM Btu/hr turbine category. Staff used these recommended guidelines in developing the lb/MW-hr limits that are consistent with the volumetric NOx concentration (ppm) limits.

EPA also recommended allowing facilities to comply with either the volumetric NOx concentration (ppm) limit, or the output-based lb/MW-hr limit. As a gas turbine increases in firing load from 60–70% load up to maximum 100% load, the thermal efficiency of the gas turbine can vary. Since the concentration (ppm) limits are consistent with the output-based limits at the base thermal efficiencies, compliance with either is appropriate. The proposed amendments would phase out the thermal efficiency adjustment for the concentration (ppm) limits after the new standards come into effect in 2010. However, in order to encourage facilities to shift to the output-based standards, facilities will still be able to use the concentration (ppm) standard to comply after 2010, but will not be allowed the benefit of the thermal efficiency adjustment.

The proposed new standards for NOx emissions from turbines in full-time use are shown in Table 2.

Table 2
Proposed NOx Emission Limits for Full Use Turbines

Turbine Heat Input	Fuel		
	Natural Gas	Refinery Gas/ Landfill Gas / LPG	Liquid Fuel
< 5 MM Btu/hour (< ~0.3 MW)	Exempt	Exempt	Exempt
5 – 50 MM Btu/hour - (~ 0.3 – 3 MW)	2.12 lbs/MW hr or 42 ppm	2.53 lbs/MW hr or 50 ppm	3.28 lbs/MW hr or 65 ppm
> 50 – 150 MM Btu/hour - (~ 3 – 10 MW) • no retrofit available • WI/SI enhancement available • Where DLN technology available	1.97 lbs/MW hr or 42 ppm 1.64 lbs/MW hr or 35 ppm 1.17 lbs/MW hr or 25 ppm	2.34 lbs/MW hr or 50 ppm	3.04 lbs/MW hr or 65 ppm
> 150 – 250 MM Btu/hour - (~ 10 – 19 MW)	0.70 lbs/MW hr or 15 ppm	0.70 lbs/MW hr or 15 ppm	1.97 lbs/MW hr or 42 ppm
> 250 – 500 MM Btu/hour – (~ 19 – 40 MW)	0.43 lbs/MW hr or 9 ppm	0.43 lbs/MW hr or 9 ppm	1.17 lbs/MW hr or 25 ppm
> 500 MM Btu/hour – (~ 40+ MW)	0.15 lbs/MW hr or 5 ppm	0.26 lbs/MW hr or 9 ppm	0.72 lbs/MW hr or 25 ppm

C. Limited Use Turbines

Approximately one third of the gas turbines in the Bay Area operate on a limited use basis, less than 877 hours per year (less than 10% of the time). These gas turbines are generally used for testing and research, or for emergency/standby power requirements. Limited-use gas turbines smaller than 4 MW are currently exempt from any NOx emission limits. Limited use gas turbines 4 MW and larger are subject to a 42 ppm NOx emission limit if they burn natural gas, or a 65 ppm NOx standard if they burn liquid fuel. None of these gas turbines burns refinery process gas, waste gas or LPG.

These units are generally simple-cycle operations, which have higher exhaust gas temperatures (greater than 800^{o}F). High-temperature SCR systems are being developed that can control these units, but initial installations have experienced problems meeting design emission levels. Water injection systems are available, however, and provide NOx control below 25 ppm for units burning natural gas, and below 42 ppm for units burning liquid fuels. For turbines that are not operated very often, retrofitting with new control technology has less of an emissions reduction benefit because their infrequent use means that they generate fewer emissions to begin with. Justification for possible control options is more challenging. However, since emissions from one of these plants operating only 1/10th of the year are approximately equal to a new turbine with BACT emission levels operating all year, and in many cases the bulk of the emissions occur during the summer ozone season, their emissions warrant scrutiny.

The proposed amendments would affect the various classes of limited-use turbines as follows:

Small Gas Turbines: For limited-use turbines with heat input ratings less than 50 MM Btu/hr (~ less than 3.0 MW equivalent), staff is not proposing any changes. These gas turbines will remain exempt. Staff is proposing to change the exemption threshold from 4 MW in the current rule (about 67 MM Btu/hr) to a 3 MW-equivalent size limit (50 MM Btu/hr) to make the small size category consistent with the small size category for full-time use turbines. However, there are no limited use turbines in the 50 – 67 MM Btu/hr turbine range, so the change will not have any practical effect. The change is proposed to clarify the rule.

Medium and Large Gas Turbines: For limited-use turbines with heat input ratings from 50 to 150 MM Btu/hr (~ 3.0 to 10.0 MW equivalent), and from 150 to 250 MM Btu/hr (~ 10.0 to 18.0 MW equivalent), staff is not proposing any changes to the existing emission limits. NOx emission limits will remain at 42 ppm for turbines that burn natural gas, and 65 ppm for those that burn liquid fuel. Equivalent output-based NOx emission limits are provided using the same thermal efficiency bases as defined for full use turbines.

Larger and Largest Gas Turbines: For limited-use turbines with heat input ratings from 250 to 500 MM Btu/hr (~ 18 to 40 MW equivalent), and over 500 MM Btu/hr (greater than ~ 40 MW equivalent), the proposed amendments reduce the NOx emission limits. These units are generally large simple-cycle gas turbines that are used for meeting peak electrical demands. NOx control is generally achieved by water injection. Enhanced water injection technology is commonly available, as it has been developed for gas turbines that are in full time operation. Staff recommends reducing NOx emission limits from 42 ppm to 25 ppm for those turbines burning natural gas, and from 65 ppm to 42 ppm for those turbines burning liquid fuels. The water injection enhancements that will be required to meet these new standards for the largest of turbines operating close to 877 hours, with a cost of $15,000 per ton of NOx reduced. The proposed amendments also provide equivalent output-based NOx emission limits in lbs/MW-hr, using the same thermal efficiency bases as defined for full use turbines.

Very Low Use Turbines: Requiring retrofits is not justified at this time for very low-use turbines such as standby/emergency generators, which may operate only a few hours per year. Under normal circumstances, these turbines are operated only for system and reliability checks and to conduct source tests and therefore emit only small amounts of NOx. The cost of requiring retrofits for these turbines would not be appropriate at this time unless they are operated near their 877 hour limits. The proposed amendments therefore provide a qualified exemption from the new low-usage limits for any turbine that operates less than 400 hours per year (less than 5% of the time), based on a review of operating hours over the previous 3 year period.

To qualify for this exemption, operators must keep records of their hours of operation, which must be retained and made available to District inspectors for review. If a turbine reaches 400 hours of operation in any 12-month period, the operator is required to notify the District of the fact that it has reached the 400 hour threshold and must provide its best estimate of the extent of future operation. If the District determines that the turbine exceeded the 400-hour limit because of unusual circumstances that are not likely to recur, the turbine will continue to be exempt from the new, lower standards. If the District determines that the turbine is likely to continue to be used over 400 hours per year in the future, it will determine which category the turbine will most likely fall into (*e.g.*, standby usage of up to 877 hours per year, or "full-time use" of more than 877 hours per year). The operator will then have a 36-month compliance timetable for planning, permitting, acquisition and installation of new equipment that may be required to meet the applicable standards. The qualified exemption will continue in effect during this compliance period, but will expire at the end of the period leaving the turbine subject to the new lower limits. Operators should also note that this qualified exemption applies only to the new lower limits that are being proposed in Section 9-9-302.2. Turbines that qualify for the exemption will still be subject to the current low-usage standards in Section 9-9-302.1, in order to prevent backsliding.

The proposed standards for NOx emissions from limited-use turbines are shown in Table 3.

Table 3
NOx Emission Limits for Limited Use Turbines
(Less than 877 hours per year)

Turbine Heat Input	**Fuel**		
	Natural Gas	Refinery Gas/ Landfill Gas / LPG	Liquid Fuel
< 50 MM Btu/hour	Exempt	Exempt	Exempt
50 – 150 MM Btu/hour (3 – 10 MW)	1.97 lbs/MW hr or 42 ppm	N/A	3.04 lbs/MW hr or 65 ppm
> 150 – 250 MM Btu/hour (10 – 19 MW)	1.97 lbs/MW hr or 42 ppm	N/A	3.04 lbs/MW hr or 65 ppm
> 250 – 500 MM Btu/hour (19 – 40 MW)	1.17 lbs/MW hr or 25 ppm	N/A	1.97 lbs/MW hr or 42 ppm
> 500 MM Btu/hour (40+ MW)	0.72 lbs/MW hr or 25 ppm	N/A	1.21 lbs/MW hr or 42 ppm

Emergency Use: In the event of an emergency declared by federal, state or local authority, the proposed amendments allow the turbine to be used without triggering the more stringent standards in Section 9-9-301 for full use turbines. For example, if an earthquake were to disrupt power generation capacity and cause a fire, and the only the only available power were from limited use turbines that have reached their 877 hour limit, those turbines could be operated to put out the fire.

D. Other Amendments

Compliance schedules: The proposed amendments set January 1, 2010, as the effective date for these new emission limits. Staff proposes June 30, 2008, as the deadline for each facility to submit an application for an Authority to Construct to the District in order to bring their facility into compliance. This timeframe should provide retrofit technology suppliers adequate time to finalize demonstration of any viable retrofit technology products and still allow operators sufficient time to plan and carry out their retrofit projects. Any additional development of enhanced water or steam injection, or DLN for specific makes and models of turbines will apply as the technology becomes commercially available using a similar 18 month timeframe for application for Authority to Construct, and 36 months to achieve compliance.

These retrofit projects are often most effectively executed during a planned major maintenance outage. If a facility does not have a planned major maintenance outage before the compliance deadline of January 1, 2010, the proposed amendments allow the facility to wait until the next planned major maintenance outage to complete the retrofit. Compliance with the new emission limits is then required 30 days after completion of the major outage, but no later than December 31, 2012.

Averaging periods for NOx excursions: For purposes of compliance with the rule's standards, NOx emissions are averaged over a certain time period in order to account for short-term fluctuations in NOx output. There has been inconsistency in the averaging periods used for turbines in the Bay Area, however. Permit conditions vary, prescribing one hour to three hour averaging periods. To help eliminate this inconsistency, the proposed amendments specify a standard averaging period for determining compliance with the rule.

BACT and BARCT standards across the nation are very consistent in specifying a NOx emissions standard with 3 hour averaging, or the NOx emission standard plus 0.5 ppm with 1 hour averaging. Staff has determined that a 3-hour averaging period is the most appropriate, based on a review of each NOx excursion that occurred in the Bay Area from January 1, 2005 through June 20, 2006. Staff found that the three hour averaging period allows for a NOx emissions limit 10% lower than it would be with one hour averaging. This reduces total NOx emissions in the Bay Area. Three-hour averages will be calculated in accordance with the District's Manual of Procedures, which currently specifies averaging emissions over three consecutive "clock hours". This approach is also consistent with the time frame used for District source tests, which are conducted by measuring emissions over three 30-minute periods normally spread over approximately three hours. Source test results are very representative of emissions over a 3-hour period, and so the proposed amendments specify that either Continuous Emissions Monitor (CEM) measurements or a source test result can be used to establish compliance with or violation of the applicable emission limits.

Elimination of the Thermal Efficiency Adjustment: As described above, the current rule has a thermal efficiency adjustment for NOx emission limits to encourage efficiency, or pollution prevention. The proposed amendments establish alternative output-based NOx limits (lb/MW-hr) to provide an improved approach to achieving the same end. The thermal efficiency adjustment will continue until the new NOx emissions standards come into effect on January 1, 2010. The thermal efficiency adjustment will then no longer apply. In order to encourage operators to shift to using the output-based (lb/MW-hr) standards, facilities may still comply using the volumetric NOx concentration limit (ppm), but without the benefit of the thermal efficiency adjustment.

Inspection and Maintenance: The current definition of inspection and maintenance period is focused primarily on state mandated inspection and repair requirements for Heat Recovery Steam Generator systems. During the rule development process, some facilities pointed out that other inspection and maintenance issues can require significant alterations in the gas turbine operation. Often, the transitions of shut down and startup generate more NOx emissions than the alternative of high NOx operation for a few hours to complete an inspection or maintenance task. A proposed amendment provides an exemption for other required inspection and maintenance work. This work must be planned and scheduled at least 24 hours in advance, and limited to 4 hours duration. If the work requires longer than 4 hours, the unit should be shutdown. Emissions during these minor inspection and maintenance periods are to be included in the total emissions annual limit identified in the turbine’s operating permit.

Startup and shutdown periods: Due to the nature of their operation and design, turbines must operate within normal operating pressure and temperature ranges to achieve low NOx emissions. In addition, emission control devices, especially SCR, are very temperature sensitive. When turbines are starting up and shutting down they cannot maintain the operating parameters and temperatures necessary to keep NOx emissions within the rule’s standards. The current rule therefore provides exemptions from the emissions standards for up to three hours during startup and up to one hour during shutdown to allow the time required to transition to and from normal operating conditions.

Several facilities have difficulty starting up their more complex units within the three hour startup exemption window. They are using the three-hour averaging period at the end of the startup exemption to complete the startup and remain within compliance. Most facilities requested an additional hour for startup, and an additional hour for shutdown. The intent of these exemptions is to provide adequate time for execution of the normal startup and shutdown sequences. Staff proposes increasing the startup exemption to 4 hours, and the shutdown exemption to 2 hours. For many facilities, this is necessary to comply with the more stringent standards.

Combined cycle facilities have a unique startup problem, in that they need 6 hours to get the entire facility on-line when starting up from a cold condition. These facilities take 3-4 hours to get the gas turbine and heat recovery steam generator operating at steady state, and then an additional 2 hours to get the steam turbine warmed, started and operating at steady state. The proposed amendments create a new 6-hour startup exemption for combined cycle facilities when going through a "cold steam turbine" startup.

Annual Compliance Testing: Facilities that have CEMs provide NOx emissions data for all operating periods. Smaller facilities that do not have CEMs require source tests in order to demonstrate that they are operating within the applicable NOx emission limits. The proposed amendments require a District-approved source test once a year, at intervals not to exceed 15 months.

The annual source test is proposed to be required every other year for very limited-use turbines (operated less than 400 hours per year). Where a turbine is not used very often, it can be difficult to schedule a source test during a period of normal operation. In such a situation, the operator may be forced to start up the turbine solely for purposes of conducting the test, which would create unnecessary NOx emissions. The proposed amendments therefore reduce the requirement to every second year for facilities that operate less than 400 hours in a 12 month period.

Use of Interchangeable Emission Reduction Credits (IERCs): Several facilities inquired whether IERCs could be used to comply with the proposed more stringent NOx emissions limits. IERCs are emission credits generated by early voluntary reductions in emissions which can be used to achieve compliance with other regulatory requirements later. Health and Safety Code Section 39607.5 requires the District to provide this alternative means of compliance. The requirements regarding IERC creation and use are set forth in District Regulation 2, Rule 9.

Affected facilities will be able to use IERCs to comply with the proposed amendments, subject to the requirements of Regulation 2, Rule 9 and any other legal restrictions, such as EPA's prohibition on using IERCs to comply with District rules that have been adopted as part of California's federal State Implementation Plan. The proposed amendments include a provision making this clear. The provision is intended simply to inform operators about the availability of IERCs, and is not intended to expand or restrict any rights or obligations associated with IERC use under existing laws and regulations.

Minor Clarifications to Rule Language: The proposed amendments include some new definitions, clarify several existing definitions, and eliminate obsolete rule language.

IV. EMISSIONS AND EMISSION REDUCTIONS

Emissions from stationary gas turbines include all the products of combustion. The primary concern with emissions from gas turbines in the Bay Area is NOx. Gas turbines also produce minor amounts of carbon monoxide (CO), sulfur oxides (SOx), organic compounds, and particulates (PM), but the contribution from gas turbines for each is relatively insignificant in the total emission inventory for the Bay Area. Combustion in stationary gas turbines also produces carbon dioxide (CO_2), a growing concern with respect to climate change.

Some NOx is formed from combustion of nitrogen in the fuel (fuel NOx), but the primary source of NOx is from the oxidation of nitrogen in the air (thermal NOx). Most gas turbines in the Bay Area burn only natural gas, which is negligible in nitrogen content. A few gas turbines can burn liquid fuels (propane, butane, jet fuel or diesel fuel), but the nitrogen content in these fuels is also very low.

CO comes from incomplete combustion. CO limits are normally included as a District permit condition for each turbine. Lean premix combustion design generates excellent combustion efficiency: CO emissions are typically 10-50 ppm from natural gas, and 20-50 ppm from diesel fuel. The District is not considering any action at this time with respect to CO limits as part of possible amendments to Regulation 9, Rule 9. Organic compound emissions are also controlled by combustion efficiency, so no standard is recommended. Particulates are generated by trace non-combustible constituents in the fuel. PM emissions are negligible when natural gas is burned. PM emissions are only marginally significant with distillate fuels. The District is not contemplating regulatory action with respect to organic compounds or PM as part of possible amendments to Regulation 9, Rule 9. However, as noted in Section II.A, NOx reductions will help reduce formation of secondary PM, such as ammonium nitrate.

The NOx emissions from stationary gas turbines in the Bay Area total 6.5 tpd. Recent shutdown of three gas turbine facilities has already reduced these emissions by 0.23 tpd. The proposed amendments will reduce NOx emissions by almost 7%, 0.43 tpd, reducing the NOx emissions from gas turbines by a total of 0.66 tpd. Additional NOx reductions may occur sporadically from the low use gas turbines that operate less than 877 hours per year. These NOx reductions are not included in the emissions reduction estimate, because they occur less than 10% of the time. Low-usage "peaking power" turbines tend to operate more in the summer months when electrical demand is highest, however, so any reductions from these facilities will come at the most opportune time of the year, when ozone concentrations are higher. In addition, if water or steam injection enhancements or DLN technology becomes commercially available for additional turbines in the future, further reductions would be achieved from those turbines.

V. ECONOMIC IMPACTS

A. Compliance Costs

This section describes the costs to the affected gas turbine operators for each proposed amendment. Not all turbines in each of the proposed size categories are affected, as explained in Section III – Proposed Amendments.

Full Use Mid-size Gas Turbines: Turbines with heat input ratings from 50 to 150 MM Btu/hr (~3.0 to 10 MW) operated over 877 hours per year will have to reduce emissions from 42 ppm to 35 ppm if enhanced water injection or steam injection retrofits are commercially available, and from 42 ppm to 25 ppm if Dry Low NOx technology is commercially available.

Where commercially available, water or steam injection enhancement technology is technically feasible and costs vary from $200,000 to more than $1,000,000 per turbine in capital costs, depending on the modifications required. There is very little impact on operating costs. Costs range from $7,000 to $19,000 per ton of NOx reduced.

Where commercially available, DLN technology costs between $1,000,000 to $2,000,000 per turbine in capital costs. There is very little impact on operating costs. Costs range from $15,000 to $18,000 per ton of NOx reduced.

If no retrofit technology is commercially available for the specific make and model of gas turbine, with its specific fuel, then staff recommends retaining the NOx emission limit at 42 ppm. There would be no cost impact on such turbines.

Where water or steam injection enhancement or DLN technology becomes commercially available in the future, the cost impacts are expected to be similar to the costs outlined above. These are well-defined technologies that have been in use for a long time, even though they are not currently commercially available for every make and model of turbine. It is unlikely that adapting these technologies to additional turbines would be introduce new costs substantially different from those associated with their use on turbines where they are commercially available today. Staff therefore believes that the analysis for current commercially available units will also hold true for units that become commercially available in the future.

Full Use Large Gas Turbines: Staff is not proposing any change at this time to the emission standard for turbines with heat input ratings from 150 to 250 MM Btu/hr (~10 to 18 MW), which is currently 15 ppm. Staff considered lowering the standard to 9 ppm or 5 ppm, which would require installation of SCR systems on the turbines in this category that do not currently have such systems. SCR system costs range from $3,000,000 to $4,000,000 per turbine, impact operating capacity and thermal efficiency, and require ammonia and ammonia injection systems and catalysts. Because the NOx reduction that would be obtained from these costly control methods would be so limited, staff is not recommending requiring these upgrades at this time.

Full Use Larger Gas Turbines: For facilities with turbine heat input ratings from 250 to 500 MM Btu/hr. (~18 to 40 MW), staff proposes an emissions standard of 9 ppm. This does not represent a change for turbines equipped with SCR systems, which are already subject to a 9 ppm limit. For facilities without an SCR system, this represents a reduction in NOx limits from 15 ppm to 9 ppm. There are six facilities in this category in the District that do not have an SCR system, but each is already achieving 9 ppm NOx. They will not have to make any further changes to comply. Accordingly, there will be no cost impacts from this proposed amendment.

Staff also considered whether it would be appropriate to lower the standard for these turbines below 9 ppm. Further reductions would require installation of SCR systems, reconfiguration of existing SCR systems, or other similarly effective retrofit work. Retrofit systems range from $3,500,000 to $4,500,000 in capital costs, impact operating capacity and thermal efficiency, and require additional ongoing operation costs for ammonia and ammonia injection systems and catalysts. The incremental NOx reduction benefit from requiring such systems to achieve NOx emissions below 9 ppm is not adequate to justify these large capital and operating costs.

Full Use Largest Gas Turbines: For facilities with turbine heat input ratings greater than 500 MM Btu/hr. (~40 MW plus), the proposed amendments set an emissions standard of 5 ppm. For facilities without an SCR, this represents a reduction in NOx limits from 15 ppm to 5 ppm. For facilities with an existing SCR, this proposal represents a reduction in NOx limits from 9 ppm to 5 ppm. To meet these limits, the existing gas turbines in this size category that are not already below 5 ppm will have to:

- enhance their SCR and ammonia injection system;
- install an SCR system; or
- install state-of-the-art DLN.

The SCR systems and state-of-the-art DLN for these largest turbines cost $4,000,000 to $5,000,000 per turbine in capital costs. SCR systems also impact capacity and thermal efficiency, and have ammonia and catalyst operating costs. (State-of-the-art DLN does not involve significant additional operating costs.) Costs for these upgrades range from $10,000 to $20,000 per ton. These costs are justified by the significant NOx reductions that can be obtained due to the large size of these turbines.

Limited Use Larger and Largest Gas Turbines: For low-usage turbines (less than 877 hours per year), staff is proposing to lower the emission limit for the largest size categories – turbines with heat input ratings from 250 to 500 MM Btu/hr. (~ 18 to 40 MW equivalent) and over 500 MM Btu/hr (greater than ~ 40 MW equivalent) – from 42 ppm to 25 ppm for turbines burning natural gas and from 65 to 42 ppm for turbines burning liquid fuels. Meeting these lower limits will require operators to install enhanced water injection technology. This technology is commonly available, as it has been developed for gas turbines that are in full time operation. These water injection enhancements for limited use turbines in these size categories typically cost $500,000 to $1,000,000 in capital costs, with very little impact on operating costs. These enhancements for the larger and largest turbines operating up to 877 hours cost $10,000 to $20,000 per ton of NOx reduced.

B. Incremental Cost Effectiveness

Section 40920.6 of the California Health and Safety Code requires an air district to perform an incremental cost analysis for any proposed Best Available Retrofit Control Technology rule or feasible measure. The air district must: (1) identify one or more control options achieving the emission reduction objectives for the proposed rule, (2) determine the cost effectiveness for each option, and (3) calculate the incremental cost effectiveness for each option. To determine incremental costs, the air district must "calculate the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option."

Staff identified two categories of retrofit control technology that can achieve the regulation's goal of reducing NOx emissions from gas turbines. The most effective and most expensive category includes SCR systems and state-of-the-art DLN systems, which can achieve less than 5 ppm NOx emissions when retrofit to existing turbines. The second category includes enhanced water injection and steam injection retrofits and ordinary DLN technology, which are not as efficient as SCR systems and state-of-the-art DLN systems, but are also not as expensive. Staff evaluated the respective incremental cost-effectiveness of each of these two categories of control technology for each turbine size range.

For the largest turbines – those with heat input ratings greater than 500 MM Btu/hr. (~40 MW plus) – staff determined that SCR or state-of-the-art DLN technology could achieve emission reductions at a cost of approximately \$10,000 to \$20,000 per ton of NOx reduced. Staff found that enhanced water injection or steam injection or ordinary DLN technology are not viable options because they are not capable of achieving significant further reductions below the already low limits applicable to these units. Staff therefore concluded that requiring SCR or equivalent technology for these turbines was the only viable control option capable of achieving the objectives of the proposed rule, and that the costs were justified by the NOx reduction benefits to be gained.

For the turbines in the large and larger size category – those with a heat input rating from 150 to 250 MMBtu/hr (~ 10-18 MW) and from 250 to 500 MMBtu/hr (~ 18-40 MW) – the District determined that SCR or state-of-the-art DLN technology could achieve emission reductions at a cost of approximately \$22,000 to \$48,000 per ton of NOx reduced. These gas turbines already have enhanced water or steam injection, DLN combustion technology, or SCR's installed in order to achieve the existing 15 ppm or 9 ppm NOx emission limits. Staff therefore determined that the costs of requiring SCR or state-of-the-art DLN technology to achieve 5 ppm NOx are not justified by the emissions reductions to be gained. Staff concluded that lowering the existing standards where feasible to capture these turbines' current performance is the best option.

For mid-size turbines – those with a heat input ratings from 50 to 150 MMBtu/hr (~ 3-10 MW) – staff expects the cost of SCR or state-of-the-art DLN technology to be even greater than the \$22,000 to \$48,000 per ton of NOx reductions found for the next largest category. The costs per ton will be larger because the costs of retrofitting the turbines will not be significantly different, but the amount of emissions reductions to be gained from the smaller turbines would be significantly less. District staff compared these large costs with the costs of water injection or steam injection enhancements or ordinary DLN technology, which are expected to be approximately \$5,000 to \$19,000 per ton of NOx reduced. Staff concluded that this second option was the most appropriate based on the costs and emission reduction benefits available.

For the smallest turbines – those below 50 MMBtu/hr (~ 3 MW) – no amendments are being proposed and so no incremental cost-effectiveness analysis is required. Based on the analyses for the larger turbines outlined above, however, Staff believe that the costs per ton of emissions reductions would be very large for either type of emissions control technology.

For limited-use turbines (under 877 hours per year), staff determined that the cost of enhanced water injection technology would be $10,000 to $20,000 per ton of NOx reduced for turbines operating between 400 and 877 hours per year. Staff expects the costs of SCR or state-of-the-art DLN technology per ton of NOx reduction will likely be much higher, given the high costs of those technologies and the limited amount of NOx reductions available due to these turbines' limited use. Staff therefore concluded that enhanced water injection is the preferable control option for limited-use turbines, with a qualified exemption for turbines operated less than 400 hours per year because of the very small emissions reductions to be gained from such turbines.

C. Socioeconomic Impacts

Section 40728.5 of the California Health and Safety Code requires an air district to assess the socioeconomic impacts of the adoption, amendment or repeal of a rule if the rule is one that "will significantly affect air quality or emissions limitations." Applied Economic Development of Walnut Creek, California has prepared a socioeconomic analysis of the proposed amendments to Regulation 9, Rule 9. The analysis concludes that the affected facilities should be able to absorb the costs of compliance with the proposed rule without significant economic dislocation or loss of jobs.

VI. ENVIRONMENTAL IMPACTS

Pursuant to the California Environmental Quality Act, the BAAQMD has had an initial study for the proposed amendments prepared by Environmental Audit, Inc. The initial study concludes that there are no potential significant adverse environmental impacts associated with the proposed amendments. A negative declaration is proposed for approval by the BAAQMD Board of Directors. The initial study and negative declaration is to be circulated for public comment during the period from November 6, 2006 to December 6, 2006.

Regulation 9, Rule 9 supports efficiency and energy conservation as a primary preventive approach to pollution. The rule currently adjusts the volumetric NOx emission limits for thermal efficiency of a facility. A more efficient gas turbine will generate more power, consume less fuel, and emit less NOx even though the concentration of the NOx in the flue gas may be slightly higher. The proposed amendments continue and enhance this approach by incorporating "output based" emission limits, as recommended by the EPA. These limits are defined as lbs. of NOx per megawatt-hour of all productive energy, and reinforce the same preventive approach to pollution. Reducing pollution while promoting efficiency is crucial considering the concern regarding CO_2 emissions and their impact on global climate change.

VII. REGULATORY IMPACTS

Section 40727.2 of the Health and Safety Code requires an air district, in adopting, amending, or repealing an air district regulation, to identify existing federal and district air pollution control requirements for the equipment or source type affected by the proposed change in air district rules. The air district must then note any difference between these existing requirements and the requirements imposed by the proposed change.

EPA developed and issued New Source Performance Standards for gas turbines in July of 2006. 40 CFR Part 60 – Standards of Performance for Stationary Combustion Turbines; Final Rule was issued on July 6, 2006. NOx emission limits proposed in Regulation 9, Rule 9 are as stringent as, or more stringent than, those issued by the EPA. The EPA rule affects new and modified sources. For new sources (constructed after February 18, 2005) the requirements of Regulation 9, Rule 9 apply, but BACT requirements would be considerably more stringent in all size categories. Current BACT limits for new natural fired gas turbines greater than 150 MM Btu/hr heat input are from 2 to 2.5 ppm NOx.

Turbine Type	**Fuel Type**	**Turbine Heat Input**	**EPA Requirement**	**9-9 Proposal**
New	Natural Gas	< 50 MM Btu/hr	42 ppm	BACT
New	Natural Gas	50 – 850 MM Btu/hr	25 ppm	BACT
New, modified or reconstructed	Natural Gas	> 850 MM Btu/hr	15 ppm	5 ppm or BACT
New	Other than Natural Gas	< 50 MM Btu/hr	96 ppm	BACT
New	Other than Natural Gas	50 – 850 MM Btu/hr	74 ppm	BACT
New, modified or reconstructed	Other than Natural Gas	> 850 MM Btu/hr	42 ppm	25 ppm or BACT
Modified or reconstructed		< 50 MM Btu/hr	150 ppm	42 – 65 ppm
Modified or reconstructed	Natural Gas	50 – 850 MM Btu/hr	42 ppm	42 ppm
Modified or reconstructed	Other than Natural Gas	50 – 850 MM Btu/hr	96 ppm	50 – 65 ppm

VIII. RULE DEVELOPMENT PROCESS

The 2005 Ozone Strategy identified Control Measure SS-14 as an opportunity to reduce NOx emission in the Bay Area. Staff initiated work on this control measure in January, 2006. Staff developed an inventory of every permitted gas turbine in the District and contacted each facility in January and February of 2006 to advise them of the 2005 Ozone Strategy, and specifically Control Measure SS 14, identifying the Districts' intent to reduce NOx emissions from gas turbines to the maximum extent feasible. District staff visited seven facilities to understand the range of turbine operations in the Bay Area, and to understand the issues and concerns these facilities may have.

In April, staff published draft rule amendments and provided a workshop report detailing the rationale for these draft amendments. First draft amendments to Regulation 9, Rule 9, and a workshop report were posted on the District Website, e-mailed and mailed to all interested parties on May 2, 2006.

In May, 2006 staff received and responded to more than 20 telephone inquires and more than 20 e-mail inquiries regarding specific topics and issues from the draft rule amendments and workshop report.

The District held a Public Workshop on May 31, 2006 to solicit comments from the public, members of State agencies, industry and environmental organizations, and other interested parties on potential amendments to Regulation 9, Rule 9. Staff received written input from 15 affected facilities and 7 other affected parties during and after the May 31, 2006 workshop.

Very little input was received from facilities that operated less than 877 hours per year, and those that burned liquid fuels. Staff developed an outreach approach to these 17 facilities, by calling each facility and obtaining a point of contact and phone number, and attempting to identify an e-mail address for each contact. This information was used to ensure these affected parties were aware of the amendments being developed for Regulation 9, Rule 9, and to solicit their participation and input.

Input from the first workshop raised concerns about the effective date included in the draft amendments, and the cost effectiveness of the revised emission limits. District staff worked with more than 10 individual facilities to develop technical options, and to begin developing estimates for capital and operating cost impacts from the various retrofit options. District staff met with representatives of two additional facilities to understand their unique issues and concerns. Staff developed a spreadsheet ranked by turbine size containing actual and permitted emission levels, fuels used, and type of control. Each facility developed and provided information for their site specific retrofit control project costs and timing. These project costs were validated with equipment vendors and previous estimates developed by San Joaquin Valley APCD and EPA. Staff worked with each facility to properly assess the economic impacts of the project on operating capacity, thermal efficiency, and downtime required for implementation. Staff then estimated control technology costs for each turbine and calculated the emissions reductions to be obtained. This analysis validated that some of the first draft amendments were not justified for some of the turbine categories.

Upon determining costs for classes of turbines in the rule, staff examined whether some turbines could meet lower emission limits. This analysis lead directly to developing a second draft of amendments for Regulation 9, Rule 9. EPA had issued 40 CFR Part 60: Standards of Performance for Stationary Combustion Turbines; Final Rule on July 6, 2006. The concept of output based emission limits from the EPA guidance was incorporated into the second draft amendments. A supplement to the workshop report was generated to summarize the differences from the original workshop report. A second workshop notice, second draft amendments and supplemental workshop report were posted on the district website, and e-mailed to all interested parties. The second workshop was held on October 13, 2006.

Input from the second workshop was focused primarily on interpretation of rule language, and a request for a definition of standard turbine heat input. Staff used this input to develop a final draft of the proposed amendments, and published the proposed amendments and this Staff Report for comment on November 6, 2006. The proposed amendments are scheduled for a public hearing by the Board of Directors on December 6, 2006.

The District will continue to follow the development of cost effective gas turbine control technologies, and assess the need for continued NOx reductions during future planning cycles.

IX. CONCLUSIONS

Pursuant to Section 40727 of the California Health and Safety Code, the proposed rule must meet findings of necessity, authority, clarity, consistency, non-duplication, and reference. The proposed amendments to Regulation 9, Rule 9:

- Are necessary to limit emissions of nitrogen oxides, a primary precursor to ground-level ozone formation, and to meet the requirements of the Bay Area 2005 Ozone Strategy;
- Are authorized under Sections 40000, 40001, 40702, and 40725 through 40728 of the California Health and Safety Code;
- Are written or displayed so that its meaning can be easily understood by the persons directly affected by it;
- Are consistent with the other BAAQMD rules, and not in conflict with state or federal law;
- Are not duplicative of other statures, rules or regulations; and
- Are implementing, interpreting and making specific the provisions of the California Health and Safety Code sections 40000 and 40702.

The proposed amendments have met all legal noticing requirements, have been discussed with the regulated community and other interested parties, and reflect the input and comments of many affected and interested parties. BAAQMD staff recommends adoption of proposed amendments to Regulation 9, Rule 9: Nitrogen Oxides from Stationary Gas Turbines

X. References

Standards of Performance for Stationary Gas Turbines; Final Rule, 71 Fed. Reg. 38482 (July 6, 2006), to be codified at 40 C.F.R. pt. 60, subpt. KKKK

California Air Resource Board, "Electrical Generation Retrofit Regulation Homepage" http://www.arb.ca.gov/energy/retro/retro.htm,

California Air Resource Board, "Gas Turbines" Compliance Assistance Program, June 1996.

California Air Resource Board, "Guidance for Power Plant Siting and Best Available Control Technology", July 22, 1999.

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