Bay Area Air Quality Management District
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Staff Report

Proposed Amendments to BAAQMD Regulation 9, Rule 10:

NITROGEN OXIDES AND CARBON MONOXIDE FROM BOILERS, STEAM GENERATORS AND PROCESS HEATERS IN PETROLEUM REFINERIES

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1.0 Executive Summary

The primary effect of the proposed amendments to Regulation 9, Rule 10: *Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries* ("Regulation 9-10" or "the rule") would be to reduce the NOx emission limits for carbon monoxide (CO) boilers, which are one category of refinery heater that is regulated under this rule, thereby achieving NOx emission reductions at these devices. NOx compounds are precursors in the formation of ground level ozone and particulate matter. The Bay Area Air Quality Management District ("BAAQMD" or "District") has non-attainment status for both the state 1-hr and 8-hr ozone standards and the federal 8-hour ozone standard. Therefore, state law requires that the District implement all feasible measures to reduce emissions of ozone precursors, including NOx. NOx reductions also reduce the formation of secondary particulate matter in the atmosphere.

This proposal will implement Control Measure SSM 10 of the Bay Area 2010 Clean Air Plan. Control Measure SSM 10 calls for a reduction in either the refinery-average NOx emission limit applied to most refinery heaters, or a reduction in the NOx emission limit at CO boilers.

District staff recommends amending Regulation 9-10 by:

(1) Establishing new NOx emission limits for CO boilers, including long-term emission limits that are significantly lower than the current short-term emission limit.

(2) Modifying one current exemption to extend the applicability of the rule to smaller devices so that all refinery heaters are regulated by Regulation 9-10.

(3) Simplifying the procedures for determining compliance with the existing refinery-average NOx limit for heaters other than CO boilers when these are at low firing rates.

The proposed amendments are expected to directly reduce total NOx emissions from regulated heaters by about 1.6 tons per day. The proposed amendments are not expected to result in any significant adverse environmental impacts.

2.0 Background

Regulation 9-10 was adopted on January 5, 1994 and amended on July 17, 2002. The regulation imposes a refinery-wide average NOx emissions limit on refinery boilers, steam generators and process heaters (excluding CO boilers) that were first permitted prior to the adoption of the rule ("pre-1994 heaters"). The NOx limits were not applied to boilers, steam generators and process heaters that would be permitted after the rule was adopted ("post-1994 heaters") because these devices would be subject to stringent NOx limits as a result of the District's permitting requirements. If these post-1994 devices, with very low NOx emission rates, were included under a refinery-wide average NOx limit, the effect would be to reduce a refinery operator's need to control emissions from older, less well-controlled devices in order to comply with the refinery-wide emission limit. In addition to the refinery-wide average NOx rule for most pre-1994 heaters, Regulation 9-10 also imposes a specific (not average) NOx emission limit on all CO boilers, regardless of when they were first permitted.

The NOx limits in Regulation 9-10 for pre-1994 heaters, combined with permit requirements for post-1994 heaters, (specifically "best available control technology" [BACT] requirements) resulted in significant reductions in NOx emissions from Bay Area refinery operations beginning around 2002. Currently, 81% of the total rated capacity of refinery boilers, steam generators and process heaters in the Bay Area is equipped with NOx controls of some kind.

Control Measure SSM 10 of the Bay Area 2010 Clean Air Plan calls for additional NOx emission reductions through Regulation 9-10 by either reducing the refinery-average NOx emission limit applied to most pre-1994 refinery heaters, or the NOx emission limit for CO boilers.

In the Bay Area 2005 Ozone Strategy, Further Study Measure FS 14, the District committed to study ways to amend Regulation 9-10 to achieve further NOx emissions reductions. In carrying out Further Study Measure FS 14, District staff has completed the following:

- Compiled an inventory of refinery boilers, steam generators and process heaters;
- Determined the type, age, retrofit ability of, and the nature of the emissions from, these refinery boilers, steam generators and process heaters;
- Evaluated the cost effectiveness of retrofits and replacement technologies;
- Evaluated the contribution to emissions of the heaters that are currently exempt from Regulation 9-10;
- Compared the NOx emissions limits imposed by other air districts on refinery boilers, steam generators and process heaters;
- Compared NOx emissions from and control of non-refinery boilers of similar size that are in use in the District; and
- Consulted extensively with industry representatives regarding these analyses.

District staff's findings and recommendations are included in this report.

2.1 Regulated Heaters, Exempt Heaters and Current NOx Limits

Boilers and steam generators are devices that heat or boil water, while process heaters (also called furnaces) heat process streams, including crude oil and intermediate products, to required processing temperatures. Most refinery heaters, over 80% by number, are classified as process heaters rather than as boilers or steam generators. For simplicity, the term "heater" will be used in this report to refer to boilers, steam generators and process heaters that are subject to Regulation 9-10.

Heaters regulated by Regulation 9-10 use a variety of fuels. Natural gas and refinery gas (a gaseous by-product composed of a variety of hydrocarbon compounds) are the predominant fuels used at the Bay Area refineries, together accounting for over 95% of the NOx emissions from heaters. Most refinery heaters are permitted to use both natural gas and refinery gas fuels. Three refineries operate CO boilers that burn off-gas from cracking or coking units in addition to natural gas and refinery gas.

As mentioned above, Regulation 9-10 imposes NOx emission limits on refinery boilers, steam generators and process heaters in two categories. The first category comprises heaters that **are not** CO boilers and that were first permitted prior to the original adoption of the rule ("pre-1994 heaters"). Under the current rule, NOx emissions from pre-1994 heaters at each refinery are aggregated and averaged, and the average emissions may not exceed 0.033 pounds of NOx per million BTU of actual heat input (0.033 lb/MM BTU, which is equivalent to 28 parts per million by volume [ppmv] of NOx at 3% excess oxygen), evaluated on a daily average basis.

Refinery heaters that **are not** CO boilers that were first permitted on or after January 5, 1994 ("post-1994 heaters") are not regulated by Regulation 9-10, but each heater in this category is subject to stringent NOx limits as a result of BACT requirements for new or modified devices.

The second category of refinery heaters that is regulated by Regulation 9-10 consists of all CO boilers. CO boilers are subject to a NOx limit of 150 ppmv at 3% excess oxygen, evaluated on a daily average basis. CO boilers are defined in Regulation 9-10 as heaters that process flue gas from fluid catalytic cracking units (FCCU) or coker units. FCCU and coker flue gas contain significant levels of CO. This CO is used as a fuel at the CO boilers (mixed with other fuel gases) with the CO converted to CO_2 in the process and the resulting heat used to produce steam or to heat process streams. In Regulation 9-10, CO boilers are regulated separately from pre-1994 heaters because FCCU and coker flue gases typically contain high concentrations of NOx precursors which form NOx in the CO boiler. This "fuel NOx" cannot be controlled by the combustion techniques that are used to prevent the formation of "thermal NOx" in other refinery heaters and therefore CO boilers may operate at higher NOx emission rates compared to heaters that primarily use natural gas and refinery gas fuels, even though FCCU and coker flue gases typically have low fuel value that results in relatively low combustion temperatures and low thermal NOx production. (For further discussion, see Section 2.6, *infra*.) CO boilers are subject to the rule regardless of when they were first permitted. Three of the five Bay Area refineries (Shell, Tesoro and Valero) operate a total of six CO boilers. Of the remaining two refineries, one (Conoco-Phillips) does not have a FCCU and therefore has no CO boiler, and the other (Chevron) operated a CO boiler until the mid-1980's, but has modified their FCCU to make a CO boiler unnecessary.

Regulation 9-10 does not apply to the following types of sources that operate at refineries:

- Internal combustion (IC) engines or boilers that recover heat from IC engine exhaust gases while burning supplementary fuel. IC engine NOx emissions are subject to Regulation 9-8.
- Boilers that recover heat from gas turbine or IC engine exhaust gases while burning supplementary fuel. Gas turbine NOx emissions are subject to Regulation 9-9. No refinery boilers are used to recover waste heat from IC engine exhaust.
- Heaters processing H_2S flue gas in sulfur recovery plants or sulfuric acid manufacturing plants. These heaters are not regulated because they have either very low NOx emissions or have no feasible NOx control options.
- Flares. Flare operations are subject to Regulation 12-12.

2.1.1 Federal NOx Limit

Regulation 9-10 includes two refinery-wide, daily-average NOx limits that apply to pre-1994 heaters: the 0.033 lb/MM BTU limit discussed in Section 2.1 that was required by state law as "best available retrofit control technology" (BARCT), and a less stringent limit of 0.20 lb/MM BTU that was required by federal law as "reasonably achievable control technology" (RACT). There is also a federal RACT limit for CO boiler emissions (300 ppmv) that is less stringent than the BARCT limit for CO boilers (150 ppmv). The District could have included only the more-stringent BARCT limits in the rule and satisfied both state and federal requirements. However, both sets of limits were included so that that the less-stringent limits could be included in the federal state implementation plan (SIP) for ozone, while excluding the more-stringent limits from the SIP. This strategy allowed refinery operators to comply with the more-stringent limits with strategies that were themselves not included in the SIP. Specifically, refinery operators could use interchangeable emission reduction credits (IERCs) as allowed by District Regulation 2-9. IERCs allow an operator that "over-complies" with a particular limit to apply this over-compliance to a different source subject to a different limit. In the case of Regulation 9-10, IERCs are primarily generated by refinery operators that operate CO boilers, since these tend to over-comply with their 150 ppmv NOx limit. The use of IERCs allows some refinery operators to operate well above the 0.033 lb/MM BTU average limit for pre-1994 heaters. State law requires the District to allow the use of IERCs. However, the specific provisions that are required to be included in the IERC rule conflict with federal guidelines for SIP regulations. Therefore, any emission limit that is included in the SIP cannot be satisfied with IERCs. If the state of California were to adopt the more-stringent limit of 0.033 lb/MM BTU for pre-1994 heaters into the SIP, then refinery operators would be barred from using IERCs for compliance.

Because the proposed, lower NOx limits will largely eliminate the ability of refinery operators to generate IERCs at CO boilers, the adoption of these limits will eventually allow the State of California to include Regulation 9-10 into the SIP in its entirety, so that it is credited with the full emission reduction associated with this rule.

2.1.2 Emission-Reduction Mechanisms in Regulation 9-10

Almost all of the NOx emission reductions attributed to Regulation 9-10 occurred in anticipation of the 2002 effectiveness date for the refinery-wide, daily-average emission limit for pre-1994 heaters and the daily-average limit for CO boilers, as refinery operators implemented NOx controls on selected heaters. Since 2002, additional emission reductions have occurred as refinery operators have replaced heater burners with lower-emitting units or have improved the operation of existing SCR and SNCR NOx-abatement systems. However, Regulation 9-10 also includes a mechanism that requires additional NOx controls on the population of pre-1994 heaters under certain circumstances, as described below.

The population of pre-1994 heaters cannot increase since the rule explicitly excludes post-1994 heaters. Therefore, the installation of new heaters which have low NOx emission rates because of BACT requirements has no effect on compliance with this rule. However, when a heater is removed from the pre-1994 population of heaters that are subject to the refinery-wide, daily-average NOx limit, either because the heater is permanently removed from service or because it is modified so that it is subject to BACT requirements for NOx, compliance with the limit will be affected in one of two ways. If the removed heater has an average NOx emission rate greater than 0.033 lb/MM BTU, then the remaining pre-1994 heaters will have a reduced average emission rate, and the compliance margin for the remaining heaters will increase relative to the emission limit. If, however, the removed heater has an average NOx emission rate less than 0.033 lb/MM BTU, then the remaining pre-1994 heaters will have an increased average emission rate, and the compliance margin for the remaining heaters will decrease, possibly requiring additional controls on the existing heaters to maintain compliance.

Although this mechanism has always existed in the rule, it has been criticized by refinery operators because the cost of implementing NOx controls has risen significantly since the rule was adopted in 1994 due to higher labor and material costs. Further, refinery operators have described this mechanism as a disincentive to the implementation of equipment upgrades that would reduce NOx emissions directly through better NOx controls and indirectly through greater energy efficiency. An example of this disincentive effect would occur if a refinery operator was inclined to replace one or more pre-1994 heaters with new heaters. The new heaters would probably be more energy efficient since many pre-1994 heaters were designed and constructed with little regard to energy efficiency. The new heaters would also have the lowest possible NOx emission rates because they would be subject to BACT requirements for NOx and other pollutants. However, if the pre-1994 heaters that were replaced had average NOx emission rates less than 0.033 lb/MM BTU, then the remaining pre-1994 heaters will have an increased average emission rate, possibly requiring additional controls on the existing heaters to maintain compliance, as described above. In this case, the refinery operator would have to fund the desired heater upgrades, and would also have to fund additional NOx controls on one or more pre-1994 heaters, many of which are quite old and therefore unattractive candidates for capital investment.

The District has explored at length the question of whether this rule mechanism may act as a disincentive to projects that would otherwise have air quality benefits because it imposes costs beyond those required to meet refinery goals and to achieve a net reduction in NOx emissions. As is shown in Table 1, below, very few new heaters have been installed at Bay Area refineries since 1994, but it is impossible for the District to know all of the factors that contributed to this lack of investment in heater infrastructure, and to be able to conclude whether the design of Regulation 9-10 has discouraged heater upgrades that would have had a net air quality benefit. Because significant heater upgrades that will improve refinery energy efficiency will be necessary to comply with state requirements to reduce greenhouse gas (GHG) emissions as described in Section 2.8, *infra*, the District will continue to evaluate whether Regulation 9-10 requires non-cost-effective NOx controls that conflict with GHG emission reduction efforts.

2.2 Number, Size and Age of Bay Area Refinery Heaters

Table 1 shows the number of heaters that are currently operated by Bay Area refineries. The data are separated according to the size (input heat rating) and type of the heater. Most refinery heaters are pre-1994 heaters that are subject to the refinery-wide average NOx limit.

Table 1 – Current Regulation 9-10 Heaters at Bay Area Refineries

Capacity Range (MM BTU/hr)	Pre-1994 Heaters Subject to Reg 9-10	CO Boilers Subject to Reg 9-10	Post-1994 Heaters Not Subject to Reg 9-10
<10	5		
10 to <20	6		1
20 to <50	46		4
50 to <100	43		4
100 to <150	21		
150 to <200	14		
200 to <250	17	3	
250 to <500	19	1	2
500 to <1000	8	2	
Total	**179**	**6** (*Note 1*)	**11**

Table 1 Notes:

(1) The Valero refinery has been issued a District permit to replace two CO boilers with two new units (Reference 29). Table 1 includes the new CO boilers, which are scheduled to begin operation in 2011.

Original construction dates and subsequent modification dates have been evaluated for the refinery heaters that are operating in the District. Many refinery heaters at the Bay Area refineries are over 40 years old and the oldest are over 75 years old. Thus, even a 30- or 40-year old heater is not necessarily approaching the end of its service life and heater age is typically not the determining factor in assessing the potential for emission reductions or the cost-effectiveness of reductions. The most important factors in determining potential emission reductions are the heater NOx emission rate, the size of the heater, the utility of the heater (*e.g.*, the fraction of time it is operated as well as the fraction of full firing rate at which it is operated) and the type of NOx control already installed. Typically, larger heaters with higher emission rates and higher utility are the best candidates for further NOx control, especially if they have no NOx controls or a low level of NOx control such as basic low-NOx burners. Since the refineries have already implemented NOx controls to meet the current refinery average NOx limit, the most cost-effective emission reductions have already been achieved, and the best candidates for NOx controls to meet a lower limit are not obvious. NOx control retrofit options for refinery heaters, including cost-effectiveness, are discussed in detail in Section 2.6, *infra*.

2.3 Refinery Heater Emissions Inventory

When Regulation 9-10 was adopted in 1994, the typical refinery heater operated at a NOx emission rate of 100 ppmv to 140 ppmv (*Reference 18*), with higher emissions at CO boilers. Most of these existing heaters were old enough that they pre-dated District permitting requirements and therefore they had never been subjected to BACT requirements, which apply to devices installed or modified after 1982. In fact, almost all of these heaters operated without emission controls of any kind. In 1994, total NOx emissions from these heaters were estimated to be about 31 ton/day, and adoption of the Regulation 9-10 limits in 1994 was expected to result in a 21 ton/day reduction in NOx. However, it appears that emissions from these heaters may have been underestimated in 1994. The current emissions and emission rates for these heaters, as well as 1994 emission rate data, suggest that total 1994 NOx emissions were about 40 ton/day and that implementation of the 1994 limits achieved a NOx reduction of about 26 ton/day, which represents about a 65% emission reduction.

Table 2 shows current refinery emissions at each of the five Bay Area refineries, based on permit data for 2008. The total 2008 NOx emissions for heaters subject to Regulation 9-10 (*i.e.*, pre-1994 heaters and CO boilers) equaled 10.9 ton/day. Post-1994 heaters that are not subject to the rule contributed another 0.1 ton/day of NOx emissions.

Table 2 - 2008 Refinery Heater NOx Emissions (ton/yr)

Refinery	Pre-1994 Heaters Subject to Reg 9-10	CO Boilers Subject to Reg 9-10	Post-1994 Heaters NOT Subject to Reg 9-10
Chevron	535	NA	7
Shell	460	516	NA
ConocoPhillips	169	NA	18
Valero	858	600	11
Tesoro	491	346	1
Total (ton/yr)	**2513**	**1462**	**37**
Total (ton/day)	**6.9 (63%)**	**4.0 (36%)**	**0.1 (1%)**

Greenhouse gas emissions at refinery heaters are estimated in Table 3 based on the rated heat input of the heaters, typical heater utilization, and the CO_2 emission factor for refinery fuel gas.

Table 3 – 2008 Refinery Heater Greenhouse Gas Emissions, CO_2 (ton/day) and Percentage of Total Emissions For Each Heater Type (*Note 1*)

Pre-1994 Heaters	CO Boilers	Post-1994 Heaters
23200 (88%)	2200 (8%)	944 (4%)

Table 3 Notes:

(1) Emissions are calculated based on the total rated heat input in each heater category, an assumed utilization of 55% for non-CO boilers and 70% for CO boilers, and a CO2 emission factor of 139 lb /thou ft^3 refinery gas (Reference 13), assuming heat value of 1000 BTU / ft^3.

As shown in Tables 2 and 3, post-1994 heaters account for about 4% of the permitted heater capacity, but only 1% of the NOx emissions. This reflects the effectiveness of BACT controls for NOx that are required on new or modified heaters, which include all post-1994 heaters. On the other hand, CO boilers account for about 8% of the permitted capacity, but about 36% of the NOx emissions. These disproportionately high NOx emissions from CO boilers reflect that these devices operate at higher utility levels than other heaters (see Table 3, note 1), and also that they tend to have higher NOx emission rates than other heaters.

2.4 Refinery Heater Regulations at Other California Air Districts

There are 13 active petroleum refineries in California (*Reference 4*): five in the Bay Area, two in Bakersfield and six in the Los Angeles area. Thus, the BAAQMD, the San Joaquin Valley Unified APCD (SJVUAPCD) and the South Coast AQMD (SCAQMD) regulate all petroleum refining operations in the state.

The San Joaquin Valley Unified APCD regulates refinery heaters under two rules. Rule 4306 is a conventional NOx control rule with different emission rate limits for different heater size ranges. The Rule 4306 limits are currently in effect and are no more stringent than the BAAQMD's current limit of 0.033 lb/MM BTU (equivalent to 28 ppmv) in Regulation 9-10 for heaters up to 110 MM BTU/hr. For larger heaters, the Rule 4306 limit of 5 ppmv (0.0062 lb/MM BTU) is significantly more stringent than the BAAQMD requirements. San Joaquin Rule 4320 imposes future NOx limits for refinery heaters up to 110 MM BTU/hr that are also significantly more stringent than the BAAQMD requirements. Importantly, however, a refinery in the SJVUAPCD may elect to pay an annual emission fee rather than comply with these limits at any heaters. The amount of the annual emission fee is capped at $13,600 per ton of NOx emitted (the cost-effectiveness threshold for the Carl Moyer Incentive Program). By contrast, BAAQMD staff estimates that the anticipated cost of achieving further NOx reductions from pre-1994 heaters (not including CO boilers) at Bay Area refineries will be over twice this cap value (in terms of annualized cost-effectiveness). Also, San Joaquin's refineries are significantly smaller than those in the Bay Area and total active refining capacity in San Joaquin is less than that at the smallest of the five Bay Area refineries (*Reference 19*). Given the difference in infrastructure between refineries in San Joaquin and the Bay Area, and the fee option for compliance with Rule 4320, the BAAQMD does not consider the numerical limits contained in SJVUAPCD's rules to be appropriate for Bay Area operations.

Compared to San Joaquin, the refining infrastructure in the South Coast AQMD is more similar to that in the Bay Area. However, the SCAQMD regulatory structure for refinery heaters differs so greatly from the BAAQMD's that the BAAQMD does not consider direct comparison to SCAQMD's program to be useful. The SCAQMD regulates NOx and SOx emissions at refineries under a voluntary regional cap-and-trade program called RECLAIM (SCAQMD Regulation XX). RECLAIM provides annual emission allocations for NOx or SOx at each facility in the RECLAIM program. The allocations were originally based on pre-1993 throughput at each source and on an emission factor for the source type. Allocations are reduced periodically, and by a uniform factor throughout the region, as necessary to meet air quality goals. If a RECLAIM facility's NOx emissions exceed its total NOx allocation, then it must either reduce emissions or purchase RECLAIM trading credits (RTCs) to make up the difference. RTCs are generated by facilities that have NOx emissions lower than their total NOx allocation and these facilities may sell their RTCs to other RECLAIM facilities. Importantly, the

RECLAIM program incorporates a "backstop" measure (South Coast Rule 2015) that requires the South Coast AQMD to track the selling price of RTCs and that triggers a RECLAIM program review, and possible suspension of allocation reductions, if the 12-month average NOx RTC price exceeds $15,000 per ton. This mechanism effectively limits the average cost of RECLAIM compliance to $15,000 per ton of NOx, since a RECLAIM facility may opt to purchase RTCs to comply with allocation limits rather than apply emission controls. The average cost of RTCs has never exceeded $15,000 per ton, except during the "energy crisis" of 2000-2001 when power producers drove the price of some NOx RTCs to $120,000 per ton (*Reference 20*). This episode triggered the 2005 amendment of the RECLAIM program that added the $15,000 per ton backstop and restrictions on RECLAIM participation by power producers.

2.5 Comparison of Emissions at Refinery Heaters and Non-Refinery Heaters

Non-refinery heaters are regulated by BAAQMD Regulation 9, Rule 7. These boilers, steam generators and process heaters contribute less NOx emissions than their refinery counterparts. In 2008, the District estimated the total NOx emissions from non-refinery heaters to be 5.1 ton/day (*Reference 11, Table 4*), whereas 2008 NOx emissions from refinery heaters that are regulated by Regulation 9-10 were approximately 10.9 ton/day (Table 2, *supra*).

Regulation 9-7 was amended in 2008 and will impose new NOx limits for non-refinery heaters in 2011 and 2012. The future NOx limits in Regulation 9-7 are summarized in Table 4.

Table 4
2011 / 2012 NOx Limits for Non-Refinery Heaters - Regulation 9-7

Rated Heat Input (MM BTU/hr)	NOx Limit (ppmv)
>2 to 5	30
>5 to <10	15
10 to <20	15
20 to <75	9
75 or more	5

Almost all refinery heaters are larger than 5 MM BTU/hr, and would be subject to a future NOx limit of 15 ppmv (6% of refinery heaters), 9 ppmv (45% of refinery heaters) or 5 ppmv (49% of refinery heaters) if they were subject to Regulation 9-7. These are more stringent than the limits currently imposed on these heaters by Regulation 9-10 (approximately 28 ppmv for pre-1994 heaters, and 150 ppmv for CO boilers). However, the population of heaters subject to Regulation 9-7 is very different than the one subject to Regulation 9-10. Almost all of the heaters that are subject to Regulation 9-7 are water boilers or low-pressure steam boilers that operate at relatively low temperatures and that use natural gas fuel exclusively. By contrast, over 80% of the heaters at refineries are process heaters rather than boilers. Process heaters typically burn refinery gas fuel, which has different properties than pipeline-quality natural gas fuel. Refinery gas composition varies among refineries, but in some cases the refinery gas has a significantly higher heat value than natural gas and therefore burns at a higher temperature, thus creating more NOx. Available low-NOx and ultra-low-NOx burners are designed and optimized to use pipeline-quality natural gas fuel exclusively, and the use of refinery gas fuel may increase NOx emissions by as much as 20% compared to natural gas (*Reference 18*). These factors make NOx control at most refinery heaters more challenging compared to the heaters regulated under Regulation 9-7. In 2005 the SCAQMD concluded that ultra-low-NOx burners, which can achieve NOx emission rates of as little as 9 ppmv in natural gas-fired boilers, were only capable of 25 ppmv performance in refinery heater applications "due to the size and design of the equipment and the combustion characteristics of refinery gas" (*Reference 20*). Although CO boilers typically do not use high-BTU fuels, they have significant levels of nitrogen in their fuel gases which promote NOx formation even at reduced temperatures.

For these reasons, District staff has determined that direct comparison of NOx emissions limits on non-refinery and refinery heaters is not appropriate and has not based the proposed amendments on Regulation 9-7 emissions limits.

2.6 NOx Emissions and Controls

A refinery heater combustion process involves the combustion of a hydrocarbon fuel in the presence of oxygen (provided by adding combustion air). The carbon in the fuel is oxidized to carbon dioxide (CO_2) and the hydrogen in the fuel becomes water vapor (H_2O). By-products of the process include: carbon monoxide (CO), nitrogen oxides (NOx), sulfur oxides (SOx), volatile organic compounds (VOCs), and particulate matter. NOx and VOC compounds react in the lower atmosphere to form ozone. NOx, SOx, VOCs, and ammonia may react to form fine particulate matter. NOx emissions that contribute to ozone formation are the focus of Regulation 9-10 and Control Measure SSM 10 in the Bay Area 2010 Clean Air Plan.

2.6.1 NOx Emission Mechanisms

The nitrogen contained in the NOx emissions from a refinery heater combustion process comes from one of two sources: (1) elemental nitrogen (N) that is chemically bound to the fuel molecules, and (2) nitrogen gas (N_2) that is part of the combustion air (air contains about 79% N_2 by volume). NOx formed from elemental, fuel-bound nitrogen is called "fuel NOx". Because natural gas and most other gaseous fuels have negligible levels of fuel-bound nitrogen, and because these are the primary fuels used in refinery heaters, fuel NOx is not a significant contributor to NOx emissions from most refinery heaters, except for CO boilers. NOx formed from gaseous nitrogen that is introduced into the combustion process with the combustion air stream is the source of "thermal NOx" and "prompt NOx". Thermal NOx is created by a set of reactions that are affected primarily by heater temperature and excess O_2 concentration, with higher temperatures (especially greater than 2800ºF) and higher O_2 concentrations causing higher NOx generation rates. Prompt NOx is created by a set of reactions that are affected primarily by the air-fuel ratio in the combustion zone, with fuel-rich conditions promoting NOx formation. Thermal NOx is the primary component of NOx emissions from most refinery heaters (*Reference 18*), although prompt NOx must be controlled to achieve overall NOx emission rates of 20 to 30 ppmv or less.

CO boilers do not produce as much thermal NOx as other heaters because they tend to have lower flame and operating temperatures because of the low heating value of the fuel gases that they use. However, these low-BTU fuel gases contain a high concentration of NOx precursors that may produce a significant amount of fuel NOx. All Bay Area CO boilers, for example, burn flue gas from FCCU catalyst regenerators. Catalyst regenerators are used to burn coke from the surface of used FCCU catalyst. This coke contains significant levels of elemental nitrogen which enters the CO boiler along with the regenerator flue gas. Although most of the elemental nitrogen is converted to inert N_2 gas rather than being emitted as NOx (*Reference 22*), subtle differences in catalyst regenerator design and operation can result in wide variations in the uncontrolled level of NOx produced by CO boilers. Although the primary purpose of a CO boiler (besides making steam) is to reduce the emission of CO by oxidizing CO to CO_2, many of the techniques that are used to promote the oxidation of CO tend to work against the reduction reaction of NOx precursor species to N_2. Coker flue gas also has elevated levels of NOx precursors and high CO concentrations.

2.6.2 Thermal NOx Controls at Non-CO Boilers

Uncontrolled heaters use conventional burners that are not designed to achieve any particular level of NOx emissions. Conventional burners are designed to produce a small, hot flame by quickly and completely mixing fuel and combustion air. Such a flame allows the heater firebox to be as small as possible, and to be stable under a wide firing range and during fast changes in load, but does not control the formation of thermal NOx.

The first level of thermal NOx control for a refinery heater is the use of low-NOx burners (LNB) which use staged-combustion techniques. Instead of mixing fuel and combustion air as quickly as possible, LNBs perform combustion in at least two stages, with the fuel-air ratio carefully controlled and the fuel and combustion air mixed thoroughly. Thorough mixing prevents combustion hot spots where NOx formation is high, while staged combustion produces a larger flame with a lower average temperature. Since the thermal NOx formation rate is highly dependent on combustion temperature, eliminating hot-spots and performing combustion at lower average temperatures reduces thermal NOx formation. Some refinery heaters continue to use conventional burners rather than LNBs because the firebox will not accommodate a larger flame. LNBs typically provide as much as 50% reduction of NOx formation compared to conventional burners, when applied to natural gas-fired heaters. Implementation of the current NOx limits in Regulation 9-10 resulted in an average refinery heater emission rate (excluding CO boilers) that was no higher than if all refinery heaters used this first level of NOx control.

The next level of thermal NOx control is ultra-low-NOx burners (ULNB). ULNBs suppress thermal NOx formation in the same way that LNBs do, but they also suppress prompt NOx formation by avoiding fuel-rich conditions and reducing combustion temperatures. ULNBs use internal exhaust gas recirculation, where a portion of the combustion gases that are leaving the combustion zone are injected back into the combustion zone to cool the combustion zone. ULNBs typically provide as much as 75% reduction of NOx formation compared to conventional burners, when applied to natural gas-fired heaters.

Finally, thermal NOx may be controlled with selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). SCR and SNCR are post-combustion controls that are designed to remove previously-formed NOx from heater exhaust by chemically "reducing" the NOx to N_2 by reacting with ammonia (NH_3), with or without the use of a catalyst. NOx catalysts operate well in a narrow temperature band, so SCR systems are less suitable in applications where a heater operates over a wide load range, which results in a wide temperature variation at the exhaust catalyst. SCR and SNCR systems can be costly to design, install and operate, although they generally are capable of reducing NOx emission concentrations to less than 10 ppmv. SCR systems, in particular, may have significant space requirements to accommodate a large catalyst grid and a long enough run of upstream ducting to ensure that heater exhaust flow through the grid is uniform.

2.6.3 Fuel NOx Controls at CO Boilers

Thermal NOx emissions at CO boilers may be controlled with the same combustion options that are available to non-CO boilers, up to SCR and SNCR. Fuel NOx emissions, which may predominate at CO boilers, are not affected by thermal NOx controls. Therefore, if SCR or SNCR is not feasible or if it has limited effectiveness, then control of fuel NOx may be an option. Fuel NOx controls may focus on reducing the elemental nitrogen in coker and FCCU feedstocks to reduce the amount of coke nitrogen that is emitted as NOx, or on reducing the amount of NOx precursors created in the coker or FCCU regenerator through a re-design or through optimized operation of these units. Because a significant reduction of elemental nitrogen in feedstocks would probably require a new hydrotreating process unit or a new hydrogen plant, and because either of these would exceed the cost of add-on controls such as SCR, this is not considered a cost-effective approach. However, optimization of coker and FCCU regenerator operation is discussed in Section 3.1, *infra*.

2.6.4 Potential Pollutant Trade-Offs

NOx controls have the potential to directly or indirectly cause emissions of other air pollutants or toxic emissions. Table 5 summarizes potential trade-offs for common NOx controls.

Table 5 – Potential Trade-Offs for Heater NOx Reductions

LNB, ULNB	• Replacing conventional burners with LNBs or ULNBs reduces heater efficiency because cooler combustion temperatures provide less radiant heat transfer. A loss of efficiency requires the heater to consume more fuel to achieve the same heating, thereby producing NOx and other combustion products. LNBs and ULNBs typically cause an efficiency loss through reduced radiant heat transfer of less than 1% of the heater output. • Installing LNBs or ULNBs may also cause an increase in CO emissions because, while lower combustion temperatures suppress the NOx formation reactions, they may also suppress the full conversion of carbon in the fuel to CO_2, resulting in higher CO formation rates. Proper burner design and operation should keep CO emissions under the current 400 ppmv limit.
LNB, ULNB + SCR	• SCR typically uses two electric SCR blowers that cause additional fuel consumption at the electricity source, which produces NOx and other combustion products. This penalty is typically less than 1% of the heater output. • SCR uses ammonia as a reducing agent in the reaction that converts NOx to N_2. Some of the ammonia does not react and escapes in the exhaust as “ammonia slip”. Although ammonia is toxic, slip emissions typically do not result in a significant toxic risk. Like NOx, ammonia is a precursor to the formation of fine particulate matter compounds such as ammonium nitrate.

2.7 CO Emissions and Controls

Carbon monoxide is produced by the incomplete oxidation of carbon in a fossil fuel to CO rather than to CO_2. Because the District is in attainment status with all state ambient air quality standards for CO and is a "maintenance area" with respect to federal CO standards, Regulation 9-10 limits the concentration of CO in the exhaust stream of refinery heaters to a reasonable level (400 ppmv), but does not attempt to achieve further CO emission reductions. All other California air districts that address CO emissions from combustion sources impose the same 400 ppmv standard.

Combustion-based thermal NOx control strategies, which limit NOx formation by limiting combustion temperature, tend to also limit complete oxidation of carbon to CO_2, thereby increasing the CO formation rate. All refinery heaters, including CO boilers, may be operated at CO emission levels below 400 ppmv through good operating practice.

2.8 Greenhouse Gas Emissions and Controls

Combustion of conventional hydrocarbon fuel results in the release of energy in the form of heat as bonds between carbon and hydrogen are broken and reformed with oxygen to create water vapor (H_2O) and the greenhouse gas (GHG) carbon dioxide (CO_2). CO_2 is the only GHG emitted in significant quantities by refinery heaters. When methane (CH_4), the primary constituent of natural gas, is burned, the reaction proceeds as follows:

$$CH_4 + 2(O_2) \rightarrow CO_2 + 2(H_2O)$$

Thus, CO_2 is not a pollutant that occurs in relatively low concentrations as a by-product of the combustion process, like NOx. Rather, CO_2 is a necessary combustion product of any fuel containing carbon. The only practical way to reduce CO_2 emissions, and by far the least expensive way, is by increasing energy efficiency, *i.e.,* by consuming less fuel to provide the same useful energy output.

The current version of Regulation 9-10 has no GHG reduction or mitigation requirements, and no such requirements are proposed. However, the California Air Resources Board (CARB) is implementing GHG reduction strategies as required by 2006 California Assembly Bill 32 (AB 32). The basic goal of AB 32 is to reduce California GHG emissions to 1990 levels by the year 2020. CARB intends to achieve this goal through a cap-and trade program for GHG and through several dozen individual measures. The individual measures most likely to affect Bay Area refineries are shown below. The first two measures are intended to directly reduce GHG emissions at refineries, while the last would reduce GHG emissions when refined transportation fuels are used.

- A measure (I-4) to reduce refinery flaring is scheduled to have an ARB board hearing in 2011 for implementation beginning in 2012.
- A measure (I-5) to eliminate exemptions for methane emissions from refinery regulations is scheduled to have an ARB board hearing in 2011 for implementation beginning in 2012.
- A low-carbon fuel standard (T-2) that calls for a phased-in 10% reduction in the carbon-intensity of transportation fuels by 2020 has been adopted and goes into effect in 2011.

On October 29, 2010, CARB released the draft GHG cap-and-trade program for public comment (*Reference 24*). The cap will be a regional cap, rather than a set of facility caps, and the cap will initially be set in 2012 at the expected level of GHG emissions for that year. It will then be reduced every three years (except in 2015 when the cap will increase to reflect the addition of the second-phase facilities to the cap in that year) through 2020 to achieve the reduction goal. Petroleum refineries, including all of the Bay Area petroleum refineries, are among the industrial facilities to be included in the first phase of the cap-and-trade program in 2012. For refineries, CARB has focused on steam generator and process heater operations as primary GHG sources, and has indicated that the necessary emission reductions may be achieved through a range of measures applied to these devices. The simplest (and least costly) measures include optimization of steam generator and process heater operation. More costly measures include enhanced maintenance to achieve and maintain optimum performance. The most costly measures include installation of air or feedwater economizers, and complete replacement of steam generators and process heaters.

Facilities covered by the cap will receive emission allowances for each 3-year period of the cap and will surrender allowances to "pay" for actual emissions of GHG at the end of each period. Allowances will initially be allocated at no charge to refineries based on total refinery GHG emissions, but will then be adjusted to reflect conformance to some GHG emission baseline. Thus, facilities that emit less GHG than the allowances they receive will be able to trade excess allowances, while those that emit more GHG than the allowances they receive will have to buy additional allowances. Also, facilities that emit more GHG than the emission benchmark suggests will receive a smaller fraction of allowances relative to their initial GHG output, and facilities that emit less GHG than the benchmark suggests will receive a greater fraction of allowances relative to their initial GHG output. CARB has evaluated three benchmark alternatives (*Reference 25*), but has not yet finalized the benchmark or the initial distribution of allowances for 2012.

3.0 Proposed Rule Amendments

District staff recommends amending Regulation 9-10 in the following ways:

(1) Establishing new NOx emission limits for CO boilers, including long-term emission limits that are significantly lower than the current short-term emission limit.

(2) Modifying one current exemption to extend the applicability of the rule to smaller devices so that all refinery heaters are regulated by Regulation 9-10.

(3) Simplifying the procedures for determining compliance with the existing refinery-average NOx limit for heaters other than CO boilers when these are at low firing rates.

3.1 CO Boiler NOx Limits

Each of the six CO boilers in the Bay Area operates in conjunction with a fluid catalytic cracking unit (FCCU). The FCCUs use a powdered catalyst to promote the hydrocarbon cracking process, and this catalyst becomes coated with burned carbonaceous material ("coke") during its exposure to the hydrocarbon feedstock. Each FCCU includes a reaction vessel where the catalyst and feedstock are mixed, as well as a catalyst regenerator where coke is burned off the surface of the catalyst to restore its activity so that it can be re-used. Catalyst regenerators may be designed to burn the coke completely to CO_2 (full burn) or to only partially burn the coke to a mixture of CO and CO_2 (partial burn), with complete combustion occurring at a CO boiler. Because partial burn regenerators have high levels of CO in their flue gas, this gas is vented to a CO boiler where the CO is further combusted to CO_2 and where steam is generated. Thus the CO boiler acts as a CO control device and also recovers the significant fuel value of the CO, as well as some of the sensible heat of the flue gas. Five of the six Bay Area CO boilers are associated with partial burn FCCU regenerators. The sixth CO boiler, operated by Tesoro, was originally operated with a partial burn regenerator, but the regenerator has since been modified to operate normally in full burn mode. Partial burn operation is achieved by limiting the amount of oxygen in the regenerator so that coke combustion cannot proceed to completion. Full burn regenerators, on the other hand, operate with some level of excess oxygen so that combustion proceeds to completion. Partial burn operation typically results in regenerator operating temperatures less than 1300°F, while full burn regenerators operate at higher temperatures. A further distinction can be made between "partial burn" regenerators which produce flue gas with as little as 1% CO by volume and "deep partial burn" regenerators which produce flue gas with at least 5% CO by volume. Three of the Bay Area CO boilers, all operated at the Shell refinery, are "deep partial burn" units.

District staff has evaluated the six CO boilers operated at Bay Area refineries to determine if revised NOx emission limits are appropriate for these devices. These six devices include the two new CO boilers scheduled to be operational at the Valero refinery in 2011 (and which will be subject to more stringent BACT limits rather than Regulation 9-10), rather than the existing CO boilers which are to be replaced. In all cases, revised NOx limits are appropriate, based on the demonstrated ability of all CO boilers to operate at an emission rate below the current (daily) limit in Regulation 9-10. Specifically, the District found that some of the CO boilers at Bay Area refineries have a demonstrated ability to operate at lower daily emission rates. In addition, all of the CO boilers in the Bay Area are capable of operating at a much lower NOx emission rate when emissions are considered on a longer-term basis. Therefore, in addition to a reduced daily-average limit for some CO boilers, staff has proposed even lower annual-average limits for all devices.

In addition to establishing NOx limits that reflect the current capability of each CO boiler, District staff has also evaluated additional NOx control options available to each CO boiler and the resulting emission reductions and associated cost.

Table 6 describes the six Bay Area CO boilers. The Shell and Valero units that process both coker and FCCU regenerator flue gas have higher uncontrolled NOx emissions than the Tesoro unit, which does not process coker flue gas. However, the Valero CO boilers have controlled emissions that are similar to the Tesoro unit because the Valero units are equipped with SCR.

Table 6 – CO Boilers at Bay Area Refineries

CO Boiler (rated heat input)	Fuel Gases	Current NOx Controls
Shell #1 (207 MM BTU/hr) Shell #2 (207 MM BTU/hr) Shell #3 (207 MM BTU/hr)	• Flexicoker flue gas ("Flexigas") • Partial burn fluid catalytic cracking unit (FCCU) regenerator flue gas	1. Over-Fire Air System (OFA) 2. Urea injection selective non-catalytic reduction (SNCR)
Tesoro #1 (668 MM BTU/hr)	• Full burn fluid catalytic cracking unit (FCCU) regenerator flue gas	Production management
Valero #1 (529 MM BTU/hr) Valero #2 (259 MM BTU/hr) ***(both new in 2011)***	• Fluid coker flue gas • Partial burn fluid catalytic cracking unit (FCCU) regenerator flue gas	Selective catalytic reduction (SCR): imposed by District as best available control technology (BACT) in 2008

Table 7 shows the current and proposed NOx limits for CO boilers.

Table 7 – Current and Proposed CO Boiler NOx Limits

	Current Limits (ppmv @ 3% O_2)	**2015 Proposed Limits (*Note 1*) (ppmv @ 3% O_2)**	
Refinery	all	"CO Boiler" (Tesoro)	"Partial-Burn CO Boiler" (Shell)
operating-day average	150	150	125
calendar year average	none	45 (*Note 2*)	85

Table 7 Notes:

(1) The new Valero CO boilers, as well as any other new CO boilers, will not be subject to these limits because they are subject to stringent best-available control technology (BACT) NOx limits (Reference 29).

(2) The 45 ppmv limit will not apply during periods when the CO boiler does not use FCCU off-gas as fuel. This off-gas has a low heat value that results in lower combustion temperatures and therefore suppressed NOx formation compared to the refinery gas and natural gas fuels that are burned when the FCCU is out of service. When FCCU off-gas is not available, Tesoro cannot comply with this limit. FCCU maintenance outages occur for 30 to 45 days every three years.

As Table 7 shows, the six Bay Area CO boilers are currently all subject to a single NOx limit: 150 ppmv on a daily average basis. This limit reflects the fact that CO boilers tend to operate at higher NOx emission rates than other types of refinery heaters, especially on a short term basis. However, all of the CO boilers have established that they are capable of operating at emission rates significantly lower than 150 ppmv on a long-term basis.

Different limits are proposed for "partial burn" CO boilers. The proposed regulation applies the two proposed standards based on whether or not the CO boiler processes off-gas from a catalytic cracking unit (CCU) regenerator that operates in partial-burn mode, as the CO boilers do at the Shell refinery. Partial-burn CCU regenerator operation produces an off-gas high in CO and NOx precursors which results in higher NOx formation in the associated CO boiler.

3.1.1 Shell CO Boilers

Shell operates three identical CO boilers that process flue gas from a FCCU regenerator that operates in "deep partial burn" mode. This operating mode is characterized by a CO concentration in the flue gas (typically 6.5% by volume) that is high compared to typical partial burn regenerators. The proposed daily NOx limit of 125 ppmv and proposed annual NOx limit for "deep partial burn" units of 85 ppmv would apply to these CO boilers.

In addition to regenerator flue gas, the three Shell CO boilers also process Flexigas that is the gaseous by-product of Shell's Flexicoker coking unit. Flexigas has a very low fuel value and significantly higher CO concentration (typically 21% by volume) than FCCU regenerator flue gas. Regenerator flue gas is the primary CO boiler fuel, with varying amounts of Flexigas burned to accommodate steam demand, and with high-BTU refinery gas used as a supplemental fuel to maintain combustion of the lower-BTU primary fuels.

The primary NOx controls on these heaters are the Over-Fire Air (OFA) combustion air control system that has been in use since 1999 and the Urea Injection system, a form of selective non-catalytic reduction (SNCR) that was installed in 1988 and then upgraded in 1993 with improved urea flow controls and improved urea injectors. The OFA and SNCR systems were specifically designed so that the CO boilers "over-complied" with the 150 ppmv NOx limit. District Regulation 2, Rule 9: *Interchangeable Emission Reduction Credits* (IERCs) allows this over-compliance to be used to comply with other NOx rule provisions, including Regulation 9-10's refinery-wide non-CO boiler heater limit of 0.033 lb NOx/MM BTU. So, to some extent, the current 150 ppmv NOx limit for CO boilers in Regulation 9-10 has allowed Shell to forgo controlling NOx emissions at some of its other refinery heaters, which otherwise would need to be controlled for Shell to comply with the refinery-wide 0.033 lb NOx/MM BTU limit.

In 2005, as part of a consent decree between the previous owner of the Shell refinery and U.S. EPA, GE Energy performed an evaluation of the performance of the OFA and SNCR systems and of the associated baseline NOx emissions at the three Shell CO boilers for the purpose of establishing NOx emission limits at these CO boilers (*Reference 26*). This evaluation concluded that the three CO boilers operated at uncontrolled NOx emission rates between 200 ppmv and 250 ppmv during normal conditions, and as high as 350 ppmv during upset conditions, and that the OFA and SNCR systems resulted in an annual average NOx emission rate of 106 ppmv at the three heaters. The proposed rule amendments would reduce the daily NOx limit from 150 ppmv to 125 ppmv for these CO boilers. Shell has historically exceeded 125 ppmv two or three times per year under unusual operating conditions. The proposed amendments would also add a new annual average NOx limit of 85 ppmv for these boilers, which represents about a 20% reduction from the historical emission rate provided by the OFA and SNCR systems. Shell has indicated that it will attempt to achieve compliance with these proposed limits through further optimization of the existing OFA and SNCR control systems. If this optimization does not provide the necessary emission reductions, Shell will attempt to manage the production processes associated with the FCCU regenerator and the Flexicoker to reduce the concentration of NOx precursors introduced to the CO boilers. Shell has indicated that it believes that a combination of OFA and SNCR optimization and production management will provide the necessary emission reductions, without the need to design and install a new SCR or SNCR system. It should be noted that Shell has questioned the technical feasibility of improving SNCR performance with a new system or of successfully operating an SCR system on these CO boilers, and has also questioned the cost-effectiveness of these techniques, if they were found to be technically feasible.

3.1.2 Tesoro CO Boiler

Tesoro operates a single CO boiler that processes flue gas from a FCCU regenerator that normally operates in "full burn" mode. Normally, a full burn regenerator would not be equipped with a CO boiler since complete conversion of CO to CO_2 occurs in the regenerator with no need for a CO boiler to complete the combustion. However the Tesoro regenerator originally operated in partial burn mode, but has since been modified to operate in full burn mode, although it may operate in partial burn mode for limited periods under unusual circumstances.

Although the Tesoro CO boiler does not use SCR or SNCR, this boiler is proposed to be subject to an annual average NOx limit of 45 ppmv, which is very close to the 43 ppmv BACT limit for the new, SCR-equipped CO boilers at Valero (see Section 3.1.3). A review of recent historical continuous emission monitoring system (CEMS) emission data for the Tesoro CO boiler indicates that this limit provides little to no compliance margin for the existing CO boiler. The Tesoro CO boiler achieves a relatively low NOx emission rate through process management that limits the amount of NOx precursors that go to the CO boiler and also limits the operating temperature of this device. Compliance with the proposed limit will require continued management of these NOx emission mechanisms, but will not require the design and installation of a new SCR or SNCR system. Given the relatively low level of NOx emissions at this CO boiler, the incremental cost-effectiveness for a new control system would be poor.

The proposed rule amendments would retain the 150 ppmv daily NOx limit for the Tesoro CO boiler since CEMS data indicate that this limit is approached during certain operating conditions, although these episodes may only occur 2 or 3 times per year. Reducing this daily limit would result in a very limited emission reduction, but would probably require additional NOx controls with poor incremental cost-effectiveness.

3.1.3 Valero CO Boilers

In 2011, Valero will operate two CO boilers that will process flue gas from a FCCU regenerator that operates in "partial burn" mode. Both CO boilers will have their NOx emissions abated by SCR systems that represent "best available control technology" (BACT). BACT is a more stringent emission standard than "best available retrofit control technology" (BARCT), which is the control standard normally applied in retrofit rules like Regulation 9-10. Because the Valero

CO boilers will satisfy the most stringent emission standard, there is no need to consider additional controls for these devices. In fact, the BACT NOx limits assigned to the Valero devices (43 ppmv annual average) are slightly more stringent than the proposed limits for the Tesoro CO boilers (*Reference 29*).

Currently, Regulation 9-10 applies to CO boilers, regardless of their service date. However, as with all new devices, new CO boilers are subject to stringent BACT limits for NOx and other pollutants. Subjecting these new CO boilers to Regulation 9-10 would not result in any additional NOx emission reductions beyond those already required for BACT. However, including these under Regulation 9-10 would result in having two different sets of applicable monitoring and recordkeeping requirements. In order to prevent the possibility of conflicting monitoring and recordkeeping requirements, new CO boilers, including the Valero CO boilers, are proposed to be excluded from the rule, the same way that new non-CO boilers (*i.e.*, post-1994 heaters) are excluded.

3.2 Extend Rule Applicability for Natural Gas and LPG-Fired Heaters

Regulation 9-10 currently applies only to natural gas and LPG-fired heaters with input heat ratings of 10 MM BTU/hr or greater. In 2008, the non-refinery heater rule (Regulation 9-7) was amended to apply to natural gas and LPG-fired heaters with input heat ratings of greater than 2 MM BTU/hr. So that refinery heaters are regulated in the same size range as non-refinery heaters, District staff proposes that the exemption for natural gas and LPG-fired heaters in Regulation 9-10 be narrowed so that it only applies to heaters smaller than 2 MM BTU/hr rather than 10 MM BTU/hr. The refineries have a very limited number of heaters smaller than 10 MM BTU/hr. To minimize the administrative burden associated with regulating these small heaters, these heaters will be allowed to be treated in the same way that liquid-fueled heaters in this same size range are currently treated in Regulation 9-10. Namely, the refineries will have the option of either maintaining a low excess oxygen concentration or of performing annual tune-ups for these small heaters. Either of these measures will provide a level of NOx control appropriate to these units.

3.3 Simplify Calculation Procedures for Non-CO Boilers at Low Firing Rates

The refinery-wide average NOx limit in Regulation 9-10 is expressed in units of “pounds of NOx per million BTU of heat input”. This particular form was chosen for a variety of reasons, one of which is that it can be applied to refineries of completely different design and with completely different product lines. However, one drawback to this form is that, because it is a ratio of the mass of NOx emissions to the corresponding heat input, the resulting emission rate tends to increase disproportionately to the actual increase in NOx mass emissions at low heater firing rates. When a refinery heater is operating at a low firing rate, as during startup or shutdown, the emission rate expressed in “lb NOx/MM BTU” may be higher than the emission rate during normal operation, even though actual NOx mass emissions may be lower than during normal operation.

Also, a refinery may comply with the refinery-wide average limit during normal operations, but if the refinery relies on one or two large heaters with low emissions to achieve compliance (because these balance out higher emissions at other heaters), then the refinery may be out of compliance if the large heaters with low emissions are temporarily out of service for testing or maintenance.

In order to address these two situations, Regulation 9-10 allows heaters that are in start-up or shutdown and heaters that are temporarily out of service to have special calculation procedures during these periods. Instead of using the actual emission rate for heaters in start-up or shutdown, any historic source test data may be substituted, and for heaters that are out of service the rule states that historic emission data and firing rate data is used. However non-CEMS equipped heaters would not have historic emission rate data available. Also, allowing any historic source test data to be used for heaters in start-up or shutdown is quite permissive.

To simplify and clarify these provisions, the proposed amendments remove the allowance to use any previous source test result for heaters in start-up or shutdown and instead allow the use of historic emission data and firing rate data to be consistent with the treatment of units that are temporarily out of service. Also, the Title V permit conditions for all refineries currently allow heaters in "curtailed operation" to also use historic data. For completeness, a definition of "curtailed operation" and the allowance to use historic data during curtailed operation is included in the proposed amendments.

3.4 Cost of Controls

The proposed changes to CO boiler emission limits in Regulation 9-10 may result in capital costs for NOx control equipment and may result in increased operating costs. The other proposed changes are not expected to result in a significant additional cost. Because the District already administers Regulation 9-10 and because the proposed amended rule will retain most of the same provisions, additional costs to the District will be limited to rule development costs, costs to process required compliance plans and permit applications for equipment modifications required by the proposed amendments, as well as initial compliance verification costs. As discussed in Section 8, *infra*, throughout this rule development process, District staff met extensively with refinery staff and representatives to evaluate the cost of each control option.

3.4.1 Cost to Refinery Operators

As described in Section 3.1, two Bay Area refineries operate CO boilers that will be subject to the proposed NOx limits. As described in Section 3.1.1, the operators of the Shell refinery will have NOx emission limits that are somewhat lower than the average historical performance of the three facility CO boilers, both on a daily and annual average basis. Shell staff has indicated that they have a number of options to achieve compliance without resorting to the installation of new add-on NOx controls (the CO boilers already have SNCR control systems). These options include further performance optimization of the combustion air (OFA) control system and of the SNCR system, as well as careful management of processes to avoid conditions that will cause NOx emissions to increase. NOx emission rates at the CO boilers vary from day to day, and sometimes show long-term increasing or decreasing trends. These variations occur for a variety of production-related reasons, some of which are poorly understood, even by refinery staff. For this reason it is impossible to definitively say what actions will be necessary to achieve compliance with the proposed limits by the 2015 effectiveness date. However, District staff assumes that there will be costs associated with the proposed changes simply because the proposed limits are lower than the recent historical emissions for these CO boilers. To estimate these costs, District staff has assumed that Shell will be able to achieve compliance by undertaking a thorough optimization of the existing OFA and SNCR systems, including some replacement of system components (e.g. controllers, urea injection equipment, ducting), and that the cost of these optimization efforts will be a fraction of the cost of a new add-on NOx control system, such as SCR. Shell has provided the estimated installed cost for two new, SCR-equipped CO boilers. Assuming that the SCR portion of this project is 10% of the cost, and that thorough optimization of the existing OFA and SNCR systems would vary from 10% to 25% of the cost of a new SCR control system, optimization costs could range from about $6 million to about $16 million. If these costs are annualized using standard District methodology, and Shell is estimated to have an emission reduction of 20% compared to 2008 emissions (103 ton/yr NOx reduction) as discussed in Section 3.1.1, the cost–effectiveness for the Shell refinery is between $8,000 and $21,000 per ton of NOx reduced. The higher estimate of $16 million (equivalent to an annualized cost of $2.2 million) is the basis for the cost used in the socioeconomic analysis discussed in Section 5, *infra*. However, in the analysis, the annualized cost was round up to $3 million.

As described in Section 3.1.2, the operators of the Tesoro refinery will have to maintain the production controls already in place to comply with the proposed NOx limits. They are not expected to need new, add-on controls or comprehensive, additional optimization of existing processes. Tesoro has not indicated that any specific actions will be necessary to comply with the proposed limits, although, as at the Shell refinery, CO boiler emissions vary on a short-term and long-term basis and it is impossible to predict how future production and operational changes may affect CO boiler emission rates. Because no specific actions are known to be necessary to comply with the proposed limits, no compliance cost has been estimated for the Tesoro refinery.

As noted in Section 3.1.3, the new Valero CO boilers will be subject to more stringent BACT limits, rather than the proposed CO boiler NOx limits. Therefore, no compliance cost has been estimated for the Valero refinery.

3.4.2 Cost to the District

In addition to the cost of developing and adopting the proposed amendments to Regulation 9-10, the District will also incur one-time costs to process permit applications for any required heater modifications. Permit fees are expected to recover any such permitting costs. Enforcement of the amended rule is not expected to result in significant new costs.

4.0 Emissions and Emission Reductions

4.1 NOx Emissons and Emission Reductions

Table 2 in Section 2.3 shows the most recent (2008) emission inventory data for each of the five Bay Area refineries in each of the heater categories relevant to Regulation 9-10 (pre-1994, post-1994 and CO boilers). Table 8 shows the CO boiler data from Table 2.

Table 8
2008 Refinery NOx Emissions – CO Boilers

Shell	516 ton/yr
Valero	600 ton/yr
Tesoro	346 ton/yr
Total	**1462 ton/yr**
	4.0 ton/day

The proposed CO boiler NOx limits represent a significant reduction from the current limit of 150 ppmv. Because the proposed limits are different for different facilities, the proposed limits may be considered as a weighted average based on the emission rate at each facility. If the annual average limit of either 45 ppmv or 85 ppmv is weighted by the emissions shown in Table 8, the weighted average proposed NOx limit is 59 ppmv. This represents a reduction of 61% from the current limit of 150 ppmv. Therefore, in the simplest terms, the emission reduction from the 2008 inventory may be estimated to be 2.4 ton/day of NOx.

However, as discussed in this report, CO boilers do not operate at the current 150 ppmv NOx limit on a long term basis. In some cases, CO boilers operate close to the proposed NOx limits. However, some refineries use the fact that they operate CO boilers below 150 ppmv to generate IERCs that are used to comply with the refinery-average daily NOx limit in Regulation 9-10 instead of actually applying NOx controls to the pre-1994 heaters that are subject to the refinery-wide limit. The new NOx limits are expected to eliminate the ability of refineries to generate IERCs, such that they will have to apply NOx controls to pre-1994 heaters to maintain compliance. Therefore, the emission reduction associated with the proposed CO boiler NOx limits may also be estimated as the amount of IERCs used by refineries with CO boilers. From 2002 through 2008, the average total use of IERCs by refineries with CO boilers was 595 ton/yr (1.6 ton/day). Therefore, a more realistic estimate of the emission reduction from the proposed CO boiler NOx limit changes is 1.6 ton/day of NOx.

4.2 Secondary Particulate Emission Reductions

Because NOx compounds in the atmosphere contribute to the formation of secondary particulate matter (PM), any NOx emission reduction will also result in a reduction of PM. Secondary PM is formed from the conversion of NOx to ammonium nitrate (NH_4NO_3). District staff has estimated the ratio between NH_4NO_3 formation to NOx emissions to range between 1:6 and 1:10. Assuming a NOx emission reduction of 1.6 ton/day, and a conversion rate of 1:8, secondary particulate matter will be reduced by as much as 0.2 tons/day by the proposed amendments.

5.0 Economic Impacts

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 9-10. The analysis concludes that the cost of the proposed amendments will not have a significant socioeconomic impact on affected businesses. As discussed in Section 8, *infra*, throughout this rule development process, District staff met extensively with refinery staff and representatives to evaluate the cost of each control option.

Cost-Effectiveness and Incremental Cost-Effectiveness

As discussed in Section 3.4.1, *supra*, the estimated cost-effectiveness for Shell refinery for the proposed CO boiler NOx limits is between $8,000 and $21,000 per ton of NOx reduced for optimization of the existing OFA and SNCR NOx control systems. The highest value in this range, $21,000 per ton, is the basis for the cost evaluated in the socioeconomic analysis. $21,000 per ton is equivalent to an annualized cost of $2.2 million. For conservatism, this amount was rounded up to $3 million in the socioeconomic analysis.

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."

The control options that will achieve the emission reduction objectives for Regulation 9-10 are described in Section 3, *supra*, and the cost-effectiveness for these options is shown in Section 3.4.1.

To evaluate incremental cost-effectiveness, District staff divided refinery heaters into the three groups shown in Table 9: pre-1994 heaters, Shell CO boilers and Tesoro CO boilers. Pre-1994 heaters are considered collectively because they are subject to a collective limit. Each CO boiler is considered separately. Valero CO boilers are not subject to an incremental cost-effectiveness evaluation because these are not subject to the proposed rule, and also these were recently determined to meet "best available control technology" (BACT) requirements (*Reference 29*). For these three heater categories, Table 9 identifies the proposed NOx limits or control technologies in the proposed rule, and then a further level of control considered to be the next most effective with the associated incremental cost-effectiveness for this further control.

Table 9 – Incremental Cost-Effectiveness for Further NOx Controls			
Category	**Proposed NOx Limit (Control Technology)**	**Further NOx Limit (Control Technology)**	**Incremental Cost-Effectiveness**
Pre-1994 Heaters	0.033 lb NOx / MM BTU heat input (equivalent to 28 ppmv), daily average (various)	0.018 lb NOx / MM BTU heat input (equivalent to 15 ppmv), daily average (various)	>$31,000 / ton NOx
3 Shell CO Boilers	85 ppmv NOx, annual average (SNCR)	9 ppmv NOx, annual average (SCR)	>$35,000 / ton NOx
Tesoro CO Boiler	45 ppmv NOx, annual average (process control)	9 ppmv NOx, annual average (SCR)	>$35,000 / ton NOx

6.0 Environmental Impacts

Pursuant to the California Environmental Quality Act, the District 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 copy of the initial study and draft Negative Declaration is provided in the appendix of this staff report. The study and draft Negative Declaration will be circulated for comment prior to the public hearing.

7.0 Regulatory Impacts

Section 40727.2 of the California Health and Safety Code requires an air district, in adopting, amending, or repealing an air district regulation, to identify existing federal and air 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 differences between these existing requirements and the requirements imposed by the proposed change.

BAAQMD Regulation 9 for NOx sources is structured so that no source is subject to more than one rule under Regulation 9. Therefore, the heaters that are currently subject to Regulation 9, Rule 10 and those that are proposed to be made subject to Regulation 9, Rule 10 are not subject to any other District regulation that establishes specific emission limits or monitoring requirements, although they may be subject to other District regulations that establish permitting requirements or fees.

U.S. EPA has established New Source Performance Standards (NSPS) in Part 60 of the Code of Federal Regulations (CFR) and National Emission Standards for Hazardous Air Pollutants (NESHAP) in Part 63 of the CFR that include NOx and CO emission limits that affect some refinery heaters as listed in Table 10.

Table 10 – New Source Performance Standards (NSPS)

Federal Standard	Affected Heaters	Requirements
NSPS Subpart D 60.44(a)	Steam Generator; input rating >250 MM BTU/hr; constructed after August 17, 1971	• 0.20 lb NOx/MM BTU limit for gaseous fuel • 0.30 lb NOx/MM BTU limit for liquid fuel
NSPS Subpart Db 60.44(b)	Steam Generator; input rating >100 MM BTU/hr; constructed after June 19, 1984	• 0.10-0.20 lb NOx/MM BTU limit for natural gas and distillate oil fuel
NSPS Subpart J 60.103	Fluid Catalytic Cracking Unit (FCCU) Catalyst Regenerators and Fuel Gas Combustion Devices constructed between June 11, 1973 and June 24, 2008	• 500 ppmv CO limit
NSPS Subpart Ja 60.103	FCCUs, Fluid Coking Units (FCUs) and Fuel Gas Combustion Devices (FGCDs) constructed after May 14, 2007	• 80 ppmv NOx limit at 0% oxygen, 7-day rolling average • 500 ppmv CO limit at 0% oxygen, hourly average
NESHAP Subpart UUU 63.1565(a)(1)	Catalytic Cracking Units (CCUs) constructed after September 11, 1998	• 500 ppmv CO limit (surrogate for hazardous organic compounds)

The details of which of these federal requirements apply to specific refinery heaters are included in the major facility (Title V) permit for each refinery. In general, Regulation 9-10 already has, and is proposed to continue to have, more restrictive NOx and CO emission limits than the NSPS and NESHAPS. The only case where this is not obvious is for the 80 ppmv NOx limit in NSPS Subpart J. This limit is expressed as a daily average corrected to 0% oxygen while Regulation 9-

10 has a refinery-wide daily average limit equivalent to 28 ppmv NOx at 3% oxygen. However, the NSPS standard applies to post-2007 heaters that would not be subject to Regulation 9-10, but would instead be subject to BACT standards if constructed in the Bay Area. BACT requirements would be at least as stringent as this NSPS standard.

8.0 Rule Development Process

District staff has reviewed refinery heater rules at all California air districts, studied each Bay Area refinery heater and considered all known NOx control technologies to establish the appropriate NOx emission limits for heaters subject to Regulation 9-10.

In 2009 the District formed an industry workgroup comprised of representatives from each Bay Area refinery and the Western States Petroleum Association (WSPA). In 2009 and 2010, District staff met individually with representatives from each Bay Area refinery and with staff from Environmental Resources Management (ERM). ERM was contracted by WSPA to prepare a methodology for estimating costs for NOx control upgrades at refinery heaters (*Reference 27*), to compile data for refinery heaters, and to estimate costs for NOx upgrades at each heater. District staff reviewed this methodology and the resulting cost data with ERM staff and with refinery staff, including various refinery technical experts. District staff validated the ERM cost methodology using U.S. EPA cost estimation tools (*Reference 28*).

District staff prepared a draft regulation in December 2009 and in February 2010 held a workshop to solicit public comment. A notice for this workshop was posted on the District website and individual notices were mailed to all refinery operators and prior participants in the rule development process. Based on comments and a further evaluation of potential control measures, District staff prepared an amended regulation and released it for public comment in August 2010. During the public comment period, District staff met and communicated with representatives from each refinery and with WSPA to clarify provisions of the proposed regulation and to receive comments. The current proposed amendments are the product of this extensive process. District staff updated the District's Stationary Source Committee on this rule development process on May 13, 2010 and on September 27, 2010.

9.0 Conclusion

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 9-10 are:

- Necessary to limit emissions of NOx, a primary precursor to ground-level ozone formation, and to meet the requirements of the Bay Area 2010 Clean Air Plan;
- Authorized under Sections 40000, 40001, 40702, and 40725 through 40728 of the California Health and Safety Code;
- Written or displayed so that its meaning can be easily understood by the persons directly affected by it;
- Consistent with other BAAQMD rules, and not in conflict with state or federal law;
- Non-duplicative of other statutes, rules or regulations; and
- Implementing, interpreting or making specific the provisions of the California Health and Safety Code Sections 40000 and 40702.

The proposed new rule has met all legal noticing requirements, has been discussed with the regulated community, and reflects the input and comments of many affected and interested parties. BAAQMD staff recommends adoption of the proposed amendments to Regulation 9-10.

10.0 References

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5. San Joaquin Valley Unified Air Pollution Control District: Rule 4306, "*Boilers, Steam Generators and Process Heaters – Phase 3*", October 2008.

6. San Joaquin Valley Unified Air Pollution Control District: Rule 4320, "*Advanced Emission Reduction Options for Boilers, Steam Generators and Process Heaters Greater than 5.0 MM BTU/HR*", October 2008.

7. South Coast Air Quality Management District: Rule 1109, "*Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries*", August 1988.

8. South Coast Air Quality Management District: Rule 2002, "*Allocations of Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx)*", January 2005.

9. South Coast Air Quality Management District: Rule 429, "*Start-Up and Shutdown Exemption Provisions for Oxides of Nitrogen*", December 1990.

10. U.S. Environmental Protection Agency: AP 42, 5th Edition, Volume I: "*Compilation of Air Pollutant Emission Factors*", Chapter 1: "*External Combustion Sources*"; Section 1.4: "*Natural Gas Combustion*", Table 1.4-1.

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12. California Air Resources Board: "*Climate Change Proposed Scoping Plan Appendices, Volume 1*", October 2008.

13. Bay Area Air Quality Management District: "*Source Inventory of Bay Area Greenhouse Gas Emissions*"; December 2008.

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17. Charles E Baukal, Editor: *"The John Zinc Combustion Handbook*", 2001, CRC Press.

18. U.S. Environmental Protection Agency: Alternative Control Technique (ACT) Document: *"NOx Emissions from Process Heaters (Revised)"*, EPA-453/R-93-034, September 1993.

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20. South Coast Air Quality Management District: Staff Report, "*Proposed Amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM)*", January 2005.

21. South Coast Air Quality Management District: Staff Report, "*Proposed Amended Rule 1146 – Emissions of Oxides of Nitrogen from Industrial Institutional and Commercial Boilers, Steam generators and Process Heaters*", August 2008.

22. Frank S. Rosser, Mark W. Schnaith, Patrick D. Walker: *"Integrated View to Understanding the FCC NOx Puzzle"*, paper at 2004 American Institute of Chemical Engineers Annual Meeting

23. Bay Area Air Quality Management District: "*Engineering Evaluation Report: Valero Improvement Project Amendments, Application 16937*", December 2008

24. California Air Resources Board: "*Staff Report: Initial Statement of Reasons, Proposed Regulation to Implement the California Cap-and-Trade Program*", Part I, Volume I; October 28, 2010

25. California Air Resources Board: "*Staff Report: Initial Statement of Reasons, Proposed Regulation to Implement the California Cap-and-Trade Program*", Appendix J; October 28, 2010

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