State of California

<u>California Environmental Protection Agency</u>

AIR RESOURCES BOARD

Report to the Legislature

Implications of Future Oxides of Nitrogen Controls From Seasonal Sources in the San Joaquin Valley

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Acknowledgements:

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I. EXECUTIVE SUMMARY

Assembly Bill (AB) 2283, Florez, September 8, 2000, amended Section 40703 of, and adds Section 39702.5 to, the Health and Safety Code, relating to air pollution. It requires the State Air Resources Board (ARB) to investigate and provide a one-time report to the Legislature by January 1, 2002, on specified matters with respect to emissions abatement equipment required by the San Joaquin Valley Unified Air Pollution Control District (District) for control of oxides of nitrogen (NOx) emissions from seasonal sources in the San Joaquin Valley (Valley). The text of the legislation is provided as Appendix 1.

AB 2283 requires ARB to investigate: a) the average useful life of emissions abatement equipment used to meet Best Available Control Technology (BACT) or Best Available Retrofit Control Technology (BARCT) for NOx emissions; b) the implications of imposing additional air pollution control requirements on sources that meet BACT/BARCT requirements; c) the average, actual, and historical costs of complying with BACT and BARCT requirements; and d) the implications of applying incremental costs to projects subject to those requirements. The study must take into account air quality and public health considerations, growth, and interbasin transport of air pollutants from other regions.

Advisory Committee

AB 2283 required ARB to develop the report in consultation with an advisory committee (Committee) consisting of representatives from the District, environmental organizations, stationary sources, seasonal stationary sources, agriculture, and the U.S. Environmental Protection Agency (U.S. EPA). A list of advisory committee members appointed by ARB is provided as Appendix 2.

Background

Achieving clean air by attainment of air quality standards is mandated by both the State and federal Clean Air Acts and is implemented at the local level by each of the 35 air pollution control districts in California. Local air districts in nonattainment areas establish permit programs to meet their responsibility for controlling the emissions from stationary sources of air pollution under their jurisdiction. A district's permit program is based on issuance of a Permit to Operate to a stationary source that contains conditions on operation that are derived from the district's rules, and/or applicable State and Federal requirements. In areas where ambient air quality standards are not being met for a particular pollutant, new and expanding stationary sources of air pollution must install BACT at the time of construction to minimize new emissions. Districts develop air quality attainment plans that contain measures, including those that require BARCT, which are designed to reduce emissions from existing stationary sources. The district plans are incorporated into the State Implementation Plan

(SIP) and are implemented in order to achieve attainment of State air quality standards for pollutant emissions.

AB 2283 was enacted because concerns had been raised about future requirements in the Valley establishing BARCT standards for retrofit seasonal process equipment. The primary concern was with the economic impacts of having to modify or replace existing air pollution control equipment to comply with more stringent BARCT rules being considered by the District.

Seasonal process equipment includes boilers and continuous dryers used to process food during the summer months. Owners and operators purchased and installed BARCT emission abatement equipment for their existing emission sources to meet the requirement of 30 parts per million (ppm) NOx emissions specified in District Rule 4305, "Boilers, Steam Generators, and Process Heaters," adopted in 1993, and provided as Appendix 3. This rule requirement affected sources that complied with BACT requirements during the last few years and sources that previously complied with BARCT requirements.

Both state and federal regulations require that the District implement all feasible emission reductions necessary to meet SIP requirements. Section 40914 of the California Clean Air Act compels the District to achieve a 5 percent or more per year reduction in ozone precursor emissions districtwide or to demonstrate that despite the inclusion of every feasible measure in the SIP, and an expeditious adoption schedule, the District is unable to achieve at least a 5- percent annual reduction in districtwide emissions. Section 172 of the federal Clean Air Act Amendments of 1990 also requires that a nonattainment District adopt plans that provide for the implementation of all reasonably available control measures as expeditiously as practical. Consequently, future planning cycles will include rulemaking that imposes more stringent BARCT limits that typically track the BACT requirement. The legislation requires ARB to examine future potential BARCT levels and evaluate the associated cost effectiveness, safety, and other matters for seasonal sources in the Valley.

Scope of the Study

In consultation with the Committee, ARB staff established the scope of the study. The following summarizes the major components:

- Seasonal sources operating in both the food processing and cotton ginning industries were considered for inclusion in the report. The primary seasonal operation in the Valley is the processing of food. For the purposes of this study, food-processing operations are used for evaluation.

- The inclusion of the terms BACT and BARCT in the legislation is confusing because there is a distinct difference between the two technology requirements: BACT is used to control emissions from new or expanded sources and does not include cost considerations in nonattainment areas such as the San Joaquin Valley Air Basin (SJVAB). BARCT is used to control emissions from existing sources and includes an evaluation of cost effectiveness. The bill sponsors have emphasized their concern about any possible requirement to operate more stringent emissions abatement equipment on existing sources currently controlled. Consequently, the report focuses on BARCT requirements.

- As directed by the legislation, the report examines NOx emissions only.

- A review of permitted sources in the food processing industry in the Valley showed that boilers and continuous (conveyor) dryers are the predominant NOx emission sources.

- The legislation allowed the Committee to determine the appropriateness of recommending that the report include internal combustion engines, providing that the inclusion would not significantly expand the scope of the report. ARB staff and the Committee determined that it is not feasible to include stationary internal combustion engines in the investigation, given the information required in the report, the schedule necessary for providing the report, and the studies of internal combustion engines ARB is conducting under other programs.

- ARB staff established the cost effectiveness thresholds when reducing NOx emissions from the current limit of 30 ppm to be 15 ppm, 9 ppm and 3 ppm.

- While the bill co-sponsors have emphasized the importance of using cost effectiveness to determine the merits of requiring stricter emission limits for previously controlled process equipment, and while state law does require that cost effectiveness be considered, and is in fact provided, in the socio-economic analysis included in District Rule 4305, there are no legal requirements to use cost effectiveness alone to determine the feasibility of a control measure. Consequently, the incremental cost effectiveness data provided in the report is just one of several factors to be considered by the District during determinations of the feasibility of control measures.

Use of this Report

Several uses for this report are anticipated. Because the principal purpose of the report is to provide a basis for evaluating the cost effectiveness, safety and related matters associated with BARCT for abatement of NOx emissions from (food processing) seasonal sources in the Valley, the report may be used by the:

- District to better understand the costs associated with emission abatement equipment needed to meet the District's rule requirements, and the impacts of additional requirements on the operations of the food processing industry;

- Food processing industry to better understand the air quality responsibilities of the District and the need for continued reduction of emissions as the Valley is challenged to meet the federal health-based standards for ozone;

- Manufacturers of emission abatement equipment to better understand the emission requirements developed by the District and the operations of the food processing industry affected by those requirements.

Findings

This report does not include conclusions or recommendations. Instead, as directed in the legislation, it provides a basis for evaluating the cost effectiveness, safety and related matters associated with BARCT for abatement of NOx emissions from seasonal sources in the Valley. The research performed and data collected to complete this report have provided the following findings for use in such evaluations:

- The boilers, dryers, and dehydrators used for food processing account for 3.1 of the 592.9 tons per day (tpd) (0.5%) total (mobile and stationary) NOx emissions inventory in the Valley. However, the food processing equipment accounts for 37% (3.1 of the 8.4 tpd) of the NOx emissions from all boilers, dryers and dehydrators operating in the Valley during July to September. The impact of these NOx emissions on the region's air quality is significant during the food processing season because: a) the processing of fruits and vegetables occurs predominantly during July, August, and September; b) those months are typically the months when the air quality is the worst due to high ozone concentrations; and c) the processing is done with equipment that operates at maximum capacity during that time, thus maximizing the production of NOx.

- The reclassification of the SJVAB to "severe" for nonattainment of the federal health-based standards for ozone challenges the District to seek further reductions in NOx emissions. Given the significant impact on emissions from the food processing industry during peak ozone season, the District may require the industry to install more effective emissions abatement equipment in order to meet more stringent emission limits and achieve the necessary additional reductions.

- The data collected on the useful life of emissions abatement equipment show that the typical useful life of the equipment currently in use is 15-20 years. Implementation of a new requirement to install more stringent emission abatement equipment would likely occur during the useful life of the existing equipment.

- Per Table 9, the cost effectiveness threshold for NOx ($9,700 per ton reduced), used by the District when Rule 4305 was developed and implemented, is among the lowest in the State. For comparison, Ventura, also classified with severe air quality, has established a cost effectiveness threshold for NOx of $18,000 per ton reduced.

- Cost information was gathered from manufacturers, distributors and facilities using emissions abatement equipment to control NOx emissions from food processing industry boilers and dehydrators subject to BARCT. The data shows that costs exceed the cost effectiveness threshold for NOx used by the District when Rule 4305 was developed and implemented. Summaries of the typical costs to reduce NOx emissions for different technologies are provided in Tables 1 and 2. These costs are strongly influenced by individual facility and equipment applications. One commenter reported that low NOx dehydrator burners are more technically challenging and expensive to operate compared to conventional burners, and in its case greatly exceeded the estimated cost effectiveness shown in Table 2.

- An implication of imposing additional requirements on emission sources already controlled to BARCT levels is that there would be additional costs associated with a) the purchase and installation of new emissions abatement equipment to retrofit the current burners on boilers and dehydrators, and b) any new energy requirements necessary to operate the equipment.

Table 1

Summary of Estimated Cost Effectiveness to Control NOx Emissions from Seasonal Boilers (in thousands of dollars per ton of NOx reduced)

Boiler Rating, mm BTU/hr	NOx Control Technologies			
	Ultra Low NOx burners	Ultra Low NOx burners with flue gas recirculation	Selective Catalytic Reduction	Ultra Low NOx burners with steam injection
50	$26-44	$27-40	$36	$44
100	$7-18	$12-19	$22	$20
150	$13-14	$11-17	$15	$16
200	$10	$11-14	$14	$15

Table 2

Summary of Estimated Cost Effectiveness to Control NOx Emissions from Seasonal Dehydrators (in thousands of dollars per ton of NOx reduced)

Dehydrator Rating, mm BTU/hr	NOx Control Technology
	Ultra Low NOx burners
10	$19

II. BACKGROUND

A. Why was this report developed?

Assembly Bill (AB) 2283, Florez, September 8, 2000, amended Section 40703 of, and adds Section 39702.5 to, the Health and Safety Code, relating to air pollution (Attachment 1). It requires the Air Resources Board (ARB) to investigate and provide a report to the Legislature by January 1, 2002, on specified matters with respect to emissions abatement equipment required by the San Joaquin Valley Unified Air Pollution Control District (District) for control of oxides of nitrogen (NOx) emissions from seasonal sources in the Valley.

The legislation requires ARB to appoint an advisory committee (Committee), consisting of representatives from the District, environmental organizations, stationary sources, seasonal stationary sources, agriculture and the U.S. Environmental Protection Agency, to consult in developing the report.

AB 2283 requires that the report to the Legislature include the following topics:

- the average useful life of emissions abatement equipment used to meet Best Available Control Technology (BACT) or Best Available Retrofit Control Technology (BARCT) for nitrogen oxides (NOx) emissions;

- the implications of imposing additional air pollution control requirements on sources that meet BACT/BARCT requirements;

- the average, actual, and historical costs of complying with BACT and BARCT requirements;

- the implications of applying incremental costs to projects subject to those requirements; and

- the effects of growth and interbasin transport of air pollutants from other regions.

B. How was this report developed?

ARB staff reviewed the current information on each of the topics listed above to prepare this report. Staff worked with representatives of the food processing industry and the manufacturers of emission abatement equipment to develop surveys that would provide information about the useful life and costs associated with installation, operation and maintenance of emission abatement equipment, as well as energy and safety considerations.

The Committee participated in the development and review of this report and assisted ARB staff by providing information to:

- Determine the scope of the study
- Identify the District's air quality challenges
- Develop an industry survey to understand the types of seasonal sources and how they operate, and
- Develop a manufacturer survey to understand the current and future types of NOx control technology.

Committee meetings were held at ARB on April 11, 2001 and at the District office in Fresno on May 8, 2001. A third Committee meeting was held as a conference call on November 29, 2001.

The report was made available to the public for review and comment. ARB received comments regarding the contribution of NOx emissions from the food processing industry and the operation of vegetable dehydrators using emission control equipment. In response, the report was revised to clarify the contribution of NOx emissions from the food processing industry relative to the total (mobile and stationary) seasonal NOx emissions inventory, and cite the experience of an operator of a vegetable dehydrator fitted with low NOx burners.

C. Best Available Control Technology and Best Available Retrofit Control Technology

The legislation includes reference to two air pollution control technology requirements commonly included in stationary source permitting programs. Since the criteria and applicability of these requirements differ significantly, it is important to review them and highlight the differences.

Best Available Control Technology (BACT): BACT is a technology requirement that comes from the New Source Review program. New or expanding stationary sources of air pollution must install the Best Available Control Technology at the time of construction to minimize new emissions to the lowest achievable level.

Per District Rule 2201, “New and Modified Stationary Source Review,” BACT is defined as ”…the most stringent emission limitation or control technique of the following:

- Has been achieved in practice for such emission unit and class of source; or

- Is contained in any State Implementation Plan approved by the Environmental Protection Agency for such emissions unit category and class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed emissions unit demonstrates to the satisfaction of the APCO that such limitation or control techniques is not presently achievable; or

- Is any other emission limitation or control technique, including process and equipment changes or basic of control equipment, found by the APCO to be technologically feasible for such class of sources or for a specific source, and cost effective as determined by the APCO.

Best Available Retrofit Control Technology (BARCT): BARCT is a technology requirement that applies to existing sources of air pollution. Local air districts develop air quality attainment plans with BARCT measures designed to reduce emissions from existing stationary sources. The Health and Safety Code, Section 40406, defines BARCT as "…an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."

The key differences between these two technology requirements are applicability and elements considered. BACT is typically more stringent than BARCT because it does not consider cost or other impacts, and it reflects the latest developments in control technology applicable to a specific class and category of source. Also, because BACT is applied to new sources, there is much greater flexibility to design an operation to emit at the lowest levels achievable.

This report focuses primarily on BARCT requirements and the costs associated with the implementation of future more stringent emission control requirements on existing sources.

III. SAN JOAQUIN VALLEY AIR BASIN AIR QUALITY PROFILE

A. Introduction

Pursuant to the federal Clean Air Act Amendments of 1990, the San Joaquin Valley Air Basin (SJVAB) was classified as a "serious" nonattainment area, and was required to attain the federal health-based one-hour ozone standard (standard) by November 15, 1999. To reach attainment, the District needed to demonstrate through ambient monitoring that no exceedances of the standard occurred on more than three days at any one monitoring site during the 1997-1999 period. The standard was exceeded at 13 separate sites in the SJVAB during this period, with 40 exceedances occurring at one site, such that the District could not attain the standard. When the U.S. Environmental Protection Agency (U.S.EPA) finds that a serious nonattainment area has not attained the standard, the area is required to be reclassified to "severe." This reclassification is generally referred to as a "bump-up."

U.S.EPA published its proposed reclassification of the San Joaquin Valley (Valley) on June 19, 2000. Many comments on the proposal focused on excluding Eastern Kern County from the bump-up. Consequently, a revised proposed bump-up notice, excluding Eastern Kern County, was published in the Federal Register (Vol. 66, No. 97) on May 18, 2001. A thirty-day review period closed on June 18, 2001. The U.S. EPA Regional Administrator signed the final notice on October 23, 2001, and published the final notice in the Federal Register on November 8, 2001. In the final action, U.S. EPA carved out the eastern portion of Kern County as a separate nonattainment area not subject to the bump-up. The District's State Implementation Plan amendment is due to U.S. EPA by May 31, 2002, with an attainment date of 2005.

The reclassification starts a new cycle of air quality planning and rulemaking for the purpose of reducing ozone-forming emissions of nitrogen oxides (NOx) and reactive organic gases (ROG) in the Valley. In order to demonstrate attainment by 2005, the Valley would need to reduce total NOx and ROG emissions by 30 percent each, or approximately 150 tons per day of each pollutant. The District must prepare and submit an Ozone Attainment Demonstration Plan (OADP) to ARB for approval, with subsequent submittal to U.S. EPA, that will need to contain a significant array of adopted regulations and/or enforceable commitments to adopt and implement control measures in regulatory form by certain specified dates. The OADP must address the attainment of the one-hour ozone standard by 2005 and the further reasonable progress (rate of progress) requirements set by Section 182 (c) of the federal Clean Air Act Amendments of 1990. This section requires that serious and above nonattainment areas adopt control measures that will reduce emissions by at least 3 percent per year.

The OADP will include programs that require the cooperation of local, regional, state, and federal governments. At the federal level, U.S. EPA is responsible for setting the NAAQS and establishing federal motor vehicle emission standards. U.S. EPA is also responsible for reducing emissions from locomotives, aircraft, heavy duty vehicles used in interstate commerce, and other sources such as off-road engines that are either preempted from state control or best regulated at the national level. U.S. EPA also has the authority under the FCAA to require preparation of state plans for air quality and may approve or disapprove state air quality plans.

ARB is the lead state agency for air quality. It is responsible for preparing and submitting a state air quality plan to U.S. EPA. In preparing a state plan, ARB reviews and approves regional air quality plans and incorporates them into a State Implementation Plan (SIP). Under state authority, ARB also establishes emission standards for on-road motor vehicle emission standards, fuel specifications, some off-road sources and "consumer product" standards in California. Other state agencies such as the Department of Pesticides and the Bureau of Automotive Repair also have responsibility for certain emission sources. The air pollution control districts and air quality management districts are responsible for developing the portion of the SIP that deals with stationary and area source controls and, in cooperation with transportation planning agencies (TPAs), the development of transportation control measures (TCMs).

The FCAA specifies that an attainment demonstration plan must be submitted as a revision to the applicable SIP. The ARB is the mandated state agency for submission of SIP revisions.

U.S. EPA also suggested in its Federal Register notice that the Valley could request to be bumped-up to the extreme classification, which would require that attainment be demonstrated by 2010. The advantage to a 2010 attainment date is that adopted ARB mobile source control measures yet to be implemented will produce significant emission reductions in the 2005 to 2010 interval, thereby making attainment more achievable in the later timeframe. However, demonstrating attainment in 2010 will remain challenging because the extreme classification would subject many more facilities to Title V permitting requirements. District staff presented the 2010-attainment date option as an informational item to the District Governing Board on November 15, 2001.

See http://www.epa.gov/region09/air/sjvalley/index.html.

B. Air Quality Trends

Due to a combination of meteorology and air pollutant emissions, the Valley experiences many days where ozone levels exceed the standard. The areas experiencing the greatest number of violations occur southeast and downwind of the major population centers in the Valley (Bakersfield, Fresno, and Stockton/Modesto). Ozone peaks generally occur during July, August, September and October (see Figure 1), with daily maximum concentrations occurring between noon and 6 p.m. (see Figure 2). As will be shown in Chapter 3 the worst air quality period coincides with the operating season of the seasonal food processing industry.

Figure 1
Total Exceedances of the Federal One-Hour Ozone Standard by Month for the Specified Years

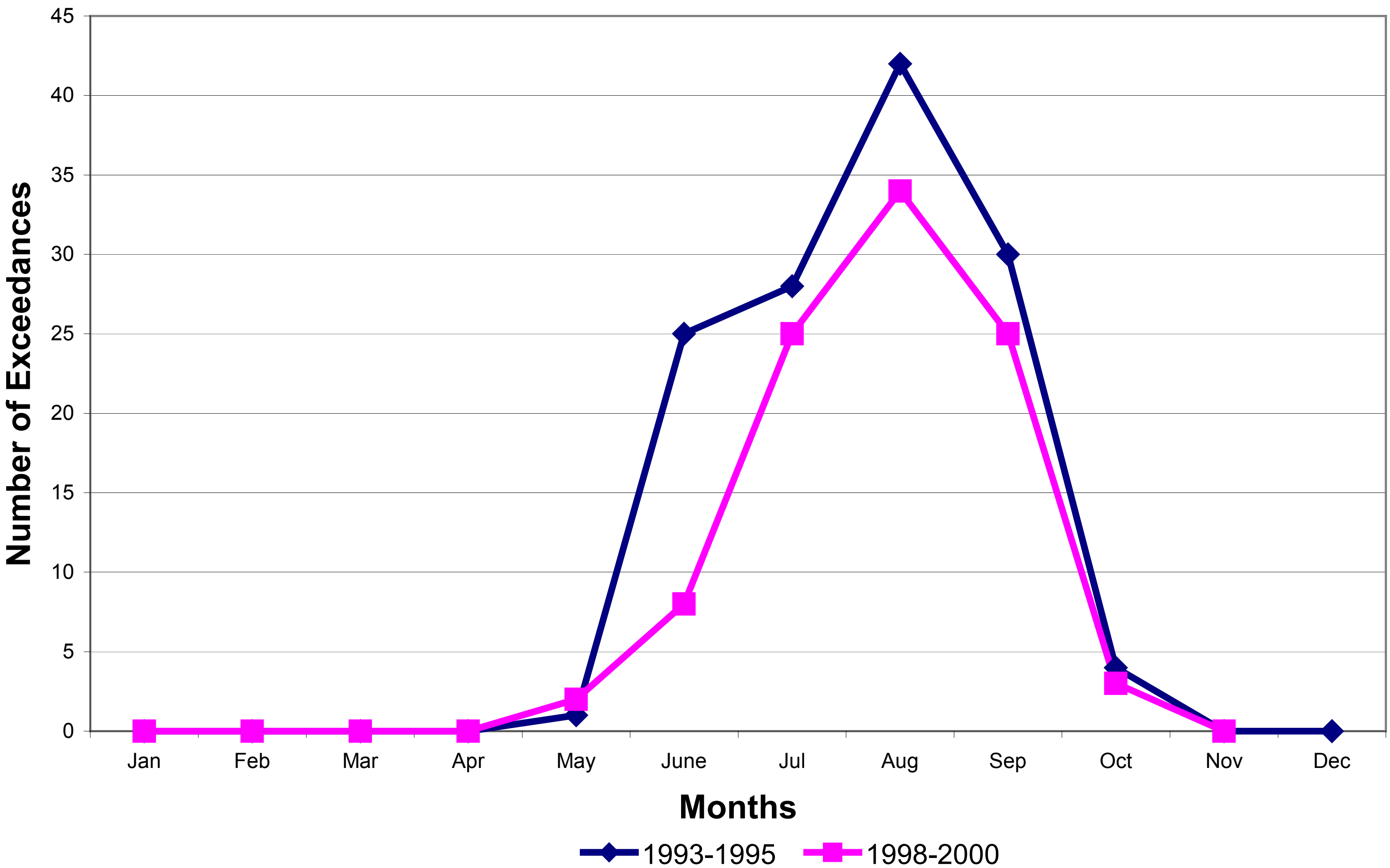
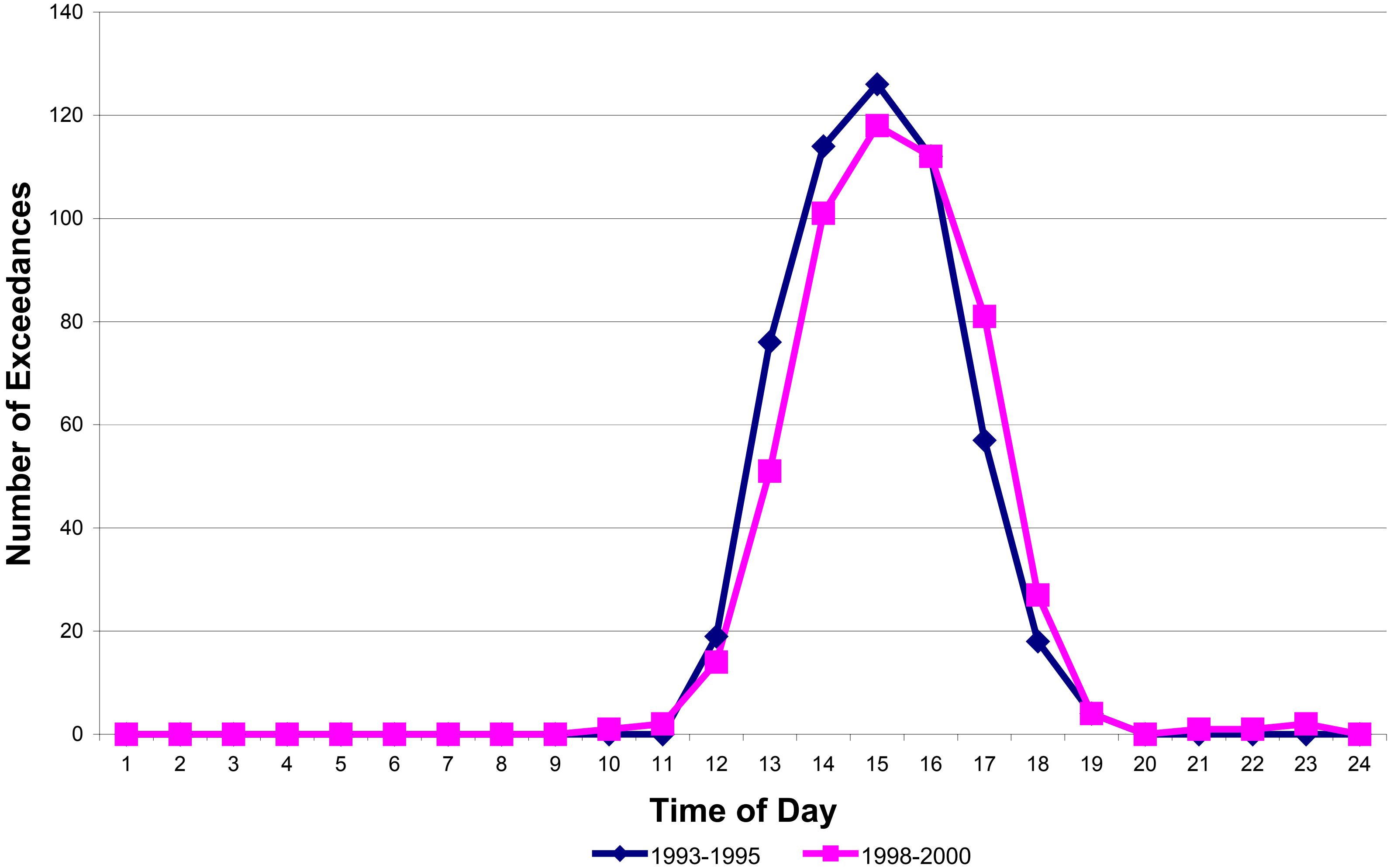


Figure 2
Total Exceedances of the Federal One-Hour Ozone Standard by Hour for the Specified Years



C. Topography and climate

California is divided into regional air basins according to topographic air drainage features. The SJVAB, which is approximately 250 miles long and averages 35 miles wide, is the second largest air basin in the state. Air pollution is directly related to a region's topographic features. The Valley can be considered a "bowl" open only to the north where the region's topographic features restrict air movement through and out of the basin. These topographic features result in weak airflow that becomes blocked vertically by high barometric pressure over the SJVAB. As a result, the SJVAB is highly susceptible to pollutant accumulation over time. Local climatological effects, including wind speed and direction, temperature, inversion layers, and precipitation and fog, can exacerbate the basin's air quality problem.

D. Transport

The movement of air pollutants across jurisdictional boundaries is called long-range transport, or simply transport. When pollutant concentrations build up because emitted pollutants do not disperse either horizontally or vertically, prevailing winds carry air pollutants and precursors from emission points to downwind locations, mixing with cleaner air or other emissions along the way. ARB, in cooperation with local air districts, is required by the California Clean Air Act to evaluate intrastate transport and to suggest mitigation for such transport. ARB has identified transport couples (source and receptor areas) throughout California, and the SJVAB is identified as both a source and a receptor of transported pollutants.

In 1996, ARB found that the SJVAB contributed overwhelmingly to ozone exceedances in the Mojave Desert, Mountain Counties, and Great Basin Valley Air Basins, overwhelmingly or significantly to the South Central Coast and Broader Sacramento Area Air Basins, and significantly to the North Central Coast Air Basin. In turn, the SJVAB is impacted from emissions emanating from the Bay Area and other upwind air basins. For details regarding this transport assessment, see the ARB document, *Assessment of the Impacts of Transported Pollutants on Ozone Concentrations in California, March 2001.*

IV. THE CALIFORNIA FOOD PROCESSING INDUSTRY

A. Introduction

Information provided by the Office of Economic Research shows that California is the top agricultural state in the nation, a position it has held for 50 years. Its agriculture is characterized by high-yielding, high-value cash crops that use advanced levels of technology, capital and management; the state exceeds the national average in yields per harvested acre for several major crops. With an enormous variety of crops, great growing conditions and increasing demand for prepared food products, California is the center for food processing, shipping $50 billion worth of food products.

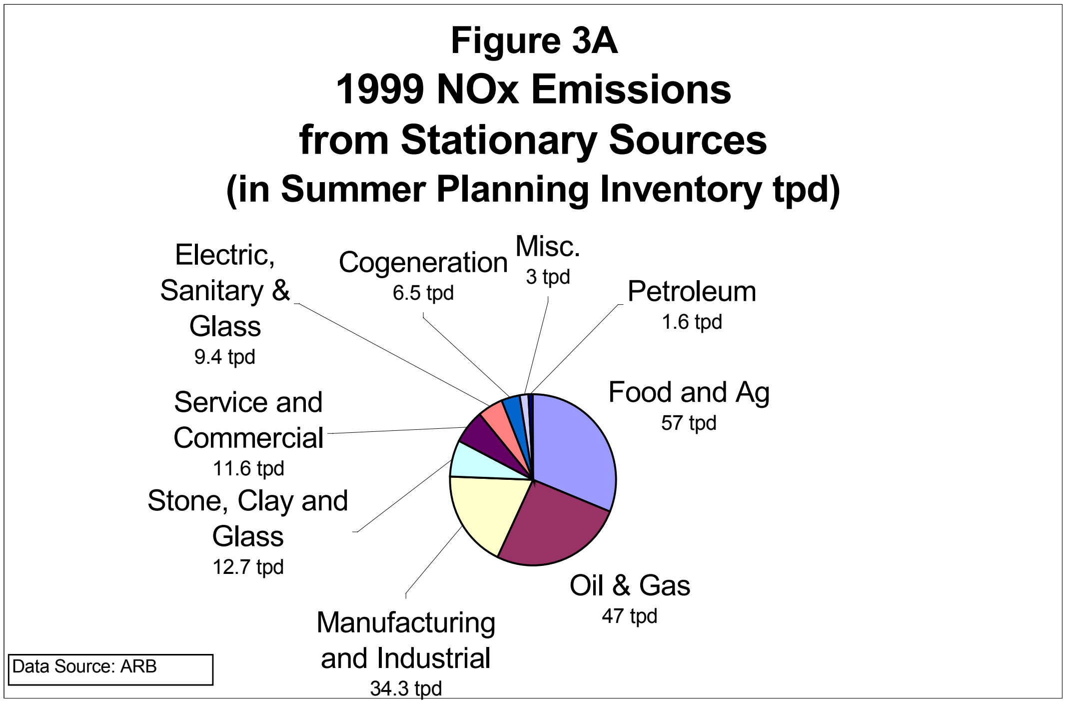
B. Food processing in California

Food processing is an umbrella term used to describe all the activities of manufacturing food and beverages for human consumption, as well as prepared feeds for animals. California food processing includes fruits and vegetables, baked goods, meats, dairy products, sugar and confections, beverages, and fats and oils. For the purposes of this report, food processing refers to the processing of fruits and vegetables, which is the largest industry group in California food processing. The nature of the processing of fruits and vegetables constrains the industry to operate predominantly during the summer months.

Regionally, the processing of fruits and vegetables is especially significant in the San Joaquin Valley (Valley), which leads the rest of the state and the nation in food production. The Valley includes six of the top ten agricultural counties in California, and is one of the leaders in domestic wine production.
The District through its permit program regulates food-processing activities that emit air contaminants.

C. NOx Emissions Profile for the San Joaquin Valley

Oxides of nitrogen (NOx) interact with hydrocarbons in the presence of sunlight to form ground-level ozone. The most recent data from 1999 shows NOx emissions from all stationary sources during July through September in Figure 3A. As shown in Figure 3B, during July through September, boilers represent only a very small portion of the total NOx inventory: 8.4 tons per day (tpd) or 1.5% of all NOx emissions. The boilers, dryers, and dehydrators used in food processing operations account for 37% (3.1 of the 8.4 tpd) of the NOx emissions from all boilers, dryers and dehydrators operating in the Valley during July through September, as shown in Figure 3C. The impact of these NOx emissions on the region's air quality is significant during the food processing season because: a) the processing of fruits and vegetables occurs predominantly during July, August, September, and October; b) those months are typically the months when the air quality is the worst due to high ozone concentrations; and c) the processing is done with equipment that operates at maximum capacity during that time, thus maximizing the production of NOx. This situation is presented in Figure 4, which shows the seasonal nature of the industry and the distribution of NOx emissions and those of all other industries throughout 1999.



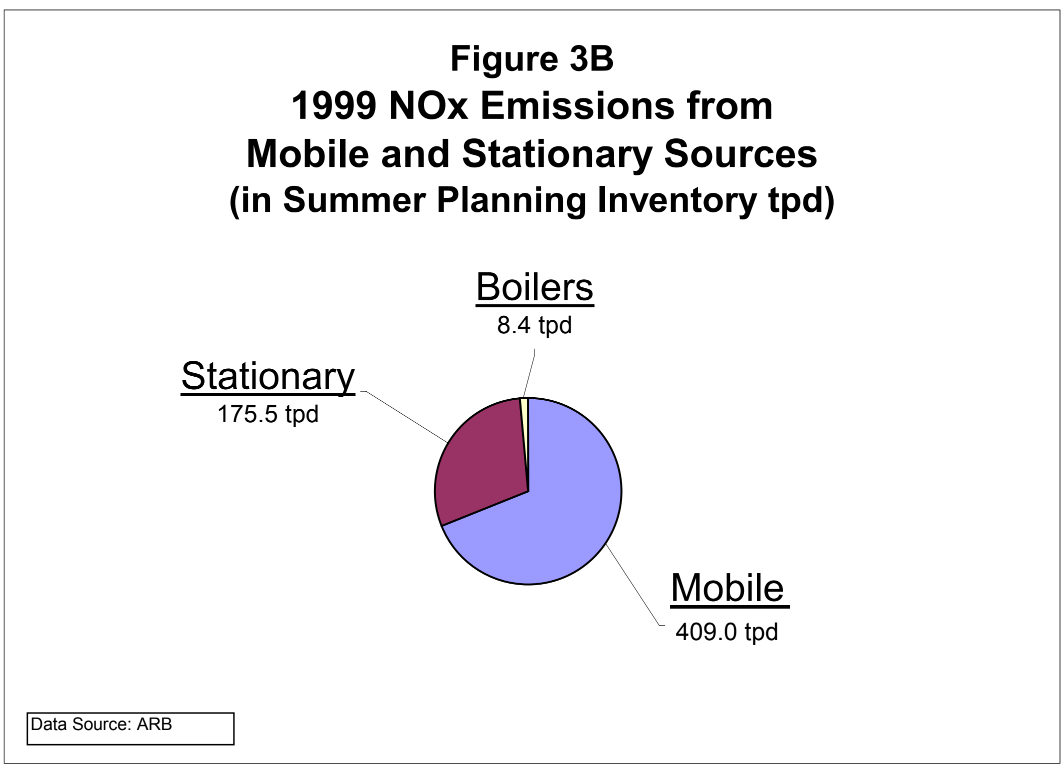


Figure 3C
1999 NOx Emissions from Boilers, Driers and Dehydrators by Industry
(in Summer Planning Inventory tpd)

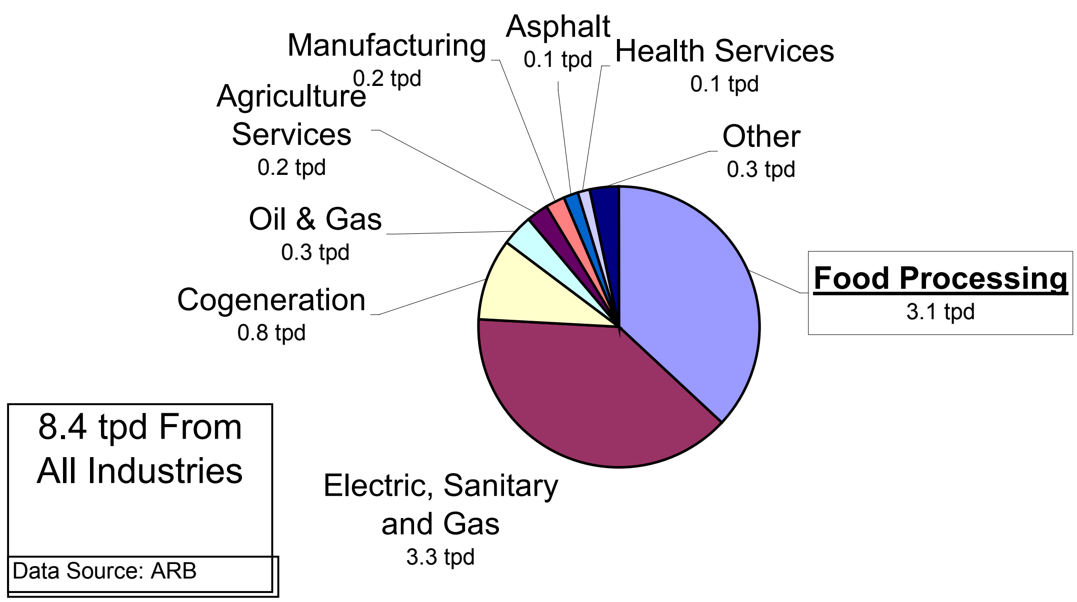
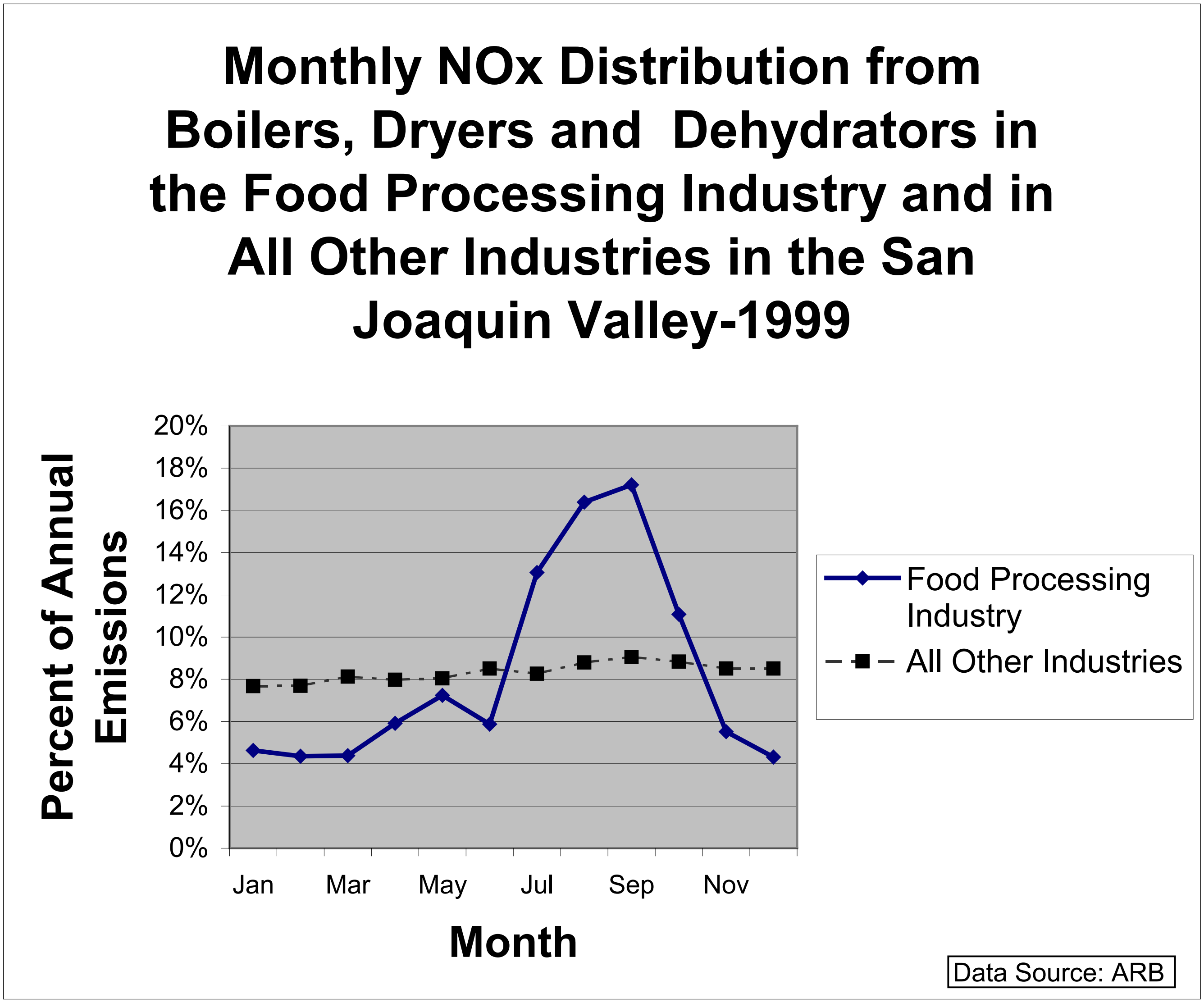


Figure 4


Monthly NOx Distribution from Boilers, Dryers and Dehydrators in the Food Processing Industry and in All Other Industries in the San Joaquin Valley-1999
Percent of Annual Emissions
20%
18%
16%
14%
12%
10%
8%
6%
4%
2%
0%
Jan
Mar
May
Jul
Sep
Nov
Month
Food Processing Industry
All Other Industries
Data Source: ARB

V. NOx EMISSIONS FROM BOILERS AND DEHYDRATORS

A. Boiler Design and Operation

A boiler is an enclosed system of pipes and vessels used to convert water into steam. Industrial boilers supply steam to manufacturing processes. In the food processing industry, the majority of boilers typically produce lower-pressure steam, in the range of 150 -1600 pounds per square inch (psi), and are designed for high reliability and low maintenance, at minimum cost. The boilers generally burn natural gas and the steam-generated heat is used to dry fruits and vegetables. The larger units are not transportable and are built at the site where the boiler will be operated.

Boilers are built to transfer as much heat as possible from the burning fuel to the water and steam. This is accomplished by making use of the three heat transfer methods: radiation, conduction, and convection. These heat transfer methods are illustrated in Figure 5.

Two basic designs for boilers are the fire tube and water tube types. The majority of boilers in the food processing industry utilize the water tube design so the following discussion will focus only on water-tube type boilers. Water-tube boilers contain the water inside heat exchange tubes while the flames and hot gases are outside the tubes. The steam generating tubes are installed more or less vertically so that the steam can rise up into the steam drum. A level of water is maintained inside the steam drum to assure that the tubes remain full. Water must continuously remove heat from the tubes to prevent overheating and eventual tube rupture. Steam pressures can be as high as 5000 pounds per square inch gauge (psig) and temperatures can be as high as 1000 degrees F. Figure 6 shows a simplified drawing of a water-tube boiler.

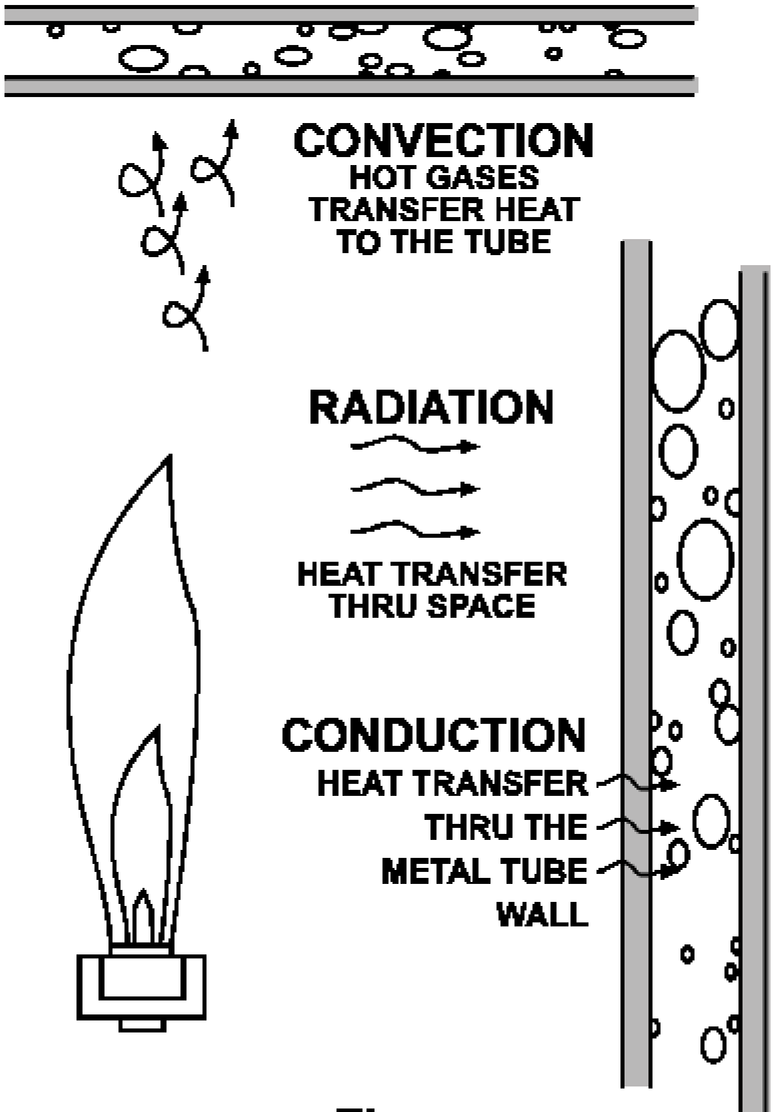
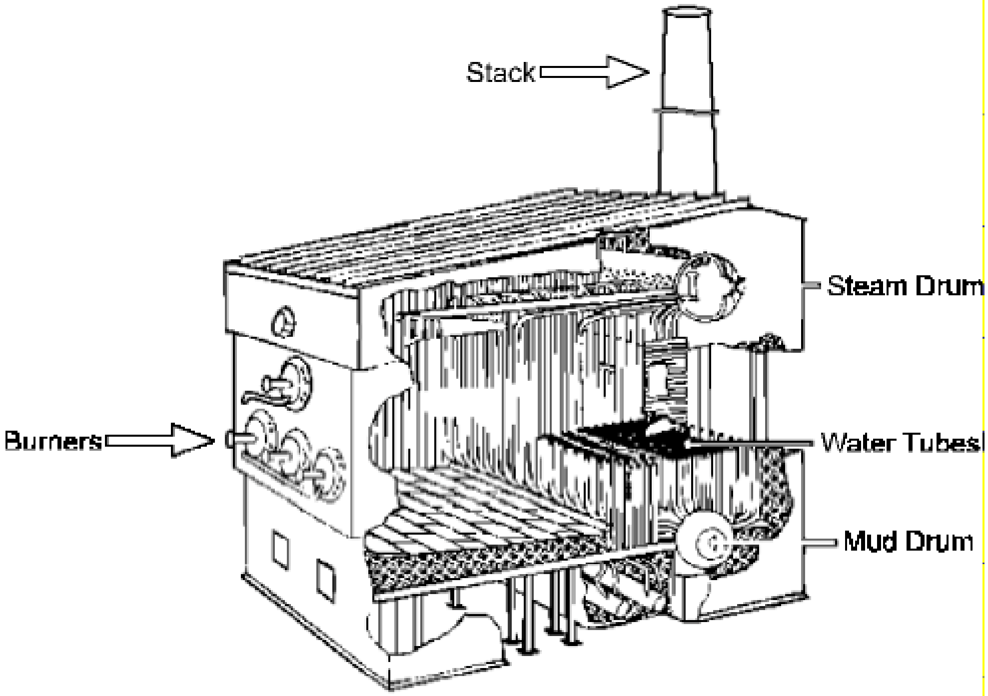


Figure 5
Heat Transfer Methods



Source: Babcock and Wilcox

Figure 6

Simple Water-tube Boiler

B. Control of NOx Emissions

What factors determine the amount of NOx emissions from boilers and dehydrators?

NOx emissions depend primarily on the peak temperature within the combustion chamber as well as the furnace-zone oxygen concentration, nitrogen concentration, and time of exposure at peak temperatures.

How can NOx emissions be controlled?

NOx emissions from combustion of natural gas can be reduced either by preventing NOx formation during fuel combustion or by later removing NOx from the flue gas.

NOx formation during combustion can be controlled using:

- Low-NOx burners
- Ultra-low NOx burners
- Flue gas recirculation (FGR) (see Figure 7)

Removing NOx from the flue gas can be accomplished with:

- Selective catalytic reduction (SCR) (see Figure 8)
- Selective non-catalytic reduction (SNCR) (see Figure 9)

SCR and SNCR are not currently used on boilers in the food processing industry that were retrofit to meet the 30 ppm NOx emissions limitations of District Rule 4305, "Boilers, Steam Generators and Process Heaters." These emission control technologies would likely be examined for applicability if the rule is revised to require more stringent NOx emission limitations.

The boiler operation and NOx controls information and figures in this section were taken from the ARB Compliance Division Compliance Assistance Program document "Boilers for the Air Pollution Inspector," 1997.

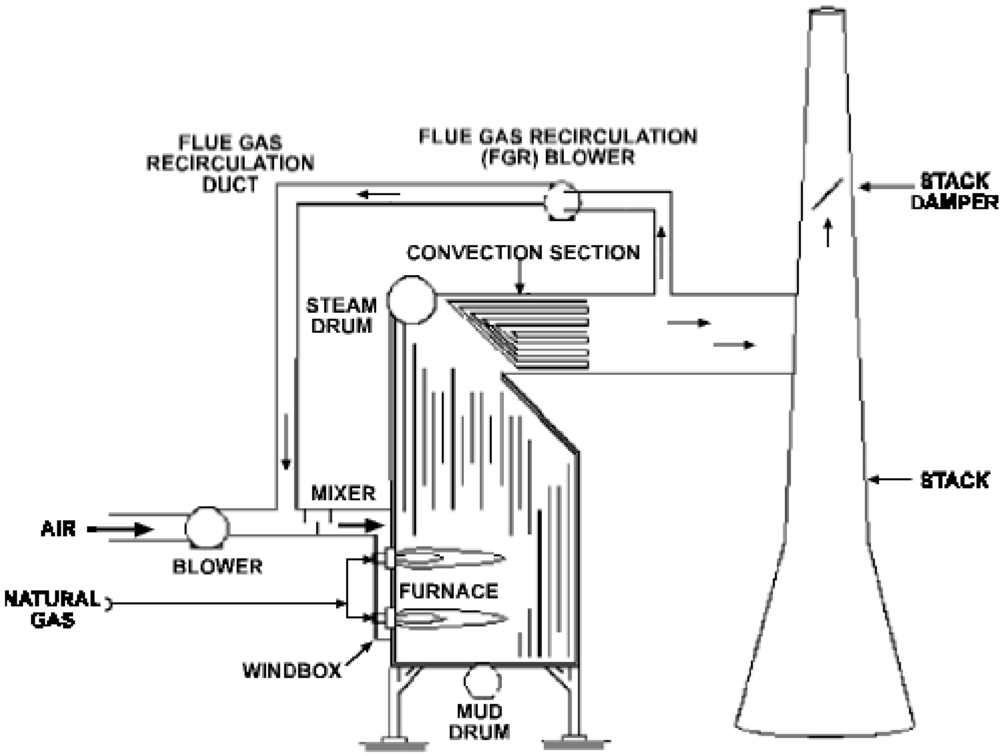


Figure 7
Flue Gas Recurculation System
(FGR)

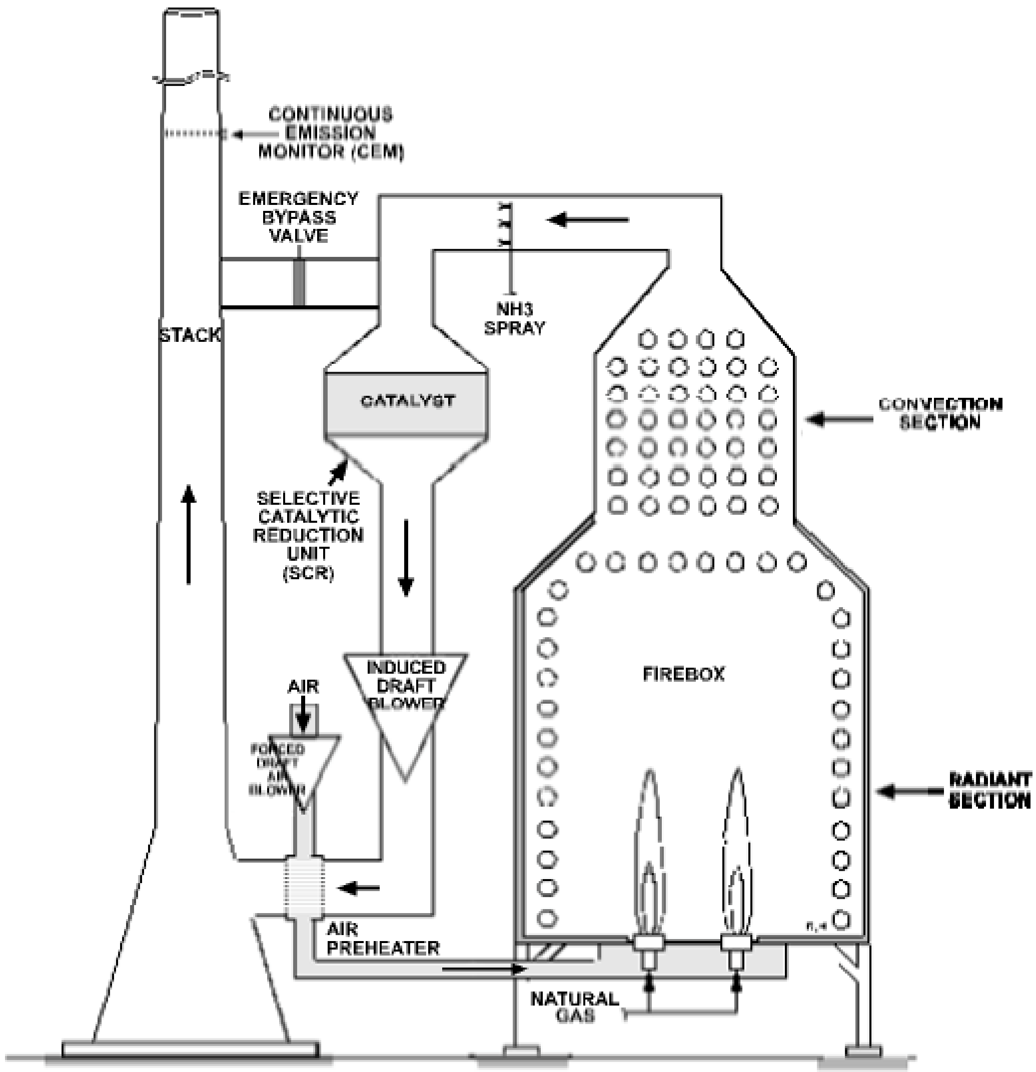


Figure 8

Boiler With Retrofit SCR System

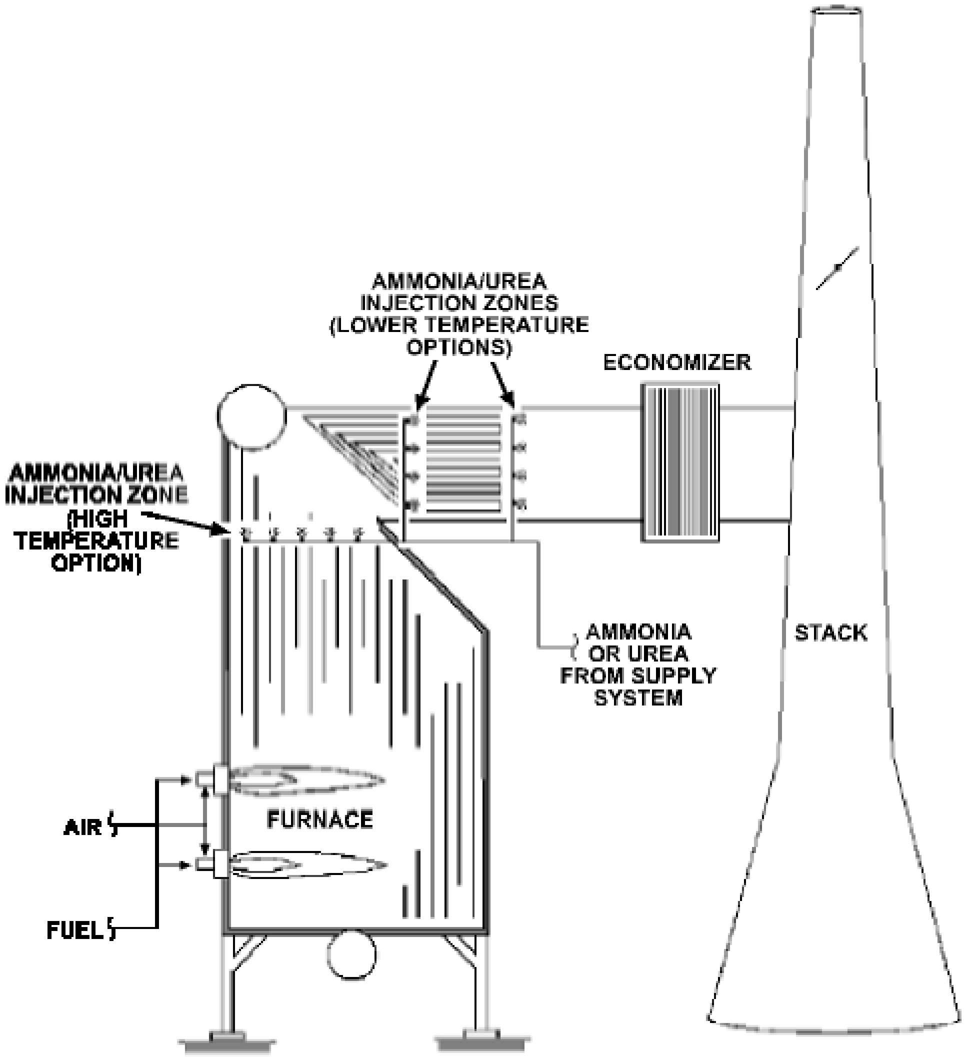


Figure 9
Selective Non-Catalytic NOx Reduction (SNCR)

C. Average Useful Life of Emissions Abatement Equipment

The legislation requires that the report evaluate the average useful life of emissions abatement equipment utilized to meet BARCT. The surveys developed by ARB staff requested useful life data, and the information collected represents the experience of the source operators, District projections, and representations made by the manufacturers. According to manufacturers and distributors of emissions abatement equipment, the useful life is expected to be the same for equipment operating seasonally versus full time; in fact, seasonal operation can be harder on the equipment because corrosion can occur while the equipment is idle. A summary of the average useful life, in years, of the emissions abatement equipment is provided in Table 3.

Table 3

Average Useful Life of Emission Abatement Equipment (years)

Control technology / Process equipment	Low NOx burners	Ultra Low NOx burners	Ultra Low NOx burners with flue gas recirculation	Selective catalytic reduction	Ultra Low NOx burners with steam injection
Boiler @ 50 mmBTU/hr	20	15	20	20	No data available
Boiler @ 100 mmBTU/hr	20	15	20	20	No data available
Boiler @ 150 mmBTU/hr	20	15	20	20	No data available
Boiler @ 200 mmBTU/hr	20	20	20	20	No data available
Dehydrator @ 10 mmBTU/hr	10	10	Not applicable	Not applicable	No data available

In 1993, food processing operations subject to District Rule 4305, "Boilers, Steam Generators, and Process Heaters," purchased and installed BARCT emission abatement equipment for their existing emission sources to meet the requirement of 30 parts per million (ppm) NOx emissions specified in the rule (Appendix 3). As can be seen above, the average useful life of low NOx burners on boilers is 20 years and 10 years for dehydrators. Therefore, a new requirement for installation of more effective emissions abatement equipment in the near future on boilers, for many facilities and applications, will likely occur within the useful life of the emissions abatement equipment currently in use.

VI. COSTS AND CONSIDERATIONS

A. Average, actual and historic costs for boilers and dehydrators subject to BARCT

The legislation requires the report to provide average, actual and historic costs for boilers and dehydrators subject to BARCT. ARB staff, in conjunction with the California League of Food Processors (CLFP), developed surveys to collect operating and cost data from facilities subject to BACT and BARCT requirements as required by the legislation. Following initial development, the surveys were circulated to the AB2283 Committee members for comment.

Upon finalizing the survey, the CLFP and Wine Institute requested that members of their associations complete and submit the surveys. The CLFP utilized its Internet web page to invite its 30 member organizations to complete and submit the survey in an on-line format. The Wine Institute provided its 12 member organizations with the survey forms via fax. Surveys were also provided to members of the California Cotton Ginners Association (CCGA) and the Manufacturers Council of the Central Valley (MCCV).

The CLFP and Wine Institute functioned as clearing houses for collection of the surveys that were completed and submitted by industry. All surveys received were then submitted to ARB staff for analysis. No surveys were received from members of the CCGA and/or the MCCV.

A summary of the surveys received follows:

AB2283 Industry Survey Data Type	Surveys Received
Best Available Retrofit Control Technology (BARCT)	18
Surveys likely depicting BARCT data yet with insufficient information to use in analysis[1]	2
Best Available Control Technology (BACT)	17
Units claiming exemption from BARCT requirements[2]	3
Total	39

1. These surveys did not include sufficient information to use for the necessary analysis.
2. Units for which operators claim exemption from BARCT requirements due to the unit(s) being rated below applicable thresholds and/or due to low fuel usage.

Only information received from facilities subject to BARCT requirements was utilized since BACT information does not include cost-effectiveness information. The useable data received in the industry surveys is presented in terms of boiler size. The data has been distributed in three tables by boiler size, in million British Thermal Units per hour (mmBtu/hr), as follows:

- Table 4 provides data for boilers rated less than and equal to 50 mmBtu/hr.

Table 4

Historical Boiler BARCT Cost and Capacity Utilization Data from the Industry Survey

Boilers Rated ≤ 50 mmBtu/hr

Boiler Rating (mmBtu/hr)	Low NOx Burner Capital Cost $	Low NOx Burner Installation Cost $	FGR Capital Cost $	FGR Installation Cost $	SCR Capital Cost $	SCR Installation Cost $	Other Costs $	Capacity Utilization
24	$55,000	Included[1]	N/A	N/A	N/A	N/A	N/A	11%
38	$64,000	Included[1]	N/A	N/A	N/A	N/A	N/A	11%
Averages	**$59,500**[2]	N/A	N/A	N/A	N/A	N/A	N/A	11%[2]

1. Itemized installation costs were not available.
2. Average using available data.

N/A = Not applicable

- Table 5 provides data for boilers rated greater than 50 mmBtu/hr and less than 100 mmBtu/hr.

Table 5

Historical Boiler BARCT Cost and Capacity Utilization Data from the Industry Survey

Boilers Rated >50mmBtu/hr and <100mmBtu/hr

Boiler Rating (mmBtu/hr)	Low NOx Burner Capital Cost $	Low NOx Burner Installation Cost $	FGR Capital Cost $	FGR Installation Cost $	SCR Capital Cost $	SCR Installation Cost $	Other Costs $	Capacity Utilization
78	$82,000	Included[1]	N/A	N/A	N/A	N/A	N/A	10%
62	$82,000	Included[1]	N/A	N/A	N/A	N/A	N/A	10%
82	$75,000	$45,500	Included[1]	Included[1]	N/A	N/A	N/A	25%[2]
82	$75,000	$45,500	Included[1]	Included[1]	N/A	N/A	N/A	25%[2]
72	N/A	N/A	$30,000	$20,000	N/A	N/A	$100,000[3]	14%
88	N/A	N/A	N/A	N/A	N/A	N/A	$50,000[4]	22%
66	$79,000	$11,000	N/A	N/A	N/A	N/A	N/A	16%
Averages	**$78,600**[5]	**$34,000**[5]	**$30,000**[5]	**$20,000**[5]	**N/A**	**N/A**	**$75,000**[5]	**17%**[5]

1. Itemized installation costs were not available
2. Capacity utilization for entire year – survey states 82% during processing season.
3. Survey attributes costs to Benz controls.
4. Survey attributes costs to installation of an economizer and fire control system following derating of the unit to comply with 30 ppm requirement.
5. Average using the available data

N/A = Not Available

- Table 6 provides data for boilers rated equal to and greater than 100 mmBtu/hr and less than and equal to 150 mmBtu/hr.

Table 6

Historical Boiler BARCT Cost and Capacity Utilization Data from the Industry Survey

Boilers Rated ≥100mmBtu/hr and ≤150mmBtu/hr

Boiler Rating (mmBtu/hr)	Low NOx Burner Capital Cost $	Low NOx Burner Installation Cost $	FGR Capital Cost $	FGR Installation Cost $	SCR Capital Cost $	SCR Installation Cost $	Other Costs $	Capacity Utilization
103	N/A	N/A	$1,000	N/A	N/A	N/A	$6,000[1]	18%
150	N/A	N/A	N/A	N/A	N/A	N/A	$75,000[2]	14%
119	N/A	N/A	N/A	N/A	N/A	N/A	$25,000[3]	26%
119	N/A	N/A	N/A	N/A	N/A	N/A	$25,000[3]	26%
100	$68,400	$20,000	N/A	N/A	N/A	N/A	N/A	25%
102	$50,000	$35,000	$10,000	$10,000	N/A	N/A	$42,500	70%
140	$50,000	$25,000	$10,000	$5,000	N/A	N/A	$42,500	75%
140	$50,000	$25,000	$10,000	$5,000	N/A	N/A	$42,500	76%
160	$50,000	$25,000	$10,000	$5,000	N/A	N/A	$42,500	76%
Averages	**$53,680[4]**	**$26,000[4]**	**$8,200[4]**	**$6,250[4]**	**N/A**	**N/A**	**$37,625[4]**	**45%[4]**

1. Survey attributes cost to installation of an economizer following the need to derate the unit to comply with 30 ppm requirement.
2. Survey attributes cost to installation of economizer and fire control system to comply with 30 ppm requirement.
3. Survey attributes cost to installation of Air Emissions Monitoring System (AEMS).
4. Average using available data

N/A = Not Available

Many surveys did not include an itemization of emissions control equipment capital and installation costs because many facilities purchased the necessary retrofit equipment "packages" that did not itemize individual costs.

The costs provided in the "Other Costs" fields are those directly related to or that resulted from installation and operation of control equipment. These other costs may include, but may not be limited to, installation of economizers, air emission monitoring systems, and/or fire control systems. Finally, the "Capacity Utilization" field provides data submitted by operators that is intended to show the actual annual usage of the boiler (number of days operated divided by 365) on a percentage basis.

There were two instances where a facility was unable to provide sufficient information to perform the cost analysis. In one case, staff made numerous efforts to contact the facility in question but did not receive any responses. In the second case, the facility was contacted but cost information could not be provided due to several changes in ownership of the facility over the past several years and the necessary data was not available to the current owner. Consequently, it was not possible to obtain the necessary information and the data from these surveys was not included in the analysis. No information for emissions abatement equipment installed on burners used in dehydrators was submitted.

A summary of the average, actual and historic costs for boilers and dehydrators subject to BARCT, as presented in Tables 4-6, is provided in Table 7.

Table 7

Summary of Average Historical Costs ($) and Capacity Utilization (%) for Boilers Subject to BARCT

Boiler Size (mmBtu/hr)	Low NOx Burner Capital Cost $	Low NOx Burner Installation Cost $	FGR Capital Cost $	FGR Installation Cost $	SCR Capital Cost $	SCR Installation Cost $	Other Costs $	Capacity Utilization
≤ 50	$59,500	Included	N/A	N/A	N/A	N/A	N/A	11%
> 50, <100	$78,600	$34,000	$30,000	$20,000	N/A	N/A	N/A	17%
≥100, ≤150	$53,680	$26,000	$8,200	$6,250	N/A	N/A	$37,625	45%

The legislation also requires the report to provide a comparison of the average, actual and historic costs for boilers and dehydrators subject to BARCT to cost estimates utilized by the District in the development of the BARCT requirements contained in Rule 4305.

The District uses the following ARB-approved cost effectiveness analysis to determine the cost effectiveness of emission control techniques:

- A capital cost amortization factor is determined using 10% interest rate and an equipment life of 10 years. When available, useful life data from the manufacturers survey was used to determine the capital cost amortization factor.

- An equivalent annual capital cost is then calculated from capital and installation costs using the capital cost amortization factor.

- Total annual cost is then determined by summing the equivalent annual capital cost and the annual operation and maintenance costs.

- Cost effectiveness is determined by dividing the total annual cost by the annual emission reduction of the pollutant.

ARB staff found the following discrepancies in its review of the industry surveys and the District's staff report for Rule 4305 when attempting to do the comparison required.

- The District determined cost estimates for boilers rated at 10,20,30,40 and 60 mmBTU/hr, yet the ARB industry surveys provided information for several boilers rated greater than 60 mmBTU/hr. The District determined that options which are considered cost effective for the 60 mmBTU/hr boilers are also considered to be cost effective for larger capacity boilers due to economies of scale for controls of the larger, higher emitting boilers.

- The District determined cost estimates for boilers with capacity factors of 0.25, 0.50 and 0.75, yet the ARB industry surveys provided information for several boilers with capacity factors less than 0.25 and greater than 0.75. However, Rule 4305 provided exemptions for low-use boilers with limited heat input to address boilers with lower heat capacities.

The comparison is provided as Table 8.

Table 8

Comparison of historical costs for boilers subject to BARCT[1] with cost estimates utilized by the District in the development of its BARCT Rule 4305

Combined capital and installation costs ($), for boilers rated at 50 mmBTU/hr[1, 2]	Control technology	
	Low NOx burners	Flue Gas Recirculation
Historical cost data from industry survey[3]	$59,500	No available data
District estimate used in development of BARCT Rule 4305[4]	$49,773	$37,778

1. ARB survey collected historical cost data for boilers rated $\leq$ 50mmBTU/hr; >50 mmBTU/hr and $\leq$100 mmBTU/hr; >100 mmBTU/hr and $\leq$150 mmBTU/hr
2. District cost estimates do not include information for boilers rated > 60 mmBTU/hr
3. Based on a capacity factor of 0.11
4. Based on a capacity factor of 0.25

B. Implications of Applying Incremental Cost Effectiveness Thresholds

The legislation requires the report to contain a discussion of the implications of applying incremental cost effectiveness thresholds to sources subject to BARCT requirements and the implications of applying those thresholds to future requirements.

Like all other California air districts, the District has not established incremental cost effectiveness thresholds for determining the feasibility of a control measure in the BARCT rulemaking process. The District notes that a distinction should be made between incremental cost effectiveness and the more common metric, “absolute” cost effectiveness. “Absolute” cost effectiveness, which is generally referred to as “cost effectiveness,” evaluates control options one-by-one, by comparing a single control option to the current baseline technology. For example, the absolute cost effectiveness of a potential new control device would be the cost of the new device divided by the emission reduction resulting from the new device.

On the other hand, incremental cost effectiveness compares two potential new control techniques to each other, but not to the current baseline equipment. In its analyses, the District uses the definition of incremental cost effectiveness contained in Health and Safety code Section 40920.6 (a)(1):” To determine the incremental cost effectiveness, …the district shall 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 results generated by incremental cost effectiveness analysis are almost always higher than corresponding absolute cost effectiveness values, sometimes by an order of magnitude. This is because the cost differential between two potential new control options are relatively large in comparison to the difference in emission reductions of the new control options.

At the time that Rule 4305 was developed, the District used an “absolute” cost effectiveness threshold of $9,700 per ton of NOx removed to determine the equity of a control option. In employing the threshold during the Rule 4305 development process, control options with cost effectiveness greater than $9,700/ton were rejected in favor of more cost effective measures, which were less costly and provided less emission reductions. In comparison with other districts with similar air quality, the thresholds used for Rule 4305 would now be considered the lowest in the State, as shown in Table 9.

In its current rulemaking projects, the District employs absolute and incremental cost effectiveness analysis, but not thresholds, in evaluating control options. The information from these analyses is part of the staff report presented to the District Governing Board for their decision-making process. The District also considers the magnitude of emission reductions needed for attainment, the likely economic impact of compliance costs on the affected industries, and other environmental effects, as factors in its rulemaking process. These latter factors are not addressed by cost effectiveness analysis. Because many sources in the San Joaquin Valley are already controlled to some extent, it is expected that reductions from future rule amendments will generally be smaller and less cost effective than previous BARCT rule amendments.

Table 9

Comparison of BARCT Cost Effectiveness Thresholds[1]

District (State Ozone Classification)	**BARCT Threshold** ($/ton reduced)	
	VOC	**NOx**
San Joaquin Valley (Severe)	$5,000	$9,700
Ventura (Severe)	$18,000	$18,000
Bay Area (Serious)	No thresholds	
San Diego (Serious)	--------	$14,000
Santa Barbara (Moderate)	No thresholds	

1. ARB Staff Report "Public Hearing to Consider Approval of the San Joaquin Valley Unified Air Pollution Control District's Triennial Progress Report and Plan Revision 1995-1997 Under the California Clean Air Act," 1999

Cost Effectiveness of Seasonal NOx Sources in the Valley

Consistent with the ARB guidance document entitled "District Options for Satisfying the Requirements of the California Clean Air Act," September, 1990, the cost effectiveness analyses performed in this report address only the direct costs of a control measure and the benefits are described in terms of emission reductions.

Surveys distributed by ARB staff to manufacturers and distributors of emission abatement equipment provided a range of capital, installation, repair, maintenance and operating costs to control NOx emissions to 30, 15 and 9 ppm for boilers rated at 50, 100, 150 and 200 mmBTU/hr and continuous dryer burners rated at 10 mmBTU/hr. The method for calculating cost effectiveness assumes a 10% interest rate. When available, useful life data from the surveys was used; otherwise, the method assumes a useful life of 10 years. The District provided capacities for numerous boilers in the food processing industry. The annual emissions reductions were then calculated using the difference in emission factors for current NOx emissions of 30 ppm and potential future NOx emissions of 15 ppm, 9 ppm, and 3 ppm. The cost effectiveness was then calculated by dividing the total cost to control NOx emissions by the NOx emissions controlled, taking into account the seasonal operation of the emission sources.

Based on the information received, the cost effectiveness values range from $7,000-$63,000 per ton of NOx removed. There is not a significant difference between the total annual cost of low-NOx burners operating at 30 ppm NOx and the ultra-low NOx burners operating at 9 ppm NOx. The total annual costs for SCR are substantially higher than those costs for ultra-low NOx burners to achieve the same emission level of 9 ppm.

A summary of cost effectiveness data is provided in Tables 10-14.

Table 10: Cost Effectiveness Data for Boilers Rated at 50 mm BTU/hr

Control technology	**Low NOx burners**	**Ultra Low NOx burners**		**Ultra Low NOx burners with flue gas recirculation**		**Selective catalytic reduction**		**Ultra Low NOx burners with steam injection**	
NOx emission limit, ppm	30	15	9	15	9	9	3[3]	15	9
Capital costs,$	$66-125K	$110-135K	$110-135K	$125-193K	$125-193K	$120K	$150K	$125K	$125K
Installation costs,$	$25-48K	$25-48K	$25-48K	$30-65K	$30-65K	$60K	$60K	$55K	$55K
Capital cost amortization factor[1]	0.117	0.132	0.132	0.117	0.117	0.117	0.117	0.163	0.163
Equivalent annual capital costs of control[2] $	$11-20K	18-24K	$18-24K	$18-30K	$18-30K	$21K	$25K	$29K	$29K
Annual repair and maintenance costs,$	$5K	$8-20K	$8-20K	$9-10K	$9-10K	$15K	$15K	$15K	$15K
Annual operation costs,$	$306	$307	$309	$309	$311	N/A[5]	N/A	N/A	N/A
Total annual costs,$	$16-25K	$26-44K	$26-44K	$27-40K	$27-40K	$36K	$40K	$44K	$44K
Average annual emission reduction,TPY[4]		0.7	1.0	0.7	1.0	1.0	1.3	0.7	1.0
Cost effectiveness, $/ton		$37-63K	$26-44K	$39-57K	$27-40K	$36K	$31K	$63K	$44K

1. Uses a 10% interest rate and useful life data from the manufacturers survey, when available.
2. Uses average capital and installation costs.
3. Cost data provided by the District assumes capital costs are 25% greater than those for control to 9 ppm.
4. Based on operating 24 hours per day and an average of five months per year operation (June-October).

Table 11: Cost Effectiveness Data for Boilers Rated at 100 mm BTU/hr

Control technology	Low NOx burners	Ultra Low NOx burners		Ultra Low NOx burners with flue gas recirculation		Selective catalytic reduction		Ultra Low NOx burners with steam injection	
NOx emission limit, ppm	30	15	9	15	9	9	3[3]	15	9
Capital costs,$	$78-168K	$50-210K	$150-210K	$165-240K	$165-240K	$200K	$225K	$186K	$186K
Installation costs,$	$35-72K	$35-72K	$35-72K	$40-96K	$40-96K	$96K	$96K	$84K	$84K
Capital cost amortization factor[1]	0.117	0.132	0.132	0.117	0.117	0.117	0.117	0.163	0.163
Equivalent annual capita costs of control[2] $	$13-28K	$11-37K	$11-37K	$24-39K	$24-39K	$35K	$38K	$44K	$44K
Annual repair and maintenance costs,$	$8-10K	$10-15K	$10-15K	$11-17K	$11-17K	$30K	$30K	$15K	$15K
Annual operation costs,$	$1222	$1226	$1234	$1234	$1244	N/A[5]	N/A	N/A	N/A
Total annual costs,$	$22-39K	$22-53K	$22-53K	$36-57K	$36-57K	$65K	$68k	$59K	$59K
Average annual emission reduction,TPY[4]		2.2	3.0	2.2	3.0	3.0	3.9	2.2	3.0
Cost effectiveness, $/ton		$10-24K	$7-18K	$16-26K	$12-19K	$22K	$17K	$27K	$20K

1. Uses a 10% interest rate and useful life data from the manufacturers survey, when available.
2. Uses average capital and installation costs.
3. Cost data provided by the District assumes capital costs are 25% greater than those for control to 9 ppm.
4. Based on operating 24 hours per day and an average of five months per year operation (June-October).

Table 12: Cost Effectiveness Data for Boilers Rated at 150 mm BTU/hr

Control technology	**Low NOx burners**	**Ultra Low NOx burners**		**Ultra Low NOx burners with flue gas recirculation**		**Selective catalytic reduction**		**Ultra Low NOx burners with steam injection**	
NOx emission limit, ppm	30	15	9	15	9	9	3[3]	15	9
Capital costs,$	$120-192K	$200-250K	$200-250K	$220-288K	$220-288K	$240K	$300K	$216K	$216K
Installation costs,$	$45-84K	$45K	$45K	$50-108K	$50-108K	$129K	$129K	$96K	$96K
Capital cost amortization factor[1]	0.117	0.132	0.132	0.117	0.117	0.117	0.117	0.163	0.163
Equivalent annual capita costs of control[2] $	$19-37K	$32-39K	$32-39K	$32-46K	$32-46K	$43K	$50K	$51K	$51K
Annual repair and maintenance costs,$	$12-15K	$23K	$23K	$15-26K	$15-26K	$26K	$26K	$20K	$20K
Annual operation costs,$	$2750	$2759	$2777	$2777	$2799	N/A[5]	N/A	N/A	N/A
Total annual costs,$	$34-50K	$58-65K	$58-65K	$50-75K	$50-75K	$69K	$76K	$71K	$71K
Average annual emission reduction,TPY[4]		3.2	4.5	3.2	4.5	4.5	5.8	3.2	4.5
Cost effectiveness, $/ton		$18-20K	$13-14K	$16-23K	$11-17K	$15K	$13K	$22K	$16K

1. Uses a 10% interest rate and useful life data from the manufacturers survey, when available.
2. Uses average capital and installation costs.
3. Cost data provided by the District assumes capital costs are 25% greater than those for control to 9 ppm.
4. Based on operating 24 hours per day and an average of five months per year operation (June-October).

Table 13: Cost Effectiveness Data for Boilers Rated at 200 mm BTU/hr

Control technology	**Low NOx burners**	**Ultra Low NOx burners**		**Ultra Low NOx burners with flue gas recirculation**		**Selective catalytic reduction**		**Ultra Low NOx burners with steam injection**	
NOx emission limit, ppm	30	15	9	15	9	9	3[3]	15	9
Capital costs,$	$150-240K	$250K	$250K	$280-342K	$280-342K	$350K	$438K	$282K	$282K
Installation costs,$	$50-102K	$50K	$50K	$60-132K	$60-132K	$150K	$150K	$120K	$120K
Capital cost amortization factor[1]	0.117	0.132	0.132	0.117	0.117	0.117	0.117	0.163	0.163
Equivalent annual capita costs of control[2] $	$23-40	$35K	$35K	$40-55	$40-55	$59K	$69	$66K	$66K
Annual repair and maintenance costs,$	$15K	$23K	$23K	$20-26K	$20-26K	$35K	$35K	$25K	$25K
Annual operation costs,$	$4888	$4904	$4936	$4936	$4976	N/A[5]	N/A	N/A	N/A
Total annual costs,$	$43-60K	$63K	$63K	$65-86K	$65-86K	$84K	$104K	$91K	$91K
Average annual emission reduction,TPY[4]		4.5	6.2	4.5	6.2	6.2	8.0	4.5	6.2
Cost effectiveness, $/ton		$14K	$10K	$14-19K	$11-14K	$14K	$13K	$20K	$15K

1. Uses a 10% interest rate and useful life data from the manufacturers survey, when available.
2. Uses average capital and installation costs.
3. Cost data provided by the District assumes capital costs are 25% greater than those for control to 9 ppm.
4. Based on operating 24 hours per day and an average of five months per year operation (June-October).

Table 14: Cost Effectiveness Data for Dehydrators Rated at 10 mm BTU/hr

Control technology	**Low NOx burners**	**Ultra Low NOx burners**		**Ultra Low NOx burners with flue gas recirculation[5]**		**Selective catalytic reduction[5]**		**Ultra Low NOx burners with steam injection[5]**	
NOx emission limit, ppm	30	15	9[4]	15	9	9	3	15	9
Capital costs,$	$5K	$35K							
Installation costs,$	$5K	$10K							
Capital cost amortization factor[1]	0.163	0.163							
Equivalent annual capita costs of control[2] $	$1.6K	$7.3K							
Annual repair and maintenance costs,$	$0.5K	$2K							
Annual operation costs,$	No data available	No data available							
Total annual costs,$	$2.1K	$9.3K							
Average annual emission reduction,TPY[3]		0.5							
Cost effectiveness, $/ton		$19K							

1. Uses a 10% interest rate and a useful life of 10 years.
2. Uses average capital and installation costs.
3. Based on operating 24 hours per day and an average of five months per year operation (June-October).
4. Per the manufacturer, current ultra low NOx burners used in dehydrators are unable to reduce NOx emissions to 9 ppm.
5. This technology is not available for burners used in dehydrators.

Staff received, but has not substantiated, comments from a respondent regarding the operation of vegetable dehydrator burners. The respondent's experience is that low-NOx dehydrator burners are more technically challenging and expensive to operate compared to conventional boiler burners. Specifically, the low-NOx dehydrator burners operated by the respondent require adjustments to accommodate changes in atmospheric temperature, a direct outcome of poor burner turndown capability that restricts the burner operation to narrow airflow and temperature ranges. The respondent has also experienced unacceptable degradation in onion products dried by low-NOx burners compared to those dried by conventional burners. In order to limit the degradation, the respondent has reduced the throughput of product through the dryer, and experienced a resulting increase in operating time and operating costs.

Incremental cost effectiveness considerations

For the purposes of this report, and consistent with the District's use of the definition of incremental cost effectiveness contained in the Health and Safety code, incremental cost effectiveness calculations are based on the difference in costs between two new control options to achieve additional emission reductions in order to achieve ambient air quality standards. Cost effectiveness data presented in Tables 10-14 is necessary to determine the incremental cost effectiveness. In order to determine the incremental cost effectiveness, the difference in total annual costs is divided by the difference in emissions reduction potential for each progressively more stringent potential control option in comparison to the next less expensive option. For example, using the data presented in Table 15 for a 50 mm BTU/hr boiler using selective catalytic reduction to control NOx emissions from 9-ppm to 3-ppm, the incremental cost effectiveness is:

($40,000 –$36,000)/(1.3-1.0 TPY) = $13,333 per ton of NOx removed annually.

Similar analyses may be done for the incremental cost effectiveness information presented in Tables 15-18 for boilers and Table 19 for dehydrators.

Table 15: Incremental Cost Effectiveness Data for Boilers Rated at 50 mm BTU/hr

Control technology	**Low NOx burners**	**Ultra Low NOx burners**		**Ultra Low NOx burners with flue gas recirculation**		**Selective catalytic reduction**		**Ultra Low NOx burners with steam injection**	
NOx emission limit, ppm	30	15	9	15	9	9	3	15	9
Total annual costs,$	$16-25K	$26-44K	$26-44K	$27-40K	$27-40K	$36K	$40K	$44K	$44K
Average annual emission reduction,TPY		0.7	1.0	0.7	1.0	1.0	1.3	0.7	1.0

Table 16: Incremental Cost Effectiveness Data for Boilers Rated at 100 mm BTU/hr

Control technology	**Low NOx burners**	**Ultra Low NOx burners**		**Ultra Low NOx burners with flue gas recirculation**		**Selective catalytic reduction**		**Ultra Low NOx burners with steam injection**	
NOx emission limit, ppm	30	15	9	15	9	9	3	15	9
Total annual costs,$	$22-39K	$22-53K	$22-53K	$36-57K	$36-57K	$65K	$68k	$59K	$59K
Average annual emission reduction,TPY		2.2	3.0	2.2	3.0	3.0	3.9	2.2	3.0

Table 17: Incremental Cost Effectiveness Data for Boilers Rated at 150 mm BTU/hr

Control technology	Low NOx burners	Ultra Low NOx burners		Ultra Low NOx burners with flue gas recirculation		Selective catalytic reduction		Ultra Low NOx burners with steam injection	
NOx emission limit, ppm	30	15	9	15	9	9	3	15	9
Total annual costs,$	$34-50K	$58-65K	$58-65K	$50-75K	$50-75K	$69K	$76K	$71K	$71K
Average annual emission reduction,TPY		3.2	4.5	3.2	4.5	4.5	5.8	3.2	4.5

Table 18: Incremental Cost Effectiveness Data for Boilers Rated at 200 mm BTU/hr

Control technology	Low NOx burners	Ultra Low NOx burners		Ultra Low NOx burners with flue gas recirculation		Selective catalytic reduction		Ultra Low NOx burners with steam injection	
NOx emission limit, ppm	30	15	9	15	9	9	3	15	9
Total annual costs,$	$43-60K	$63K	$63K	$65-86K	$65-86K	$84K	$104K	$91K	$91K
Average annual emission reduction,TPY		4.5	6.2	4.5	6.2	6.2	8.0	4.5	6.2

Table 19: Cost Effectiveness Data for Dehydrators Rated at 10 mm BTU/hr

Control technology	Low NOx burners	Ultra Low NOx burners		Ultra Low NOx burners with flue gas recirculation[2]		Selective catalytic reduction[2]		Ultra Low NOx burners with steam injection[2]	
NOx emission limit, ppm	30	15	9[1]	15	9	9	3	15	9
Total annual costs,$	$2K	$9K							
Average annual emission reduction,TPY		0.5							

1. Per the manufacturer, current ultra low NOx burners used in dehydrators are unable to reduce NOx emissions to 9 ppm or 3 ppm.
2. This technology is not available for burners used in dehydrators.

The implications of applying the incremental cost effectiveness thresholds for the development of future BARCT requirements are dependent on the District's air quality challenges. The reclassification of the District to "severe" for ozone nonattainment of the health-based federal standards starts a new cycle of air quality planning and rulemaking for the purpose of reducing ozone-forming NOx emissions in the San Joaquin Valley. The District must prepare and submit a Severe Ozone Attainment Demonstration Plan for ARB and U.S.EPA approval that must contain a significant array of proposed regulations and/or enforceable commitments to adopt and implement control measures in regulatory form by the 2005 deadline. Consequently, the boilers and dehydrators used in the food processing industry that currently meet the District's BARCT rule requirement of 30-ppm NOx emissions may be included with similar equipment used in numerous other industries in the District's quest to seek further reductions in NOx emissions to meet its future air quality challenges.

Since the majority of NOx emissions from food processing occur during the season of the year when ozone concentrations in the Valley are the worst,, an implication of applying additional requirements would be that the owners or operators of the boilers and dehydrators would be required to retrofit the current burners with new emissions abatement equipment in order to meet the new emission limits that would be set forth in a revised rule. The additional costs associated with the purchase and installation of the equipment, and any new energy requirements, are implications of imposing additional requirements on emission sources.

C. Operation and Maintenance Costs

The legislation requires the report to discuss operation and maintenance (O&M) costs. The surveys distributed to industry and manufacturers and distributors of emission abatement equipment requested information about O&M costs. The surveys distributed to industry included a question asking for pre-BARCT and post-BARCT O&M costs. Of the 19 usable BARCT surveys received, only one facility provided a response to this question. The data that was received is provided in Table 20.

Table 20

Boiler Size (mmBtu/hr)	Pre-BARCT O&M Costs $/year	Post-BARCT O&M Costs $/year
88	Minimal[1]	$3,000
103	Minimal[1]	$4,000
150	Minimal[1]	$3,000

1. No quantitative information was provided

The surveys distributed to manufacturer and distributors of emission abatement equipment requested information about combined repair and maintenance costs and separate information about operating costs. Information was provided for boilers rated at 50,100,150 and 200 mmBTU/hr, as well as for dehydrators with burners rated at 10 mmBTU/hr, for several types of emission abatement equipment. The information provided is presented in Tables 21-25.

Table 21

Annual repair, maintenance and operation cost data for boilers rated at 50 mm BTU/hr

Control technology	Low NOx burners	Ultra Low NOx burners		Ultra Low NOx burners with flue gas recirculation		Selective catalytic reduction		Ultra Low NOx burners with steam injection	
NOx emission limit, ppm	30	15	9	15	9	15	9	15	9
Annual repair and maintenance costs	$5K	$7.5-20K	$7.5-20K	$8.5-10K	$8.5-10K	$15K	$15K	$15K	$15K
Annual operation costs	$306	$307	$309	$309	$311	N/A	N/A	N/A	N/A

Table 22

Annual repair, maintenance and operation cost data for boilers rated at 100 mm BTU/hr

Control technology	Low NOx burners	Ultra Low NOx burners		Ultra Low NOx burners with flue gas recirculation		Selective catalytic reduction		Ultra Low NOx burners with steam injection	
NOx emission limit, ppm	30	15	9	15	9	15	9	15	9
Annual repair and maintenance costs	$8-10K	$10-15K	$10-15K	$11-17K	$11-17K	$30K	$30K	$15K	$15K
Annual operation costs	$1222	$1226	$1234	$1234	$1244	N/A	N/A	N/A	N/A

Table 23

Annual repair, maintenance and operation cost data for boilers rated at 150 mm BTU/hr

Control technology	Low NOx burners	Ultra Low NOx burners		Ultra Low NOx burners with flue gas recirculation		Selective catalytic reduction		Ultra Low NOx burners with steam injection	
NOx emission limit, ppm	30	15	9	15	9	15	9	15	9
Annual repair and maintenance costs	$12-15K	$22.5K	$22.5K	$15-25.5K	$15-25.5K	$25.5K	$25.5K	$20K	$20K
Annual operation costs	$2750	$2759	$2777	$2777	$2799	N/A	N/A	N/A	N/A

Table 24

Annual repair, maintenance and operation cost data for boilers rated at 200 mm BTU/hr

Control technology	Low NOx burners	Ultra Low NOx burners		Ultra Low NOx burners with flue gas recirculation		Selective catalytic reduction		Ultra Low NOx burners with steam injection	
NOx emission limit, ppm	30	15	9	15	9	15	9	15	9
Annual repair and maintenance costs	$15K	$22.5K	$22.5K	$20-25.5K	$20-25.5K	$35K	$35K	$25K	$25K
Annual operation costs	$4888	$4904	$4936	$4936	$4976	N/A	N/A	N/A	N/A

Table 25

Annual repair, maintenance and operation cost data for dehydrators rated at 10 mm BTU/hr

Control technology	Low NOx burners	Ultra Low NOx burners[1]		Ultra Low NOx burners with flue gas recirculation[2]		Selective catalytic reduction[2]		Ultra Low NOx burners with steam injection[2]	
NOx emission limit, ppm	30	15							
Annual repair and maintenance costs	$0.5K	$2K							
Annual operation costs	No data available	No data available							

1. Per the manufacturer, current ultra low NOx burners used in dehydrators are unable to reduce NOx emissions to 9 ppm.
2. This technology is not available for burners used in dehydrators.

VII. SAFETY ISSUES

The legislation requires that the report contain a discussion about safety issues related to boilers and dehydrators that have installed emissions control equipment. The California League of Food Processors distributed a survey to operators in the food processing industry that asked for a description of any accidents or catastrophic events that occurred as a direct result of the installation and use of emissions control equipment.

Of the 39 surveys received, there were 13 affirmative responses to the survey's safety question, and those responses contained information pertaining to boilers equipped with emissions abatement equipment installed to meet District requirements for NOx emissions of 9 ppm (BACT) and 30 ppm (BARCT). The majority of the responses indicated that some vibration and rumbling occurred in the boiler when BACT, typically a low-NOx burner used in conjunction with flue gas recirculation (FGR), was installed. Some boilers using BARCT (low-NOx burners only) experienced rumbling.

Staff was notified verbally of, but has not substantiated, an incident that was not reported in the survey responses and is telling of the safety issues that may occur when a boiler is required to meet NOx emissions of 9 ppm. A boiler equipped with a low-NOx burner in conjunction with FGR experienced flame instability in the burner when operated at 25% load. The flame began pulsing, causing the boiler walls to pulsate. This was accompanied by white smoke (unburned fuel) exiting the stack and a roar. The boiler was shut down immediately and no damage was done. The operator reviewed the incident with the manufacturer and was told that this was not the first time this type of incident has occurred. The flame instability was due to a high rate of airflow (wind in this case) across the air inlet, causing a large fluctuation in the signal to the airflow measurement sensor in the inlet. This in turn caused the control processor to open the fuel flow valve to allow in more fuel, resulting in an unstable flame. The operator believes that this situation may be improved by adding a shield around the air inlet to minimize the bursts of additional air that may enter the inlet and cause false signals.

Staff further researched this phenomenon and learned that flame stabilization is crucial when FGR is employed in conjunction with low-NOx or ultra low-NOx burners to meet NOx emission limits of 9 ppm. In current FGR systems, one fan is used to draw in both the fresh air and the recirculated flue gas; thus, the amounts of fresh air and gas may vary and cause flame stabilization problems. It is the task of the control processor to determine if the amounts of air and fuel are correct for safe and efficient operation, and this task requires greater attention as the boiler is operated at fluctuating loads.

While it is possible that the use of future control techniques may lead to additional safety concerns, staff concluded that overall safety issues could be avoided or minimized by employing several measures where needed:

- enhanced operator training in the operation of the new control equipment
- additional mechanical guards installed around the air inlet to prevent extra air from entering the inlet
- a variable frequency drive controller for the air damper to improve response to load demand
- fuel valve technology that improves response to load demand
- an in-stack monitor that provides stack gas measurement and analysis
- processor controls that can analyze stack gas data to determine if the fuel-to-air ratio is correct, and shut the boiler down if necessary

If a boiler utilizes an ultra-low NOx burner that employs high-excess air instead of FGR, the flame stabilization problems that may occur with use of the FGR system are not present. However, the use of high excess air requires the use of extra fuel because of increased energy loss from the burner stack. The use of extra fuel and the increased energy losses may represent significant energy costs to the operator in today's energy market.

VIII. ENERGY EFFICIENCY

Electricity Usage and Efficiency

The industry surveys asked the operators to report pre-BARCT and post-BARCT electricity usage. Of the 18 usable BARCT surveys, nine reported increases in electricity usage, eight reported no increase, and one did not respond in this category. Of the nine surveys that reported increases, four provided quantification of the increases. The increases were typically due to the operation of additional equipment such as fans, pumps, and control systems. This information is provided in Table 26.

Table 26

Boiler Size (mmBtu/hr)	Information Provided
82	Increase of 18.5 kW/hr operation (approx. 50% increase $)
82	Increase of 18.5 kW/hr operation (approx. 50% increase $)
119	Increase FGR usage load on motors
119	Increase FGR usage load on motors

Fuel Usage and Efficiency

The industry surveys also asked the operators to report pre-BARCT and post-BARCT fuel efficiency. Of the 18 usable BARCT surveys five reported increases in fuel usage yet provided no data regarding quantification of the increases. Nine reported no increase, one reported that the operator was unable to determine the fuel efficiency, and three provided no response in this category.

IX. IMPLICATIONS OF POTENTIAL CATASTROPHIC EVENTS

The legislation requires the report to discuss the implications of potential catastrophic events on the seasonal sources. These events can be categorized as either those that result from equipment failures, such as explosions, or those that are the result of acts of nature, such as a flood.

While the likelihood of a boiler exploding or a burner starting a fire is small, the implication of such an event is that the safety of the operator is jeopardized. The California Environmental Quality Act (CEQA) analysis that occurs in the rule making process requires that any safety concerns be addressed and mitigated prior to implementation of the rule.

The implication of a natural disaster occurring is that the operation could be destroyed, or seriously damaged such that operation ceases. The District has a provision for the temporary replacement of disaster-damaged equipment, such as a standby generator needed to create electrical power, so that operations may continue. In an emergency situation that is not covered under the routine replacement, the District would work with the applicant to process the project in a timely manner.

There is no special District rule or policy for emergencies that would allow an exemption from any applicable rules or regulations. In some instances, variances may be required to allow any additional emissions. If granted by the local hearing board, such variances would allow seasonal sources to continue to operate.

APPENDICES

Appendix 1

BILL NUMBER: AB 2283 CHAPTERED
BILL TEXT

CHAPTER 397
FILED WITH SECRETARY OF STATE SEPTEMBER 11, 2000
APPROVED BY GOVERNOR SEPTEMBER 8, 2000
PASSED THE ASSEMBLY AUGUST 24, 2000
PASSED THE SENATE AUGUST 22, 2000
AMENDED IN SENATE AUGUST 18, 2000
AMENDED IN SENATE AUGUST 7, 2000
AMENDED IN SENATE JUNE 26, 2000
AMENDED IN ASSEMBLY MAY 15, 2000
AMENDED IN ASSEMBLY APRIL 25, 2000
AMENDED IN ASSEMBLY APRIL 3, 2000

INTRODUCED BY Assembly Member Florez
(Co-author: Assembly Member Cardoza)

FEBRUARY 24, 2000

An act to amend Section 40703 of, and to add Section 39702.5 to, the Health and Safety Code, relating to air pollution.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. Section 39702.5 is added to the Health and Safety Code, to read:

39702.5. (a) The state board, in consultation with the advisory committee established pursuant to subdivision (e), shall investigate and provide a report to the Legislature by January 1, 2002, on all of the following matters with regard to emissions abatement equipment required by the San Joaquin Valley Unified Air Pollution Control District with respect to primarily seasonal sources from steam generators, boilers, process heaters, furnaces, and dehydrators that are subject to BACT and BARCT requirements:

(1) The average useful life of emissions abatement equipment utilized to meet "best available control technology" (BACT), as defined in Section 40405, or "best available retrofit control technology" (BARCT), as defined in Section 40406. This assessment shall be based on projections provided by the district, the experience of source operators, and representations made by manufacturers of the equipment.

(2) The implications of imposing additional requirements on emission sources already controlled to BACT and BARCT levels, accounting for the costs of, and the emission reductions attributable to, previous BACT and BARCT controls.
(3) The average, actual, and historical costs, for a representative number of sources of steam generators, boilers, process heaters, furnaces, and dehydrators that are subject to BACT and BARCT requirements of complying with those requirements, and a comparison of those costs to estimates utilized by the district in the development of those requirements.
(4) The implications of applying incremental cost effectiveness thresholds to sources that are subject to BACT and BARCT requirements, and the implications of applying these thresholds for the development of future BACT and BARCT requirements.
(b) The investigation required by this section shall include only the sources of oxides of nitrogen (NOx) controlled by BACT and BARCT requirements in the district described in subdivision (a).
(c) The report required by subdivision (a) shall take into account air quality and public health considerations, as well as factors such as growth, interbasin transport of air pollutants from other regions, and other factors deemed appropriate by the state board.

The report shall also specifically take into account the operation of seasonal sources, safety issues, energy efficiency, capital costs, operational and maintenance costs, and the implications of potential catastrophic events on sources. The state board shall also consider any other factors deemed appropriate by the advisory committee appointed pursuant to subdivision (e). The advisory board, if it deems appropriate, may recommend that the state board also consider including stationary internal combustion engines in the report, if the advisory board also determines that the inclusion of stationary internal combustion engines would not significantly expand the scope of the report.
(d) The state board shall have the final determination of the scope of the investigation and the report required by this section.
(e) The state board shall appoint an advisory committee to assist the state board in, and to provide advice on, the investigation conducted and the report prepared pursuant to subdivision (a). To the extent practicable, this advisory committee shall include representatives from all of the following:
(1) The district.
(2) Environmental organizations.
(3) Stationary source related organizations.
(4) Seasonal stationary source related organizations.
(5) Agricultural interests.
(6) A representative of the United States Environmental Protection Agency shall be invited to participate.
(7) Any other entity or organization the state board deems appropriate.
(f) The principal purpose of the report required by subdivision (a) is to provide a basis for evaluating the cost effectiveness, safety, and related matters associated with air pollution control technologies in the San Joaquin Valley.

SEC. 2. Section 40703 of the Health and Safety Code is amended to read:

40703. In adopting any regulation, the district shall consider, pursuant to Section 40922, and make available to the public, its findings related to the cost effectiveness of a control measure, as well as the basis for the findings and the considerations involved.
A district shall make reasonable efforts, to the extent feasible within existing budget constraints, to make specific reference to the direct costs expected to be incurred by regulated parties, including businesses and individuals.

SEC. 3. Notwithstanding Section 17610 of the Government Code, if the Commission on State Mandates determines that this act contains costs mandated by the state, reimbursement to local agencies and school districts for those costs shall be made pursuant to Part 7 (commencing with Section 17500) of Division 4 of Title 2 of the Government Code. If the statewide cost of the claim for reimbursement does not exceed one million dollars ($1,000,000), reimbursement shall be made from the State Mandates Claims Fund.

Appendix 2: AB2283 Advisory Committee Members

Name	Group	Position
	District	
Mark Boese	SJVUAPCD	Assistant APCO
	Environmental Organization	
Bonnie Holmes	American Lung Assoc.	Assistant V.P., Government Relations
V. John White	Sierra Club	Environmental Representative
Shannon Eddy	Sierra Club	Senior Legislative Advocate
	Stationary Source-related Organization	
John Sullivan	Alzeta Corporation	Vice President Engineering
Adrian Howes	Control Technologies Specialists	Consultant
Sky Wirth	Heat Transfer Systems	President
Michael D. MacDonald	R.F. MacDonald Company	Co-President
	Seasonal Stationary Source-related Organization	
Ed Yates	CA League of Food Processors	Senior V.P.
	Agricultural Interests	
Roger Isom	CA Cotton Ginners Association	V.P. and Director of Technical Services
Dan Webb	CA Dept of Food & Agriculture	Deputy Secretary
Manuel Cunha	Nisei Farmers League	President
Gerardo Rios	**U.S.EPA Region IX**	Permits Office
Tom Canaday	**U.S.EPA Region IX**	Rulemaking Office
	Other	
Jeff Sickenger	CA Manufacturers & Technology Association	Legislative representative
Paul Smokler	ENSR Corporation	Program Manager
Chris Savage	E & J Gallo Winery	Manager, Corporate Environmental Affairs
Les Clark	Independent Oil Producers Association	President
Chris Reardon	Manufacturers Council of the Central Valley	Executive Director
Catherine Reheis	Western States Petroleum Association	Manager, Upstream Issues
Mike Falasco	Wine Institute	Legislative representative

Appendix 3

RULE 4305 BOILERS, STEAM GENERATORS, AND PROCESS HEATERS (Adopted December 16, 1993; Amended March 16, 1995; Amended December 19, 1996)

1.0 Purpose

The purpose of this rule is to limit emissions of oxides of nitrogen from boilers, steam generators, and process heaters.

2.0 Applicability

2.1 This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with rated heat input greater than 5 million Btu per hour.

2.2 The requirements of this rule shall not constitute applicable State Implementation Plan requirements pursuant to Section 182(f) of the federal Clean Air Act for units located west of Interstate Highway 5 in Fresno, Kern, or Kings county. This section does not relieve owners from complying with any applicable provision of this rule.

3.0 Definitions

3.1 Annual Heat Input: the actual, total heat input of fuels burned by a unit in a calendar year, as determined from the higher heating value and cumulative annual usage of each fuel.

3.2 Boiler or Steam Generator: any external combustion equipment fired with any fuel used to produce hot water or steam.

3.3 Box or Cabin Type Unit: a natural or induced draft unit with a rated heat input equal to or less than 40 MMBtu/hr, and which has a rectangular shaped radiant section with any horizontal distance between opposite inner walls of 12 feet or less. Said unit must be permanently installed at a gas processing plant or petroleum refinery and have a valid Permit to Operate on December 19, 1996.

3.4 British Thermal Unit (Btu): the amount of heat required to raise the temperature of one pound of water from 59°F to 60°F at one atmosphere.

3.5 Dryer: any unit in which material is dried in direct contact with the products of combustion.

3.6 Gaseous fuel: any fuel which is a gas at standard conditions.

3.7 Heat Input: the heat (hhv basis) released due to fuel combustion in a unit, not including the sensible heat of incoming combustion air and fuel.

3.8 Higher Heating Value (hhv): the total heat liberated per mass of fuel burned (Btu per pound), when fuel and dry air at standard conditions undergo complete combustion and all resulting products are brought to their standard states at standard conditions.

3.9 Induced Draft Unit: a unit with an air fan located downstream of the combustion chamber, which creates negative pressure on the combustion chamber. This negative pressure draws, or induces, combustion air into the burner register.

3.10 Liquid Fuel: any fuel which is a liquid at standard conditions.

3.11 Natural Draft Unit: a unit with no combustion air fan or exhaust fan.

3.12 NOx Emissions: the sum of oxides of nitrogen expressed as NO_2 in the flue gas.

3.13 Parts Per Million by Volume (ppmv): the ratio of the number of gas molecules of a given species, or group of species, to the number of millions of total gas molecules.

3.14 Process Heater: any combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to water or process streams. This definition excludes: kilns or ovens used for drying, baking, cooking, calcining, or vitrifying; and unfired waste heat recovery heaters used to recover sensible heat from the exhaust of combustion equipment.

3.15 Rated Heat Input (million Btu per hour): the heat input capacity specified on the nameplate of the unit. If the unit has been physically modified such that its maximum heat input differs from what is specified on the nameplate, the modified maximum heat input shall be considered as the rated heat input and made enforceable by Permit to Operate.

3.16 Replacement Standby Unit: a unit permanently installed at a single stationary source that replaces a primary unit during breakdown or maintenance of the primary unit. Simultaneous operation of the replacement standby unit and the primary unit shall not occur except during start-up or shutdown of the primary unit.

3.17 Small Producer: a person who is engaged exclusively in the production of oil, and who produces an average of less than 6000 barrels of crude oil per day from all operations in any one county within the District, and who does not engage in refining, transporting or marketing of refined petroleum products.

3.18 Solid Fuel: any fuel which is a solid at standard conditions.

3.19 Standard Conditions: standard conditions as defined in Rule 1020 (Definitions).

3.20 Unit: any boiler, steam generator or process heater as defined in this rule.

3.21 Vertical Cylindrical Process Heater: a bottom-firing, cylindrical natural draft process heater with a rated heat input equal to or less than 40 million Btu/hr. Such unit shall be located at a petroleum refinery.

4.0 Exemptions

4.1 This rule shall not apply to:

4.1.1 Solid fuel fired units.

4.1.2 Dryers and glass melting furnaces.

4.1.3 Kilns and smelters where the products of combustion come into direct contact with the material to be heated.

4.1.4 Unfired or fired waste heat recovery boilers that are used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines.

4.1.5 Any unit in which the rated heat input of each burner is less than or equal to 5 million Btu per hour as specified on the Permit to Operate, and in which each burner's products of combustion do not come into contact with the products of combustion of any other burner.

4.2 The requirements of Section 5.1 and 5.3 shall not apply to a unit when burning any fuel other than natural gas during natural gas curtailment provided fuels other than natural gas are burned no more than 336 cumulative hours in a calendar year plus 48 hours per calendar year for equipment testing, as limited by Permit to Operate.

4.3 Except for the provisions of Section 6.1 and either Section 5.2.1 or 5.2.2, this rule shall not apply to units operated exclusively in the months of November, December, January, or February for less than 500 hours during these four consecutive months as limited by Permit to Operate.

4.4 Equipment modified or installed for the sole purpose of complying with the requirements of this rule shall be exempt from the Best Available Control Technology (BACT) and Offset requirements of District Rule 2201 (New and Modified Stationary Source Review Rule) provided that:

4.4.1 the proposed project will not result in an increase in capacity utilization of the unit being controlled.

4.4.2 the facility operator demonstrates to the satisfaction of the APCO that the proposed project is environmentally beneficial and will not cause or contribute to any violation of a national ambient air quality standard (NAAQS), prevention of significant deterioration (PSD) increment, or air quality related value (AQRV) in a class I area.

4.5 The modification of a Permit to Operate to increase fuel use limits (billion Btu/yr) shall be exempt from the BACT and Offset requirements of Rule 2201, provided:

4.5.1 the existing fuel use limit was established prior to July 1, 1996 for Rule 4305 purposes,

4.5.2 the owner of any such unit submits a complete application for ATC, for modification of the fuel use limitation, by May 31, 1997, and

4.5.3 the succeeding Permit to Operate is conditioned to ensure that future fuel use does not exceed the maximum fuel use allowed before the Rule 4305 fuel use limitation was established.

5.0 Requirements

All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen in accordance with Section 8.1.

5.1 Except for units subject to Section 5.2, NOx emissions shall not exceed:

5.1.1

	Operated on Gaseous fuel	Operated on Liquid Fuel
For all units, except box or cabin type units and vertical cylindrical process heaters	30 ppmv or 0.036 lb/MMBtu	40 ppmv or 0.052 lb/MMBtu
For box or cabin type units, and vertical cylindrical process heaters	147 ppmv or 0.18 lb/MMBtu	155 ppmv or 0.2 lb/MMBtu

5.1.2 the heat input weighted average of the limits specified in Sections 5.1.1 when operated on combinations of gaseous fuel and liquid fuel.

5.2 For each unit with an annual heat input less than 30 billion Btu as made enforceable by Permit to Operate, or any replacement standby unit with an annual heat input less than 90 billion Btu as made enforceable by Permit to Operate, the owner shall comply with one of the following:

5.2.1 tune the unit at least once each calendar year in which it operates by a technician that is qualified, to the satisfaction of the APCO, in accordance with the procedure described in Rule 4304 (Equipment Tuning Procedure for Boilers, Steam Generators, and Process Heaters); or

5.2.2 operate the unit in a manner that maintains exhaust oxygen concentrations at less than or equal to 3.00 percent by volume on a dry basis; or

5.2.3 operate the unit in compliance with the applicable emission requirements of Sections 5.1 and 5.3.

5.3 For units subject to Section 5.1, carbon monoxide emissions shall not exceed 400 ppmv.

5.4 Monitoring Provisions

Before any unit is operated,

5.4.1 the owner of any unit which simultaneously fires gaseous and liquid fuels, and is subject to the requirements of Section 5.1 and 5.3, shall install and maintain a non-resettable, totalizing mass or volumetric flow meter in each fuel line to each unit. Volumetric flow measurements shall be compensated for temperature and pressure.

5.4.2 the owner of any unit equipped with NOx reduction technology shall either install and maintain continuous emissions monitoring equipment for NOx, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install and maintain APCO-approved alternate monitoring consisting of one or more of the following:

5.4.2.1 periodic NOx and CO exhaust emission concentrations,
5.4.2.2 periodic exhaust oxygen concentration,
5.4.2.3 flow rate of reducing agent added to exhaust,
5.4.2.4 catalyst inlet and exhaust temperature,
5.4.2.5 catalyst inlet and exhaust oxygen concentration,
5.4.2.6 periodic flue gas recirculation rate,
5.4.2.7 other operational characteristics.

5.4.3 For units without NOx reduction technology, monitor operational characteristics recommended by the manufacturer and approved by the APCO.

5.4.4 the owner of any unit subject to Section 5.2.1 or 5.2.2 shall install and maintain a non-resettable, totalizing mass or volumetric flow meter in each fuel line to each unit. Volumetric flow measurements shall be periodically compensated for temperature and pressure. A master meter, which measures fuel to all units in a group of similar units, may satisfy these requirements if approved by the APCO in writing. The cumulative annual fuel usage may be verified from utility service meters, purchase or tank fill records, or other acceptable methods, as approved by the APCO.

5.5 Compliance Determination

5.5.1 The owner of any unit shall have the option of complying with either the heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.1. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling).

5.5.2 All emissions measurements shall be made with the unit operating at normal firing rate, air-to-fuel ratio, and fuel quality. No determination of compliance with the requirements of Section 5.1 or 5.3 shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or during start-up, shutdown, or breakdown conditions.

5.5.3 All emissions measurements shall be averaged in accordance with the applicable test methods in Section 6.2. Emissions from units with continuous monitoring systems (CEMS) shall be averaged in accordance with the requirements of 40 CFR Part 60.13. Any averaged CEMS value exceeding an applicable emission limit shall constitute a violation of this rule.

5.6 The owner of any functionally identical replacement for a box or cabin type unit shall not operate such unit in a manner which results in a measured NOx emissions concentration of greater than 30 ppmv when firing on gaseous and 40 ppmv when firing on liquid fuel.

6.0 Administrative Requirements

6.1 Recordkeeping

Records shall be maintained for two calendar years and shall be made available to the APCO upon request.

6.1.1 The owner of any unit operated under the exemption of Section 4.2 shall monitor and record for each unit the cumulative annual hours of operation on each fuel other than natural gas during curtailment and during testing.

6.1.2 The owner of any unit operated under the exemption of Section 4.3 shall monitor and record for each unit the cumulative annual hours of operation.

6.1.3 The owner of any unit subject to Section 5.2.1 or 5.2.2 shall record the amount of fuel use on a monthly basis for each unit, or for a group of units as specified in Section 5.4.4.

6.2 Test Methods

6.2.1 Fuel hhv shall be certified by third party fuel supplier or determined by:

6.2.1.1 ASTM D 240-87 or D 2382-88 for liquid hydrocarbon fuels;

6.2.1.2 ASTM D 1826-88 or D 1945-81 in conjunction with ASTM D 3588-89 for gaseous fuels.

6.2.2 Oxides of nitrogen (ppmv) - EPA Method 7E, or ARB Method 100.

6.2.3 Carbon monoxide (ppmv) - EPA Method 10, or ARB Method 100.

6.2.4 Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.

6.2.5 NOx Emission Rate (Heat Input Basis) - EPA Method 19.

6.2.6 Stack gas velocities - EPA Method 2.

6.2.7 Stack gas moisture content - EPA Method 4.

6.3 Compliance Testing

6.3.1 Each unit subject to Section 5.1 or 5.2.3 shall be tested to determine compliance with the applicable requirements of Section 5.1 and 5.3 not less than once every 12 months. Gaseous fuel fired units demonstrating compliance on two consecutive compliance source tests may defer the following source test for up to thirty-six months.

6.3.2 In lieu of compliance with Section 6.3.1, compliance with the applicable limits shall be demonstrated by submittal of annual emissions test results to the District from a unit or units that represents a group of units, provided:

6.3.2.1 All units are initially source tested and the emissions from all units in the group are similar; and

6.3.2.2 All units in a group are similar in terms of rated heat input, make and series, operational conditions, fuel used, and control method; and

6.3.2.3 The group is owned by a single owner and is located at a single stationary source; and

6.3.2.4 Selection of the representative unit(s) is approved by the APCO prior to testing; and

6.3.2.5 The number of representative units source tested shall be at least 10% of the total number of units in the group; and

6.3.2.6 All units in the group shall have received the same maintenance and tune-up procedures as the representative unit(s); and

6.3.2.7 Should any of the representative units exceed the required emission limits, each of the units in the group shall demonstrate compliance by emissions testing. Failure to complete emissions testing within 90 days of the failed test shall result in the untested units being in violation of this rule.

6.3.3 Once Section 6.3.2.7 has been satisfied, subsequent testing shall be performed pursuant to Section 6.3.1 or 6.3.2

6.4 Emission Control Plan

Effective December 19, 1996, the owner of any unit shall submit to the APCO for approval an Emissions Control Plan according to the schedule in Section 7.1. For each unit, the plan shall contain the following:

6.4.1 Permit to Operate number,
6.4.2 Fuel type and hhv,
6.4.3 Annual fuel consumption (Btu/yr),
6.4.4 Current emission level, including method used to determine emission level, and
6.4.5 Plan of actions, including a schedule of increments of progress, which will be taken to satisfy the requirements of Section 5.0 and the compliance schedule in Section 7.0.

7.0 Compliance Schedule

7.1 Group I through Group VII units, as defined in Sections 7.1.1 through 7.1.7, shall be in compliance with applicable requirements according to the schedule listed in Table 1:

TABLE 1 - Compliance Schedules

Group	Emission Control Plan	ATC Application	Full Compliance
I	6/16/95	6/16/95	12/16/97
II	6/16/95	6/16/97	12/16/99
III	6/16/95, except as provided in Section 7.3	6/16/98	12/31/2000
IV			12/16/94
V	6/19/97		12/19/97
VI	6/19/97	6/19/97	5/31/99
VII	6/19/97	5/31/99	5/31/2001

7.1.1 Group I units are those with annual heat input equal to or greater than 90 billion Btu requiring the installation of equipment to comply with applicable requirements.

7.1.2 Group II units are those with annual heat input equal to or greater than 90 billion Btu requiring the installation of equipment to comply with applicable requirements, and that meet one or more of the conditions in Sections 7.1.2.1 through 7.1.2.5.

7.1.2.1 On June 16, 1995, the unit's NOx emissions were within 0.025 lb/MMBtu of the applicable limit in Section 5.1, and

7.1.2.1.1 the unit's Permit to Operate limited NOx emissions to within 0.025 lb/MMBtu of the applicable limit in Section 5.1, or

7.1.2.1.2 a complete application for Authority to Construct had been submitted to limit the unit's NOx emissions to within 0.025 lb/MMBtu of the applicable limit in Section 5.1.

7.1.2.2 On June 16, 1995, the unit had a rated heat input of less than or equal to 35 million Btu per hour; or

7.1.2.3 On June 16, 1995, the unit was identified to be shutdown or replaced to comply with this rule; or

7.1.2.4 On June 16, 1995, the method of achieving compliance identified a change of fuel type or quality; or

7.1.2.5 On June 16, 1995, the unit was identified as, and continues to be fired exclusively on liquid fuel and is owned by a small producer.

7.1.3 Group III units are those associated with any petroleum refinery engaged in the production of state required reformulated fuels.

7.1.4 Group IV units are those with annual heat input equal to or greater than 90 billion Btu that do not require the installation of equipment to comply with applicable requirements.

7.1.5 Group V units are those:

7.1.5.1 with annual heat input less than 90 billion Btu that do not require the installation of equipment to comply with requirements of Section 5.1, and 5.3; or

7.1.5.2.1 subject to Section 5.2.1 or 5.2.2.

7.1.6 Group VI units are those:

7.1.6.1 with annual heat input less than 90 billion Btu and requiring the installation of equipment to comply with requirements of Section 5.1, and 5.3; or

7.1.6.2 natural draft units rated less than or equal to 40 MMBtu/hr; or

7.1.6.3 subject to the BACT or Offset exemption in Section 4.5; or

7.1.6.4 box or cabin type units; or

7.1.6.5 vertical cylindrical process heater

7.1.7 Group VII units are those:

7.1.7.1 with annual heat input less than 90 billion Btu for which the method of achieving compliance includes change of fuel type or quality; or

7.1.7.2 with annual heat input less than 90 billion Btu, which will be shutdown or replaced to comply with this rule.

7.2 As shown in Table 1, the column labeled:

7.2.1 "Emission Control Plan" identifies the date by which the owner shall submit an Emission Control Plan pursuant to Section 6.4 which identifies all units subject to this rule and units exempted by Section 4.3, or an Alternative Emission Control Plan pursuant to Section 9.0. The Emission Control Plan shall identify steps to be taken to comply with this rule.

7.2.2 "ATC Application" identifies the date by which the owner shall submit a complete application for Authority to Construct for necessary modifications to each unit.

7.2.3 "Full Compliance" identifies the date by which the owner shall demonstrate that each unit is in compliance with applicable requirements.

7.3 The owner of any Group III unit shall submit an Emission Control Plan by June 19, 1997 for:

7.3.1 any unit with annual heat input less than 90 billion Btu, or

7.3.2 any natural draft unit with a rated heat input less than or equal to 40 MMBtu/hr.

7.4 The owner of any Group I, II, III, or IV unit that was not in operation on or before December 16, 1993, or any Group V, VI, or VII unit that is not in operation on or before December 19, 1996, shall:

7.4.1 comply with the schedule in Section 7.1, or

7.4.2 submit a complete application for Authority to Construct for any modifications necessary to comply with this rule prior to operation of the unit, and comply with the applicable provisions of this rule upon initial operation of the unit.

7.5 The owner of a unit which, after December 19, 1996, exceeds an hours of operation, fuel use, or heat input limit specified in Sections 4.2, 4.3, or 5.2 shall within 30 days, submit a complete application for Authority to Construct to meet the requirements of this rule. Full compliance with Sections 5.0 and 6.0 shall be demonstrated within 12 months from the date the limit is exceeded or by the appropriate full compliance date in Section 7.1, whichever is later.

8.0 Calculations

8.1 All ppmv emission limits specified in Section 5.0 are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen as follows:

$$[\,ppmNO_x\,]_{corrected} = \frac{17.95\%}{20.95\% - [\%\,O_2\,]_{measured}}\, x[\,ppmNO_x\,]_{measured}\ 0$$

$$[ppmCO\,]_{corrected} = \frac{17.95\%}{20.95\% - [\%\,O_2\,]_{measured}}\, x[ppmCO\,]_{measured}\ 0$$

8.2 All pounds per million Btu NOx emission rates shall be calculated as pounds of nitrogen dioxide per million Btu of heat input (hhv).

9.0 Alternative Emission Control

9.1 General

The single owner of two or more units may comply with Section 5.1 by controlling units in operation at the same stationary source, or at two contiguous stationary sources, to achieve an aggregated NOx emission factor no higher than the aggregated NOx emission factor limit that would result if each unit in operation were individually in compliance with Section 5.1. The owner shall submit an Alternative Emission Control Plan (AECP) that is enforceable by the APCO, and receive written approval of the AECP from the APCO prior to implementation.

9.2 Eligibility

Any unit subject to Section 5.1 or Section 5.2.3 is eligible for inclusion in an AECP.

9.3 Exclusion

No unit subject to Sections 5.2.1 or 5.2.2 shall be included in an AECP.

9.4 AECP Definitions

For the purposes of Section 9.0, the following definitions shall apply:

9.4.1 Aggregated emission factor limit: the sum of the NOx emissions during the previous 14 calendar days that would result if all units in the AECP were in compliance with the lb/MMBtu limits in Section 5.1 and operating at their actual firing rates, divided by the sum of the actual 14-day heat input of all units in the AECP. Aggregated emission factor limit is calculated as:

$$L_A = \frac{\Sigma L_i F_i}{\Sigma F_i} \underline{0}$$

where: L_A is the aggregated emission factor limit (lb/MMBtu),

L_i is the emission factor limit (lb/MMBtu) for each unit in the AECP:

0.036 lb/MMBtu for gaseous fuel fired units, or

0.052 lb/MMBtu for liquid fuel fired units, or

fuel-weighted average for dual fuel units.

F_i is the total heat input (hhv basis) of fuel (MMBtu) combusted in each unit during the previous 14 day period, and

i identifies each unit in the AECP.

9.4.2 Aggregated emission factor: the sum of the actual NOx emissions during the previous 14 calendar days from all units in the AECP, divided by the sum of the actual 14-day heat input of all units in the AECP. Aggregated emission factor is calculated as:

$$E_A = \frac{\Sigma E_i F_i}{\Sigma F_i} \underline{0}$$

where: E_A is the aggregated emission factor (lb/MMBtu),

E_i is the emission factor (lb/MMBtu) for each unit in the AECP, established and verified by source testing, or continuous emission monitors,

F_i is the total heat input (hhv basis) of fuel (MMBtu) combusted in each unit during the previous 14-day period, and

i identifies each unit in the AECP.

9.5 AECP Requirements

The aggregated emission factor (E_A) shall not exceed the aggregated emission limit (L_A). The owner of any unit in an AECP shall notify the APCO within 24 hours of any violation of this section.

9.6 AECP Administrative Requirements

9.6.1 The AECP shall:

9.6.1.1 Contain all data, records, and other information necessary to determine eligibility of the units for alternative emission control, including but not limited to:

9.6.1.1.1 A list of units subject to alternative emission control,
9.6.1.1.2 Daily average and maximum hours of utilization for each unit,
9.6.1.1.3 Rated heat input of each unit, and
9.6.1.1.4 Fuel type for each unit.

9.6.1.2 Present the methodology for recordkeeping and reporting required by Sections 9.6.4 and 9.6.5.

9.6.1.3 Demonstrate that the aggregated emission factor will meet the requirements of Section 9.5 on each day.

9.6.1.4 Demonstrate that the schedule for achieving AECP NOx emission levels is at least as expeditious as the schedule if applicable units were to comply individually with the emission levels in Section 5.0 and the increments of progress in Section 7.0.

9.6.2 Revision of AECP

Owners shall demonstrate APCO approval of the AECP prior to applying for a modification to said AECP.

9.6.3 Determination of Emissions

9.6.3.1 NOx Emission measurements shall be in terms of pounds NO_2 per million Btu heat input.

9.6.3.2 NOx and carbon monoxide emission measurements shall be averaged according to procedures and test methods specified in Section 6.0, or by certified continuous emission monitor (CEM) as required by Section 9.6.3.3. Emissions from units with continuous monitoring systems (CEMS) shall be averaged in accordance with the requirements of 40 CFR Part 60.13. Any averaged CEMS value exceeding an applicable emission limit shall constitute a violation of this rule.

9.6.3.3 Each unit identified in the AECP shall be tested to determine its actual emission factor (E_i) as required in Section 9.4.2, according to the schedules in Section 6.3. Any unit required by Permit to Operate condition to record NOx emissions with a certified CEM shall use the CEM to determine E_i on a daily basis.

9.6.3.4 All emissions measurements shall be made with the unit operating at normal firing rate, air-to-fuel ratio, and fuel quality. No determination of an actual emission factor shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or during start-up, shutdown, or breakdown conditions.

9.6.3.5 The owner of any unit equipped with NOx reduction technology shall either install and maintain continuous emissions monitoring equipment for NOx, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install and maintain APCO-approved alternate monitoring consisting of one or more of the following:

9.6.3.5.1 periodic NOx and CO exhaust emission concentrations,
9.6.3.5.2 periodic exhaust oxygen concentration,
9.6.3.5.3 flow rate of reducing agent added to exhaust,
9.6.3.5.4 catalyst inlet and exhaust temperature,
9.6.3.5.5 catalyst inlet and exhaust oxygen concentration,
9.6.3.5.6 periodic flue gas recirculation rate,
9.6.3.5.7 other operational characteristics.

9.6.3.6 For units without NOx reduction technology, monitor operational characteristics recommended by the manufacturer and approved by the APCO.

9.6.4 AECP Recordkeeping

9.6.4.1 Records shall be maintained for two calendar years and shall be made available to the APCO upon request.

9.6.4.2 For each unit included in the AECP the owner shall maintain the following records for each day:

9.6.4.2.1 fuel type and amount used for each unit (F_i),
9.6.4.2.2 the actual emission factor for each unit (E_i) ,
9.6.4.2.3 the total emissions for all units ($\Sigma E_i F_i$) ,
9.6.4.2.4 the aggregated emission factor (E_A) , and
9.6.4.2.5 the aggregated emission factor limit (L_A).

9.6.5 Reporting and Annual Updates

Notifications of any violation pursuant to Section 9.5 shall include:

9.6.5.1 name and location of facility,
9.6.5.2 list of applicable units,
9.6.5.3 cause and expected duration of exceedance,
9.6.5.4 the amount of excess emissions,
9.6.5.5 proposed corrective actions and schedule.

9.7 Compliance Schedule

The AECP schedule for achieving reduced NOx emission levels shall be at least as expeditious as the schedule if applicable units were to comply individually with the emissions levels of Section 5.0 and the increments of progress in Section 7.0.

9.8 Fees

This section shall be in effect until such time that Regulation III (Fees) are amended to incorporate the following: The fee for establishing or revising an Alternate Emission Control Plan shall be one filing fee pursuant to Rule 3010 (Permit Fee) and an evaluation fee calculated using the staff hours expended and the prevailing weighted labor rate.