Northern Region Office
4800 Enterprise Way
Modesto, CA 95356-8718
(209) 557-6400 • FAX (209) 557-6475

Central Region Office
1990 East Gettysburg Avenue
Fresno, CA 93726-0244
(559) 230-6000 • FAX (559) 230-6061

Southern Region Office
34946 Flyover Court
Bakersfield, CA 93308-9725
(661) 392-5500 • FAX (661) 392-5585

www.valleyair.org

DATE: December 17, 2020

TO: SJVUAPCD Governing Board

FROM: Samir Sheikh, Executive Director/APCO
Project Coordinator: Jonathan Klassen

RE: **ITEM NUMBER 13: ADOPT PROPOSED AMENDMENTS TO RULE 4306 (BOILERS, STEAM GENERATORS, AND PROCESS HEATERS – PHASE 3) AND RULE 4320 (ADVANCED EMISSION REDUCTION OPTIONS FOR BOILERS, STEAM GENERATORS, AND PROCESS HEATERS GREATER THAN 5.0 MMBTU/HR)**

RECOMMENDATIONS:

1. Adopt proposed amendments to Rule 4306 (Boilers, Steam Generators, and Process Heaters – Phase 3) and Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr).

2. Authorize the Chair to sign the attached Resolution.

BACKGROUND:

The *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards (2018 PM2.5 Plan)* was adopted by your Board on November 15, 2018. The development of the *2018 PM2.5 Plan* utilized extensive science and research, state of the art air quality modeling, and the best available information in developing a strategy for bringing the Valley into attainment with the federal health-based 1997, 2006, and 2012 PM2.5 standards as expeditiously as practicable by the respective federal deadlines of 2020, 2024, and 2025. The attainment strategy includes a combination of innovative regulatory and non-regulatory measures for both stationary and mobile sources that built upon stringent air quality measures already in place from earlier District attainment plans and measures adopted by your Board. The *2018 PM2.5 Plan* was developed through an extensive public process, with wide-ranging input and support from involved parties representing environmental, business, and city interests. Among the measures identified in the *2018 PM2.5 Plan* is a commitment from the District to amend District Rule 4306 (Boilers, Steam Generators, and Process Heaters - Phase 3) and Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr) for further reductions of nitrogen oxides (NOx) emissions.

Today's recommendations satisfy the District's control measure commitment in the District's *2018 PM2.5 Plan*. Based on a comprehensive technical analysis, in-depth review of local, state, and federal regulations, and a robust public process, the proposed amendments would establish more stringent emission limits for oxides of nitrogen (NOx). If adopted, Rule 4306 and Rule 4320 would be the most stringent regulations in the country for the subject type of units. The proposed regulations would assist the District achieve the reductions necessary to meet air quality standards and protect public health, while allowing businesses to make case-by-case compliance decisions based on their own unique economic and logistical circumstances. Overall, the proposed amendments are estimated to generate 0.19 tons per day (tpd) of NOx emission reductions in 2024, to be applied towards the District's aggregate commitment included in the *2018 PM2.5 Plan*. An additional 0.03 tpd of NOx emission reductions is estimated to be achieved by proposed amendments to Rule 4306 in 2030. Proposed amendments to Rule 4320 will achieve an estimated additional 0.45 tpd (46%) of NOx emission reductions from this source category in 2024, although District staff are not proposing these reductions for State Implementation Plan (SIP) credit at this time.

The District's Citizens Advisory Committee made up of members representing environmental, industry/ag, and city interests provided consensus support for the proposed regulatory measures. The purpose of this item is to seek approval from your Board to adopt the proposed amendments to District Rules 4306 and 4320.

DISCUSSION:

Boilers, steam generators and process heaters are used throughout the Valley in many different industries. The District's permits system lists over 1,200 units affected by this rule project. Boilers are used in a wide range of industries, including but not limited to electrical utilities, cogeneration, petroleum refining, manufacturing and industrial, food and agricultural processing, and service and commercial facilities. Steam generators, particularly the larger units, are primarily used in the oil production industry to generate steam for heavy oil production enhancement. Process heaters provide heat for industrial and commercial processes including food production, manufacturing, and refineries. Boilers, process heaters, and steam generators with a heat input greater than 5.0 MMBtu/hr fired on gaseous or liquid fuel in the Valley emit 1.35 tpd of NOx emissions, representing 0.65% of the annual average NOx emissions in the Valley.

Rule 4306 was adopted on September 18, 2003, and amended in March 2005, and October 2008. Prior to the adoption of Rule 4306, these sources were controlled by Rule 4305, which was first adopted on December 16, 1993, and amended four times before the adoption of the more stringent Rule 4306. The purpose of Rule 4306 is to establish NOx and CO emission limits that units must comply with to operate in the District. Rule 4320 was adopted on October 16, 2008. The purpose of Rule 4320 is to establish more stringent, potentially-technology forcing NOx, CO, SO_2, and PM10 emission limits. Through the requirements of Rules 4305, 4306, and 4320, NOx emissions from sources subject to these rules have been reduced by 96% to date.

Control Technology for Boilers, Steam Generators, and Process Heaters

Control of NOx from boilers, steam generators, and process heaters is typically achieved by using improved combustion technology such as ultra-low NOx burners (ULNB), conventional low-NOx burners (LNB), oxygen controls like flue gas recirculation (FGR), and/or exhaust gas control technology such as selective catalytic reduction (SCR). The District evaluated the feasibility of further reducing NOx emissions through replacing natural gas units with electric units and solar powered oil field steam generators. The feasibility of requiring direct PM controls on units subject to this rule was also evaluated, although such controls were determined to not be feasible as a rule requirement at this time.

The NOx limits in proposed Rule 4306 are generally achievable with ULNB, although some operators prefer the operational flexibility offered by the combination of LNB and SCR. The most stringent NOx limits proposed in Rule 4320 are technology forcing and may be technologically feasible by using ULNB, SCR or a combination of SCR and ULNB. Most of the units subject to Rule 4320 have undergone several generations of NOx controls, and consequently, certain applications of SCR may not be feasible due to economic considerations and/or space limitations. In situations where a retrofit may not be the best option given the technology forcing nature of the limits, facilities may also comply by paying the annual emissions fee while the facility continually evaluates the feasibility of potential controls.

Summary of Proposed Amendments to Rule 4306

Rule 4306 establishes NOx emission limits that operators must comply with in order to operate in the Valley. Proposed modifications to Rule 4306 include lowering NOx emissions limits for a variety of unit classes and categories and establishing dates for emission control plans, authorities to construct, and compliance deadlines. The proposed Rule 4306 categories have been updated from the previous categories in the rule to account for differences in technologically achievable and cost-effective limits, which vary between different types and sizes of units. Updated category groupings also establish consistency in the categories included in Rule 4306 as well as Rule 4320. Definitions would be added to the rule to improve clarity and reflect changes to rule requirements. Test methods will be updated to reflect the latest version of test methodology available. The proposed emissions limits for each class and category of unit are included in Table 2 of the rule, included below:

Rule 4306 Table 2: Tier 2 NOx and CO Limits

Category	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit	CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G unit				
1. Fire Tube Boilers	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
2. Units at Schools	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units fired on Digester Gas	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
4. Thermal Fluid Heaters	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
5. All other units	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units				
1. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
2. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units with a rated heat input > 75 MMBtu/hour	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
C. Oilfield Steam Generators				
1. Units with a total rated heat input > 5.0 MMBtu/hr and ≤ 20.0 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
2. Units with a total rated heat input > 20.0 MMBtu/hr and ≤ 75.0 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units with a total rated heat input > 75.0 MMBtu/hr	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
4. Units firing on less than 50%, by volume, PUC quality gas	15 ppmv or 0.018 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
D. Refinery Units				
	30 ppmv or 0.036 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

Rule 4306 Table 2: Tier 2 NOx and CO Limits

Category	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit	CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
1. Boilers with a total rated heat input > 5.0 MMBtu/hr and ≤ 40.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu for replacement units			
2. Boilers with a total rated heat input > 40.0 MMBtu/hr and ≤110 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu 5 ppmv or 0.0061 lb/MMBtu for replacement units	400	40 ppmv or 0.052 lb/MMBtu	400
3. Boilers with a total rated heat input >110 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
4. Process Heaters with a total rated heat input > 5.0 MMBtu/hr and ≤ 40.0 MMBtu/hr	30 ppmv or 0.036 lb/MMBtu 9 ppmv or 0.011 lb/MMBtu for replacement units	400	40 ppmv or 0.052 lb/MMBtu	400
5. Process Heaters with a total rated heat input > 40.0 MMBtu/hr and ≤110 MMBtu/hr	15 ppmv or 0.018 lb/MMBtu 9 ppmv or 0.011 lb/MMBtu for replacement units	400	40 ppmv or 0.052 lb/MMBtu	400
6. Process Heaters with a total rated heat input >110 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
E. Units limited by a Permit to Operate to an annual heat input of 9 billion Btu/year to 30 billion Btu/year	30 ppmv or 0.036 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

Through the implementation of the proposed Rule 4306 amendments, an estimated 16.4% further reduction of NOx emissions will be achieved in 2024, with an additional 2.6% reduction of NOx emissions in 2030. Based on the emissions inventory used for the *2018 PM2.5 Plan*, this will result in 0.19 tons per day (tpd) of NOx emission reductions in 2024, and an additional 0.03 tpd of NOx emission reductions in 2030. Compliance dates for some of the lower emission limits have been extended to allow additional time for development of new, lower-cost burners and to allow for the useful life of the equipment. Average cost effectiveness for unit categories ranges from $13,000 to $106,000 per ton of NOx reduced.

Summary of Proposed Amendments to Rule 4320

Rule 4320 establishes NOx limits separate from Rule 4306 and provides Advanced Emission Reduction Options for rule compliance. Proposed modifications to Rule 4320 include lowering NOx emissions limits for a variety of unit classes and categories and establishing dates for emission control plans, authorities to construct, and compliance deadlines. Owners with units subject to Rule 4320 may choose to meet the NOx emission requirements or pay an annual emission fee. Definitions would be added to the rule to improve clarity and reflect changes to rule requirements. Test methods will also be updated to reflect the latest version of test methodology available. The proposed emissions limits for each class and category of unit are included in Table 2 of the rule, as shown below.

Rule 4320 Table 2: Tier 2 NOx Emission Limits

Category	NOx Limit	Emission Control Plan	Authority to Construct	Compliance Deadline
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through E units				
1. Fire Tube Boilers	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Units at Schools	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Units fired on Digester Gas	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
4. Thermal Fluid Heaters	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
5. All other units	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through E units				
1. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Units with a rated heat input > 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
C. Oilfield Steam Generators				
1. Units with a total rated heat input > 5.0 MMBtu/hr and ≤ 20.0 MMBtu/hr	6 ppmv or 0.0073 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Units with a total rated heat input > 20.0 MMBtu/hr and ≤ 75.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023

Rule 4320 Table 2: Tier 2 NOx Emission Limits				
Category	NOx Limit	Emission Control Plan	Authority to Construct	Compliance Deadline
3. Units with a total rated heat input > 75.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
4. Units firing on less than 50%, by volume, PUC quality gas	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
D. Refinery units				
1. Boilers with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Boilers with a total rated heat input > 40.0 MMBtu/hr to ≤ 110.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Boilers with a total rated heat input > 110.0 MMBtu/hr	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
4. Process Heaters with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
5. Process Heaters with a total rated heat input > 40.0 MMBtu/hr to ≤ 110.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
6. Process Heaters with a total heat input > 110.0 MMBtu/hr	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
E. Units limited by a Permit to Operate to an annual heat input >1.8 billion Btu/year but < 30 billion Btu/year.	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023

The NOx limits in Rule 4320 are technology-forcing limits and may not be achievable by all units due to space limitations and economic considerations. Because the affected units have typically had several levels of NOx controls, obtaining additional reductions can require expensive systems. Although the technology is available, for certain units, those technologies may not be economically feasible. Cost effectiveness will depend on the current level of controls, unit size, fuel usage and final emission levels. Some units have previously installed state-of-the-art controls and are in compliance with the most stringent emission limits and will therefore have minimal compliance costs. Average cost effectiveness for the affected categories ranges from $13,000 to $95,000 per ton of NOx reduced. In situations where a retrofit may not be the best option given the technology forcing nature of the limits, facilities may also comply by paying the annual emissions fee while the facility continually evaluates the feasibility of potential controls. These fees may then be used by the District to support cost-effective emission reductions and other pollution reduction activities. Fees would be paid annually and continue until the unit complies with the applicable limit. The affected sources will have the option, on an annual basis, to stop the fee option and install controls specified in the rule.

Compliance Schedule for Units Subject to Rules 4306 and 4320

The final Rule 4306 compliance date for most categories is December 31, 2023. However, the District determined that later compliance dates were appropriate for operations that had invested in lower-emission units, due to the high costs of retrofitting those units, and significant remaining useful life of the equipment. The District is proposing to extend the compliance dates for these lower-emitting units to December 31, 2029 to allow for the useful life of these lower-emitting units. For Rule 4320, the final compliance date for all categories is December 31, 2023. These compliance dates ensure that emission reductions will be achieved in the years 2024 and 2025, as committed to in the *2018 PM2.5 Plan*, to support attainment of the health-based federal PM2.5 standards. The additional emission reductions achieved through lower-emitting units complying with the limits required in the 2029 timeframe will assist with continued NOx emissions reductions throughout the Valley, which will be required to attain the recently strengthened federal 8-hour ozone standard.

Health Benefits of Implementing Plan Measures

The health risks of PM2.5 have been linked to a variety of health issues, including aggravated asthma, increased respiratory symptoms (irritation of the airways, coughing, difficulty breathing), decreased lung function in children, development of chronic bronchitis, irregular heartbeat, non-fatal heart attacks, increased respiratory and cardiovascular hospitalizations, lung cancer, and premature death. CARB explains that even short-term exposure of less than 24 hours can cause for premature mortality, increased hospital admissions for heart or lung causes, acute and chronic bronchitis, asthma attacks, emergency room visits, respiratory symptoms, and restricted activity days. Children, older adults, and individuals with heart or lung diseases are the most likely to be affected by PM2.5.

PM2.5 emissions are characterized by a unique combination of direct and secondarily formed constituents. As NOx emissions are a key precursor to the formation of ammonium nitrate, which is a large portion of total PM2.5 during the peak winter season, continuing to assess the feasibility of achieving additional NOx reductions across the Valley is critical for continuing to improve PM2.5 throughout the region.

PM2.5 is a major health risk because it can be inhaled more deeply into the gas exchange tissues of the lungs, where it can be absorbed into the bloodstream and carried to other parts of the body. Exposure to elevated concentrations of ozone also poses significant health risks, and the Valley has long worked to reduce NOx emissions as the primary precursor for the formation of ozone in the Valley.

To address federal health-based standards for ozone and PM2.5 and improve public health, the District develops attainment plans and implements control measures to lower direct and precursor emissions throughout the San Joaquin Valley. The proposed amendments will achieve additional reductions in NOx emissions as requirements are implemented by affected sources and new technologies are installed. New regulatory and incentive-based measures proposed by both the District and CARB, combined with existing measures achieving new emissions reductions, are necessary to achieve the emissions reductions required to attain the health-based federal standards as expeditiously as practicable, and will improve public health as emissions reductions are realized.

COVID-19 Pandemic Considerations

The COVID-19 pandemic is first and foremost a human tragedy, which has sent society into uncharted territory, and the economic impacts to the United States and the world are significant and far-reaching. The Valley and nation are currently facing uncertain economic times that have the potential to be devastating to local Valley businesses and residents. As an essential public health agency and member of the Valley community, the District has a responsibility to continue providing essential public services while keeping our employees and our communities safe. As the COVID-19 situation continues to evolve, the District has remained open, providing essential services to the residents, businesses, and public agencies of the Valley through virtual tools and direct support from our employees working remotely. District staff also understand the major disruption to the Valley and nation’s economy caused by the COVID-19 pandemic; and have committed to work closely with those that we regulate to understand the evolving situation and associated impacts, and develop options for meeting air quality obligations.

In response to COVID-19, District has modified public participation process to ensure continued development of measures included in District commitments in the federally approved *2018 PM2.5 Plan*. Beginning in March 2020, the District transitioned public workshop processes for this rule project to virtual online webinars with multiple options for public participation including video, phone, and email, with full translation services provided at public meetings. The District has continued to hold public workshops and to meet directly with stakeholders through virtual meeting tools throughout the pandemic to enable robust remote public participation.

The COVID-19 pandemic has resulted in the third oil price collapse that the oil and gas extraction industry has seen in just the last 12 years. Manufacturing and supply chains have been dramatically impacted. A combination of job losses and remote work means that far fewer people are commuting. Additionally, travel for recreational activities is reduced as well, whether because facilities are closed or have restrictions in place or because people are reluctant to expose themselves to illness. Those who have lost their jobs as a result of the coronavirus are conscious of their expenses, including on travel. Because the COVID-19 pandemic has dramatically altered metrics used to estimate socioeconomic impacts, such as revenue and employment, the socioeconomic impact analysis conducted for this rule uses a “COVID-adjusted baseline” for these metrics, with details presented in Appendix D to the Final Draft Staff Report.

While the pandemic has had far-reaching economic impacts, it is critical that the Valley continue to make progress towards attainment of the health-based federal ambient air quality standards. The health benefits of improved air quality, and the associated economic benefits, have been well documented. District staff have worked to develop proposed amendments to this rule that provides as much flexibility to affected industry as possible, while still ensuring that real emission reductions will be achieved to support increased air quality, and associated benefits to public health, throughout the Valley.

Supporting Regulatory Analyses

Cost Effectiveness Analysis

The California Health and Safety Code (CH&SC) Section 40920.6(a) requires the District to conduct both an absolute cost effectiveness analysis and an incremental cost effectiveness analysis of available emission control options before adopting each BARCT rule. The purpose of conducting a cost effectiveness analysis is to evaluate the economic reasonableness of the pollution control measure or rule. The analysis also serves as a guideline in developing the control requirements of a rule. Details of the cost effectiveness analysis is contained in Appendix C to the report.

Socioeconomic Analysis

Pursuant to CH&SC 40728.5, “whenever a district intends to propose the adoption, amendment, or repeal of a rule or regulation that will significantly affect air quality or emissions limitations, that agency shall, to the extent data are available; perform an assessment of the socioeconomic impacts of the adoption, amendment, or repeal of the rule or regulation.” The District, through a competitive solicitation process, selected Eastern Research Group, Inc. (ERG) to perform the socioeconomic impact analysis. District staff identified units subject to proposed Rules 4306 and 4320 and the units that would be affected by new provisions. Compliance cost information was collected from vendors and stakeholders throughout the public process. This information was provided to ERG to perform the socioeconomic impact analysis. ERG's report includes analysis of the impacts of the COVID-19 pandemic. Because the COVID-19 pandemic has dramatically altered metrics used to estimate socioeconomic impacts, such as revenue and employment, the consultant used a "COVID-adjusted baseline" to estimate these metrics. The socioeconomic report is attached as Appendix D to the final draft staff report.

Rule Consistency Analysis

Pursuant to CH&SC 40272.2, District staff prepared a rule consistency analysis that compares the elements of proposed Rules 4306 and 4320 with the corresponding elements of other District rules, federal regulations, and guidelines that apply to the same source category or type of equipment. District staff found that none of the revised proposed requirements of these rules would conflict with other District rules, or federal rules, regulations, or policies covering similar stationary sources.

Environmental Impacts

Pursuant to the California Environmental Quality Act (CEQA), staff investigated the possible environmental impacts of the revised proposed amendments to Rules 4306 and 4320. Based on the analysis conducted, District staff has concluded that the proposed amendments are exempt from the provisions of CEQA, as identified in the Staff Report referenced herein. Staff recommends filing a Notice of Exemption under the provisions of Public Resource Code 15062.

Public Rule Development Process

As part of the rule development process, District staff conducted public workshops to present and discuss proposed amendments to Rules 4306 and 4320. District staff held public workshops in December 2019, July 2020, September 2020, and October 2020. At the public meetings, District staff presented the objectives of the proposed rulemaking project, explained the District's rule development process, solicited suggestions from affected stakeholders, and informed all interested parties about tentative upcoming workshop dates, comment periods, and project milestones. Additionally, emission reductions from these source categories have been a priority for the Community Steering Committees (CSC) as a part of adopted Community Emission Reduction Programs under AB 617, and the District has invited CSC feedback in the rule development process. Updates were also presented throughout the rulemaking process at multiple public meetings of the Citizens Advisory Committee, Environmental Justice Advisory Group, and the District Governing Board.

In accordance with CH&SC Section 40725, the proposed amendments to Rules 4306 and 4320 were publicly noticed and made available for public review on November 17, 2020. The public was also invited to provide comments during the public hearing for the proposed adoption of these rules.

The comments received throughout this public process have been integral to the development of this rule amendment, and have been incorporated as appropriate into the proposed rules and final draft staff report. A summary of significant comments and District responses is available in Appendix A of the final draft staff report.

FISCAL IMPACT:

District staff expects no fiscal impact to result from this action.

Attachments:

Attachment A: Resolution for Proposed Amendments to Rule 4306 and Rule 4320 (5 pages)
Attachment B: Proposed Amendments to Rule 4306 (24 pages)
Attachment C: Proposed Amendments to Rule 4320 (22 pages)
Attachment D: Final Draft Staff Report with Appendices for Proposed Amendments to Rule 4306 (Boilers, Steam Generators, and Process Heaters – Phase 3) and Proposed Amendments to Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr) (145 pages)

San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
December 17, 2020

ADOPT PROPOSED AMENDMENTS TO RULE 4306 (BOILERS, STEAM GENERATORS, AND PROCESS HEATERS – PHASE 3) AND RULE 4320 (ADVANCED EMISSION REDUCTION OPTIONS FOR BOILERS, STEAM GENERATORS, AND PROCESS HEATERS GREATER THAN 5.0 MMBTU/HR)

Attachment A:

Resolution for Proposed Amendments to Rule 4306 and Rule 4320
(5 PAGES)

BEFORE THE GOVERNING BOARD OF THE
SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL DISTRICT

IN THE MATTER OF: PROPOSED AMENDMENTS TO RULE 4306 (BOILERS, STEAM GENERATORS, AND PROCESS HEATERS – PHASE 3) AND RULE 4320 (ADVANCED EMISSION REDUCTION OPTIONS GREATER THAN 5.0 MMBTU/HR)	**) RESOLUTION NO. ___________**

WHEREAS, the San Joaquin Valley Unified Air Pollution Control District (District) is a duly constituted unified air pollution control district, as provided in California Health and Safety Code (CH&SC) Sections 40150 et seq. and 40600 et seq.; and

WHEREAS, said District is authorized by CH&SC Section 40702 to make and enforce all necessary and proper orders, rules, and regulations to accomplish the purpose of Division 26 of the CH&SC; and

WHEREAS, pursuant to federal Clean Air Act (CAA) §107, the San Joaquin Valley Air Basin (Valley) is designated as nonattainment for the national health-based air quality standards for particulate matter 2.5 microns and smaller (PM2.5); and

WHEREAS, the District Governing Board adopted 2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards (*2018 PM2.5 Plan*) on November 15, 2018 pursuant to the federal Clean Air Act; and

WHEREAS, the District's *2018 PM2.5 Plan* commits the District to amend Rule 4306 and 4320 to further reduce NOx emissions from this source category; and

WHEREAS, the staff report and other supporting documentation was presented to the District Governing Board and the Board has reviewed and considered the entirety of this information prior to approving the project; and

WHEREAS, District staff conducted public workshops regarding Proposed Rules 4306 and 4320 on July 30, 2020, September 24, 2020, and October 8, 2020; and

WHEREAS, a public hearing for the adoption of proposed amendments to Rules 4306 and 4320 was duly noticed for December 17, 2020, in accordance with CH&SC §40725.

SJVUAPCD
1990 E. Gettysburg Ave.
Fresno, CA 93726
(559) 230-6000

NOW, THEREFORE, BE IT RESOLVED AS FOLLOWS:

1. The Governing Board hereby adopts Proposed Amendments to Rule 4306 (Boilers, Steam Generators, and Process Heaters – Phase 3) and Rule 4320 (Advanced Emission Reduction Options Greater Than 5.0 MMBtu/hr). Said rules shall become effective on December 17, 2020.

2. The Governing Board hereby finds, based on the evidence and information presented at the hearing upon which its decision is based, that all notices required to be given by law have been duly given in accordance with CH&SC §40725, and the Governing Board has allowed public testimony in accordance with CH&SC §40726.

3. In connection with said rulemaking, the Governing Board makes the following findings as required by CH&SC §40727:

a. **NECESSITY.** The Governing Board finds, based on the staff report, public testimony, and the record for this rulemaking proceeding, that a need exists for said rule amendments. Adopting said rules is necessary to meet the commitments of the SIP and requirements of the federal CAA and the California CAA. Said rules satisfy the commitment in the District's *2018 PM2.5 Plan*.

b. **AUTHORITY.** The Governing Board finds that it has the legal authority for said rulemaking under CH&SC §40000 and 40001.

c. **CLARITY.** The Governing Board finds that said rules are written or displayed so that the meaning can be easily understood by those persons or industries directly affected by said rules.

d. **CONSISTENCY.** The Governing Board finds that said rules are in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.

e. **NONDUPLICATION.** The Governing Board finds that said rules do not impose the same requirements as any existing state or federal regulation.

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f. **REFERENCE.** The Governing Board finds that said rulemaking implements federal CAA §172(c)(1) and CH&SC §40920.

4. The Governing Board hereby finds that the requirements of CH&SC §40728.5 and 40920.6 have been satisfied to the greatest extent possible, and that the Governing Board has actively considered and made a good faith effort to minimize any adverse socioeconomic impacts associated with the proposed rulemaking.

5. The Governing Board finds that, because this rulemaking will not cause either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment, the proposed actions do not constitute a project under the provisions of the California Environmental Quality Act (CEQA) Guidelines §15378. Furthermore, the proposed actions are exempt for actions taken by regulatory agencies, as authorized by state or local ordinance, to assure the maintenance, restoration, enhancement, or protection of the environment where the regulatory process involves procedures for protection of the environment (CEQA Guidelines §15308) (Actions by Regulatory Agencies for Protection of the Environment) and exempt from CEQA per the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061 (b)(3)).

6. Pursuant to Section 15062 of the CEQA guidelines, the Executive Director/Air Pollution Control Officer is directed to file a Notice of Exemption with the County Clerks of each of the counties in the District.

7. The Executive Director/Air Pollution Control Officer is directed to file with all appropriate agencies certified copies of this resolution and the rules adopted herein and is directed to maintain a record of this rulemaking proceeding in accordance with CH&SC §40728.

8. The Executive Director/Air Pollution Control Officer is directed to transmit said rules to the California Air Resources Board for incorporation into the SIP.

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9. The Governing Board authorizes the Executive Director/Air Pollution Control Officer to include in the submittal or subsequent documentation any technical corrections, clarifications, or additions that may be needed to secure EPA approval, provided such changes do not alter the substantive requirements of the approved rules.

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Fresno, CA 93726
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THE FOREGOING was passed and adopted by the following vote of the Governing Board of the San Joaquin Valley Unified Air Pollution Control District this 17th day of December 2020, to wit:

AYES:

NOES:

ABSENT:

SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL DISTRICT

By ________________________________
Craig Pederson, Chair
Governing Board

ATTEST:
Clerk to the Governing Board

By ____________________
Michelle Franco
Clerk to the Board

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Fresno, CA 93726
(559) 230-6000

San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
December 17, 2020

ADOPT PROPOSED AMENDMENTS TO RULE 4306 (BOILERS, STEAM GENERATORS, AND PROCESS HEATERS – PHASE 3) AND RULE 4320 (ADVANCED EMISSION REDUCTION OPTIONS FOR BOILERS, STEAM GENERATORS, AND PROCESS HEATERS GREATER THAN 5.0 MMBTU/HR)

Attachment B:

Proposed Amendments to Rule 4306
(24 PAGES)

RULE 4306 BOILERS, STEAM GENERATORS, AND PROCESS HEATERS – PHASE 3 (Adopted September 18, 2003; Amended March 17, 2005; Amended October 16, 2008; Amended (rule adoption date))

1.0 Purpose

The purpose of this rule is to limit emissions of oxides of nitrogen (NOx) and carbon monoxide (CO) from boilers, steam generators, and process heaters.

2.0 Applicability

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

3.0 Definitions

3.1 Annual Capacity Factor: the ratio of the amount of fuel burned by the unit in a calendar year to the amount of fuel that the unit could have burned if it had operated at its maximum rated capacity for 8,760 hours during the calendar year.

3.2 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.

3.3 Boiler or Steam Generator: any external combustion equipment, except oilfield steam generators, fired with any fuel used to produce hot water or steam.

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 Digester Gas: gas derived from the decomposition of organic matter in a digester.

3.~~5~~6 Dryer: any unit in which material is dried in direct contact with the products of combustion.

3.7 Fire Tube Boiler: any boiler that passes hot gases from a fire box through one or more tubes running through a sealed container of water. The heat of the gases is transferred through the walls of the tubes by thermal conduction, heating the water and ultimately creating steam or hot water.

3.~~6~~8 Gaseous Fuel: any fuel which is a gas at standard conditions.

3.~~7~~9 Gas Liquids Processing Facility: a facility that is engaged in the catalytic processing of gas liquids to produce finished products.

3.~~8~~10 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.~~9~~11 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.

3.12~~0~~ Liquid Fuel: any fuel which is a liquid at standard conditions.

~~3.11 Load-following Unit: for the purposes of this rule, a load-following unit is defined as a unit with normal operational load fluctuations and requirements which exceed the operational response range of an Ultra-Low NOx burner system(s) operating at 9 ppmv NOx. The operator shall designated load-following units on the Permit to Operate.~~

3.13 Normal Operation: the period of operating time during which a unit is not in a startup or a shutdown event.

3.14~~2~~ NOx Emissions: the sum of oxides of nitrogen expressed as NO_2 in the flue gas.

3.15~~3~~ Oilfield Steam Generator: an external combustion equipment which converts water to dry steam or to a mixture of water vapor and steam, with an absolute pressure of more than 30 psia, and which is used exclusively in thermally enhanced crude oil production.

3.16~~4~~ 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.

3.17~~5~~ 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.

3.18~~6~~ Public Utilities Commission (PUC) Quality Natural Gas: any gaseous fuel, gas-containing fuel where the sulfur content is no more than one-fourth (0.25) grain of hydrogen sulfide per one hundred (100) standard cubic feet and no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet. PUC quality natural gas also means high methane gas (at least 80% methane by volume) as specified in PUC General order 58-A.

3.19~~7~~ PUC Quality Natural Gas Curtailment: means a shortage in the supply of Public Utility Commission (PUC) quality natural gas, due solely to supply limitations or restrictions in distribution pipelines by the utility supplying the gas, and not due to the cost of natural gas.

3.20~~18~~ Qualified Technician: a stationary source employee or any personnel contracted by a stationary source operator who has a documented training and a demonstrated experience performing tune-ups on a unit to the satisfaction of the APCO. The documentation of tune-up training and experience shall be made available to the APCO upon request.

3.21~~19~~ 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.

3.22~~0~~ Refinery Unit: a unit that is permanently installed and operated at a petroleum refinery or a gas liquids processing facility.

3.23~~1~~ Re-ignition: the relighting of a unit after an unscheduled and unavoidable interruption or shut off of the fuel flow or electrical power, for a period of less than 30 minutes, due to reasons outside the control of the operator.

3.24 Replacement Unit: the replacement of a boiler, steam generator, oil field steam generator, or process heater. The retrofit of an existing unit does not qualify as a replacement.

3.25 School: any public or private school used for the purpose of education and instruction of school pupils in Kindergarten through Grade 12, and any college or university which provides postsecondary education and has the authority to confer Associate, Bachelors, or Graduate/Professional level degrees. This does not include any private school in which education and instruction are primarily conducted in private homes.

3.26~~2~~ Shutdown: the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off.

3.27~~3~~ Solid Fuel: any fuel which is a solid at standard conditions.

3.28~~4~~ Standard Conditions: standard conditions as defined in Rule 1020 (Definitions).

3.29~~5~~ Start-up: the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation.

3.30 Thermal Fluid Heater: a natural gas fired process heater in which a process stream is heated indirectly by a heated fluid other than water.

3.31~~26~~ Unit: any boiler, steam generator, oilfield steam generator, or process heater as defined in this rule.

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.

4.2 The requirements of Sections 5.1.1 and 5.1.2 shall not apply to a unit when burning any fuel other than PUC quality natural gas during PUC quality natural gas curtailment provided all of the following conditions are met:

4.2.1 Fuels other than PUC quality natural gas are burned no more than 168 cumulative hours in a calendar year plus 48 hours per calendar year for equipment testing, as limited by Permit to Operate.

4.2.2 NOx emission shall not exceed 150 ppmv or 0.215 lb/MMBtu. Demonstration of compliance with this limit shall be made by either source testing, continuous emission monitoring system (CEMS), an APCO approved Alternate Monitoring System, or an APCO approved portable NOx analyzer.

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 NOx and CO Emission Limits

5.1.1 Except for units subject to Sections 5.2, on and after the Compliance Deadline specified in Section 7, units shall not be operated in a manner which exceeds the applicable NOx and carbon monoxide (CO) emissions limits specified in Table 1 (until December 30, 2023) and Table 2 (on and after December 31, 2023).~~shall not exceed the limits specified in Table 1 on and after the dates specified in Tables 2 and 3.~~

Table 1: Tier 1 NOx and CO Limits					
Category	Operated on Gaseous Fuel			Operated on Liquid Fuel	
	NOx Limit		CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
	Standard Option	Enhanced Option			
A. Units with a rated heat input equal to or less than 20.0 MMBtu/hour, except for Categories C, D, E, F, G, H, and I units	15 ppmv or 0.018 lb/MMBtu	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
B. Units with a rated heat input greater than 20.0 MMBtu/hour, except for Categories C, D, E, F, G, H, and I units	9 ppmv or 0.011 lb/MMBtu	6 ppmv or 0.007 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
C. Oilfield Steam Generators	15 ppmv or 0.018 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
D. Refinery units with a rated heat input greater than 5 MMBtu/hr up to 65 MMBtu/hr	30 ppmv or 0.036 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
E. Refinery units with a rated heat input greater than 65 MMBtu/hr up to 110 MMBtu/hr	25 ppmv or 0.031 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
F. Refinery units with a rated heat input greater than 110 MMBtu/hr	5 ppmv or 0.0062 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
G. Load-following units	15 ppmv or 0.018 lb/MMBtu	9 ppmv or 0.011 lb/MMbtu	400	40 ppmv or 0.052 lb/MMBtu	400
H. Units limited by a Permit to Operate to an annual heat input of 9 billion Btu/year to 30 billion Btu/year	30 ppmv or 0.036 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400

Table 1: Tier 1 NOx and CO Limits					
Category	Operated on Gaseous Fuel			Operated on Liquid Fuel	
	NOx Limit		CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
	Standard Option	Enhanced Option			
I. Units in which the rated heat input of each burner is less than or equal to 5 MMBtu/hr but the total rated heat input of all the burners in a unit is greater than 5 MMBtu/hr, as specified in the Permit to Operate, and in which the products of combustion do not come in contact with the products of combustion of any other burner.	30 ppmv or 0.036 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400

Table 2: Tier 2 NOx and CO Limits				
Category	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit	CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G unit				
1. Fire Tube Boilers	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
2. Units at Schools	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units fired on Digester Gas	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
4. Thermal Fluid Heaters	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
5. All other units	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units				
1. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

Table 2: Tier 2 NOx and CO Limits				
Category	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit	CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
2. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units with a rated heat input > 75 MMBtu/hour	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
C. Oilfield Steam Generators				
1. Units with a total rated heat input > 5.0 MMBtu/hr and ≤ 20.0 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
2. Units with a total rated heat input > 20.0 MMBtu/hr and ≤ 75.0 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units with a total rated heat input > 75.0 MMBtu/hr	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
4. Units firing on less than 50%, by volume, PUC quality gas	15 ppmv or 0.018 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
D. Refinery Units				
1. Boilers with a total rated heat input > 5.0 MMBtu/hr and ≤ 40.0 MMBtu/hr	30 ppmv or 0.036 lb/MMBtu 5 ppmv or 0.0061 lb/MMBtu for replacement units	400	40 ppmv or 0.052 lb/MMBtu	400
2. Boilers with a total rated heat input > 40.0 MMBtu/hr and ≤110 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu 5 ppmv or 0.0061 lb/MMBtu for replacement units	400	40 ppmv or 0.052 lb/MMBtu	400
3. Boilers with a total rated heat input >110 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

Table 2: Tier 2 NOx and CO Limits				
Category	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit	CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
4. Process Heaters with a total rated heat input > 5.0 MMBtu/hr and ≤ 40.0 MMBtu/hr	30 ppmv or 0.036 lb/MMBtu 9 ppmv or 0.011 lb/MMBtu for replacement units	400	40 ppmv or 0.052 lb/MMBtu	400
5. Process Heaters with a total rated heat input > 40.0 MMBtu/hr and ≤110 MMBtu/hr	15 ppmv or 0.018 lb/MMBtu 9 ppmv or 0.011 lb/MMBtu for replacement units	400	40 ppmv or 0.052 lb/MMBtu	400
6. Process Heaters with a total rated heat input >110 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
E. Units limited by a Permit to Operate to an annual heat input of 9 billion Btu/year to 30 billion Btu/year	30 ppmv or 0.036 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

5.1.2 When a unit is operated on combinations of gaseous fuel and liquid fuel, the NOx limit shall be the heat input weighted average of the applicable limits specified in Sections 5.1.1, as calculated by the following equation:

$$\text{Weighted Average Limit} = \frac{(\text{NOx limit for gaseous fuel x G}) + (\text{NOx limit for liquid fuel x L})}{\text{G} + \text{L}}$$

Where: G = annual heat input from gaseous fuel
L = annual heat input from liquid fuel

5.2 For each unit that is limited to less than 9 billion Btu per calendar year heat input pursuant to a Permit to Operate, the operator shall comply with the requirement of Section 7.4 and one of the following:

5.2.1 T~~t~~une the unit at least twice per calendar year, (from four to eight months apart) by a qualified technician in accordance with the procedure described in Rule 4304 (Equipment Tuning Procedure for Boilers, Steam Generators, and Process Heaters). If the unit does not operate throughout a continuous six-month period within a calendar year, only one tune-up is required for that calendar year. No tune-up is required for any unit that is not operated during that calendar year; this unit may be test fired to verify availability of the unit for its intended use, but once the test firing is completed the unit shall be shutdown; or

5.2.2 O~~o~~perate 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 O~~o~~perate the unit in compliance with the applicable emission limits of Sections 5.1.1 or 5.1.2.

5.3 On and after the full compliance schedule specified in Section 7.1, the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 shall not apply during start-up or shutdown provided an operator complies with the requirements specified below.

5.3.1 The duration of each start-up or each shutdown shall not exceed two hours, except as provided in Section 5.3.3.

5.3.2 The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during start-up or shutdown.

5.3.3 Notwithstanding the requirement of Section 5.3.1, an operator may submit an application for a Permit to Operate condition to allow more than two hours for each start-up or each shutdown provided the operator meets all of the conditions in specified in Sections 5.3.3.1 through 5.3.3.3.

5.3.3.1 The maximum allowable duration of start-up or shutdown will be determined by the APCO. The allowable duration of start-up shall not exceed twelve hours and the allowable duration of shutdown shall not exceed nine hours.

5.3.3.2 The APCO will only approve start-up or shutdown duration longer than two hours when the application meets the following conditions:

5.3.3.2.1 C~~c~~learly identifies the control technologies or strategies to be utilized; and

5.3.3.2.2 D~~d~~escribes what physical conditions prevail during start-up or shutdown periods that prevent the controls from being effective; and

5.3.3.2.3 P~~p~~rovides a reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions.

5.3.3.3 The operator shall submit to the APCO any information deemed necessary by the APCO to determine the appropriate length of start-up or shutdown. The information shall include, but is not limited to the following:

5.3.3.3.1 Aa detailed list of activities to be performed during start-up or shutdown and a reasonable explanation for the length of time needed to complete each activity; and

5.3.3.3.2 Aa description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and

5.3.3.3.3 Bbasis for the requested additional duration of start-up or shutdown.

5.3.4 Permit to Operate (PTO) modifications solely to include start-up or shutdown conditions may be exempt from Best Available Control Technology (BACT) and emission offset requirements if the PTO modifications meet the requirements of Rule 2201 (New or Modified Stationary Source Review Rule) Section 4.2 (BACT Exemptions) and Rule 2201 Section 4.6 (Offset Exemptions).

5.4 Monitoring Provisions

5.4.1 The operator of any unit which simultaneously fires gaseous and liquid fuels, and is subject to the requirements of Section 5.1, shall install and maintain an operational 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.

5.4.2 The operator of any unit subject to the applicable emission limits in Sections 5.1 shall install and maintain an operational APCO approved Continuous Emissions Monitoring System (CEMS) for NOx, CO, and oxygen, or implement an APCO-approved Alternate Monitoring System. An APCO approved CEMS shall comply with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Part 60 Appendix B (Performance Specifications) and 40 CFR Part 60 Appendix F (Quality Assurance Procedures, and applicable provisions of Rule 1080 (Stack Monitoring). An APCO approved Alternate Monitoring System shall monitor one or more of the following:

5.4.2.1 Pperiodic NOx and CO exhaust emission concentrations,
5.4.2.2 Pperiodic exhaust oxygen concentration,
5.4.2.3 Fflow rate of reducing agent added to exhaust,

5.4.2.4 C~~c~~atalyst inlet and exhaust temperature,
5.4.2.5 C~~c~~atalyst inlet and exhaust oxygen concentration,
5.4.2.6 P~~p~~eriodic flue gas recirculation rate,
5.4.2.7 O~~o~~ther operational characteristics.

5.4.3 For units subject to the requirements of Section 5.2.1 or 5.2.2, the operator shall monitor, at least on a monthly basis, the operational characteristics recommended by the manufacturer and approved by the APCO.

5.4.4 The operator of any Category H unit ~~listed~~ in ~~Section 5.1.1~~ Table 1, Category E unit in Table 2, and any unit subject to Section 5.2.1 or 5.2.2 shall install and maintain an operational 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.

5.4.5 The APCO shall not approve an alternative monitoring system unless it is documented that continued operation within ranges of specified emissions-related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits. The operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards.

5.5 Compliance Determination

5.5.1 The operator of any unit shall have the option of complying with either the applicable 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 either at conditions representative of normal operations or conditions specified in the Permit to Operate. Unless otherwise specified in the Permit to Operate no determination of compliance 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 within 30 minutes after a re-ignition as defined in Section 3.0.

5.5.3 All Continuous Emissions Monitoring System (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes to demonstrate compliance with the applicable emission limits of this rule. Any 15-consecutive-minute block average CEMS measurement exceeding the applicable emission limits of this rule shall constitute a violation of this rule.

5.5.4 For emissions monitoring pursuant to Sections 5.4.2, 5.4.2.1, and 6.3.1 using a portable NOx analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period.

5.5.5 For emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit.

6.0 Administrative Requirements

6.1 Recordkeeping

The records required by Sections 6.1.1 through 6.1.4 shall be maintained for five calendar years and shall be made available to the APCO upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

6.1.1 The operator 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 periods of natural gas curtailment and equipment testing. The NOx emission concentration (in ppmv or lb/MMBtu) for each unit that is operated during periods of natural gas curtailment shall be recorded. Failure to maintain records required by Section 6.1.1 or information contained in the records that demonstrates noncompliance with the conditions for exemption under Section 4.2 will result in loss of exemption status. On and after the applicable compliance schedule specified in Section 7.0, any unit losing an exemption status shall be brought into full compliance with this rule as specified in Section 7.3.

6.1.2 The operator of any Category H unit ~~listed~~ in ~~Section 5.1.1~~ Table 1, or Category E unit in Table 2 and any unit that is subject to the requirements of Section 5.2 shall record the amount of fuel use at least on a monthly basis for each unit, or for a group of units as specified in Section 5.4.4. On and after the applicable compliance schedule specified in Section 7.0, in the event that such unit exceeds the applicable annual heat input limit ~~specified~~ in ~~Sections 5.1.1~~ Table 1 Category H, Table 2 Category E, and Section 5.2, the unit shall be brought into full compliance with this rule as specified in Section 7.4.

6.1.3 The operator of any unit subject to Section 5.2.1 or Section 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics of the unit have been performed.

6.1.4 The operator performing start-up or shutdown of a unit shall keep records of the duration of start-up or shutdown.

6.2 Test Methods

The following test methods shall be used unless otherwise approved by the APCO and EPA.

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 4809~~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 the requirements in Sections 5.1 or 5.2.3 shall be source tested to determine compliance with the applicable emission limits at least once every 12 months, (no more than 30 days before or after the required annual source test date). Units that demonstrate compliance on two consecutive 12-month source tests may defer the following 12-month source test for up to 36 months (no more than 30 days before or after the required 36-month source test date). During the 36-month source testing interval, the operator shall tune the unit in accordance with the provisions of Section 5.2.1, and shall monitor, on a monthly basis, the unit's operational characteristics recommended by the manufacturer to ensure compliance with the applicable emission limits specified in Sections 5.1 or 5.2.3. Tune-ups required by Sections 5.2.1 and 6.3.1 do not need to be performed for units that operate and maintain an APCO approved CEMS or an APCO approved Alternate

Monitoring System where the applicable emission limits are periodically monitored. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits specified in Sections 5.1 or 5.2.3, the source testing frequency shall revert to at least once every 12 months. Failure to comply with the requirements Section 6.3.1, or any source test results that exceed the applicable emission limits in Sections 5.1 or 5.2.3 shall constitute a violation of this rule.

6.3.2 In lieu of compliance with Section 6.3.1, compliance with the applicable emission limits in Sections 5.1 or 5.2.3 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 in the group are initially source tested. The emissions from all test runs from units within the group are less than 90% of the permitted value, and the emissions do not vary greater than 25% from the average of all test runs; 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. No unit with a rated heat input greater than 100 MMBtu shall be considered as part of the group; 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 30% of the total number of units in the group. The representative tests shall rotate each year so that within three years all units in the group have been tested at least once.

6.3.2.6 All units in the group shall have received the similar maintenance and tune-up procedures as the representative unit(s) as listed in the Permit to Operate. The operator shall submit to the APCO the specific maintenance procedures to be performed on each unit that will be included in the group for representative testing. Such maintenance procedures shall be specified in the Permit to Operate for units that are included in the group for representative testing. Any maintenance work on a unit which has no effect on emissions standards and which is not specified in the maintenance procedures shall be submitted to the APCO for approval before such unit can be included as part of the group for representative testing. Any unit that necessitates any maintenance work which has an effect on emission standards and is beyond the maintenance procedures identified in the Permit to Operate, shall not be included as part of the group for representative testing. The unit shall be source tested in accordance with the provisions of Section 6.3.1; 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. After compliance with the requirements of Section 6.3.2.7 has been demonstrated, subsequent source testing shall be performed pursuant to Sections 6.3.1 or 6.3.2.

6.4 Emission Control Plan (ECP)

6.4.1 The operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0. For each unit, the plan shall contain the following:

6.4.1.1 Permit to Operate number,
6.4.1.2 Fuel type and hhv,
6.4.1.3 Annual fuel consumption (Btu/yr),
6.4.1.4 Current emission level, including method used to determine emission level,
6.4.1.4 <u>Applicable Table 1 and Table 2 Category for each unit</u> ~~NOx limit to be satisfied, either Standard Option or Enhanced Option~~, and
6.4.1.6 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.

~~6.4.2 The operator shall submit to the APCO for approval, as part of the ECP, a list of units which are to be designated as load-following units. The APCO shall only designate, as load-following, units for which the following information has been provided to demonstrate that the units qualify as load-following:~~

~~6.4.2.1 Technical data such as steam demand charts or other information to demonstrate the normal operational load fluctuations and requirements of the unit,~~
~~6.4.2.2 Technical data about the operational response range of an Ultra-Low NOx burner system(s) operating at 9 ppmv NOx, and~~
~~6.4.2.3 Technical data demonstrating that the unit(s) are designed and operated to optimize the use of base-loaded units in conjunction with the load-following unit(s).~~

7.0 Compliance Schedule

7.1 An operator ~~with multiple units at a stationary source~~ shall comply with this rule in accordance with the schedule specified in Table ~~2~~3, Table 4, and Table 5. ~~A stationary source with only one unit shall comply with the schedule specified in Table 2 Group 1 for standard option or Table 3 Group 1 for enhanced option.~~

Table~~ABLE~~ ~~2~~3: Tier 1 – Standard Option Compliance Schedule			
Units to be in Compliance at a Stationary Source	Emission Control Plan	Authority to Construct	Full Compliance
Group 1: 25% or more of the total number of units subject to this rule on June 1, 2005, excluding Group 4	June 1, 2004	June 1, 2004	June 1, 2005
Group 2: 62.5% or more of the total number of units subject to this rule on June 1, 2006, excluding Group 4	June 1, 2004	January 2, 2005	June 1, 2006
Group 3: 100% of the total number of units subject to this rule on June 1, 2007	June 1, 2004	January 2, 2006	June 1, 2007
Group 4: A. Load-following units B. Units limited by Permit to Operate to an annual capacity factor of 10% or less as of June 1, 2005 C. Category I units at any stationary source that has no more than two units subject to this rule.	June 1, 2004	January 2, 2006	June 1, 2007

Units are considered to be subject to this rule if the rule is applicable to the units pursuant to Section 2.0 and the units are not exempt pursuant to Section 4.1.

Table~~ABLE~~ ~~3~~4: Tier 1 – Enhanced Option Compliance Schedule			
Units to be in Compliance at a Stationary Source	Emission Control Plan	Authority to Construct	Full Compliance
Group 1: 25% or more of the total number of units subject to this rule on June 1, 2005, excluding Group 4	December 1, 2005	December 1, 2005	December 1, 2006
Group 2: 62.5% or more of the total number of units subject to this rule on June 1, 2006, excluding Group 4	December 1, 2005	July 1, 2006	December 1, 2007
Group 3: 100% of the total number of units subject to this rule on June 1, 2007	December 1, 2005	July 1, 2007	December 1, 2008
Group 4: A. Load-following units	December 1, 2005	July 1, 2007	December 1, 2008

Table 5: Tier 2 - Compliance Schedule			
Category	Emission Control Plan	Authority to Construct	Compliance Deadline
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G unit			
1a. Fire Tube Units permitted greater than 9 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
1b. Fire Tube Units permitted less than or equal to 9 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
2. Units at Schools	May 1, 2022	May 1, 2022	December 31, 2023
3. Units fired on Digester Gas	May 1, 2022	May 1, 2022	December 31, 2023
4. Thermal Fluid Heaters	May 1, 2022	May 1, 2022	December 31, 2023
5a. All other units permitted greater than 12 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
5b. All other units permitted less than or equal to 12 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units			
1a. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted greater than 9 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
1b. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted less than or equal to 9 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
2a. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted greater than 9 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
2b. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted less than or equal to 9 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
3a. Units with a rated heat input > 75 MMBtu/hour permitted greater than 7 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
3b. Units with a rated heat input > 75 MMBtu/hour permitted less than or equal to 7 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
C. Oilfield Steam Generators			

Table 5: Tier 2 - Compliance Schedule			
Category	Emission Control Plan	Authority to Construct	Compliance Deadline
1. Units with a total rated heat input > 5.0 MMBtu/hr and ≤ 20.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
2. Units with a total rated heat input > 20.0 MMBtu/hr and ≤ 75.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
3. Units with a total rated heat input > 75.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
4. Units firing on less than 50%, by volume, PUC quality gas	May 1, 2022	May 1, 2022	December 31, 2023
D. Refinery Units			
1. Boilers with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
2. Boilers with a total rated heat input > 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
3. Heaters with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
4. Heaters with a total rated heat input > 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
E. Units limited by a Permit to Operate to an annual heat input of 9 billion Btu/year to 30 billion Btu/year	May 1, 2022	May 1, 2022	December 31, 2023

Units are considered to be subject to this rule if the rule is applicable to the units pursuant to Section 2.0 and the units are not exempt pursuant to Section 4.1.

7.2 As shown in ~~Table 2 and~~ Table 3, Table 4, and Table 5 the column labeled:

7.2.1 "Emission Control Plan" identifies the date by which the operator shall submit an Emission Control Plan pursuant to Section 6.4. The Emission Control Plan shall identify all units subject to this rule. -The Emission Control Plan shall identify steps to be taken to comply with this rule.

7.2.2 “Authority to Construct” identifies the date by with the operator shall submit an Application for Authority to Construct for each unit subject to the rule.

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

7.3 Any unit that is exempted under Section 4.2 that becomes subject to the emission limits of this rule through the loss of exemption status, shall be in full compliance with this rule on and after the date the exemption status is lost.

7.4 Any unit that becomes subject to the emission limits of this rule as a result of exceeding the applicable annual heat input limit specified in either ~~Section 5.1.1~~ Table 1 Category H~~,~~ ~~or~~ Table 2 Category E~~,~~ or Section 5.2, shall be in compliance with the applicable ~~standard option~~ emission limits ~~for Category A and B units~~ in Section 5.1.1 on and after the date the annual heat input limit is exceeded.

8.0 Calculations

8.1 All ppmv emission limits specified in Section 5.1 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:

$$[\text{ppm NOx}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%\text{O2}]_{\text{measured}}} \text{ x } [\text{ppm NOx}]_{\text{measured}}$$

$$[\text{ppm CO}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%\text{O2}]_{\text{measured}}} \text{ x } [\text{ppm CO}]_{\text{measured}}$$

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 90 percent of the aggregated NOx emission factor limit that would result if each unit in operation were individually in compliance with the applicable NOx emission limits in Section 5.1. An operator that is subject to the Alternative Emission Control Plan (AECP) requirements below shall also comply with the applicable requirements of Sections 5.0, 6.0, 7.0 and 8.0.

9.2 Eligibility

A unit not subject to Section 5.1 or Section 5.2.3 is not 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 NOx emission factor limit: the sum of the NOx emissions, over seven consecutive 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 heat input of all units in the AECP over seven consecutive calendar days. Aggregated emission factor limit is calculated as:

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

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

L_i is the applicable NOx emission factor limit (lb/MMBtu) specified in Section 5.1.1 Table 1, Table 2, or Section 5.1.2 for each category of unit in the AECP,

F_i is the total heat input (hhv basis) of fuel (MMBtu) combusted in each unit during seven consecutive calendar days, and

i identifies each unit in the AECP.

9.4.2 Aggregated NOx emission factor: the sum of the actual NOx emissions during seven consecutive calendar days from all units in the AECP, divided by the sum of the heat input of all units in the AECP during seven consecutive calendar days. The aggregated emission factor is calculated as:

$$\mathrm{E_A} = \frac{\Sigma \mathrm{E_i F_i}}{\Sigma \mathrm{F_i}}$$

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

E_i is the NOx 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 seven consecutive calendar days, and

i identifies each unit in the AECP.

9.5 AECP Requirements

9.5.1 The aggregated NOx emission factor (E_A) shall not exceed 90 percent of 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. A violation of E_A is a violation for every day in the averaging period.

$$E_A \text{ must be} \leq 0.90 \times L_A$$

9.5.2 Only units in the AECP which were operated during seven consecutive calendar days shall be included in the calculations of the aggregated NOx emission factor (L_A) and the aggregated NOx emission limit (E_A).

9.5.3 During each seven consecutive calendar days of operation that the AECP is used, the operator shall calculate and record the aggregated NOx emission factor (L_A) and the aggregate NOx emission limit (E_A).

9.5.4 The operator shall submit a NOx emission factor for each unit that is included in the AECP. The established NOx emission factor of the unit shall be no less than the emission factor of the unit from the most recent source test conducted pursuant to Section 6.3 and approved by the APCO. The operator shall not operate any AECP unit in such a manner that the NOx emissions exceed the established NOx emission factor of the unit.

9.5.5 The operator shall submit the AECP, for approval by the APCO, ~~by June 1, 2004 or~~ at least 24 months before compliance with the applicable emission limits in Section 5.1 is required, pursuant to the Section 7.1~~, whichever is later~~. The AECP shall be submitted with an application for an Authority to Construct pursuant to complying with Section 7.1 as applicable. The operator shall obtain a written approval of the AECP from the APCO prior to implementation.

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 Specify which NOx limit~~, either Standard Option or Enhanced Option,~~ will be satisfied by the units under the AECP.

9.6.1.4 Demonstrate that the aggregated emission factor will meet the requirements of Section 9.5.

9.6.1.5 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 applicable emission levels in Section 5.1 and the ~~increments of progress~~ Compliance Schedule in Section 7.0.

9.6.2 Revision of AECP

The owner shall submit an application for an Authority to Construct to revise an existing AECP, and shall obtain APCO approval of the revised AECP prior to implementing the revised AECP. ~~Owners shall demonstrate APCO approval of the AECP prior to applying for a modification to said AECP.~~

9.6.3 AECP Recordkeeping

In addition to the records kept pursuant to Section 6.1, the operator shall maintain records, on a daily basis, of the parameters needed to demonstrate compliance with the applicable NOx emission limits when operating under the AECP. -The records shall be retained for at least five years and shall be made available to the APCO upon request. The records shall include, but are not limited to, the following:

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

9.6.3.1.1 F~~f~~uel type and amount used for each unit (F_i),
9.6.3.1.2 T~~t~~he actual emission factor for each unit (E_i),
9.6.3.1.3 T~~t~~he total emissions for all units ($\Sigma E_i F_i$),
9.6.3.1.4 T~~t~~he aggregated emission factor (E_A),
9.6.3.1.5 T~~t~~he aggregated emission factor limit (L_A), and
9.6.3.1.6 A~~a~~ny other parameters needed to demonstrate daily compliance with the applicable NOx emissions when operating the units under the AECP.

9.6.4 Reporting and Annual Updates

Notifications of any violation pursuant to Section 9.5 shall include:
9.6.4.1 N~~n~~ame and location of facility,
9.6.4.2 L~~l~~ist of applicable units,
9.6.4.3 C~~c~~ause and expected duration of exceedance,

9.6.4.4 T~~t~~he amount of excess emissions, and

9.6.4.5 P~~p~~roposed 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 limits specified in Sections 5.1.1 and 5.1.2 and the applicable compliance schedule required by Section 7.0.

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San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
December 17, 2020

ADOPT PROPOSED AMENDMENTS TO RULE 4306 (BOILERS, STEAM GENERATORS, AND PROCESS HEATERS – PHASE 3) AND RULE 4320 (ADVANCED EMISSION REDUCTION OPTIONS FOR BOILERS, STEAM GENERATORS, AND PROCESS HEATERS GREATER THAN 5.0 MMBTU/HR)

Attachment C:

Proposed Amendments to Rule 4320
(22 PAGES)

RULE 4320 ADVANCED EMISSION REDUCTION OPTIONS FOR BOILERS, STEAM GENERATORS, AND PROCESS HEATERS GREATER THAN 5.0 MMBTU/HR (Adopted October 16, 2008; Amended (rule adoption date))

1.0 Purpose

The purpose of this rule is to limit emissions of oxides of nitrogen (NOx), carbon monoxide (CO), oxides of sulfur (SO_2), and particulate matter 10 microns or less (PM10) from boilers, steam generators, and process heaters.

2.0 Applicability

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

3.0 Definitions

3.1 Air Pollution Control Officer (APCO): as defined in Rule 1020 (Definitions).

3.2 Air Resources Board (ARB): as defined in Rule 1020 (Definitions).

3.3 Annual Capacity Factor: the ratio of the amount of fuel burned by the unit in a calendar year to the amount of fuel that the unit could have burned if it had operated at its maximum rated capacity for 8,760 hours during the calendar year.

3.4 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.

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

3.6 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.

3.7 California Public Utility Commission (PUC) Quality Natural Gas: any gaseous fuel, gas-containing fuel where the sulfur content is no more than one-fourth (0.25) grain of hydrogen sulfide per one hundred (100) standard cubic feet and no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet. PUC quality natural gas also means high methane gas of at least 80% methane by volume.

3.8 California PUC Quality Natural Gas Curtailment: means a shortage in the supply of California Public Utility Commission (PUC) quality natural gas, due solely to supply limitations or restrictions in distribution pipelines by the utility supplying the gas, and not due to the cost of natural gas.

3.9 Digester Gas: gas derived from the decomposition of organic matter in a digester.

3.~~9~~10 Dryer: any unit in which material is dried in direct contact with the products of combustion.

3.11~~0~~ EPA: United States Environmental Protection Agency.

3.12 Fire Tube Boiler: any boiler that passes hot gases from a fire box through one or more tubes running through a sealed container of water. The heat of the gases is transferred through the walls of the tubes by thermal conduction, heating the water and ultimately creating steam or hot water.

3.13~~1~~ Gaseous Fuel: any fuel which is a gas at standard conditions.

3.14~~2~~ Gas Liquids Processing Facility: a facility that is engaged in the catalytic processing of gas liquids to produce finished products.

3.15~~3~~ 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.

3.16~~4~~ Higher Heating Value (hhv): the total heat liberated per mass of fuel burned (expressed as 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.

3.17~~5~~ Liquid Fuel: any fuel which is a liquid at standard conditions.

3.18 Normal Operation: the period of operating time during which a unit is not in a startup or a shutdown event.

3.19~~6~~ NOx Emissions: the sum of oxides of nitrogen expressed as NO_2 in the flue gas.

3.~~17~~20 Oilfield Steam Generator: an external combustion equipment which converts water to dry steam or to a mixture of water vapor and steam, with an absolute pressure of more than 30 psia, and which is used exclusively in thermally enhanced crude oil production.

3.~~18~~21 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.~~19~~22 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.

3.23~~0~~ Qualified Technician: a stationary source employee or any personnel contracted by a stationary source operator who has a documented training and a demonstrated experience performing tune-ups on a unit to the satisfaction of the APCO. The documentation of tune-up training and experience shall be made available to the APCO upon request.

3.24~~1~~ Rated Heat Input (expressed as million Btu per hour): the heat input capacity specified on the nameplate of the unit.

3.25~~2~~ Refinery Unit: a unit that is permanently installed and operated at a petroleum refinery or a gas liquids processing facility.

3.26~~3~~ Re-ignition: the relighting of a unit after an unscheduled and unavoidable interruption or shut off of the fuel flow or electrical power, for a period of less than 30 minutes, due to reasons outside the control of the operator.

3.27 School: any public or private school used for the purpose of education and instruction of school pupils in Kindergarten through Grade 12, and any college or university which provides postsecondary education and has the authority to confer Associate, Bachelors, or Graduate/Professional level degrees. This does not include any private school in which education and instruction are primarily conducted in private homes.

3.28~~4~~ Seasonal Source: as defined in District Rule 2201 (New And Modified Stationary Source Review Rule)

3.29~~5~~ Shutdown: the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off.

3.~~26~~30 Solid Fuel: any fuel which is a solid at standard conditions.

3.~~27~~31 Small Producer: as defined in District Rule 1020 (Definitions)

3.~~28~~32 Standard Conditions: standard conditions as defined in Rule 1020 (Definitions).

3.~~29~~33 Start-up: the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation.

3.34 Thermal Fluid Heater: a natural gas fired process heater in which a process stream is heated indirectly by a heated fluid other than water.

3.35~~0~~ Unit: any boiler, steam generator or process heater as defined in this rule.

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.

4.2 The requirements of Sections 5.2 shall not apply to a unit when burning any fuel other than California PUC quality natural gas during California PUC quality natural gas curtailment provided all of the following conditions are met:

4.2.1 Fuels other than California PUC quality natural gas are burned no more than 168 cumulative hours in a calendar year plus 48 hours per calendar year for equipment testing, as limited by Permit to Operate.

4.2.2 NOx emission shall not exceed 150 ppmv or 0.215 lb/MMBtu. Demonstration of compliance with this limit shall be made by either source testing, continuous emission monitoring system (CEMS), an APCO approved Alternate Monitoring System, or an APCO approved portable NOx analyzer.

5.0 Requirements

5.1 An operator of a unit(s) subject to this rule shall comply with all applicable requirements of the rule and one of the following, on a unit-by-unit basis:

5.1.1 Operate the unit to comply with the emission limits specified in Sections 5.2 and 5.4; or

5.1.2 Pay an annual emissions fee to the District as specified in Section 5.3 and comply with the control requirements specified in Section 5.4; or

5.1.3 Comply with the applicable Low-use Unit requirements of Section 5.5.

5.2 NOx and CO Emission Limits

5.2.1 On and after the indicated Compliance Deadline, units shall not be operated in a manner which exceeds the applicable NOx emissions limit specified in Table 1 (until December 31, 2023) and Table 2 (on and after December 31, 2023). ~~On and after October 1, 2008, u~~Units shall not be operated in a manner to which exceeds a carbon monoxide (CO) emissions limit of 400 ppmv.

5.2.2 No unit fired on liquid fuel shall be operated in a manner to exceed emissions of 40 ppmv NOx and 400 ppmv CO.

5.2.3 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.

Table 1: Tier 1 NOx Emission Limits

Category	NOx Limit	Authority to Construct	Compliance Deadline
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G units	a) Standard Schedule 9 ppmv or 0.011 lb/MMBtu; or	July 1, 2011	July 1, 2012
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu	January 1, 2013	January 1, 2014
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units	a) Standard Schedule 7 ppmv or 0.008 lb/MMBtu; or	July 1, 2009	July 1, 2010
	b) Enhanced Schedule 5 ppmv or 0.0062 lb/MMBtu	January 1, 2013	January 1, 2014
C. Oilfield Steam Generators			
1. Units with a total rated heat input > 5.0 MMBtu/hr to ≤20.0 MMBtu/hr	a) Standard Schedule 9 ppmv or 0.011 lb/MMBtu; or	July 1, 2011	July 1, 2012
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu	January 1, 2013	January 1, 2014
2. Units with a total rated heat input >20.0 MMBtu/hr	a) Standard Schedule 7 ppmv or 0.008 lb/MMBtu; or	July 1, 2009	July 1, 2010
	b) Staged Enhanced Schedule Initial Limit 9 ppmv or 0.011 lb/MMBtu; and	July 1, 2011	July 1, 2012
	Final Limit 5 ppmv or 0.0062 lb/MMBtu	January 1, 2013	January 1, 2014

Table 1: Tier 1 NOx Emission Limits			
Category	NOx Limit	Authority to Construct	Compliance Deadline
3. Units firing on less than 50%, by volume, PUC quality gas.	Staged Enhanced Schedule Initial Limit 12 ppmv or 0.014 lb/MMBtu; and	July 1, 2010	July 1, 2011
	Final Limit 9 ppmv or 0.011 lb/MMBtu	January 1, 2013	January 1, 2014
D. Refinery units			
1. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr	a) Standard Schedule 9 ppmv or 0.011 lb/MMBtu; or	July 1, 2011	July 1, 2012
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu	January 1, 2013	January 1, 2014
2. Units with a total rated heat input >20.0 MMBtu/hr to ≤ 110.0 MMBtu/hr	a) Standard Schedule 6 ppmv or 0.007 lb/MMBtu; or	July 1, 2010	July 1, 2011
	b) Staged Enhanced Schedule Initial Limit 9 ppmv or 0.011 lb/MMBtu; and	July 1, 2011	July 1, 2012
	Final Limit 5 ppmv or 0.0062 lb/MMBtu	January 1, 2013	January 1, 2014
3. Units with a total rated heat input > 110.0 MMBtu/hr	Standard Schedule 5 ppmv or 0.0062 lb/MMBtu	N/A	June 1, 2007
4. Units firing on less than 50%, by volume, PUC quality gas.	Staged Enhanced Schedule Initial Limit 12 ppmv or 0.014 lb/MMBtu; and	July 1, 2010	July 1, 2011
	Final Limit 9 ppmv or 0.011 lb/MMBtu	January 1, 2013	January 1, 2014
E. Units, from any Category, that were installed prior to January 1, 2009 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/year but ≤ 30 billion Btu/year.	Standard Schedule 9 ppmv or 0.011 lb/MMBtu	Twelve months before the next unit replacement but no later than January 1, 2013.	At the next unit replacement but no later than January 1, 2014

Table 1: Tier 1 NOx Emission Limits			
Category	NOx Limit	Authority to Construct	Compliance Deadline
F. Units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas.	Staged Enhanced Schedule Initial Limit 12 ppmv or 0.01~~4~~5 lb/MMBtu; and	July 1, 2010	July 1, 2011
	Final Limit 9 ppmv or 0.011 lb/MMBtu	January 1, 2013	January 1, 2014
G. Units operated by a small producer in which the rated heat input of each burner is less than or equal to 5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 MMBtu/hr and 20 MMBtu/hr, as specified in the Permit to Operate, and in which the products of combustion do not come in contact with the products of combustion of any other burner.	Standard Schedule 9 ppmv or 0.011 lb/MMBtu	Twelve months before the next unit replacement but no later than January 1, 2013.	At the next unit replacement but no later than January 1, 2014

Table 2: Tier 2 NOx Emission Limits				
Category	NOx Limit	Emission Control Plan	Authority to Construct	Compliance Deadline
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through E units				
1. Fire Tube Boilers	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Units at Schools	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Units fired on Digester Gas	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
4. Thermal Fluid Heaters	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
5. All other units	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023

Table 2: Tier 2 NOx Emission Limits				
Category	NOx Limit	Emission Control Plan	Authority to Construct	Compliance Deadline
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through E units				
1. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Units with a rated heat input > 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
C. Oilfield Steam Generators				
1. Units with a total rated heat input > 5.0 MMBtu/hr and ≤ 20.0 MMBtu/hr	6 ppmv or 0.0073 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Units with a total rated heat input > 20.0 MMBtu/hr and ≤ 75.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Units with a total rated heat input > 75.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
4. Units firing on less than 50%, by volume, PUC quality gas	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
D. Refinery units				
1. Boilers with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Boilers with a total rated heat input > 40.0 MMBtu/hr to ≤ 110.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Boilers with a total rated heat input > 110.0 MMBtu/hr	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023

Table 2: Tier 2 NOx Emission Limits				
Category	NOx Limit	Emission Control Plan	Authority to Construct	Compliance Deadline
4. Process Heaters with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
5. Process Heaters with a total rated heat input > 40.0 MMBtu/hr to ≤ 110.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
6. Process Heaters with a total heat input > 110.0 MMBtu/hr	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
E. Units limited by a Permit to Operate to an annual heat input >1.8 billion Btu/year but < 30 billion Btu/year.	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023

5.2.4 When a unit is operated on combinations of gaseous fuel and liquid fuel, the NOx limit shall be the heat input weighted average of the applicable limits specified in Sections 5.1.1, as calculated by the following equation:

$$\text{Weighted Average Limit} = \frac{(\text{NOx limit for gaseous fuel x G}) + (\text{NOx limit for liquid fuel x L})}{\text{G} + \text{L}}$$

Where: G = annual heat input from gaseous fuel
L = annual heat input from liquid fuel

5.2.5 Prior to January 1, 2014, if a unit was designated to comply with a Staged Enhanced Schedule in Table 1, an operator may redesignate the unit for compliance under Section 5.1.2, provided the unit meets the Initial NOx Limit; emission fees are paid, at time of the application for redesignation, for all past emissions from the unit since January 1, 2009 through the calendar year prior to the calculation date; and the total annual fee is paid from that date forward. The past emissions fee shall be calculated using the equations in Section 5.3 and the Fee Rate in place at the time of that calculation. The future total annual fees shall be calculated and paid according to Section 5.3.

5.3 Annual Fee Calculation

5.3.1 On and after January 1, 2010, an operator, with units that will comply ~~under~~ with the requirements of Section 5.1.2 in lieu of complying with Section 5.2 Table 1 shall pay a total annual fee to the District based on the total NOx emissions from those units. ~~That fee shall be calculated in the following manner.~~

5.3.2 Beginning January 1, 2025, an operator with units that will comply with the requirements of Section 5.1.2 in lieu of complying with Section 5.2 Table 2 shall pay a total annual emission fee to the District based on total NOx emissions from those units. Units paying an emissions fee under this section are not subject to Section 5.3.1.

5.3.3 Annual Fee Calculation Methodology

5.3.~~1~~3.1 The operator shall calculate the total emissions for all units operating at a stationary source that will comply with Section 5.1.2. The total NOx emissions shall be calculated in accordance with Section 5.3.3.3.

5.3.~~1~~3.2 The total annual emissions fee shall be calculated in accordance with Section 5.3.3.4. These calculations include only the units that have been identified to comply under Section 5.1.2.

5.3.~~1~~3.3 Total Emissions (TE) Calculation

$$\text{Total TE} = \sum \text{E(unit)}$$

Where: $\sum$ E(unit) = Sum of all NOx emissions from each unit, in tons per year.

$$\text{E(unit)} = \frac{EF(Unit)\ x\ \ AFU(Unit)}{2{,}000\ \ lb\ \ per\ \ ton}$$

Where: E(unit) = Annual NOx emissions for each unit, in tons/year.

EF(Unit) = NOx Emission Limit for the Permit to Operate, in lb/MMBtu

AFU(Unit) = actual amount of fuel, in MMBTU, used by each unit during the previous calendar year.

5.3.~~1~~3.4 Total Annual Fee Calculation

Total Annual Fee = (Total TE x FR) + Administrative Fee

Where: FR (Fee Rate) = The cost of NOx reductions, in dollars per ton, as established pursuant to Sections 7.2 and 7.6 of District Rule 9510, as adopted on December 15, 2005. Under no circumstances shall the cost of NOx reductions exceed the cost effectiveness threshold for the Carl Moyer Cost Effectiveness as established by the applicable state law.

Administrative Fee = 4% x (Total TE x FR)

5.3.~~1~~3.5 For units that will pay annual emission fees per Section 5.1.2 in lieu of complying with the NOx emission limits in Table 1, ~~T~~the operator shall pay the total annual fee to the District, no later than July 1 of each year, for the emissions of the previous calendar year. The first payment is due to the District no later than July 1, 2010. Should July 1 fall on a day when the District is closed, the payment shall be made by the next District working day after July 1.

5.3.3.6 For units that will pay annual emission fees per Section 5.1.2 in lieu of complying with the NOx emission limits in Table 2, the operator shall pay the total annual fee to the District, no later than July 1 of each year, for the emissions of the previous calendar year. The first payment is due to the District no later than July 1, 2025. Should July 1 fall on a day when the District is closed, the payment shall be made by the next District working day after July 1.

5.3.~~2~~4 Payments shall continue annually until the unit either is permanently removed from use in the San Joaquin Valley Air Basin and the Permit to Operate is surrendered or the operator demonstrates compliance with applicable NOx emissions limits shown in Table ~~2:~~3 and the applicable NOx emission limits in Table 2.

Table ~~2~~3 Applicable NOx Emission Limits in Table 1 for Section 5.3.~~2~~4

Category	Date of Compliance Demonstration	Applicable NOx Emissions Limit from Table 1
A. Units with only a Standard Schedule in Table 1.	Either prior to or after the Standard Compliance Deadline	Standard NOx Limit
B. Units with both Standard and Enhanced Schedules in Table 1.	Prior to the Enhanced Compliance Deadline	Standard NOx Limit
	After the Enhanced Compliance Deadline	Enhanced NOx Limit
C. Units with both Standard and Staged Enhanced	Prior to the Initial Limit Compliance Deadline	Standard NOx Limit

Table ~~2~~3 Applicable NOx Emission Limits in Table 1 for Section 5.3.~~2~~4		
Category	Date of Compliance Demonstration	Applicable NOx Emissions Limit from Table 1
Schedules in Table 1.	After the Initial Limit Deadline but before the Final Limit Deadline	Initial NOx Limit then the Final NOx Limit by the applicable Compliance Deadline
	After the Final Limit Deadline	Final NOx Limit

5.3.~~2~~4.1 The emissions fee for units that operate for less than the full calendar year before demonstrating compliance under Section 5.3.~~2~~4, shall be based on the actual fuel used during the portion of the calendar year prior to demonstrating that compliance or removing the unit from operation within the San Joaquin Valley Air Basin.

5.3.~~3~~5 Operators of units for which an annual emissions fee is provided must also certify that the units meet federal RACT control requirements at the time the annual fee is provided.

5.4 Particulate Matter Control Requirements

5.4.1 To limit particulate matter emissions, an operator shall comply with one of the following requirements:

5.4.1.1 On and after the applicable NOx Compliance Deadline specified in Section 5.2 Table 1, operators shall fire units exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases;

5.4.1.2 On and after the applicable NOx Compliance Deadline specified in Section 5.2 Table 1, operators shall limit fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or

5.4.1.3 On and after the applicable NOx Compliance Deadline specified in Section 5.2 Table 1, operators shall install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight; or limit exhaust SO_2 to less than or equal to 9 ppmv corrected to 3.0% O2.

5.4.1.4 Notwithstanding the compliance deadlines indicated in Sections 5.4.1.1 through 5.4.1.3, refinery units, which require modification of refinery equipment to reduce sulfur emissions, shall be in compliance with the applicable requirement in Section 5.4.1 no later than July 1, 2013.

5.4.2 Liquid fuel shall be used only during PUC quality natural gas curtailment periods, provided the requirements of Sections 4.2 and 6.1.5 are met and the fuel contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.2.

5.5 Low-use Unit

For each unit that was installed prior to January 1, 2009 and is limited to less than or equal to 1.8 billion Btu per calendar year heat input pursuant to a District Permit to Operate, the operator shall comply with the requirement of Sections 5.7 and 7.3 and one of the following:

5.5.1 Tune the unit at least twice per calendar year, (from four to eight months apart) by a qualified technician in accordance with the procedure described in Rule 4304 (Equipment Tuning Procedure for Boilers, Steam Generators, and Process Heaters). If the unit does not operate throughout a continuous six-month period within a calendar year, only one tune-up is required for that calendar year. No tune-up is required for any unit that is not operated during that calendar year; this unit may be test fired to verify availability of the unit for its intended use, but once the test firing is completed the unit shall be shutdown; or

5.5.2 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.

5.6 Start-up and Shutdown Provision

On and after the Compliance Deadline specified in Section 5.0, the applicable emission limits of Sections 5.2 Table 1, Table 2, and 5.5.2 shall not apply during start-up or shutdown, provided an operator complies with the requirements specified below.

5.6.1 The duration of each start-up or each shutdown shall not exceed two hours, except as provided in Section 5.6.3.

5.6.2 The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during start-up or shutdown.

5.6.3 Notwithstanding the requirement of Section 5.6.1, an operator may submit an application for a Permit to Operate condition to allow more than two hours for each start-up or each shutdown provided the operator meets all of the conditions specified in Sections 5.6.3.1 through 5.6.3.3.

5.6.3.1 The maximum allowable duration of start-up or shutdown will be determined by the APCO. The allowable duration of start-up shall not exceed twelve hours and the allowable duration of shutdown shall not exceed nine hours.

5.6.3.2 The APCO will only approve start-up or shutdown duration longer than two hours when the application meets the following conditions:

5.6.3.2.1 Clearly identifies the control technologies or strategies to be utilized; and

5.6.3.2.2 Describes what physical conditions prevail during start-up or shutdown periods that prevent the controls from being effective; and

5.6.3.2.3 Provides a reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions.

5.6.3.3 The operator shall submit to the APCO any information deemed necessary by the APCO to determine the appropriate length of start-up or shutdown. The information shall include, but is not limited to the following:

5.6.3.3.1 A detailed list of activities to be performed during start-up or shutdown and a reasonable explanation for the length of time needed to complete each activity; and

5.6.3.3.2 A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and

5.6.3.3.3 The basis for the requested additional duration of start-up or shutdown.

5.6.4 Permit to Operate (PTO) modifications ~~solely to~~<u>for the sole purpose of adding</u> conditions to comply with the provisions of this rule may be exempt from Best Available Control Technology (BACT) and emission offset requirements if the PTO modifications meet the requirements of Rule 2201 (New and Modified Stationary Source Review Rule) Section 4.2 (BACT Exemptions) and Rule 2201 Section 4.6 (Emission Offset Exemptions).

5.6.5 For existing facilities, a replacement unit installed for the sole purpose of complying with the requirements of this rule shall be considered to be an emission control technique and may be exempt from the Best Available Control Technology (BACT) and Offsets requirements of District Rule 2201 (New and Modified Stationary Source Review Rule) provided that all other requirements of Rule 2201 are met.

5.7 Monitoring Provisions

5.7.1 The operator of any unit subject to the applicable emission limits in Section~~s~~ 5.2 shall install and maintain an operational APCO approved Continuous Emissions Monitoring System (CEMS) for NOx, CO, and oxygen, or implement an APCO-approved Alternate Monitoring System. An APCO approved CEMS shall comply with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Part 60 Appendix B (Performance Specifications) and 40 CFR Part 60 Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). An APCO-approved Alternate Monitoring System shall monitor one or more of the following:

5.7.1.1 Periodic NOx and CO exhaust emission concentrations,
5.7.1.2 Periodic exhaust oxygen concentration,
5.7.1.3 Flow rate of reducing agent added to exhaust,
5.7.1.4 Catalyst inlet and exhaust temperature,
5.7.1.5 Catalyst inlet and exhaust oxygen concentration,
5.7.1.6 Periodic flue gas recirculation rate, or
5.7.1.7 Other operational characteristics.

5.7.2 For units subject to the requirements of Sections 5.5.1 or 5.5.2, the operator shall monitor, at least on a monthly basis, the operational characteristic(s) recommended by the manufacturer and approved by the APCO.

5.7.3 The operator of any unit subject to Section 5.5 shall install and maintain an operational 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.

5.7.4 Units operated at seasonal sources that are subject to the requirements of 40 CFR 60, Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units) may implement an APCO approved parametric monitoring system (PMS) in lieu of a CEMS for compliance with federal emission limits provided all of the following apply:

5.7.4.1 The boiler is fired solely on California PUC quality natural gas, and

5.7.4.2 The applicable District emission limit for NOx is more stringent than the limit specified in 40 CFR Part 60, Subpart Db.

5.7.5 The APCO shall not approve an alternative monitoring system or parametric monitoring system unless it is documented that continued operation within ranges of specified emissions-related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits. The operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards.

5.7.5.1 The predictive or parametric monitoring system shall continuously monitor the key parameters which affect the emissions and demonstrate the compliance within the established key parameters operating envelope.

5.7.5.2 Initial and annual real time modeling shall be performed to verify the key parameters operational range.

5.7.6 Monitoring SOx Emissions

5.7.6.1 Operators complying with Sections 5.4.1.1 or 5.4.1.2 shall provide an annual fuel analysis to the District unless a more frequent sampling and reporting period is included in the Permit To Operate. Sulfur analysis shall be performed in accordance with the test methods in Section 6.2.

5.7.6.2 Operators complying with Section 5.4.1.3 by installing and operating a control device with 95% SOx reduction shall propose the key system operating parameters and frequency of the monitoring and recording. The monitoring option proposed shall be submitted for approval by the APCO.

5.7.6.3 Operators complying with Section 5.4.1.3 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit To Operate. Source tests shall be performed in accordance with the test methods in Section 6.2.

5.8 Compliance Determination

5.8.1 The operator of any unit shall have the option of complying with either the applicable heat input, in lb/MMBtu, emission limits or the concentration, in ppmv, emission limits specified in Section 5.2. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling).

5.8.2 All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. Unless otherwise specified in the Permit to Operate, no determination of compliance 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 within 30 minutes after a re-ignition as defined in Section 3.0.

5.8.3 Continuous Emissions Monitoring System (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes to demonstrate compliance with the applicable emission limits. Any 15-consecutive-minute block average CEMS measurement exceeding the applicable emission limits shall constitute a violation.

5.8.4 For emissions monitoring pursuant to Sections 5.7.1, and 6.3.1 using a portable NOx analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five readings evenly spaced out over the 15-consecutive-minute period.

5.8.5 For emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit.

6.0 Administrative Requirements

6.1 Recordkeeping

The records required by Sections 6.1.1 through 6.1.5 shall be maintained for five calendar years and shall be made available to the APCO and EPA upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

6.1.1 The operator 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 periods of natural gas curtailment and equipment testing. The NOx emission concentration, expressed in ppmv or lb/MMBtu, for each unit that is operated during periods of natural gas curtailment shall be recorded. Failure to maintain records required by Section 6.1.1 or information contained in the records that demonstrates noncompliance with the conditions for exemption under Section 4.2 will result in loss of exemption status. On and after the applicable compliance schedule specified in Section 5.2 Table 1 and Table 2, any unit losing an exemption status shall be brought into full compliance with this rule as specified in Section 7.2.

6.1.2 The operator of any unit that is subject to the requirements of Section 5.5 shall record the amount of fuel use at least on a monthly basis for each unit. On and after the applicable compliance schedule specified in Section 7.0, in the event that such unit exceeds the applicable annual heat input limit specified in Section 5.5, the unit shall be brought into full compliance with this rule as specified in Section 5.2 Table 1 or Table 2.

6.1.3 The operator of any unit subject to Section 5.5.1 or Section 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics of the unit have been performed.

6.1.4 The operator performing start-up or shutdown of a unit shall keep records of the duration of start-up or shutdown.

6.1.5 The operator of any unit firing on liquid fuel during a PUC-quality natural gas curtailment period pursuant to Section 5.4.2 shall record the sulfur content of the fuel, amount of fuel used, and duration of the natural gas curtailment period.

6.2 Test Methods

The following test methods shall be used unless otherwise approved by the APCO and EPA.

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

6.2.1.1 American Society for Testing and Materials (ASTM) D 240~~-87~~ or D 4809~~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.

6.2.8 SOx Test Methods

6.2.8.1 Oxides of sulfur – EPA Method 6C, EPA Method 8, or ARB Method 100

6.2.8.2 The SOx emission control system efficiency shall be determined using the following:

% Control Efficiency = $[(C_{SO2,\ inlet} - C_{SO2,\ outlet}) / C_{SO2,\ inlet}]$ X 100
Where:

$C_{SO2,\ inlet}$ = concentration of SOx (expressed as SO_2) at the inlet side of the SOx emission control system, in lb/dscf

$C_{SO2,\ outlet}$ = concentration of SOx (expressed as SO_2) at the outlet side of the SOx emission control system, in lb/dscf

6.2.9 Determination of total sulfur as hydrogen sulfide (H_2S) content – EPA Method 11 or EPA Method 15, as appropriate.

6.2.10 Sulfur content of liquid fuel – ~~American Society for Testing and Materials (~~ASTM~~)~~ D ~~6920-03 or ASTM D~~ 5453~~-99~~

6.3 Compliance Testing

6.3.1 Each unit subject to the requirements in Section 5.2 shall be source tested to determine compliance with the applicable emission limits at least once every 12 months, (no more than 30 days before or after the required annual source test date).

6.3.1.1 Units that demonstrate compliance on two consecutive 12-month source tests may defer the following 12-month source test for up to 36 months (no more than 30 days before or after the required 36-month source test date). –During the 36-month source testing interval, the operator shall tune the unit in accordance with the provisions of Section 5.5.1, and shall monitor, on a monthly basis, the unit's operational characteristics recommended by the manufacturer to ensure compliance with the applicable emission limits specified in Section 5.2.

6.3.1.2 Tune-ups required by Sections 5.5.1 and 6.3.1 do not need to be performed for units that operate and maintain an APCO approved CEMS or an APCO approved Alternate Monitoring System where the applicable emission limits are periodically monitored.

6.3.1.3 If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits specified in Section 5.2, the source testing frequency shall revert to at least once every 12 months.

6.3.1.4 Failure to comply with the requirements of Section 6.3.1 or any source test results that exceed the applicable emission limits in Section 5.2 shall constitute a violation of this rule.

6.3.2 In lieu of compliance with Section 6.3.1, compliance with the applicable emission limits in Section 5.2 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 in the group are initially source tested. The emissions from all test runs from units within the group are less than 90% of the permitted value, and the emissions do not vary greater than 25% from the average of all test runs; 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. No unit with a rated heat input greater than 100 MMBtu shall be considered as part of the group; 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 30% of the total number of units in the group. The representative tests shall rotate each year so that within three years all units in the group have been tested at least once.

6.3.2.6 All units in the group shall have received the similar maintenance and tune-up procedures as the representative unit(s) as listed in the Permit to Operate. The operator shall submit to the APCO the specific maintenance procedures to be performed on each unit that will be included in the group for representative testing. Such maintenance procedures shall be specified in the Permit to Operate for units that are included in the group for representative testing. Any maintenance work on a unit which has no effect on emissions standards and which is not specified in the maintenance procedures shall be submitted to the APCO for approval before such unit can be included as part of the group for representative testing. Any unit that necessitates any maintenance work which has an effect on emission standards and is beyond the maintenance procedures identified in the Permit to Operate, shall not be included as part of the group for representative testing. The unit shall be source tested in accordance with the provisions of Section 6.3.1; 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. After compliance with the requirements of Section 6.3.2.7 has been demonstrated, subsequent source testing shall be performed pursuant to Sections 6.3.1 or 6.3.2.

6.4 Emission Control Plan (ECP)

6.4.1 No later than ~~January 1, 2010~~the date specified in Table 2, the operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0. For each unit, the plan shall contain the following:

6.4.1.1 Permit to Operate number,
6.4.1.2 Fuel type and hhv,
6.4.1.3 Annual fuel consumption (expressed as Btu/yr),
6.4.1.4 Current emission level, including method used to determine emission level,
6.4.1.5 NOx limit to be satisfied pursuant to Section 5.2 Table ~~1~~2 or emission fee payment to be made pursuant to Section 5.3, and
6.4.1.6 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 As shown in Section 5.2 Table ~~1~~2, the column labeled:

7.1.1 "Emission Control Plan" identifies the date by which the operator shall submit an Emission Control Plan pursuant to Section 6.4. The Emission Control Plan shall identify all units subject to this rule. The Emission Control Plan shall identify steps to be taken to comply with this rule.

7.1.~~1~~2 "Authority to Construct" identifies the date by with the operator shall submit an Application for Authority to Construct for each unit subject to the rule.

7.1.~~2~~3 "Compliance Deadline" identifies the date by which the owner shall demonstrate that each unit is in compliance with the applicable requirements of this rule.

7.2 Any unit that is exempted under Section 4.2 that becomes subject to the emission limits of this rule through the loss of exemption status shall be in full compliance with this rule on and after the date the exemption status is lost.

7.3 Any unit that becomes subject to the emission limits of this rule as a result of exceeding the applicable annual heat input limit specified in Section 5.5 shall be in compliance with the applicable emission limits in Section 5.2 Table 1 or Table 2, depending on the applicable compliance date, and Section 5.4 on and after the date the annual heat input limit is exceeded.

8.0 Calculations

8.1 All ppmv emission limits specified in Section 5.2 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:

$$[\text{ppm NOx}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%O2]_{\text{measured}}} \text{ x } [\text{ppm NOx}]_{\text{measured}}$$

$$[\text{ppm CO}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%O2]_{\text{measured}}} \text{ x } [\text{ppm CO}]_{\text{measured}}$$

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

San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
December 17, 2020

ADOPT PROPOSED AMENDMENTS TO RULE 4306 (BOILERS, STEAM GENERATORS, AND PROCESS HEATERS – PHASE 3) AND RULE 4320 (ADVANCED EMISSION REDUCTION OPTIONS FOR BOILERS, STEAM GENERATORS, AND PROCESS HEATERS GREATER THAN 5.0 MMBTU/HR)

Attachment D:

Final Draft Staff Report with Appendices for Proposed Amendments to Rule 4306 and Rule 4320
(145 PAGES)

SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT

FINAL DRAFT STAFF REPORT

December 17, 2020

Proposed Amendments to Rule 4306 (Boilers, Steam Generators, and Process Heaters – Phase 3)
Proposed Amendments to Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr)

Prepared by: Ross Badertscher, Air Quality Specialist

Reviewed by: Jessica Coria, Planning Manager
Nick Peirce, Permit Services Manager
Leonard Scandura, Permit Services Manager
Jon Klassen, Director of Air Quality Science and Planning
Sheraz Gill, Deputy Air Pollution Control Officer

I. SUMMARY

A. Reasons for Rule Development and Implementation

The U.S. Environmental Protection Agency (EPA) periodically reviews and establishes health-based air quality standards for ozone, particulates, and other pollutants. Although the San Joaquin Valley's (Valley) air quality is steadily improving, the Valley experiences unique and significant difficulties in achieving these increasingly stringent standards. The Valley's challenges in meeting national ambient air quality standards are unmatched in the nation due to the region's unique geography, meteorology and topography. In response to the latest federal mandates and to improve quality of life for Valley residents, the District has developed and implemented multiple generations of rules on various sources of air pollution. Valley businesses are currently subject to the most stringent air quality regulations in the nation. Since 1992, the District has adopted nearly 650 rules to implement an aggressive on-going control strategy to reduce emissions in the Valley, resulting in air quality benefits throughout the Valley. Similarly, the California Air Resources Board (CARB) has adopted stringent regulations for mobile sources. Together, these efforts represent the nation's toughest air pollution emissions controls and have greatly contributed to reduced ozone and particulate matter concentrations in the Valley.

Due to the significant investments made by Valley businesses and residents and stringent regulatory programs established by the District and CARB, the Valley's ozone and PM2.5 (particulate matter that is 2.5 microns or less in diameter) emissions are at historically low levels, and air quality over the past few years has continued to set new clean air records. Despite the significant progress under these regulations, greatly aided by the efforts of Valley businesses and residents, many air quality challenges remain, including attainment of the federal air quality standards for PM2.5 that are addressed in the District's recently adopted *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards* (*2018 PM2.5 Plan*).

The *2018 PM2.5 Plan* contains a comprehensive set of local and state measures that build on existing measures to further reduce air pollution from stationary, area, and mobile sources throughout the Valley. Attaining the multiple federal PM2.5 standards by the mandated deadlines is not possible without significant additional reductions in directly emitted PM2.5 and PM2.5 precursors like NOx (oxides of nitrogen).

The *2018 PM2.5 Plan* includes a suite of innovative regulatory and incentive-based measures, supported by robust public education and outreach efforts to reduce emissions of PM2.5 in the Valley. One of the measures included in the plan is to amend District Rule 4306 (Boilers, Steam Generators, and Process Heaters - Phase 3) and Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr) as a necessary cost-effective measure for further reducing NOx emissions and bringing the Valley into attainment with federal PM2.5 standards within the mandated federal deadlines.

Based on a comprehensive technical analysis, in-depth review of local, state, and federal regulations, and a robust public process, District staff are proposing several modifications to Rules 4306 and 4320 to reduce emissions from boilers, process heaters, and steam generators in the San Joaquin Valley. The proposed Rule 4306 and Rule 4320 go above and beyond federal standards of Reasonably Available Control Technology (RACT), Best Available Retrofit Control Technology (BARCT), and Most Stringent Measures (MSM). This rule amendment project is proposed to satisfy the commitments in the District's *2018 PM2.5 Plan*.

B. Health Benefits of Implementing Plan Measures

The health risks of PM2.5 have been linked to a variety of health issues, including aggravated asthma, increased respiratory symptoms (irritation of the airways, coughing, difficulty breathing), decreased lung function in children, development of chronic bronchitis, irregular heartbeat, non-fatal heart attacks, increased respiratory and cardiovascular hospitalizations, lung cancer, and premature death. CARB explains that even short-term exposure of less than 24 hours can cause for premature mortality, increased hospital admissions for heart or lung causes, acute and chronic bronchitis, asthma attacks, emergency room visits, respiratory symptoms, and restricted activity days. Children, older adults, and individuals with heart or lung diseases are the most likely to be affected by PM2.5.

PM2.5 emissions are characterized by a unique combination of direct and secondarily formed constituents. As NOx emissions are a key precursor to the formation of ammonium nitrate, which is a large portion of total PM2.5 during the peak winter season, continuing to assess the feasibility of achieving additional NOx reductions across the Valley is critical for continuing to improve PM2.5 throughout the region. PM2.5 is a major health risk because it can be inhaled more deeply into the gas exchange tissues of the lungs, where it can be absorbed into the bloodstream and carried to other parts of the body. Exposure to elevated concentrations of ozone also poses significant health risks, and the Valley has long worked to reduce NOx emissions as the primary precursor for the formation of ozone in the Valley.

To address federal health-based standards for ozone and PM2.5 and improve public health, the District develops attainment plans and implements control measures to lower direct and precursor emissions throughout the San Joaquin Valley. The proposed amendments will achieve additional reductions in NOx emissions as requirements are implemented by affected sources and new technologies are installed. New regulatory and incentive-based measures proposed by both the District and CARB, combined with existing measures achieving new emissions reductions, are necessary to achieve the emissions reductions required to attain the health-based federal standards as expeditiously as practicable, and will improve public health as emissions reductions are realized.

C. Description of the Project

The District's Governing Board adopted Rule 4306 on September 18, 2003, and last amended this rule on October 16, 2008. Rule 4320 was adopted on October 16, 2008. The rules apply to any gaseous fuel or liquid fuel fired boilers, steam generators, and process heaters with a rated heat input greater than 5 million Btu/hour. Facilities with units subject to this control measure represent a wide range of industries, including but not limited to electrical utilities, cogeneration, oil and gas production, petroleum refining, manufacturing and industrial, food and agricultural processing, and service and commercial facilities.

Proposed amendments would amend Rule 4306 and Rule 4320 to satisfy commitments in the *2018 PM2.5 Plan*. The proposed amendments to Rule 4306 and 4320 include lowering NOx emissions limits for multiple classes and categories of units subject to these rules, clarifying definitions, and updating test methods. The limits proposed require the installation of ultra-low NOx burners or the most advanced add-on control equipment, including Selective Catalytic Reduction (SCR). An evaluation was also conducted as to the feasibility of requiring alternative technologies, including electric and solar technologies. Through the implementation of the proposed Rule 4306 amendments, an estimated 16.4% reduction of NOx emissions will be achieved in 2024, with an additional 2.6% reduction of NOx emissions in 2030. Based on the emissions inventory used for the *2018 PM2.5 Plan*, this will result in 0.19 tons per day (tpd) of NOx emission reductions in 2024, and an additional 0.03 tpd of NOx emission reductions in 2030. Proposed amendments to Rule 4320 will achieve an additional 46% (0.45 tpd) of NOx emission reductions from this source category in 2024, although District staff are not proposing these reductions for SIP-credit at this time.

D. Rule Development Process

As part of the rule development process, District staff conducted public workshops to present and discuss proposed amendments to Rule 4306 and Rule 4320. District staff conducted public workshops in December 2019, July 2020, September 2020, and October 2020. Updates were also presented throughout the rulemaking process at multiple public meetings of the Citizens Advisory Committee, Environmental Justice Advisory Group, and the District Governing Board.

At the workshops, District staff presented the objectives of the proposed rulemaking project and provided the draft rules. District staff solicited information from affected source operators, consultants, vendors and manufacturers of control technologies, and trade associations on the technological feasibility and compliance cost information that would be useful in developing amendments to Rule 4306 and Rule 4320. The comments received from the public, affected sources, interested parties, CARB, and EPA, during the public workshop process were incorporated into the draft rules as appropriate.

Pursuant to state law, the District is required to perform a socioeconomic impact analysis prior to adoption, amendment, or repeal of a rule that has significant air quality benefits or that will strengthen emission limitations. As part of the District's socioeconomic analysis process, the District hired a socioeconomic consultant to prepare a socioeconomic impact report. The results of the socioeconomic analysis are included in this report (Appendix D).

The proposed rule amendments, final draft staff report with appendices, and final draft socioeconomic analysis report were published for 30-day notice prior to the public hearing to consider the adoption of rule amendments to Rule 4306 and Rule 4320 by the District Governing Board. The public hearing is scheduled on December 17, 2020.

II. BOILERS, STEAM GENERATORS, AND PROCESS HEATERS GREATER THAN 5 MMBTU/HR IN THE SAN JOAQUIN VALLEY

NOx emissions from sources subject to Rules 4306 and 4320 total 1.35 tons per day in 2020. These emissions account for 5% of all NOx emissions from stationary sources in the District. NOx emission from these sources have already been reduced by 96% from previous rule amendments.

There are over 1,200 units in the District subject to Rules 4306 and 4320. Fire tube boilers, water tube boilers, steam generators, and process heaters are used at a wide range of facilities throughout the San Joaquin Valley, including:

- Food and agricultural product processing operations
- Oil and Gas Production facilities
- Petroleum Refineries
- Manufacture and industrial facilities
- Ethanol Production facilities
- Hospitals
- Schools, Universities
- Livestock husbandry operations (dairies, cattle feedlots, etc.)

The current inventory of boilers, steam generators, and process heaters currently located in the San Joaquin Valley is shown in the table below. This table shows the inventory broken out depending on the size and type of unit in categories further defined in the current version of Rule 4320.

Table 1: Current Inventory of Units in the Valley

Rule 4320 Category	# Units
Group A. Units 5-20 MMBtu/hr except for Categories C-G Units	302
Group B. Units >20 MMBtu/hr except for Categories C-G Units	230
Group C.1 Oilfield Steam Generators 5-20 MMBtu/hr	8
Group C.2 Oilfield Steam Generators >20 MMBtu/hr	410
Group C.3 Oilfield Steam Generators firing on less than 50% PUC quality gas	142
Group D.1 Refinery Boiler 5-40 MMBtu/hr	2
Group D.2 Refinery Boilers ≥40 MMBtu/hr to ≥110 MMBtu/hr	3
Group D.3 Refinery Boilers >110 MMBtu/hr	1
Group D.4 Refinery Process Heaters 5-40 MMBtu/hr	42
Group D.5 Refinery Process Heaters ≥40 MMBtu/hr	9
Group D.6 Refinery Process Heaters >110 MMBtu/hr	1
Group E. Units with an annual heat input 1.8-30 billion Btu/yr	65
Total	**1,215**

Specific considerations for each of these types of units have been taken into account throughout this rulemaking, and are further discussed in the "Proposed Amendments" section of this staff report, and in Appendix C.

III. EMISSION CONTROL TECHNOLOGIES

Over the years, the District has adopted numerous generations of rules and rule amendments for units greater than 5 MMBtu/hr that have significantly reduced NOx and PM emissions from this source category. As part of these regulatory efforts, hundreds of boilers in the Valley have been equipped with the best available NOx and PM control technologies. Even though significant effort has already been made to reduce emissions from this source category, the possibility of further reducing emissions from units greater than 5 MMBtu/hr is evaluated in the following discussion.

The two primary methods of controlling NOx emissions from boilers, steam generators, and process heaters are either to change the combustion parameters (i.e., combustion modification) to reduce NOx formation, or to treat the NOx formed before it is emitted into the atmosphere with the use of selective catalytic reduction. The District also evaluated the potential for reducing NOx with electrification, and solar powered oil field steam generators as well as direct PM controls.

Combustion Modification

Combustion modification systems are designed to reduce thermal NOx formation by changing the flame characteristics to reduce peak flame temperature. Combustion controls include low excess air operation, staged combustion, overfire air ports, biased firing, and placing selected burners out-of-service.

Combustion modification is also achieved by different burner designs such as Low NOx Burners (LNB) and Ultra Low NOx Burners (ULNB). ULN and LNBs control fuel air mixing to improve flame structure resulting in less NOx formation through the use of staged air burners, staged fuel burners, pre-mix burners, internal recirculation, and radiant burners. ULNBs can be installed on most units and are capable of achieving NOx emissions as low as 5 ppmv for certain types and sizes of units. Retrofitting a unit with ULNBs has a capital cost of $30,000 to $400,000 depending on the size of the unit. The use of ULNBs can also increase annual costs due decreased thermal efficiency and the need for more electricity.

A combustion control system may be used by itself or in combination with Flue Gas Recirculation (FGR), additional oxygen flow controls, and tuning. FGR recycles a portion of the exhaust stream back into the burner windbox, mixing low oxygen air with combustion air prior to entering the combustion chamber. This technique reduces thermal NOx formation by reducing the peak temperature and by reducing oxygen in the combustion zone. FGR when combined with additional control equipment and tuning can allow an operator to meet a lower NOx limit without replacing burners. The capital cost for a FGR system is $17,000 to $84,000 depending on the size of the unit. FGR also increases annual costs due to the additional electricity needed to run the recirculation fan.

Although there may be a very small increase in fuel consumption for a small number of facilities, the proposed rule as a whole will result in a decrease in fuel consumption sector-wide.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is another way to reduce NOx. NOx is reduced to molecular nitrogen by adding a flue gas treatment system consisting of a catalyst module and a reagent injection system located after the boiler firebox. SCR units operate at a certain temperature range to effectively reduce NOx in the exhaust gas by injecting either ammonia stored in aqueous form, anhydrous form, generated on demand, or released from urea into the post-combustion zone of the boiler. SCR systems are generally paired with LNB.

SCR systems have significant initial capital cost and require large footprints. The installed cost of an SCR system is $230,000 to $750,000 depending on the size of the unit. Some facilities may also require additional construction costs to accommodate the large size of the catalyst. However, the use of an SCR system can result in an annual cost savings as a result of less need for electricity to run FGR fans and decreased fuel use from the increased efficiency of a LNB. The annual cost savings could range from $16,000 to $148,000, depending on the size of the unit, with vendors and some operators noting that the initial capital cost could be recouped in a number of years.

SCR technology is not a common NOx emission control technology for oilfield steam generators. The temperature required for SCR to work (400-800 F) is higher than the temperature that of oilfield steam generator exhaust (~250 F). The steam generators would have to be cut open to retrofit SCR into the convection section of the steam generator to operate the SCR system at the correct temperature. This would cause heat loss, preventing the production of the steam necessary for the oil field operation. Additional feasibility limitations associated with the installation of SCR for oil field steam generators include space limitations within installed infrastructure, and concerns with the storage of anhydrous ammonia in the remotely located, unsecure oil fields where these types of units operate. Due to these factors, SCR is not a feasible control system for use on oil field steam generators at this time.

Electrification of Units

Electric boilers and process heaters are commercially available and generally cost about the same as similarly sized natural gas units. However, the cost to operate a large unit on electricity is much higher than on natural gas. Our analysis has also shown that the electricity generation required to operate units larger than 5 MMBtu/hr would produce more NOx than units operating at the proposed NOx limits in Rule 4306. For example, a 5 MMBtu/hr fire tube boiler would cost nearly seven times as much to operate on electricity compared to natural gas and the NOx emitted from the electric utility grid to operate the unit would be twice as much as a natural gas fired unit operating at 7 ppmv NOx.

Currently, there are no electric steam generators capable of meeting the demands of conventional steam generators. One of the largest electric steam generators available produces 4,882 lb/hr @ 135 pounds per square inch gauge (psig). This steam flow rate is only 1/10 of the rate needed from one conventional steam generator and the pressure rating of 135 psig is far below the needed pressure of 800 – 900 psig.

Furthermore, a typical conventional natural gas-fired steam generator is rated (designed) to burn up to 62.5 million Btu/hr of natural gas and consumes approximately 50 million Btu/hr (i.e. 80% firing rate). This will require, on average, 13.75 MW of electricity to replace one conventional steam generator. Therefore, the electricity needs to replace one conventional steam generator with electric steam generation would be the equivalent electricity demand of over 10,000 homes. To replace conventional steam generators operating in the San Joaquin Valley with electric steam generation would require approximately 5,160 MW, which would be the equivalent electricity demand of 3,800,000 homes. The immense amount of power needed to electrify all steam generators in the District would require significant infrastructure upgrades to California's power grid. Therefore, electric steam generators are not feasible at this time.

Solar Powered Oilfield Steam Generation

Emissions from oilfield steam generators that provide steam to reduce the viscosity of oil in thermally enhanced oil recovery operations have been significantly reduced through decades of increasingly stringent rule requirements. Instead of fuel oil, steam generators today are powered by natural gas or field gas, which are significantly cleaner. To ensure that all potential emission reduction opportunities are evaluated, the District performed a comprehensive review of solar powered steam generators.

In the Valley, two small pilot projects were conducted to demonstrate the feasibility of solar powered steam generation technologies and found that such technologies were not feasible:

Berry Petroleum Company: This company installed a small pilot test facility designed to use solar energy to pre-heat feed water for the existing natural gas fired steam generators. The system consisted of mirrors in a glass greenhouse (supplied by Glasspoint Solar). The mirrors were designed to focus solar energy onto a pipe carrying water to heat the water. The heated water would then be sent to the input of the steam generators. The facility had a designed heat production of 300 kW. This project operated for a short time and was ultimately shut down based on the following shortcomings:

1) Significant heat loss: The heat losses to the water from the pipe runs from the solar installation to the actual steam generator locations were such that the water delivered to the steam generators was ambient or slightly warmer.
2) Excessively large footprint requirement: The footprint of the solar steam generators needed to provide the thermal output of one 85 MMBtu steam generator would be excessively large.
3) Inconsistent steam quality: The inability of the solar steam generators to consistently generate the quality of steam that is needed for injection that is currently supplied by the steam generators.
4) Unreliable power: The solar steam generators would still need to be supplemented by gas fired steam generators at night and during cloudy days.

Chevron: This company installed a pilot solar thermal steam plant near Coalinga, consisting of 7,600 mirrors that would direct solar energy towards a single solar collector tower (supplied by Brightsource Energy). The heat collected in the tower would turn water into steam. The installation had a footprint of 100 acres. This system discontinued operation in 2014. Although information from Chevron on their findings on the performance of this project is unavailable, based on news articles,[1,2] the system was excessively costly. A news article referencing the manufacturer's SEC filings stated the company realized a 40 million dollar loss on the project.

Aera Energy: Aera Energy was previously in collaboration with Glasspoint Solar to evaluate the potential installation of a large 770-acre solar steam generation system adjacent to an Aera Energy oil production operation in western Kern County. However, this project has run into major delays due to financial and technical issues and appears to be completely stalled.[3]

This proposed system would have generated the steam equivalent to approximately 10 gas-fired steam generators. The solar steam generators would still have needed to be supplemented by gas-fired steam generators at night and during cloudy days. Based on discussions with Aera Energy, the project would have relied heavily on solar tax credits, the generation and sale of low carbon fuel standard (LCFS) credits, and the reduction in costs of greenhouse gas allowances for Aera. According to Aera Energy, there was no economic benefit to implementing such technologies. In fact, without the LCFS credits, the cost of steam using this solar technology would be as much as 3 times the current cost. AERA Energy was pursuing this technology to continue its effort in helping lead the industry to cleaner energy. The system proposed would have been primarily funded

[1] "Potential For Solar-Assisted EOR in California Oilfield Still Unfulfilled" Natural Gas Intelligence, 2015, https://www.naturalgasintel.com/potential-for-solar-assisted-eor-in-california-oilfield-still-unfulfilled

[2] "BrightSource's solar steam project went way over budget" GigaOm, 2011, https://gigaom.com/2011/10/12/brightsources-solar-steam-project-went-way-over-budget

[3] "Omani- and Shell-Backed Solar EOR Firm Runs Out of Steam" *Journal of Petroleum Technology*, 2020, https://pubs.spe.org/en/jpt/jpt-article-detail/?art=7057.

by the solar steam generation equipment manufacturer and outside investors. Aera Energy would commit to purchasing the steam if successfully built.

The project faced technical challenges, similar to the above pilot projects. Furthermore, the gas-fired steam generators that are required to supplement the system could have faced difficulty meeting current rule limits due to the need to ramp up and down. There has not been a successful large scale implementation of such technologies. The District was working closely with AERA to facilitate this project, and is committed to supporting similar projects in the event that they become feasible in the future.

In summary, solar powered oilfield steam generators are not yet feasible and still face significant technical and economic challenges as outlined below:

- **Costs:** The use of solar steam generation rely on a complex set of funding sources to make the operations economically feasible, including the Federal 30% tax credit, the value of California low-carbon fuel standards credits that may be generated as a result of using solar steam generation to produce oil, and a reduction in the costs for the oil producer of AB32 cap-and-trade credits required for their operations in California. The value of the GHG credits generated varies based on the price of credits on the open market. As the value of the credits is not fixed, the economic viability of a project may change depending on the value of the credits prior to construction and during operation. Even with available credits, the costs continue to be a challenge.

- **Land Availability:** Adequate open land next to the steam injection wells is needed to house the solar collectors. Both the amount of land and the distance of the land to the injection point are important factors. It is estimated that to create the steam needed to replace one steam generator would require at least 60 acres of solar generation. Finding the required amount of land available next to oilfield operations may be difficult. The solar systems have to be close to the steam injection wells. Otherwise, additional solar capacity will need to be developed to account for the heat loss because of travel distance.

- **Variability of Solar Steam Generation Output:** Solar steam generation plants need sunny days to be able to collect enough energy to make steam. During cloudy days and also during the night, the solar equipment would not make enough steam. Oilfield operators will need to supplement the solar operation with natural gas fired steam generators for when the solar equipment is not producing enough steam. On partly cloudy days, the natural gas steam generators would need to cycle on and off depending on the cloud cover. This may cause operational difficulties as the gas fired steam generators are tuned to operate at constant load. A variable load could cause emissions variability and potentially have emissions higher than that allowed in permit limits and/or District prohibitory rules.

Direct PM2.5 Controls

Post-combustion control devices remove pollutants from the flue gases downstream of the unit. These controls are effective at removing PM, SO_2, and NOx. PM post-combustion controls include fabric filters, ceramic filters, electrostatic precipitators (ESPs), and wet scrubbers. SO_2 post-combustion controls include flue gas desulfurization and dry sorbent injection.

ESPs use an electrical charge to separate the particles in the flue gas. The ESP particles in the flue gas are then attracted to an oppositely charged plate or tube and collected to a hopper by vibrating the collection surface. ESPs have been reported to achieve 99 percent PM2.5 removal efficiency. Currently, there are a several produced gas fired steam generators operating in crude oil production facilities that are required by their permits to operate SOx scrubbers and ESPs (to reduce SOx emissions and visible emissions to burning high sulfur produced gas).

Fabric filters and ceramic filters known as a baghouses trap particulates in the flue gas before they exit the stack. Fabric filters are not recommended for units that use oil exclusively. A baghouse downstream of an ESP provides high rates of PM2.5 removal. Baghouses can capture up to 99 percent of filterable particulates and 20% of condensable particulates. Baghouses are not commonly used on units affected by Rule 4306 and Rule 4320.

Flue gas desulfurization typically uses lime or limestone as a sorbent to remove SO_2 from the exhaust gas. The most common flue gas desulfurization technology is wet scrubbers. A wet scrubber operates by introducing the dirty gas stream with a scrubbing liquid, typically water. Particulates are collected in the scrubbing liquid. Wet scrubbers control large particulates (>PM5) by 99% and PM2.5 emissions by approximately 50%.

The majority of boilers (>5 MMBtu/hr) in the Valley combust Public Utilities Commission (PUC) quality natural gas, which contains a very low sulfur content and inherently has low emissions. Few boilers in the Valley use alternative fuels for their combustion processes. Alternative fuels include digester gas, produced gas, and liquid fuel. Units fired on digester gas or produced gas are already required to use inlet gas scrubbers to meet District rule requirements.

Current rule language requires that liquid fuel shall be used only during a PUC-quality natural gas curtailment period provided it contains no more than 15 ppmv sulfur. While the use of liquid fuel is strictly limited, the feasibility of reducing PM emissions through adding PM2.5 limits for boilers and steam generators was explored as part of the District's comprehensive technology evaluation.

Units firing on natural gas, propane, liquefied petroleum gas, or low sulfur diesel tend to emit very low levels of PM2.5 and SO_2. AP-42 indicates that the uncontrolled total PM (condensable and filterable) is 0.007 pound per million Btu and uncontrolled SO_2 is 0.0006 pound per million Btu for boilers firing on natural gas.

Cost analyses for baghouses, electrostatic precipitators, and wet scrubbers show these technologies are not cost effective options for PM control. For more information on the cost effectiveness analyses of PM controls, refer to Appendix C of this staff report.

IV. CURRENT AND PROPOSED REGULATIONS

A. Existing Rule 4306

The purpose of Rule 4306 is to limit NOx and CO emissions from boilers, steam generators, and process heaters. The rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, and process heater with a rated heat input greater than 5.0 million Btu/hr.

The current rule does not apply to units that are addressed by other District rules. These units include solid fuel fired units, dryers, glass melting furnaces, kilns and smelters, unfired or fired waste heat recovery boilers, and any unit in which the total rated heat input of each burner is less than or equal to 5 million Btu per hour as specified in the operating permit, and in which each burner's products of combustion does not come in contact with the products of combustion of any other burner. The rule also contains certain exemptions such as burning of any fuel other than natural gas during natural gas curtailment for no more than 168 hours. Units subject to the rule must comply with the NOx and CO limits listed in the following table.

Table 2: Existing Rule 4306 Table 1 - Existing NOx and CO Limits

Category	Operated on Gaseous Fuel			Operated on Liquid Fuel	
	NOx Limit		CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
	Standard Option	Enhanced Option			
A. Units with a rated heat input equal to or less than 20.0 MMBtu/hour, except for Categories C, D, E, F, G, H, and I units	15 ppmv or 0.018 lb/MMBtu	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
B. Units with a rated heat input greater than 20.0 MMBtu/hour, except for Categories C, D, E, F, G, H, and I units	9 ppmv or 0.011 lb/MMBtu	6 ppmv or 0.007 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

Category	Operated on Gaseous Fuel			Operated on Liquid Fuel	
	NOx Limit		CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
	Standard Option	Enhanced Option			
C. Oilfield Steam Generators	15 ppmv or 0.018 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
D. Refinery units with a rated heat input greater than 5 MMBtu/hr up to 65 MMBtu/hr	30 ppmv or 0.036 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
E. Refinery units with a rated heat input greater than 65 MMBtu/hr up to 110 MMBtu/hr	25 ppmv or 0.031 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
F. Refinery units with a rated heat input greater than 110 MMBtu/hr	5 ppmv or 0.0062 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
G. Load-following units	15 ppmv or 0.018 lb/MMBtu	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
H. Units limited by a Permit to Operate to an annual heat input of 9 billion Btu/year to 30 billion Btu/year	30 ppmv or 0.036 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400
I. Units in which the rated heat input of each burner is less than or equal to 5 MMBtu/hr but the total rated heat input of all the burners in a unit is greater than 5 MMBtu/hr, as specified in the Permit to Operate, and in which the products of combustion do not come in contact with the products of combustion of any other burner.	30 ppmv or 0.036 lb/MMBtu	No option	400	40 ppmv or 0.052 lb/MMBtu	400

Other provisions contained in the rule include periodic source testing, monitoring, and recordkeeping.

B. Summary of Proposed Amendments to Rule 4306

Based on the comprehensive technology assessment that District staff have conducted for this source category, as well as a thorough review of state, federal, and other air district regulations, District staff are proposing several modifications to Rules 4306 and 4320. Proposed modifications to Rule 4306 include lowering NOx emissions limits for a variety of source categories. Proposed changes are further discussed below.

Section 3.0 – Definitions

The following definitions would be added to the rule to improve clarity and reflect changes to rule requirements:

- Digester Gas: gas derived from the decomposition of organic matter in a digester.
- Fire Tube Boiler: any boiler that passes hot gases from a fire box through one or more tubes running through a sealed container of water. The heat of the gases is transferred through the walls of the tubes by thermal conduction, heating the water and ultimately creating steam or hot water.
- Normal Operation: the period of operating time during which a unit is not in a startup or a shutdown event.
- Replacement Unit: the replacement of a boiler, steam generator, oil field steam generator, or process heater. The retrofit of an existing unit does not qualify as a replacement.
- School: any public or private school used for the purpose of education and instruction of school pupils in Kindergarten through Grade 12, and any college or university which provides postsecondary education and has the authority to confer Associate, Bachelors, or Graduate/Professional level degrees. This does not include any private school in which education and instruction are primarily conducted in private homes.
- Thermal Fluid Heater: a natural gas fired process heater in which a process stream is heated indirectly by a heated fluid other than water.

The definition of load following unit will be removed from the rule because there will not be specific NOx or CO limits for these units. Load following units will need to comply with the proposed NOx limits in the applicable category in Table 2.

Section 5.0 – Requirements

Units subject to the rule must comply with the NOx limits in Table 1 until the NOx limits in Table 2 take effect. Table 2 summarizes the NOx proposed emission limits and the dates for the emission control plans, authorities to construct, and compliance deadlines. The NOx emission limits are in concentrated units of parts per million at dry stack gas conditions and 3% by volume stack gas oxygen.

The proposed NOx limits are based on an in-depth technical analysis, a thorough public process, and meetings with vendors, manufacturers, and operators. The control technologies necessary to achieve the proposed limits were deemed to be reasonably available, economically feasible, and cost effective.

The proposed Rule 4306 categories have been updated from the previous categories in the rule. Categories were updated to account for differences in technologically achievable and cost-effective limits which may differ between different types and sizes of units. Updated category groupings also establish consistency in the categories included in Rule

4306 as well as Rule 4320. Major changes include:

- Category A was split into 5 sub categories based on type of unit, operating fuel, and location of the unit.
- Category B was split into 3 sub categories based on heat input and the type of unit
- Category C was split into 4 sub categories based on heat input and if the units are fired on less than 50% PUC quality gas
- Category D was split into 6 sub categories with based on size and whether the unit is a boiler or a process heater

Table 2: Tier 2 NOx and CO Limits				
Category	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit	CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G unit				
1. Fire Tube Boilers	7 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
2. Units at Schools or Colleges	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units fired on Digester Gas	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
4. Thermal Fluid Heaters	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
5. All other units	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units				
1. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
2. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units with a rated heat input > 75 MMBtu/hour	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
C. Oilfield Steam Generators				
1. Units with a total rated heat input > 5.0 MMBtu/hr and ≤ 20.0 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

Table 2: Tier 2 NOx and CO Limits				
Category	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit	CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
2. Units with a total rated heat input > 20.0 MMBtu/hr and ≤ 75.0 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
3. Units with a total rated heat input > 75.0 MMBtu/hr	7 ppmv or 0.0085 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
4. Units firing on less than 50%, by volume, PUC quality gas	15 ppmv or 0.018 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
D. Refinery Units				
1. Boilers with a total rated heat input > 5.0 MMBtu/hr and ≤ 40.0 MMBtu/hr	30 ppmv or 0.036 lb/MMBtu 5 ppmv or 0.0061 lb/MMBtu upon replacement of unit	400	40 ppmv or 0.052 lb/MMBtu	400
2. Boilers with a total rated heat input > 40.0 MMBtu/hr and ≤110 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu 5 ppmv or 0.0061 lb/MMBtu upon replacement of unit	400	40 ppmv or 0.052 lb/MMBtu	400
3. Boilers with a total rated heat input >110 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
4. Process Heaters with a total rated heat input > 5.0 MMBtu/hr and ≤ 40.0 MMBtu/hr	30 ppmv or 0.036 lb/MMBtu 9 ppmv or 0.011 lb/MMBtu upon replacement of unit	400	40 ppmv or 0.052 lb/MMBtu	400
5. Process Heaters with a total rated heat input >	15 ppmv or 0.018 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

Table 2: Tier 2 NOx and CO Limits				
Category	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit	CO Limit (ppmv)	NOx Limit	CO Limit (ppmv)
40.0 MMBtu/hr and ≤110 MMBtu/hr	9 ppmv or 0.011 lb/MMBtu upon replacement of unit			
6. Process Heaters with a total rated heat input >110 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400
E. Units limited by a Permit to Operate to an annual heat input of 9 billion Btu/year to 30 billion Btu/year	30 ppmv or 0.036 lb/MMBtu	400	40 ppmv or 0.052 lb/MMBtu	400

The proposed Rule 4306 NOx limit for Category A fire tube boilers is 7 ppmv and 9 ppmv for all other units in this size range (including units at schools, units fired on digester gas, and thermal fluid heaters). District staff are proposing to add fire tube boilers as a new category, as the technology assessment has shown that fire tube boilers are capable of meeting lower limits than water tube boilers or fire tube heaters.

The proposed Rule 4306 NOx limit for Category B units is 7 ppmv for units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour, and 5 ppmv for units with a rated heat input > 75 MMBtu/hour. The remaining units can retrofit to meet the proposed limits by retrofitting with ultra low NOx burners, oxygen flow controls such as flue gas recirculation, and/or SCR.

The proposed Rule 4306 NOx limit for Category C is 9 ppmv and 7 ppmv respectively for natural gas fired oil field steam generators for units with a total rated heat input > 5.0 MMBtu/hr and ≤ 75 MMBtu/hour and for units > 75 MMBtu/hour. The District is proposing to maintain the 15 ppmv NOx limit for oil field steam generators fired on less the 50% PUC quality gas. Units fired on natural gas can meet the proposed NOx limits by retrofitting with ultra-low NOx burners and oxygen flow controls. Oil field steam generators fired on less than 50% PUC quality gas have a more difficult time achieving lower NOx limits due to the impurities in field gas like ammonia that can create additional NOx when combusted.

The proposed Rule 4306 NOx limit for Category D units ≤ 40 MMBtu/hr will be maintained at 30 ppmv, but units will have to meet lower limits of 5 ppmv upon replacement. Proposed NOx limits for units > 40 MMBtu/hr and ≤ 110 MMBtu/hr is 9 ppmv for boilers and 15 ppmv for heaters. These units would also be required to meet lower NOx limits when replaced. For the largest units at refineries, the District proposes to maintain the existing 5 ppmv NOx limit. The proposed Rule 4306 NOx limits for boilers and heaters at petroleum refineries are generally higher than limits for other boilers and heaters due to their design and operating conditions. In addition, refineries use a mix of natural gas and non-PUC quality process gas to fuel their boilers and heaters. Process gas contains differing amounts of impurities, including hydrocarbons, which create additional NOx when combusted. The majority of refinery units are natural draft instead of forced draft and would require oxygen flow controls or SCR to meet lower limits. Due to these considerations, retrofitting these types of units was not shown to be cost-effective. Therefore, the District is proposing to require more stringent limits upon replacement for these types of units to allow for the useful life of the equipment and increase the cost-effectiveness of the requirements.

Section 6.0 – Administrative Requirements

Section 6.4.2 will be removed, as there is no longer a category for load following units. Test methods will be updated to reflect the latest version of test methodology available.

Section 7.0 – Compliance Schedule

Units subject to the rule must comply with Rule 4306 in accordance with the schedule specified in Table 3 and Table 4 (previously Table 2 and Table 3) until the schedule specified in Table 5.

Table 5: Tier 2 - Compliance Schedule			
Category	Emission Control Plan	Authority to Construct	Compliance Deadline
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G unit			
1a. Fire Tube Units permitted greater than 9 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
1b. Fire Tube Units permitted less than or equal to 9 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
2. Units at Schools	May 1, 2022	May 1, 2022	December 31, 2023
3. Units fired on Digester Gas	May 1, 2022	May 1, 2022	December 31, 2023
4. Thermal Fluid Heaters	May 1, 2022	May 1, 2022	December 31, 2023

Table 5: Tier 2 - Compliance Schedule			
Category	Emission Control Plan	Authority to Construct	Compliance Deadline
5a. All other units permitted greater than 12 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
5b. All other units permitted less than or equal to 12 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units			
1a. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted greater than 9 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
1b. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted less than or equal to 9 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
2a. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted greater than 9 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
2b. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour permitted less than or equal to 9 ppmv as of 6 months from date of rule amendment	May 11, 2028	May 1, 2028	December 31, 2029
3a. Units with a rated heat input > 75 MMBtu/hour permitted greater than 7 ppmv as of 6 months from date of rule amendment	May 1, 2022	May 1, 2022	December 31, 2023
3b. Units with a rated heat input > 75 MMBtu/hour permitted less than or equal to 7 ppmv as of 6 months from date of rule amendment	May 1, 2028	May 1, 2028	December 31, 2029
C. Oilfield Steam Generators			
1. Units with a total rated heat input > 5.0 MMBtu/hr and ≤ 20.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
2. Units with a total rated heat input > 20.0 MMBtu/hr and ≤ 75.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
3. Units with a total rated heat input > 75.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023

Table 5: Tier 2 - Compliance Schedule			
Category	Emission Control Plan	Authority to Construct	Compliance Deadline
4. Units firing on less than 50%, by volume, PUC quality gas	May 1, 2022	May 1, 2022	December 31, 2023
D. Refinery Units			
1. Boilers with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
2. Boilers with a total rated heat input > 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
3. Heaters with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
4. Heaters with a total rated heat input > 40.0 MMBtu/hr	May 1, 2022	May 1, 2022	December 31, 2023
E. Units limited by a Permit to Operate to an annual heat input of 9 billion Btu/year to 30 billion Btu/year	May 1, 2022	May 1, 2022	December 31, 2023

The final compliance date for most categories is December 31, 2023. However, the District determined that later compliance dates were appropriate for operations that had invested in lower-emission units due to the high costs of retrofitting those units. The District is proposing to extend the compliance dates for these lower-emitting units to 2029 to allow for the useful life of the unit.

C. Existing Rule 4320

The purpose of Rule 4320 is to limit emissions of NOx, CO, SO_2, and PM10 from boilers, steam generators, and process heaters. The rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, and process heater with a rated heat input greater than 5.0 million Btu/hr. Rule 4320 establishes NOx limits separate from Rule 4306 and provides Advanced Emission Reduction Options for rule compliance, whereby an operator may either:

1. Meet the specific NOx emission and the particulate matter control requirements; or

2. Pay an annual emissions fee to the District and meet the particulate matter control requirements

The current rule does not apply to units that are addressed by other District rules. These units include solid fuel fired units, dryers, glass melting furnaces, kilns and smelters, and 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.

Currently, units subject to the rule must comply with the NOx and CO limits listed in the following table.

Table 1 NOx Emission Limits

Category	NOx Limit	Authority to Construct	Compliance Deadline
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G units	a) Standard Schedule 9 ppmv or 0.011 lb/MMBtu; or	July 1, 2011	July 1, 2012
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu	January 1, 2013	January 1, 2014
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units	a) Standard Schedule 7 ppmv or 0.008 lb/MMBtu; or	July 1, 2009	July 1, 2010
	b) Enhanced Schedule 5 ppmv or 0.0062 lb/MMBtu	January 1, 2013	January 1, 2014
C. Oilfield Steam Generators			
1. Units with a total rated heat input > 5.0 MMBtu/hr to ≤20.0 MMBtu/hr	a) Standard Schedule 9 ppmv or 0.011 lb/MMBtu; or	July 1, 2011	July 1, 2012
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu	January 1, 2013	January 1, 2014
2. Units with a total rated heat input >20.0 MMBtu/hr	a) Standard Schedule 7 ppmv or 0.008 lb/MMBtu; or	July 1, 2009	July 1, 2010
	b) Staged Enhanced Schedule Initial Limit 9 ppmv or 0.011 lb/MMBtu; and	July 1, 2011	July 1, 2012

Table 1 NOx Emission Limits			
Category	NOx Limit	Authority to Construct	Compliance Deadline
	Final Limit 5 ppmv or 0.0062 lb/MMBtu	January 1, 2013	January 1, 2014
3. Units firing on less than 50%, by volume, PUC quality gas.	Staged Enhanced Schedule Initial Limit 12 ppmv or 0.014 lb/MMBtu; and	July 1, 2010	July 1, 2011
	Final Limit 9 ppmv or 0.011 lb/MMBtu	January 1, 2013	January 1, 2014
D. Refinery units			
1. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr	a) Standard Schedule 9 ppmv or 0.011 lb/MMBtu; or	July 1, 2011	July 1, 2012
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu	January 1, 2013	January 1, 2014
2. Units with a total rated heat input >20.0 MMBtu/hr to ≤ 110.0 MMBtu/hr	a) Standard Schedule 6 ppmv or 0.007 lb/MMBtu; or	July 1, 2010	July 1, 2011
	b) Staged Enhanced Schedule Initial Limit 9 ppmv or 0.011 lb/MMBtu; and	July 1, 2011	July 1, 2012
	Final Limit 5 ppmv or 0.0062 lb/MMBtu	January 1, 2013	January 1, 2014
3. Units with a total rated heat input > 110.0 MMBtu/hr	Standard Schedule 5 ppmv or 0.0062 lb/MMBtu	N/A	June 1, 2007

Table 1 NOx Emission Limits			
Category	NOx Limit	Authority to Construct	Compliance Deadline
4. Units firing on less than 50%, by volume, PUC quality gas.	Staged Enhanced Schedule Initial Limit 12 ppmv or 0.014 lb/MMBtu; and	July 1, 2010	July 1, 2011
	Final Limit 9 ppmv or 0.011 lb/MMBtu	January 1, 2013	January 1, 2014
E. Units, from any Category, that were installed prior to January 1, 2009 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/year but ≤ 30 billion Btu/year.	Standard Schedule 9 ppmv or 0.011 lb/MMBtu	Twelve months before the next unit replacement but no later than January 1, 2013	At the next unit replacement but no later than January 1, 2014

<table>
<tr><th colspan="4">Table 1 NOx Emission Limits</th></tr>
<tr><th>Category</th><th>NOx Limit</th><th>Authority to Construct</th><th>Compliance Deadline</th></tr>
<tr><td rowspan="2">F. Units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas.</td><td>Staged Enhanced Schedule Initial Limit 12 ppmv or 0.014 lb/MMBtu; and</td><td>July 1, 2010</td><td>July 1, 2011</td></tr>
<tr><td>Final Limit 9 ppmv or 0.011 lb/MMBtu</td><td>January 1, 2013</td><td>January 1, 2014</td></tr>
<tr><td>G. Units operated by a small producer in which the rated heat input of each burner is less than or equal to 5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 MMBtu/hr and 20 MMBtu/hr, as specified in the Permit to Operate, and in which the products of combustion do not come in contact with the products of combustion of any other burner.</td><td>Standard Schedule 9 ppmv or 0.011 lb/MMBtu</td><td>Twelve months before the next unit replacement but no later than January 1, 2013.</td><td>At the next unit replacement but no later than January 1, 2014</td></tr>
</table>

D. Summary of Proposed Amendments to Rule 4320

Proposed modifications to Rule 4320 include lowering NOx emissions limits for a variety of unit classes and categories. Proposed changes are further discussed below.

Section 3.0 – Definitions

The following definitions would be added to the rule to improve clarity and reflect changes to rule requirements:

- Digester Gas: gas derived from the decomposition of organic matter in a digester.
- Fire Tube Boiler: any boiler that passes hot gases from a fire box through one or more tubes running through a sealed container of water. The heat of the gases is transferred through the walls of the tubes by thermal conduction, heating the water and ultimately creating steam or hot water.
- Normal Operation: the period of operating time during which a unit is not in a startup or a shutdown event.
- School: any public or private school used for the purpose of education and instruction of school pupils in Kindergarten through Grade 12, and any college or university which provides postsecondary education and has the authority to confer Associate, Bachelors, or Graduate/Professional level degrees. This does not include any private school in which education and instruction are primarily conducted in private homes.
- Thermal Fluid Heater: a natural gas fired process heater in which a process stream is heated indirectly by a heated fluid other than water.

Section 5.0 – Requirements

Owners with units subject to Rule 4320 may choose to meet the NOx emission requirements, pay an annual emission fee, or comply with the low-use unit provision. These requirements will be maintained in the proposed Rule 4320.

In order to meet the NOx limits, units must be in compliance with the limits and schedules listed in Table 1 until the NOx limits and compliance schedule in Table 2 take effect. Table 2 summarizes the NOx proposed emission limits and the dates for emission control plans, authorities to construct, and compliance deadlines. The NOx emission limits are in concentrated units of parts per million at dry stack gas conditions and 3% by volume stack gas oxygen.

Table 2: Tier 2 NOx Emission Limits				
Category	NOx Limit	Emission Control Plan	Authority to Construct	Compliance Deadline
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through E units				
1. Fire Tube Boilers	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Units at Schools	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Units fired on Digester Gas	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
4. Thermal Fluid Heaters	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
5. All other units	5 ppmv or 0.061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
B. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through E units				
1. Fire Tube Boilers with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. All other units with a total rated heat input > 20.0 MMBtu/hour and ≤ 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Units with a rated heat input > 75 MMBtu/hour	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
C. Oilfield Steam Generators				
1. Units with a total rated heat input > 5.0 MMBtu/hr and ≤ 20.0 MMBtu/hr	6 ppmv or 0.0073 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Units with a total rated heat input > 20.0 MMBtu/hr and ≤ 75.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023

3. Units with a total rated heat input > 75.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
4. Units firing on less than 50%, by volume, PUC quality gas	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
D. Refinery units				
1. Boilers with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
2. Boilers with a total rated heat input > 40.0 MMBtu/hr to ≤ 110.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
3. Boilers with a total rated heat input > 110.0 MMBtu/hr	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
4. Process Heaters with a total heat input > 5.0 MMBtu/hr to ≤ 40.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
5. Process Heaters with a total rated heat input > 40.0 MMBtu/hr to ≤ 110.0 MMBtu/hr	5 ppmv or 0.0061 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
6. Process Heaters with a total heat input > 110.0 MMBtu/hr	2.5 ppmv or 0.003 lb/MMBtu	May 1, 2022	May 1, 2022	December 31, 2023
E. Units limited by a Permit to Operate to an annual heat input >1.8 billion Btu/year but < 30 billion Btu/year.	9 ppmv or 0.011 lb/MMBtu	May 1, 2022	May 1, 2022.	December 31, 2023

The low level of emissions proposed in Table 2 of Rule 4320 may not be able to be achievable by all units due to space limitations and economic considerations. Most of the affected units have typically had several levels of controls and can only reach the new limits with a Selective Catalytic Reduction (SCR). To offset the higher costs associated with the proposed controls, the District developed the concept of an annual emissions fee, which was included in the previous version of Rule 4320 and is proposed to be maintained in this amendment. In situations where a retrofit may not be the best option given the technology forcing nature of the limits, operators have the option of paying an annual emissions fee based on the actual emissions of the unit during the previous calendar year while the facility continually evaluates the feasibility of potential controls. These fees may then be used by the District to support cost-effective emission reductions and other pollution reduction activities. Fees would be paid annually and continue until the unit complies with the applicable limit. The affected sources will have the option, on an annual basis, to stop the fee option and install controls specified in the rule.

The emissions fee is based on the total emissions from the units that do not comply with the applicable NOx limits, and not the difference between the actual and rule limits. The emissions are calculated using the NOx emission limit in the Permit to Operate, in lb/MMBtu, and the actual annual fuel usage, in MMBtu, for the past year. The total annual fee is calculated by multiplying the total emissions by a fee rate plus an administrative fee. The fee rate is based on the cost of NOx reductions, in dollars per ton, as established pursuant to Sections 7.2 and 7.6 of District Rule 9510 (Indirect Source Review (ISR)), as adopted on December 15, 2005, and amended on December 21, 2017.

The proposed Rule 4320 NOx limit for Category A units at schools, units fired on digester gas, and thermal fluid heaters is 9 ppm. The current Rule 4320 limits for Category A units is 9 ppm for the standard schedule and 6 ppm for the enhanced schedule. The majority of units subject Category A are located at schools, with remaining units located at public facilities, and they have all complied with the earlier compliance deadline under the "standard" schedule by meeting the 9 ppm limit. Based on the District's technical evaluation and potential impact to already heavily impacted schools and public agencies, and to avoid penalizing operators that installed lower-emitting units on an earlier timeframe, the District proposes to maintain the current standard schedule permitted limits of 9 ppm. Additionally, any new units installed in these categories will have to meet more stringent BACT limits determined through the District's New Source Review program through Rule 2201.

Section 6.0 – Administrative Requirements

Test methods will be updated in Section 6.4 to reflect the latest version of test methodology available.

IV. SUPPORTING ANALYSIS

The following analysis implement or reference requirements in the California Health and Safety Code, federal Clean Air Act, and the California Environmental Protection Act.

A. Emissions Inventory and Potential Emission Reductions

The NOx emission reductions achieved from the proposed amendments to the Rule 4306 0.19 tons per day (tpd) in 2024 and 0.03 tpd in 2030, on an annual average basis. Additional NOx emission reductions achieved from the proposed amendments to Rule 4320 are estimated to reduce NOx emissions by an additional 46% (0.45 tpd) on an annual average basis, although District staff are not submitting these emission reductions for SIP credit at this time. Please see Appendix B of this draft staff report for further details.

B. Cost Effectiveness Analysis

The California Health and Safety Code (CH&SC) Section 40920.6(a) requires the District to conduct both an absolute cost effectiveness analysis and an incremental cost effectiveness analysis of available emission control options before adopting each BARCT rule. The purpose of conducting a cost effectiveness analysis is to evaluate the economic reasonableness of the pollution control measure or rule. The analysis also serves as a guideline in developing the control requirements of a rule. Cost effectiveness will depend on the current level of controls, unit size, fuel usage and final emission levels. Details of the cost effectiveness analysis is contained in Appendix C to this report.

C. Socioeconomic Analysis

State law requires the District to analyze the socioeconomic impacts of any proposed rule or rule amendment that significantly affects air quality or strengthens an emission limitation. The socioeconomic analysis has been used to further refine the rule amendments. The final socioeconomic report is attached to this staff report as Appendix D.

D. Rule Consistency Analysis

Pursuant to CH&SC §40727.2, prior to adopting, amending, or repealing a rule or regulation, the District is required to perform a written analysis that identifies and compares the air pollution control elements of the rule or regulation with corresponding elements of existing or proposed District and EPA rules, regulations, and guidelines that apply to the same source category. District staff has concluded that the proposed rules are not in conflict with nor inconsistent with other District rules, nor are the proposed rules in conflict with nor inconsistent with federal policy, rule, or regulations governing the same source category. The analysis is discussed further in Appendix E of this staff report.

E. Environmental Impacts

The District is proposing to amend existing District Rule 4306 and District Rule 4320 (Boilers>5MMBtu/hr). The Purpose of this rule amendment project includes lowering the NOx emission limits for specific classes and categories of units, with the Advanced Emission Reduction Option to allow for advanced technology development and deployment in order to meet commitments made to the *2018 PM2.5 Plan*.

There are no other actions or rule requirements associated with this project. Based on the District's investigation, substantial evidence supports the District's conclusion that the amendments will not cause either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment, and as such is not a "project" as that term is defined under the California Environmental Quality Act (CEQA) Guidelines § 15378. In addition, substantial evidence supports the District's conclusion that, if one assumes the amendment is a "project" under CEQA in spite of our conclusion to the contrary, it will not have any significant adverse effects on the environment.

In addition, the amendments to District Rule 4306 and Rule 4320 is an action taken by a regulatory agency, the San Joaquin Valley Air District, as authorized by state law to assure the maintenance, restoration, enhancement, or protection of air quality in the San Joaquin Valley where the regulatory process involves procedures for protection of air quality.

California Environmental Quality Act (CEQA) Guidelines §15308 (Actions by Regulatory Agencies for Protection of the Environment), provides a categorical exemption for "actions taken by regulatory agencies, as authorized by state or local ordinance, to assure the maintenance, restoration, enhancement, or protection of the environment where the regulatory process involves procedures for protection of the environment. Construction activities and relaxation of standards allowing environmental degradation are not included in this exemption." No construction activities or relaxation of standards are included in this project. Therefore, the rule amendment project is exempt from CEQA.

Finally, according to Section 15061 (b)(3) of the CEQA Guidelines, a project is exempt from CEQA if, "(t)he activity is covered by the common sense exemption that CEQA applies only to projects which have the potential for causing a significant effect on the environment. Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA." As such, for this additional reason, the District finds that the rule amendment project is exempt from CEQA.

APPENDIX A

Summary of Significant Comments and Responses
For Proposed Amendments to Rule 4306 and Rule 4320

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SUMMARY OF SIGNIFICANT COMMENTS
DRAFT AMENDMENTS TO RULE 4306 and 4320
(Boilers, Steam Generators, and Process Heaters – Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr)
November 17, 2020

The District published the proposed rules November 17, 2020 for 30-day public review and comment. Summaries of significant comments received during the associated comment period are summarized below.

Comments were received from the following:
Penny Newman Grain Co, (PNG)

1. **COMMENT:** The proposed limits for 5-20 MMBtu/hr firetube boilers are too stringent. Units that meet 9 ppm have been recently installed (in 2015/2016), and having to modify or replace these units before the end of their useful life to meet 7 ppm per the rule requirements will be too costly. (PNG)

   RESPONSE: The District crafted the requirements of Rule 4306 with consideration for operators that have made relatively recent investments in lower-emitting units, allowing these cleaner units an extended compliance period to meet the required limits specified in the proposed amendments. The technology assessment conducted by District staff shows that units operating at 9 ppmv currently would be able to meet the 7 ppmv limit with a number of options including tuning, flue gas recirculation, or possible burner replacement with ULNB. These retrofits would be required in 2029, rather than 2023, to allow for the useful life of these affected lower emitting units.

2. **COMMENT:** Commenter suggests that further analysis is required under CEQA, arguing that the rule amendments are a “project” under CEQA, the “common sense exemption” does not apply, and the “Class 8” exemption (for actions protecting the environment) does not apply. Commenter argues that CEQA requires more analysis because the increased fuel consumption has the potential to increase GHG emissions. (PNG)

   RESPONSE: As documented in the staff report, these rule amendments will result in an environmental benefit through decreased NOx emissions and improved air quality. Although there may be a very small increase in fuel consumption for a small number of facilities, the rule as a whole will result in a decrease in fuel consumption sector-wide. Because the rule has a net benefit to the environment, the Class 8 exemption applies. Additional detailed analysis is not required under CEQA for the common sense exemption to apply.

3. **COMMENT:** The District should postpone consideration of the proposed amendments to engage with affected stakeholders. Industry stakeholders have not been provided sufficient time to evaluate and provide comments on the proposed amendments. (PNG)

   RESPONSE: As part of the rule development process, District staff conducted an extensive public process to present and discuss proposed amendments to Rule 4306 and Rule 4320. District staff conducted public workshops in December 2019, July 2020, September 2020, and October 2020. In addition to the workshops, numerous meetings were held with stakeholders to discuss their individual issues and suggestions. Updates were also presented throughout the rulemaking process at multiple public meetings of the Citizens Advisory Committee, Environmental Justice Advisory Group, and the District Governing Board. The District will continue working with affected and interested stakeholders to ensure effective outreach regarding new requirements.

SUMMARY OF SIGNIFICANT COMMENTS
DRAFT AMENDMENTS TO RULE 4306 and 4320
(Boilers, Steam Generators, and Process Heaters – Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr)
October 8, 2020

The District held a public workshop to present, discuss, and receive comments on the draft amendments to Rule 4306 and 4320 on October 8, 2020. Summaries of significant comments received during the public workshop and associated comment period are summarized below.

Comments were received from the following:
Christine Zimmerman, Western States Petroleum Association (WSPA)
Kim Burns, E&J Gallo (Gallo)
Shannon Corcoran, Air Conditioning Heating and Refrigeration Institute (AHRI)
Wendy Fairchild, York Engineering (York)
David B. Nielsen, Kern Oil & Refining Co. (Kern)
John E. Haley, Aera Energy LLC (Aera)
Matthew Jalali, Bakersfield Renewable Fuels, LLC (BKRF)

1. **COMMENT:** Rule 4320 limits for fire tube boilers of 5 ppmv are too low and we are unsure if there are commercially available units that can meet those limits, we would like that information**.** (AHRI, WSPA)

   RESPONSE: District staff have carefully considered the technological and economic feasibility of numerous candidate controls, and have incorporated as much flexibility into Rule 4320 as is possible. While these limits are currently achievable today based on the performance data of some existing installations, District staff tailored the compliance schedules to achieve the maximum NOx reductions as expeditiously as possible, while providing the time needed to identify the most economically feasible compliance options. In situations where a retrofit may not be the best option given the technology forcing nature of the limits, facilities may also comply by paying the annual emissions fee while the facility continually evaluates the feasibility of potential controls.

2. **COMMENT:** How will the District ensure that the units will be able to meet the proposed NOx emission limits? (AHRI)

   RESPONSE: The District and affected entities have significant experience and knowledge in working with source testing companies to conduct and provide source test data to the District with high degree of accuracy that meet local, state, and federal requirements. Approved test methods are also included in the rules.

3. **COMMENT:** With SCR required to support these very low NOx limits, ammonia slip is going to be a concern. Will there be flexibility to address any issues related to ammonia slip? (York, BKRF, Gallo)

RESPONSE: Based on discussions with vendors and manufacturers an ammonia slip limit of 10 ppm should be sufficient for units with SCR to comply with NOx limits as low as 2 ppm. Ammonia slip limits are established during the permitting process, and a case-by-case determination could be made based on the technological considerations associated with achieving the proposed NOx limits.

4. **COMMENT:** Please explain the proposed 2.5 ppmv limit for B.1 for boilers (< 75 MMBtu/hr.; fire tube). (Gallo)

RESPONSE: The proposed limit has been established consistent with the 2.5 ppmv limits proposed for category B.2 (*boilers < 75 MMBtu/hr for all other units…)*, as the technologies available to achieve the 2.5 ppmv level are the same.

5. **COMMENT:** There are potential issues with the installation of ultra low NOx burners on units at petroleum refineries. These include the longer flames which are more sensitive to firebox configuration, adequate spacing to prevent burner interaction, burner tip plugging, narrow fuel gas composition variability, and that ULNBs are designed to be fired on PUC quality gas, not refinery fuel gas. (Kern)

RESPONSE: The District is proposing limits designed specifically for refinery process heaters to account for the different configurations for these types of units. Based on discussions with vendors and manufacturers, complying with a 15 ppmv NOx limit does not necessarily require retrofitting with ULNBs. In some cases, the proposed limits may be achieved with combustion modification technologies including additional oxygen flow controls such as flue gas recirculation, advanced control systems, and tuning.

6. **COMMENT:** Installation of an SCR system on refinery units (to comply with Rule 4320) require significant physical space, higher cost, and increased reliance on utility electrical capacity. (Kern and BKRF)

RESPONSE: District staff have carefully considered the technological and economic feasibility of numerous control technologies, and have incorporated as much flexibility into Rule 4320 as is possible. The District understands that SCR systems can be costly and can have challenges in terms of installation due to space constraints. However, complying with Rule 4320 does not necessarily require the installation of an SCR system. In situations where a retrofit may not be the best option given the technology forcing nature of the limits, facilities may also comply by paying the annual emissions fee while the facility continually evaluates the feasibility of potential controls.

7. **COMMENT:** The rules should be clarified to allow for voluntary retrofits without having to achieve the NOx limit for replacement units at petroleum refineries. (Kern)

RESPONSE: A definition for "Replacement Unit" was added to Rule 4306 to clarify this item. A replacement unit is "the replacement of a boiler, steam generator, oil field steam generator, or process heater. The retrofit of an existing unit does not qualify as a replacement."

8. **COMMENT:** Aera Energy LLC and the Western States Petroleum Association (WSPA) provided cost estimates for retrofitting oil field steam generators with ULN control equipment, and requests that those estimates be reflected in the District's analysis. (Aera)

RESPONSE: The District included the cost estimates provided by Aera and WSPA in the cost effectiveness analysis, in addition to estimates obtained from vendors and other sources. The provided costs were consistent with costs provided by manufacturers and vendors of control equipment. Cost effectiveness was calculated based on the average of all cost estimates, including those provided by Aera and WSPA.

9. **COMMENT:** There are technical limitations in adapting some of the ULN control equipment to oil field steam generators, particularly with respect to SCR control technologies. (Aera)

RESPONSE: The District concluded that SCR is not a viable control technology for oil field steam generators at this time. Based on permit limits and source test results, the NOx limits in Rules 4306 and 4320 for oil field steam generators are achievable without the use of SCR.

10. **COMMENT:** Permitting equipment modifications to reduce emissions can be complicated and time consuming. On-site construction cannot commence until an Authority to Construct (ATC) has been issued. The compliance deadlines in Rule 4306 should be December 31, 2023 or 24 months after ATC issuance, whichever is later. (Aera)

RESPONSE: The compliance deadlines in the rule have been crafted in a manner that will allow for SIP-creditable emission reductions by the year 2024 per commitments in the federally-approved and enforceable *2018 PM2.5 Plan*. The District has designed the proposed amendments to allow for sufficient time for permitting and installation, and commits to working closely with affected stakeholders to streamline the permitting process.

11. **COMMENT:** The District should clarify that a unit is either subject to the Rule 4320 fee in Section 5.3.1 or the fee in Section 5.3.2. (Aera)

RESPONSE: Language was added to Section 5.3 to clarify that units would not be subject to the fees in Sections 5.3.1 and 5.3.2 concurrently.

12. **COMMENT:** Boilers located at refineries may not be able to meet the 5 ppmv Rule 4306 limits that other categories of boilers are subject to, due to technological considerations in part because these units are typically fired on process gas. (BKRF)

RESPONSE: The District understands that there may be certain challenges in retrofitting an existing unit under this category to meet the 5 ppmv NOx limit. Therefore, the District is proposing that the 5 ppmv limit only be met upon replacement of the unit, making the NOx emission limit achievable.

13. **COMMENT:** The District's draft Rule 4320 NOx limits of 2 ppmv for petroleum refinery boilers and heaters greater are too low, because they require the installation of ULN burners and SCR, which may not be technologically feasible for installation at petroleum refineries. (BKRF)

RESPONSE: District staff analyzed available technology and permit information and determined that the proposed Rule 4320 NOx limit for boilers and heaters at petroleum refineries between 40 and 110 MMBtu/hr should be 5 ppm instead of 2 ppm. Additionally, the Rule 4320 NOx limits for units greater than 110 MMBtu/hr have been adjusted from 2 ppm to 2.5 ppm. In situations where a retrofit may not be the best option given the technology forcing nature of the limits, facilities may also comply by paying the annual emissions fee while the facility continually evaluates the feasibility of potential controls.

SUMMARY OF SIGNIFICANT COMMENTS
PROPOSED AMENDMENTS TO RULE 4306 and 4320
(Boilers, Steam Generators, and Process Heaters – Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr)
September 24, 2020

The District held a public workshop on September 24, 2020. Summaries of significant comments received are summarized below.

Comments were received from the following:

Glen Mears, Plains LPG Services (Plains)
Jeff Beecher, San Joaquin Refining Company (SJR)
Kim Burns, E&J Gallo Winery (Gallo)

1. **COMMENT:** The proposed Rule 4320 limits require the installation of SCR with ammonia. The District should consider the potential safety implications of requiring the installation of control equipment that requires the use of ammonia, which is a hazardous substance. (SJR)

RESPONSE: Anhydrous ammonia can be hazardous if not stored and handled safely. Occupational Safety And Health Administration (OSHA) has stringent requirements for the storage and handling of anhydrous ammonia. Emissions controls relying on ammonia have long been utilized in wide varieties of applications. Additionally, there are other reagents that can be used in SCR systems that are less hazardous, including urea and aqueous ammonia. In addition, operators are required to comply with ammonia limits on their permits to minimize the impacts.

2. **COMMENT:** A Rule 4320 limit of 2 ppm NOx for units over 40 MMBTU is not achievable and retrofitting equipment to meet this limit would result in significant impacts to our operation, including job losses and potential facility closure. (Plains)

RESPONSE: District staff analyzed available technology and permit information and determined that the proposed Rule 4320 NOx limit for boilers and heaters at petroleum refineries between 40 and 110 MMBtu/hr should be 5 ppm instead of 2 ppm. Additionally, the Rule 4320 NOx limits for units greater than 110 MMBtu/hr have been adjusted from 2 ppm to 2.5 ppm. In situations where a retrofit may not be the best option given the technology forcing nature of the limits, facilities may also comply by paying the annual emissions fee while the facility continually evaluates the feasibility of potential controls.

3. **COMMENT:** The District should consider establishing Rule 4320 limits at 5 ppmv for all classes of boilers less than 75 MMBtu/hr. (Gallo)

   RESPONSE: District staff determined that a Rule 4320 NOx limit of 2.5 ppmv is technologically feasible for Category B units. In situations where a retrofit may not be the best option given the technology forcing nature of the limits, facilities may also comply by paying the annual emissions fee while the facility continually evaluates the feasibility of potential controls.

SUMMARY OF SIGNIFICANT COMMENTS
PROPOSED AMENDMENTS TO RULE 4306 and 4320
(Boilers, Steam Generators, and Process Heaters – Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr)
July 30, 2020

The District held a public workshop on rule concepts under consideration on July 30, 2020. Summaries of significant comments received are summarized below.

Comments were received from the following:

Daniel Beck, Chevron (Chevron)
Kris Rickards, Chevron (Chevron)

1. **COMMENT:** With FGR and SCR, there is a loss in efficiency which may result in increased fuel and electricity use, and an associated increase in GHG emissions. Will these considerations be addressed in the socio-economic analysis? (Chevron)

   RESPONSE: As documented in the staff report, these rule amendments will result in an environmental benefit through decreased NOx emissions and improved air quality. Although there may be a very small increase in fuel consumption for a small number of facilities, the rule as a whole will result in a decrease in fuel consumption sector-wide. Additionally, statewide decarbonization requirements will continue to reduce the carbon intensity in the fuel and energy sectors. The District’s cost-effective analysis takes into consideration potential increases/decreases in costs, which are included in Appendix C.

APPENDIX B

EMISSIONS REDUCTION ANALYSIS FOR PROPOSED AMENDMENTS TO RULE 4306 AND RULE 4320

December 17, 2020

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APPENDIX B
EMISSIONS REDUCTION CALCULATIONS FOR RULES 4306 AND 4320

I. Summary

As shown in this analysis, the proposed amendments will result in total emission reductions of 0.99 tons NOx/Day in 2024 and 0.16 tons NOx/Day in 2030.

Table B-1 Emission Summaries		
Rule	NOx Baseline (tons/day)	NOx Reductions (tons/day)
4306 (2024)	6.02	0.99
4306 (2030)	6.02	0.16

II. Emissions Reductions for NOx – Rule 4306

District staff used the Permit Database to identify the number of boilers, steam generators, and process heaters as well as the rated heat input of each unit so they could be appropriately distributed in the range of rated heat inputs for which different emission limits are established. There are 1,175 permitted boilers, steam generators, and process heaters subject to amendments of Rule 4306.

The oilfield steam generators and refinery units were assumed to be operated at 80% of their maximum rated heat input capacity while all other units were assumed to operate at 50% capacity. Based on the calculations shown in Table B-2, the proposed controls would result in emission reductions of 0.99 tons of NOx/day in 2024 and 0.16 tons of NOx per day in 2030. This is a reduction of 16.4% in 2024 and 2.6% in 2030 from the calculated baseline of 6.02 tons of NOx/day.

The emission inventory used in the 2018 PM2.5 Plan had a 2024 baseline of 1.18 tons of NOx per day and a baseline of 1.00 tons of NOx per day in 2030. To effectively compare the baselines, the calculated percent reduction is multiplied by the Plan baseline.

Normalized emission reduction (2024) = 1.18 tons per day NOx x 16.4%
= 0.19 tons per day NOx

Normalized emission reduction (2030) = 1.00 tons per day NOx x 2.6%
= 0.03 tons per day NOx

Table B-2 NOx Emissions Reduction Calculation for Rule 4306 Limits

Category	Permitted Level	# Units	Total MMBtu/hr	Operating Capacity	Current ppmv	Current lb/MMBtu	Current Emission (tpd)	New ppmv	New lb/MMBtu	New Emission (tpd)	Reduction in 2023 (tpd)	Reduction in 2029 (tpd)
A. 5 to 20.0 MMBtu/hr	**Fire Tube Boilers 15 ppm**	19	258	0.50	15	0.0182	0.028	7	0.0085	0.013	0.015	
	Fire Tube Boilers 9 ppm	143	2,073	0.50	9	0.0109	0.136	7	0.0085	0.106	N/A	0.030
	Fire Tube Boiler 8 ppm	1	11	0.50	7	0.0097	0.001	7	0.0085	0.001	N/A	0.000
	Fire Tube Boilers 7 ppm	9	170	0.50	7	0.0085	0.009	7	0.0085	0.009	0.000	
	Fire Tube Boilers 6 ppm	3	35	0.50	6	0.0073	0.002	6	0.0073	0.002	0.000	
	Fire Tube Boilers 5 ppm	3	45	0.50	5	0.0061	0.002	5	0.0061	0.002	0.000	
	Units at Schools	9	112.60	0.50	9	0.0109	0.007	9	0.0109	0.007	0.000	
	Units Fired on Digester Gas	2	33.50	0.50	9	0.0109	0.002	9	0.0109	0.002	0.000	
	Thermal Fluid Heaters	3	31.30	0.50	9	0.0109	0.002	9	0.0109	0.002	0.000	
	Other Units 15 ppm	17	228	0.50	15	0.0182	0.025	9	0.0109	0.015	0.010	
	Other Units 12 ppm	2	17	0.50	12	0.0146	0.001	9	0.0109	0.001	N/A	0.000
	Other Unit 9 ppm	83	869	0.50	9	0.0109	0.057	9	0.0109	0.057	0.000	
	Other Unit 7 ppm	3	48	0.50	7	0.0085	0.002	7	0.0085	0.002	0.000	
	Other Unit 6 ppm	4	65	0.50	6	0.0073	0.003	6	0.0073	0.003	0.000	
	Other Unit 5 ppm	1	20	0.50	5	0.0061	0.001	5	0.0061	0.001	0.000	
B. 20-75 MMBtu/hr	**Fire Tube Boilers 9 ppm**	25	732	0.50	9	0.0109	0.048	7	0.0085	0.037	N/A	0.011
	Fire Tube Boilers 7 ppm	48	1,421	0.50	7	0.0085	0.072	7	0.0085	0.072	0.000	
	Fire Tube Boilers 6 ppm	2	67	0.50	6	0.0073	0.003	6	0.0073	0.003	0.000	
	Fire Tube Boilers 5 ppm	12	355	0.50	5	0.0061	0.013	5	0.0061	0.013	0.000	
	Fire Tube Boilers 2.5 ppm	1	29	0.50	2.5	0.003	0.001	2.5	0.003	0.001	0.000	
	Other Units 9 ppm	9	413	0.50	9	0.0109	0.027	7	0.0085	0.021	N/A	0.006
	Other Units 7 ppm	33	1,682	0.50	7	0.0085	0.086	7	0.0085	0.086	0.000	
	Other Units 6 ppm	2	70	0.50	6	0.0073	0.003	6	0.0073	0.003	0.000	
	Other Units 5 ppm	12	587	0.50	5	0.0061	0.021	5	0.0061	0.021	0.000	

Category	Permitted Level	# Units	Total MMBtu/hr	Operating Capacity	Current ppmv	Current lb/MMBtu	Current Emission (tpd)	New ppmv	New lb/MMBtu	New Emission (tpd)	Reduction in 2023 (tpd)	Reduction in 2029 (tpd)
B. >75 MMBtu/hr	**9 ppm**	2	300	0.50	9	0.0109	0.020	5	0.0061	0.011	0.009	
	7 ppm	54	7,071	0.50	7	0.0085	0.361	5	0.0061	0.259	N/A	0.102
	6 ppm	7	942	0.50	6	0.0073	0.041	5	0.0061	0.034	N/A	0.007
	5 ppm	23	3,161	0.50	5	0.0061	0.116	5	0.0061	0.116	0.000	
C.1 OFSG 5-20 MMBtu/hr	**15 ppm**	1	15	0.80	15	0.0182	0.003	9	0.0109	0.002	0.001	
	9 ppm	5	99	0.80	9	0.0109	0.010	9	0.0109	0.010	0.000	
	7 ppm	1	20	0.80	7	0.0085	0.002	7	0.0085	0.002	0.000	
	6 ppm	1	18	0.80	6	0.0073	0.001	6	0.0073	0.001	0.000	
C.2 OFSG 20-75 MMBtu/hr	**15 ppm**	180	11,226	0.80	15	0.0182	1.961	9	0.0109	1.175	0.787	
	14 ppm	15	938	0.80	14	0.017	0.153	9	0.0109	0.098	0.055	
	12 ppm	1	63	0.80	12	0.0146	0.009	9	0.0109	0.007	0.002	
	10.5 ppm	10	690	0.80	10.5	0.0128	0.085	9	0.0109	0.072	0.013	
	9 ppm	4	140	0.80	9	0.0109	0.015	9	0.0109	0.015	0.000	
	7 ppm	60	3,338	0.80	7	0.0085	0.272	7	0.0085	0.272	0.000	
	5 ppm	6	375	0.80	5	0.0061	0.022	5	0.0061	0.022	0.000	
C.3 OF SG <75 MMBtu/hr	**7 ppm**	100	8,507	0.80	7	0.0085	0.694	7	0.0085	0.694	0.000	
	6 ppm	6	510	0.80	6	0.0073	0.036	6	0.0073	0.036	0.000	
	5 ppm	28	2,380	0.80	5	0.0061	0.139	5	0.0061	0.139	0.000	
C.4 OFSG <50% PUC	**15 ppm**	45	2,813	0.80	15	0.0182	0.491	15	0.0182	0.491	0.000	
	14 ppm	12	750	0.80	14	0.017	0.122	14	0.017	0.122	0.000	
	9 ppm	51	3,088	0.80	9	0.0109	0.323	9	0.0109	0.323	0.000	
	7 ppm	30	2,401	0.80	7	0.0085	0.196	7	0.0085	0.196	0.000	
	5 ppm	4	250	0.80	5	0.0061	0.015	5	0.0061	0.015	0.000	
D.1 Refinery Boilers <40 MMBtu/hr	**30 ppm**	1	31	0.50	30	0.0364	0.007	30	0.0364	0.007	0.000	
	5 ppm	1	27	0.50	5	0.0061	0.001	5	0.0061	0.001	0.000	

Category	Permitted Level	# Units	Total MMBtu/hr	Operating Capacity	Current ppmv	Current lb/MMBtu	Current Emission (tpd)	New ppmv	New lb/MMBtu	New Emission (tpd)	Reduction in 2023 (tpd)	Reduction in 2029 (tpd)
D.2 Refinery Boilers >40 MMBtu/hr to <110 MMBtu/hr	**25 ppm**	3	292	0.50	25	0.0304	0.053	9	0.0109	0.019	0.034	
D.3 Refinery Boilers >110 MMBtu/hr	**5 ppm**	1	200	0.50	5	0.0061	0.007	5	0.0061	0.007	0.000	
D.4 Refinery Heaters <40 MMBtu/hr	**30 ppm**	27	571	0.50	30	0.0364	0.125	30	0.0364	0.125	0.000	
	25 ppm	13	214	0.50	25	0.0304	0.039	25	0.0304	0.039	0.000	
	9 ppm	1	8	0.50	9	0.0109	0.001	9	0.0109	0.001	0.000	
	6 ppm	1	15	0.50	6	0.0073	0.001	6	0.0073	0.001	0.000	
D.5 Refinery Heaters >40 MMBtu/hr to <110 MMBtu/hr	**30 ppm**	7	424	0.50	30	0.0364	0.093	15	0.0182	0.046	0.046	
	25 ppm	2	185	0.50	25	0.0304	0.034	15	0.0182	0.020	0.014	
D.6 Refinery Heaters <110 MMBtu/hr	**5 ppm**	1	233	0.50	5	0.0061	0.009	5	0.0061	0.009	0.000	
E. Units limited by a Permit to Operate to an annual heat input > 9 billion Btu/year but < 30 billion Btu/year.	**30 ppm**	12	282.02	0.10	30	0.0364	0.012	30	0.0364	0.012	0.000	
	20 ppm	1	12.75	0.10	20	0.0243	0.000	20	0.0243	0.000	0.000	
	15 ppm	1	7.00	0.10	15	0.0182	0.000	15	0.0182	0.000	0.000	
	9 ppm	11	123.16	0.10	9	0.0109	0.002	9	0.0109	0.002	0.000	
	TOTAL	1,175	61,089				6.02			4.88	0.99	0.16
									Percent Reduction		**16.4%**	**2.6%**

APPENDIX C

COST EFFECTIVENESS ANALYSIS FOR PROPOSED AMENDMENTS TO RULE 4306 AND RULE 4320

December 17, 2020

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APPENDIX C
COST EFFECTIVENESS ANALYSIS

I. INTRODUCTION

The California Health and Safety Code 40920.6(a) requires the San Joaquin Valley Unified Air Pollution Control District to conduct both an "absolute" cost effectiveness analysis and an incremental cost effectiveness analysis of available emission control options prior to adopting each Best Available Retrofit Control Technology (BARCT) rule. The purpose of conducting a cost effectiveness analysis is to evaluate the economic reasonableness of the pollution control measure or rule. The analysis also serves as a guideline in developing the control requirements of a rule.

II. SUMMARY AND CONCLUSION

A. Absolute Cost Effectiveness Analysis

Absolute cost effectiveness examines the cost of reaching the proposed emission limits using the current emissions as a baseline. Cost effectiveness is calculated as the added annual cost (in $/year) of a control technology or technique, divided by the emission reduction achieved (in tons reduced/year). The annual costs include annualized capital equipment costs and engineering design costs plus the annual labor and maintenance costs. Higher cost numbers are typically for smaller, low-use units since the annual costs result in relatively lower emission reductions. The analysis shows that the cost effectiveness values improve for larger units, units with a higher operating capacity factor, and more restrictive NOx limits relative to the current limits.

The detailed analyses showing the costs for installed capital equipment, electricity, fuel, and operations and maintenance costs are shown in Tables C-2 to C-40. Results are summarized in Table C-1, below. Rule 4306 establishes NOx limits that units must achieve to operate in the District and are based on technologic and economic feasibility. The Rule 4320 Advanced Emission Reduction Option (AERO) limits are meant to be the most stringent technologically feasible options but may not be economically feasible for all units to achieve. The controls required to reach the final NOx emission levels are either Selective Catalytic Reduction (SRC) or Ultra-Low NOx Burners (ULNB). As summarized in Table 1, cost for these controls can be very high and implementation may not be possible due to space limitations that would prevent installation of the control equipment. In situations where a retrofit may not be the best option given the technology forcing nature of the limits, facilities may also comply by paying the annual emissions fee while the facility continually evaluates the feasibility of potential controls.

Table C-1 Cost Effectiveness Summary

Compliance Scenario	Average Cost Effectiveness ($/ton)	Absolute Cost Effectiveness Range ($/ton)
RULE 4306		
ULNB (15 ppmv to 7 ppmv)	$54,700	$49,800 to $62,900
Tuning (9 ppmv to 7 ppmv)	$72,700 to 84,000	$57,600 to $100,700
ULNB (15 ppmv to 9 ppmv)	$72,600	$66,100 to $83,500
Tuning (12 ppmv to 9 ppmv)	$65,600	$55,700 to $82,400
ULNB (12 ppmv to 9 ppmv)	$106,500	$93,900 to $128,300
SCR (9 ppmv to 5 ppmv)	$22,000 to $52,000	$2,100 to $70,100
SCR (7 ppmv to 5 ppmv)	$44,100 to $104,000	$4,200 to $140,200
Oil Field Steam Generator (15 ppmv to 9 ppmv)	$43,100 to $106,000	$43,100 to $118,500
Refinery Boilers (25 ppmv to 9 ppmv)	$27,600	$27,300 to $28,000
Refinery Heaters (30 ppmv to 15 ppmv)	$13,000	$12,000 to $15,200
RULE 4320		
SCR (9 ppmv to 2.5 ppmv)	$13,400 to $66,100	$1,300 to $145,900
SCR (7 ppmv to 2.5 ppmv)	$19,300 to $94,900	$1,800 to $209,600
Oil Field Steam Generator (7 ppmv to 5 ppmv)	$50,600	$50,600
Existing SCR Modification (5 ppmv to 2.5 ppmv)	$13,200 to $14,900	$10,000 to $17,400

Note: The Average Value is the average for the range of units with a spread indicating the different fuel usages that were analyzed. The Absolute Value is the lowest and highest values calculated under that compliance scenario and typically represent the cost for a large, high-use unit and a small, low-use unit. All values were rounded to two significant digits due to uncertainty in the data and variations between units.

B. Incremental Cost Effectiveness

Incremental cost effectiveness (ICE) indicates the additional cost for further controlling a unit from the proposed limit to the lowest possible level. Costs are evaluated similar to absolute costs but are only calculated for the controls and reductions beyond what is required to comply with the rule. ICE does not reveal the emission reduction potential of the control options, but examines the more stringent options which were not considered to be cost effective. Due to the increased costs and marginal emission reductions, the ICE calculations are typically much higher cost effectiveness than the absolute cost effectiveness values are not directly comparable.

The incremental cost effectiveness analysis result would be similar to those shown in Tables C-2 through C-40. For the ICE analysis, the emission reduction is the difference between the current rule NOx limits to proposed NOx limits.

III. SOURCES OF COST DATA

District staff used cost information provided by control equipment manufacturers and vendors, and from stakeholders to conduct a cost effectiveness analysis of the proposed NOx limits in Proposed Rules 4306 and 4320. Specifically the data used in the analysis came from the following sources:

1. R.F. MacDonald Company
2. Nationwide Boiler
3. Esys The Energy Controls Company
4. PCL Industrial Services, Inc
5. Aera Energy LLC.
6. Zeeco, Inc.
7. Honeywell International Inc. (Callidus Technologies)
8. Kern Oil & Refining Co.
9. Western States Petroleum Association
10. Bakersfield Renewable Fuels, LLC

Cost information submitted to the District was used to create the range of costs located in Tables C-1 through C-40.

IV. COST EFFECTIVENESS ANALYSIS PROCEDURE

A. Cost Effectiveness Analysis Procedure

To illustrate the cost effectiveness of complying with the proposed limits, District staff's analysis provides varying cost effectiveness values depending on the size of the unit and the annual capacity factor that the unit is operated. The actual compliance costs and cost effectiveness values would depend on several factors such as the type of unit, site-specific operating conditions, and the appropriate emission limits the unit has to meet.

B. Absolute Cost Effectiveness (ACE) Calculation Method

The absolute cost effectiveness of a control technology is calculated as follows:

1. Determine an equivalent annual equipment cost using a capital recovery factor based on an assumed interest rate of 10 percent and equipment life of 10 years. The annualized capital equipment cost is calculated by multiplying the installed capital equipment cost by the capital recovery factor of 0.163.
2. Determine the annual electricity, fuel, and operation and maintenance costs of a control technology.
3. Calculate the annual cost by adding the costs calculated in Step 1 and Step 2.
4. Calculate the emission reduction in tons/year.
5. Calculate the absolute cost effectiveness by dividing the cost in Step 3 by the emissions reduction in Step 4.

C. Incremental Cost Effectiveness (ICE) Calculation Method

The incremental cost effectiveness of a control technology is calculated as follows:

1. Identify the complying control options appropriate to the existing equipment.
2. Estimate the annual average cost of each control option by using Steps 1 to 3 of the ACE calculation method.
3. Calculate the potential emission reduction for each control option. The potential emission reductions (PE) are the difference between the current emissions and the potential emissions using the new control technology.

D. Cost Calculation Details

For Rule 4306, District staff analyzed the absolute cost effectiveness based on installing and operating an ultra low NOx (ULNB) burner system, tuning of the unit, or installing a selective catalytic reduction (SCR) system. The absolute cost effectiveness analysis was conducted for several sizes of units operating at 75% capacity factor for boilers and heaters. 80% capacity factor was used for oil field steam generators.

E. Cost Effectiveness Tables

Rule 4306 Category A.1 (>5 MMBtu/hr and ≤20 MMBtu/hr Fire Tube Boilers)

<u>Category A.1a</u>
Retrofit Technology Needed to Achieve Proposed Rule Limit of 7 ppmv by **2023**:

- New Ultra Low NOx (ULN) burner, Combustion Controls Upgrade, and FGR fan Upgrade

Table C-2

ULN Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
15 ppmv to 7 ppmv Cost Effectiveness

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
20	$85,500	$13,937	$4,016	$13,758	$31,710	0.64	$49,757
15	$68,400	$11,149	$3,346	$10,318	$24,814	0.48	$51,915
10	$51,300	$8,362	$2,008	$6,879	$17,248	0.32	$54,131
>5	$34,200	$5,575	$1,004	$3,439	$10,018	0.16	$62,878
					Average Cost Effectiveness		$54,670

<u>Category A.1b</u>

Retrofit Technology Needed to Achieve Proposed Rule Limit of 7 ppmv by **2029**:

- Tuning existing burner, Combustion Controls Upgrade, and FGR fan Upgrade

Based on meetings with manufacturers and vendors, the majority of units permitted at 9 ppmv can comply with the 7 ppmv NOx limit by tuning the existing burner, upgrading combustion controls, and upgrading the FGR fan. However, some units may be required to retrofit their units with ultra low NOx burners. The longer compliance schedule for these units will allow for technological advances and for operators to explore more cost effective options to comply with the proposed Rule 4306 or Rule 4320 NOx limits.

Table C-3

Tuning Existing Burner Cost Effectiveness Calculation for Units at 75% Capacity Factor
9 ppmv to 7 ppmv Cost Effectiveness

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
20	$28,500	$4,646	$1,004	$3,439	$9,089	0.16	$57,641
15	$24,700	$4,026	$837	$2,580	$7,442	0.12	$62,931
10	$20,900	$3,407	$502	$1,720	$5,628	0.08	$71,389
>5	$17,100	$2,787	$251	$860	$3,898	0.04	$98,887
					Average Cost Effectiveness		$72,712

Rule 4306 Categories A.2-A.5 (>5 MMBtu/hr and ≤20 MMBtu/hr)

Category A.2-A.5a
Retrofit Technology Needed to Achieve Proposed Rule Limit of 9 ppmv by **2023**:

- New Ultra Low NOx (ULN) burner, Combustion Controls Upgrade, FGR fan Upgrade

Table C-4

ULN Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
15 ppmv to 9 ppmv Cost Effectiveness

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
20	$85,500	$13,937	$4,016	$13,758	$31,710	0.48	$66,115
15	$68,400	$11,149	$3,346	$10,318	$24,814	0.36	$68,983
10	$51,300	$8,362	$2,008	$6,879	$17,248	0.24	$71,927
>5	$34,200	$5,575	$1,004	$3,439	$10,018	0.12	$83,550
					Average Cost Effectiveness		$72,644

Category A.2-A.5b
Retrofit Technology Needed to Achieve Proposed Rule Limit of 9 ppmv by **2029**:

- Tuning existing burner, Combustion Controls Upgrade, and FGR fan Upgrade
- New Ultra Low NOx (ULN) burner, Combustion Controls Upgrade, and FGR fan Upgrade

Based on meetings with manufacturers and vendors, some units permitted at 12 ppm can comply with the 9 ppm NOx limit by tuning the existing burner, upgrading combustion controls, and upgrading the FGR fan. Other units may be required to retrofit their units with ultra low NOx burners. The longer compliance schedule for these units will allow for technological advances and for operators to explore more cost effective options to comply with the proposed Rule 4306 or Rule 4320 NOx limits.

Table C-5

Tuning Existing Burner Cost Effectiveness Calculation for Units at 75% Capacity Factor
12 ppmv to 9 ppmv Cost Effectiveness

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
20	$28,500	$4,646	$2,008	$6,879	$13,532	0.24	$55,667
15	$24,700	$4,026	$1,673	$5,159	$10,858	0.18	$59,557
10	$20,900	$3,407	$1,004	$3,439	$7,850	0.12	$64,585
>5	$17,100	$2,787	$502	$1,720	$5,009	0.06	$82,421
					Average Cost Effectiveness		$65,558

Table C-6

ULN Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
12 ppmv to 9 ppmv Cost Effectiveness

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
20	$85,500	$13,937	$2,008	$6,879	$22,823	0.24	$93,887
15	$68,400	$11,149	$1,673	$5,159	$17,981	0.18	$98,627
10	$51,300	$8,362	$1,004	$3,439	$12,805	0.12	$105,353
>5	$34,200	$5,575	$502	$1,720	$7,796	0.06	$128,286
					Average Cost Effectiveness		$106,538

Rule 4306 Category B.1 and B.2 (>20 MMBtu/hr and ≤75 MMBtu/hr)

Category B.1 and B.2
Retrofit Technology Needed to Achieve Proposed Rule Limit of 7 ppmv by **2023**:

- Tuning existing burner, Combustion Controls Upgrade, and FGR fan Upgrade

Based on meetings with manufacturers and vendors, the majority of units permitted at 9 ppm can comply with the 7 ppm NOx limit by tuning the existing burner, upgrading combustion controls, and upgrading the FGR fan.

Table C-7

Tuning Existing Burner Cost Effectiveness Calculation for Units at 75% Capacity Factor
9 ppmv to 7 ppmv Cost Effectiveness

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
75	$95,190	$15,516	$13,385	$17,197	$46,098	0.59	$77,961
70	$91,720	$14,950	$13,385	$16,051	$44,386	0.55	$80,427
65	$88,248	$14,384	$10,039	$14,904	$39,327	0.51	$76,742
60	$84,776	$13,818	$10,039	$13,758	$37,615	0.47	$79,517
55	$81,304	$13,253	$10,039	$12,611	$35,903	0.43	$82,797
50	$77,832	$12,687	$8,366	$11,465	$32,517	0.39	$82,489
45	$74,360	$12,121	$6,693	$10,318	$29,131	0.35	$82,111
40	$70,888	$11,555	$5,019	$9,172	$25,746	0.32	$81,640
35	$67,416	$10,989	$4,016	$8,025	$23,030	0.28	$83,459
30	$63,944	$10,423	$3,346	$6,879	$20,648	0.24	$87,299
25	$60,472	$9,857	$2,677	$5,732	$18,266	0.20	$92,675
>20	$57,000	$9,291	$2,008	$4,586	$15,885	0.16	$100,740
					Average Cost Effectiveness		$83,988

Rule 4306 Category B.3 (>75 MMBtu/hr)

Category B.3a
Retrofit Technology Needed to Achieve Proposed Rule Limit of 5 ppmv by **2023**:

- SCR with anhydrous ammonia reagent system
- SCR with urea or aqueous ammonia reagent system with reagent vaporizer

Boilers and process heaters with a heat input greater than 75 MMBtu/hr require SCR retrofit to comply with the proposed 5 ppm NOx limit. SCR systems require a reducing agent to reduce NOx emissions. Anhydrous ammonia is the least expensive reagent, but can be hazardous. Aqueous ammonia and urea are safer reagents, but are more expensive because they require additional processing equipment.

The use of an SCR system can result in an annual cost savings as a result of less need for electricity to run FGR fans and decreased fuel use from the increased efficiency of a LNB. The annual cost savings ranges depending on the size of the unit.

Table C-8

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
9 ppmv to 5 ppmv Cost Effectiveness – *Anhydrous Ammonia Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$689,000	$112,307	-$33,463	-$91,717	$7,260	$12,221	$6,608	3.15	$2,095
150	$689,000	$112,307	-$33,463	-$68,788	$5,445	$12,221	$27,722	2.37	$11,721
125	$689,000	$112,307	-$33,463	-$57,323	$4,537	$12,221	$38,279	1.97	$19,421
100	$627,000	$102,201	-$33,463	-$45,859	$3,630	$11,110	$37,619	1.58	$23,858
95	$627,000	$102,201	-$33,463	-$43,566	$3,448	$11,110	$39,731	1.50	$26,523
90	$627,000	$102,201	-$33,463	-$41,273	$3,267	$11,110	$41,842	1.42	$29,485
85	$570,000	$92,910	-$33,463	-$38,980	$3,085	$10,100	$33,653	1.34	$25,109
80	$570,000	$92,910	-$33,463	-$36,687	$2,904	$10,100	$35,764	1.26	$28,352
>75	$570,000	$92,910	-$33,463	-$34,394	$2,722	$10,100	$37,876	1.18	$32,027
							Average Cost Effectiveness		$22,066

Table C-9

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
9 ppmv to 5 ppmv Cost Effectiveness – *32.5% Urea Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$917,000	$149,471	-$33,463	-$91,717	$8,515	$12,221	$45,027	3.61	$12,461
150	$917,000	$149,471	-$33,463	-$68,788	$6,386	$12,221	$65,827	2.71	$24,289
125	$917,000	$149,471	-$33,463	-$57,323	$5,322	$12,221	$76,228	2.26	$33,752
100	$855,000	$139,365	-$33,463	-$45,859	$4,257	$11,110	$75,411	1.81	$41,738
95	$855,000	$139,365	-$33,463	-$43,566	$4,044	$11,110	$77,491	1.72	$45,147
90	$855,000	$139,365	-$33,463	-$41,273	$3,832	$11,110	$79,571	1.63	$48,934
85	$798,000	$130,074	-$33,463	-$38,980	$3,619	$10,100	$71,350	1.54	$46,460
80	$798,000	$130,074	-$33,463	-$36,687	$3,406	$10,100	$73,430	1.45	$50,803
>75	$798,000	$130,074	-$33,463	-$34,394	$3,193	$10,100	$75,510	1.36	$55,725
							Average Cost Effectiveness		$39,923

Table C-10

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
9 ppmv to 5 ppmv Cost Effectiveness – *19.5% Aqueous Ammonia Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$917,000	$149,471	-$33,463	-$91,717	$28,185	$12,221	$64,697	3.15	$20,515
150	$917,000	$149,471	-$33,463	-$68,788	$21,139	$12,221	$80,580	2.37	$34,069
125	$917,000	$149,471	-$33,463	-$57,323	$17,616	$12,221	$88,522	1.97	$44,912
100	$855,000	$139,365	-$33,463	-$45,859	$14,093	$11,110	$85,246	1.58	$54,063
95	$855,000	$139,365	-$33,463	-$43,566	$13,388	$11,110	$86,834	1.50	$57,968
90	$855,000	$139,365	-$33,463	-$41,273	$12,683	$11,110	$88,423	1.42	$62,308
85	$798,000	$130,074	-$33,463	-$38,980	$11,979	$10,100	$79,710	1.34	$59,473
80	$798,000	$130,074	-$33,463	-$36,687	$11,274	$10,100	$81,298	1.26	$64,449
>75	$798,000	$130,074	-$33,463	-$34,394	$10,569	$10,100	$82,887	1.18	$70,089
							Average Cost Effectiveness		$51,983

Category B.3b
Retrofit Technology Needed to Achieve Proposed Rule Limit of 5 ppmv by **2029**:

- SCR with anhydrous ammonia reagent system
- SCR with urea or aqueous ammonia reagent system with reagent vaporizer

District staff determined that it was less cost effective for units permitted at 7 ppm or less to retrofit to meet the proposed 4306 NOx limit of 5 ppm than for units permitted at higher limits. The longer compliance schedule for these units will allow for technological advances and for operators to explore more cost effective options to comply with the proposed Rule 4306 or Rule 4320 NOx limits.

Table C-11

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
7 ppmv to 5 ppmv Cost Effectiveness – *Anhydrous Ammonia Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$689,000	$112,307	-$33,463	-$91,717	$7,260	$12,221	$6,608	1.58	$4,191
150	$689,000	$112,307	-$33,463	-$68,788	$5,445	$12,221	$27,722	1.18	$23,442
125	$689,000	$112,307	-$33,463	-$57,323	$4,537	$12,221	$38,279	0.99	$38,842
100	$627,000	$102,201	-$33,463	-$45,859	$3,630	$11,110	$37,619	0.79	$47,716
95	$627,000	$102,201	-$33,463	-$43,566	$3,448	$11,110	$39,731	0.75	$53,047
90	$627,000	$102,201	-$33,463	-$41,273	$3,267	$11,110	$41,842	0.71	$58,969
85	$570,000	$92,910	-$33,463	-$38,980	$3,085	$10,100	$33,653	0.67	$50,217
80	$570,000	$92,910	-$33,463	-$36,687	$2,904	$10,100	$35,764	0.63	$56,704
>75	$570,000	$92,910	-$33,463	-$34,394	$2,722	$10,100	$37,876	0.59	$64,055
							Average Cost Effectiveness		$44,131

Table C-12

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
7 ppmv to 5 ppmv Cost Effectiveness – *32.5% Urea Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$917,000	$149,471	-$33,463	-$91,717	$8,278	$12,221	$44,790	1.58	$28,406
150	$917,000	$149,471	-$33,463	-$68,788	$6,209	$12,221	$65,650	1.18	$55,513
125	$917,000	$149,471	-$33,463	-$57,323	$5,174	$12,221	$76,080	0.99	$77,199
100	$855,000	$139,365	-$33,463	-$45,859	$4,139	$11,110	$75,293	0.79	$95,501
95	$855,000	$139,365	-$33,463	-$43,566	$3,932	$11,110	$77,379	0.75	$103,312
90	$855,000	$139,365	-$33,463	-$41,273	$3,725	$11,110	$79,465	0.71	$111,991
85	$798,000	$130,074	-$33,463	-$38,980	$3,518	$10,100	$71,250	0.67	$106,320
80	$798,000	$130,074	-$33,463	-$36,687	$3,311	$10,100	$73,336	0.63	$116,273
>75	$798,000	$130,074	-$33,463	-$34,394	$3,104	$10,100	$75,422	0.59	$127,552
							Average Cost Effectiveness		$91,341

Table C-13

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor **7 ppmv to 5 ppmv Cost Effectiveness – *19.5% Aqueous Ammonia Reagent***									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$917,000	$149,471	-$33,463	-$91,717	$28,185	$12,221	$64,697	1.58	$41,031
150	$917,000	$149,471	-$33,463	-$68,788	$21,139	$12,221	$80,580	1.18	$68,138
125	$917,000	$149,471	-$33,463	-$57,323	$17,616	$12,221	$88,522	0.99	$89,824
100	$855,000	$139,365	-$33,463	-$45,859	$14,093	$11,110	$85,246	0.79	$108,126
95	$855,000	$139,365	-$33,463	-$43,566	$13,388	$11,110	$86,834	0.75	$115,937
90	$855,000	$139,365	-$33,463	-$41,273	$12,683	$11,110	$88,423	0.71	$124,616
85	$798,000	$130,074	-$33,463	-$38,980	$11,979	$10,100	$79,710	0.67	$118,945
80	$798,000	$130,074	-$33,463	-$36,687	$11,274	$10,100	$81,298	0.63	$128,898
>75	$798,000	$130,074	-$33,463	-$34,394	$10,569	$10,100	$82,887	0.59	$140,177
							Average Cost Effectiveness		$103,966

Rule 4306 Category C.1 (>5 MMBtu/hr and ≤20 MMBtu/hr Oil Field Steam Generators)

Retrofit Technology Needed to Achieve Proposed Rule Limit of 9 ppmv:

- New Ultra Low NOx (ULN) burner, Combustion Controls Upgrade, and FGR fan Upgrade

Table C-14

ULN Retrofit Cost Effectiveness Calculation for Units at 80% Capacity Factor **15 ppmv to 9 ppmv Cost Effectiveness**							
Size MMBtu/hr	Avg Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
20	$339,750	$55,379	$5,230	-	$60,609	0.51	$118,473
18	$275,198	$44,857	$2,615	-	$47,472	0.46	$103,105
15	$210,645	$34,335	$2,615	-	$36,950	0.38	$96,302
					Average Cost Effectiveness		$105,960

Rule 4306 Category C.2 (>20 MMBtu/hr and ≤75 MMBtu/hr Oil Field Steam Generators)

Retrofit Technology Needed to Achieve Proposed Rule Limit of 9 ppmv:

- New Ultra Low NOx (ULN) burner, Combustion Controls Upgrade, and FGR fan Upgrade

Approximately 90% of the oilfield steam generators in this size range have a heat input of 62.5 MMBtu/hr. As this is the most common size unit, the cost effectiveness analysis focused on units with a heat input of 62.5 MMBtu/hr. These units are generally older and higher emitting than larger oilfield steam generators. Units in this category will be required to retrofit to meet the proposed 9 ppm NOx limit.

Table C-15

ULN Retrofit Cost Effectiveness Calculation for Units at 80% Capacity Factor 15 ppmv to 9 ppmv Cost Effectiveness							
Size MMBtu/hr	Avg Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
62.5	$342,581	$55,841	$13,075	-	$68,915	1.60	$43,107
					Average Cost Effectiveness		

Rule 4306 Category C.3 (>75 MMBtu/hr Oil Field Steam Generators)

98% of the oilfield steam generators in this size range have a heat input of 85 MMBtu/hr. These units are generally newer and have better control technology than smaller oilfield steam generators. All permitted units in this category already meet proposed Rule 4306 NOx limit of 7 ppmv.

Rule 4306 Category C.4 (>20 MMBtu/hr and ≤75 MMBtu/hr Oil Field Steam Generators fired on <50% PUC natural gas)

The District is proposing to maintain the Rule 4306 NOx limit of 15 ppmv for units fired on less than 50% PUC quality gas. This is because the impurities in waste gas can increase NOx emissions and ultra low NOx burners are designed to be operated on PUC quality gas. All permitted units in this category already meet proposed Rule 4306 limit of 15 ppmv.

Rule 4306 Category D.1 (>5 MMBtu/hr and ≤40 MMBtu/hr Boilers at Refineries)

The District is proposing to maintain the Rule 4306 NOx limit of 30 ppmv for smaller boilers at refineries. This is because many of these units are fired on non-PUC quality gas, the impurities in waste gas can increase NOx emissions, and ultra low NOx burners are designed to be operated on PUC quality gas. All permitted units in this category already meet proposed Rule 4306 limit of 30 ppmv. However, the units will be subject to a 5 ppmv NOx limit when the unit is replaced. The cost effectiveness analysis below is for the incremental cost of installing an SCR system on the replacement unit.

Retrofit Technology Needed to Achieve Proposed Rule Limit of 5 ppmv upon replacement:

- SCR with anhydrous ammonia reagent system
- SCR with urea or aqueous ammonia reagent system

Table C-16

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
30 ppmv to 5 ppmv Cost Effectiveness – *Anhydrous Ammonia Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
30	$407,290	$66,388	-	-	$2,681	$5,509	$74,578	2.99	$24,975
25	$390,320	$63,622	-	-	$2,234	$5,280	$71,136	2.49	$28,587
							Average Cost Effectiveness		$26,781

Table C-17

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
30 ppmv to 5 ppmv Cost Effectiveness – *32.5%* Urea *Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
30	$705,970	$115,073	-	-	$3,087	$5,509	$123,669	2.99	$41,415
25	$689,000	$112,307	-	-	$2,572	$5,280	$120,159	2.49	$48,288
							Average Cost Effectiveness		$44,852

Table C-18

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 30 ppmv to 5 ppmv Cost Effectiveness – *19.5% Aqueous Reagent*									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
30	$705,970	$115,073	-	-	$10,634	$5,509	$131,216	2.99	$43,943
25	$689,000	$112,307	-	-	$8,861	$5,280	$126,448	2.49	$50,815
							Average Cost Effectiveness		$47,379

Rule 4306 Category D.2 (>40 MMBtu/hr and ≤110 MMBtu/hr Boilers at Refineries)

Retrofit/Replacement Technology Needed to Achieve Proposed Rule Limit of 9 ppmv by **2023**:

- New Ultra Low NOx (ULN) burner, Combustion Controls Upgrade, and FGR fan Upgrade

The District is proposing a Rule 4306 NOx limit of 9 ppmv for boilers at refineries with a heat input greater than 40 MMBtu/hr and less than or equal to 110 MMBtu/hr. This NOx limit is lower for process heaters. Based on conversations with operators, vendors, and manufacturers, boilers in this size range are capable of meeting lower NOx limits than process heaters. The cost effectiveness analysis below is based on units retrofitting from a 25 ppmv NOx limit, because all units in this size range are currently permitted at 25 ppmv, to a 9 ppmv limit.

Table C-19

ULN Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 25 ppmv to 9 ppmv Cost Effectiveness							
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
100	$438,900	$71,541	$33,463	$68,788	$173,791	6.37	$27,270
95	$418,950	$68,289	$33,463	$65,349	$167,100	6.05	$27,600
90	$399,000	$65,037	$33,463	$61,909	$160,409	5.74	$27,967
					Average Cost Effectiveness		$27,613

Retrofit Technology Needed to Achieve Proposed Rule Limit of 5 ppmv <u>upon replacement</u>:

- SCR with anhydrous ammonia reagent system
- SCR with urea or aqueous ammonia reagent system

Units in this size range will be subject to a 5 ppmv NOx limit when the unit is replaced. The cost effectiveness analysis below is for the incremental cost of installing an SCR system on the replacement unit.

Table C-20

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
25 ppmv to 5 ppmv Cost Effectiveness – *Anhydrous Ammonia Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
100	$821,370	$133,883	-	-	$8,935	$11,110	$153,929	7.95	$19,363
95	$821,370	$133,883	-	-	$8,488	$11,110	$153,482	7.55	$20,323
90	$821,370	$133,883	-	-	$8,042	$11,110	$153,035	7.15	$21,389
							Average Cost Effectiveness		$20,358

Table C-21

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
30 ppmv to 5 ppmv Cost Effectiveness – *32.5% Urea Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
100	$1,120,050	$182,568	-	-	$10,289	$11,110	$203,967	7.95	$25,657
95	$1,120,050	$182,568	-	-	$9,774	$11,110	$203,452	7.55	$26,939
90	$1,120,050	$182,568	-	-	$9,260	$11,110	$202,938	7.15	$28,364
							Average Cost Effectiveness		$26,987

Table C-22

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
30 ppmv to 5 ppmv Cost Effectiveness – *19.5% Aqueous Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
100	$1,120,050	$182,568	-	-	$35,445	$11,110	$229,123	7.95	$28,822
95	$1,120,050	$182,568	-	-	$33,673	$11,110	$227,351	7.55	$30,104
90	$1,120,050	$182,568	-	-	$31,901	$11,110	$225,579	7.15	$31,529
							Average Cost Effectiveness		$30,151

Rule 4306 Category D.3 (>110 MMBtu/hr Boilers at Refineries)

The District is proposing to maintain the Rule 4306 NOx limit of 5 ppmv for boilers with a heat input greater than 110 MMBtu/hr. There is only one boiler in this size range operating in the District. This unit has a SCR system and meets the proposed Rule 4306 limit of 5 ppmv.

Rule 4306 Category D.4 (>5 MMBtu/hr and ≤40 MMBtu/hr Process Heaters at Refineries)

The District is proposing to maintain the Rule 4306 NOx limit of 30 ppmv for smaller process heaters at refineries. This is because many of these units are fired on non-PUC quality gas, the impurities in waste gas can increase NOx emissions, and ultra low NOx burners are designed to be operated on PUC quality gas. All permitted units in this category already meet proposed Rule 4306 limit of 30 ppmv. However, the units will be subject to a 9 ppmv NOx limit when the unit is replaced. The cost effectiveness analysis below is for the incremental cost of installing ultra low NOx burners, combustion controls, and FGR on the replacement unit.

Retrofit Technology Needed to Achieve Proposed Rule Limit of 9 ppmv upon replacement.

- New Ultra Low NOx (ULN) burner, Combustion Controls Upgrade, and FGR fan Upgrade

Table C-23

ULN Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 30 ppmv to 9 ppmv Cost Effectiveness							
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
40	144,960	23,585	7,355	-	30,940	3.29	9,404
35	124,009	20,176	7,355	-	27,531	2.87	9,593
30	103,058	16,768	7,355	-	24,123	2.47	9,766
25	93,431	15,201	7,355	-	22,556	2.06	10,950
20	72,480	11,792	7,355	-	19,147	1.64	11,675
15	62,854	10,226	7,355	-	17,581	1.23	14,293
10	41,903	6,818	7,355	-	14,173	0.83	11,764
>5	20,951	3,409	7,355	-	10,764	0.41	26,254
					Average Cost Effectiveness		12,962

Rule 4306 Category D.5 (>40 MMBtu/hr and ≤110 MMBtu/hr Process Heaters at Refineries)

Retrofit Technology Needed to Achieve Proposed Rule Limit of 15 ppmv by **2023**:

- New Ultra Low NOx (ULN) burner, Combustion Controls Upgrade, and FGR fan Upgrade

The District is proposing a Rule 4306 NOx limit of 15 ppmv for process heaters at refineries with a heat input greater than 40 MMBtu/hr and less than or equal to 110 MMBtu/hr. This NOx limit is higher for process heaters than for similarly sized boilers. Based on conversations with operators, vendors, and manufacturers, process heaters in this size range are not capable of meeting as low of NOx limits as boilers. The cost effectiveness analysis below is based on units retrofitting from a 30 ppmv NOx limit because the majority of units in this size range are currently permitted at 30 ppmv.

Table C-24

ULN Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
30 ppmv to 15 ppmv Cost Effectiveness

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
110	404,303	65,780	12,257	-	78,037	6.50	12,006
100	362,400	58,962	12,257	-	71,219	5.91	12,051
80	289,920	47,170	12,257	-	59,427	4.73	12,564
60	217,440	35,377	12,257	-	47,634	3.55	13,418
40	144,960	23,585	12,257	-	35,842	2.36	15,187
					Average Cost Effectiveness		13,045

Rule 4306 Category D.6 (>110 MMBtu/hr Process Heaters at Refineries)

The District is proposing to maintain the Rule 4306 NOx limit of 5 ppmv for process heaters with a heat input greater than 110 MMBtu/hr. There is only one unit in this size range operating in the District. This unit has a SCR system and meets the proposed Rule 4306 limit of 5 ppmv.

Rule 4306 Category E (Low Use Boilers – 9-30 Billion Btu/yr)

The District is proposing to maintain the Rule 4306 NOx limit of 30 ppmv units with fuel use less than 30 billion Btu/year. This category is necessary for low use and emergency units. District staff determined that it was not cost effective to require units with low fuel usage to retrofit to meet lower NOx limits. All permitted units in this category already meet proposed Rule 4306 limit of 30 ppmv.

Rule 4320 Cost Effectiveness Discussion

Cost effectiveness for Rule 4320 depend on the current level of controls, unit size, fuel usage and NOx emission limits. For larger, high operating capacity units, SCR costs may be as low as $1,000 per ton due to the cost savings from decreased fuel and electricity usage. SCR costs for smaller units, with lower total emissions, can be as high as $210,000 per ton. Below are some examples of cost effectiveness analyses for units retrofitting to meet proposed Rule 4320 NOx limits.

Rule 4320 Categories B.1 and B.2 (>20 MMBtu/hr and ≤75 MMBtu/hr)

Retrofit Technology Needed to Achieve Proposed Rule Limit of 2.5 ppmv:

- SCR with anhydrous ammonia reagent system

- SCR with urea or aqueous ammonia reagent system with reagent vaporizer

Boilers and process heaters with a heat input greater than 20 MMBtu/hr and less than or equal to 75 MMBtu require SCR retrofit to comply with the proposed 2.5 ppm NOx limit. SCR systems require a reducing agent to reduce NOx emissions. Anhydrous ammonia is the least expensive reagent, but can be hazardous. Aqueous ammonia and urea are safer reagents, but are more expensive because they require additional processing equipment.

For units already equipped with a SCR system designed to meet a higher NOx limit, complying with a 2.5 ppmv NOx limit requires an additional layer of catalyst and more reagent, and may also require a new SCR housing.

Table C-25

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
7 ppmv to 2.5 ppmv Cost Effectiveness – *Anhydrous Ammonia Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
75	$427,500	$69,683	-$33,463	-$34,394	$2,722	$7,575	$12,123	1.36	$8,947
70	$414,550	$67,572	-$33,463	-$32,101	$2,541	$7,346	$11,894	1.26	$9,405
65	$401,595	$65,460	-$33,463	-$29,808	$2,359	$7,116	$11,664	1.17	$9,932
60	$388,640	$63,348	-$33,463	-$27,515	$2,178	$6,886	$11,435	1.08	$10,548
55	$375,685	$61,237	-$33,463	-$25,222	$1,996	$6,657	$11,205	0.99	$11,276
50	$362,730	$59,125	-$16,731	-$22,929	$1,815	$6,427	$27,707	0.90	$30,670
45	$349,775	$57,013	-$16,731	-$20,636	$1,633	$6,198	$27,477	0.81	$33,795
40	$336,820	$54,902	-$16,731	-$18,343	$1,452	$5,968	$27,247	0.72	$37,702
35	$323,865	$52,790	-$10,039	-$16,051	$1,270	$5,739	$33,710	0.63	$53,308
30	$310,910	$50,678	-$6,693	-$13,758	$1,089	$5,509	$36,826	0.54	$67,942
25	$297,955	$48,567	-$6,693	-$11,465	$907	$5,280	$36,596	0.45	$81,022
>20	$285,000	$46,455	-$6,693	-$9,172	$726	$5,050	$36,367	0.36	$100,641
							Average Cost Effectiveness		$37,932

Table C-26

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 9 ppmv to 2.5 ppmv Cost Effectiveness – *Anhydrous Ammonia Reagent*									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
75	$427,500	$69,683	-$33,463	-$34,394	$2,722	$7,575	$12,123	1.95	$6,229
70	$414,550	$67,572	-$33,463	-$32,101	$2,541	$7,346	$11,894	1.82	$6,548
65	$401,595	$65,460	-$33,463	-$29,808	$2,359	$7,116	$11,664	1.69	$6,915
60	$388,640	$63,348	-$33,463	-$27,515	$2,178	$6,886	$11,435	1.56	$7,344
55	$375,685	$61,237	-$33,463	-$25,222	$1,996	$6,657	$11,205	1.43	$7,850
50	$362,730	$59,125	-$16,731	-$22,929	$1,815	$6,427	$27,707	1.30	$21,353
45	$349,775	$57,013	-$16,731	-$20,636	$1,633	$6,198	$27,477	1.17	$23,528
40	$336,820	$54,902	-$16,731	-$18,343	$1,452	$5,968	$27,247	1.04	$26,248
35	$323,865	$52,790	-$10,039	-$16,051	$1,270	$5,739	$33,710	0.91	$37,113
30	$310,910	$50,678	-$6,693	-$13,758	$1,089	$5,509	$36,826	0.78	$47,301
25	$297,955	$48,567	-$6,693	-$11,465	$907	$5,280	$36,596	0.65	$56,407
>20	$285,000	$46,455	-$6,693	-$9,172	$726	$5,050	$36,367	0.52	$70,067
							Average Cost Effectiveness		$26,409

Table C-27

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 7 ppmv to 2.5 ppmv Cost Effectiveness – *32.5% Urea Reagent*									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
75	$655,000	$106,765	-$33,463	-$34,394	$3,193	$7,575	$49,676	1.36	$36,660
70	$642,090	$104,661	-$33,463	-$32,101	$2,980	$7,346	$49,422	1.26	$39,078
65	$629,181	$102,557	-$33,463	-$29,808	$2,767	$7,116	$49,169	1.17	$41,868
60	$616,272	$100,452	-$33,463	-$27,515	$2,554	$6,886	$48,915	1.08	$45,123
55	$603,363	$98,348	-$33,463	-$25,222	$2,342	$6,657	$48,661	0.99	$48,969
50	$590,454	$96,244	-$16,731	-$22,929	$2,129	$6,427	$65,139	0.90	$72,107
45	$577,545	$94,140	-$16,731	-$20,636	$1,916	$6,198	$64,886	0.81	$79,806
40	$564,636	$92,036	-$16,731	-$18,343	$1,703	$5,968	$64,632	0.72	$89,431
35	$551,727	$89,932	-$10,039	-$16,051	$1,490	$5,739	$71,071	0.63	$112,389
30	$538,818	$87,827	-$6,693	-$13,758	$1,277	$5,509	$74,163	0.54	$136,827
25	$525,909	$85,723	-$6,693	-$11,465	$1,064	$5,280	$73,910	0.45	$163,630
>20	$513,000	$83,619	-$6,693	-$9,172	$851	$5,050	$73,656	0.36	$203,836
							Average Cost Effectiveness		$89,144

Table C-28

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 9 ppmv to 2.5 ppmv Cost Effectiveness – *32.5% Urea Reagent*									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
75	$655,000	$106,765	-$33,463	-$34,394	$3,193	$7,575	$49,676	1.95	$25,523
70	$642,090	$104,661	-$33,463	-$32,101	$2,980	$7,346	$49,422	1.82	$27,206
65	$629,181	$102,557	-$33,463	-$29,808	$2,767	$7,116	$49,169	1.69	$29,148
60	$616,272	$100,452	-$33,463	-$27,515	$2,554	$6,886	$48,915	1.56	$31,414
55	$603,363	$98,348	-$33,463	-$25,222	$2,342	$6,657	$48,661	1.43	$34,093
50	$590,454	$96,244	-$16,731	-$22,929	$2,129	$6,427	$65,139	1.30	$50,201
45	$577,545	$94,140	-$16,731	-$20,636	$1,916	$6,198	$64,886	1.17	$55,561
40	$564,636	$92,036	-$16,731	-$18,343	$1,703	$5,968	$64,632	1.04	$62,262
35	$551,727	$89,932	-$10,039	-$16,051	$1,490	$5,739	$71,071	0.91	$78,246
30	$538,818	$87,827	-$6,693	-$13,758	$1,277	$5,509	$74,163	0.78	$95,259
25	$525,909	$85,723	-$6,693	-$11,465	$1,064	$5,280	$73,910	0.65	$113,920
>20	$513,000	$83,619	-$6,693	-$9,172	$851	$5,050	$73,656	0.52	$141,911
							Average Cost Effectiveness		$62,062

Table C-29

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 7 ppmv to 2.5 ppmv Cost Effectiveness – *19.5% Aqueous Ammonia Reagent*									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
75	$655,000	$106,765	-$33,463	-$34,394	$11,050	$7,575	$57,533	1.36	$42,458
70	$642,090	$104,661	-$33,463	-$32,101	$10,313	$7,346	$56,756	1.26	$44,876
65	$629,181	$102,557	-$33,463	-$29,808	$9,577	$7,116	$55,978	1.17	$47,666
60	$616,272	$100,452	-$33,463	-$27,515	$8,840	$6,886	$55,201	1.08	$50,921
55	$603,363	$98,348	-$33,463	-$25,222	$8,103	$6,657	$54,423	0.99	$54,768
50	$590,454	$96,244	-$16,731	-$22,929	$7,367	$6,427	$70,377	0.90	$77,905
45	$577,545	$94,140	-$16,731	-$20,636	$6,630	$6,198	$69,600	0.81	$85,605
40	$564,636	$92,036	-$16,731	-$18,343	$5,893	$5,968	$68,822	0.72	$95,229
35	$551,727	$89,932	-$10,039	-$16,051	$5,157	$5,739	$74,737	0.63	$118,188
30	$538,818	$87,827	-$6,693	-$13,758	$4,420	$5,509	$77,306	0.54	$142,625
25	$525,909	$85,723	-$6,693	-$11,465	$3,683	$5,280	$76,529	0.45	$169,429
>20	$513,000	$83,619	-$6,693	-$9,172	$2,947	$5,050	$75,751	0.36	$209,634
							Average Cost Effectiveness		$94,942

Table C-30

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
9 ppmv to 2.5 ppmv Cost Effectiveness – *19.5% Aqueous Ammonia Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
75	$655,000	$106,765	-$33,463	-$34,394	$11,050	$7,575	$57,533	1.95	$29,559
70	$642,090	$104,661	-$33,463	-$32,101	$10,313	$7,346	$56,756	1.82	$31,243
65	$629,181	$102,557	-$33,463	-$29,808	$9,577	$7,116	$55,978	1.69	$33,185
60	$616,272	$100,452	-$33,463	-$27,515	$8,840	$6,886	$55,201	1.56	$35,451
55	$603,363	$98,348	-$33,463	-$25,222	$8,103	$6,657	$54,423	1.43	$38,129
50	$590,454	$96,244	-$16,731	-$22,929	$7,367	$6,427	$70,377	1.30	$54,237
45	$577,545	$94,140	-$16,731	-$20,636	$6,630	$6,198	$69,600	1.17	$59,598
40	$564,636	$92,036	-$16,731	-$18,343	$5,893	$5,968	$68,822	1.04	$66,299
35	$551,727	$89,932	-$10,039	-$16,051	$5,157	$5,739	$74,737	0.91	$82,283
30	$538,818	$87,827	-$6,693	-$13,758	$4,420	$5,509	$77,306	0.78	$99,296
25	$525,909	$85,723	-$6,693	-$11,465	$3,683	$5,280	$76,529	0.65	$117,957
>20	$513,000	$83,619	-$6,693	-$9,172	$2,947	$5,050	$75,751	0.52	$145,948
							Average Cost Effectiveness		$66,099

Rule 4320 Category B.3 (>75 MMBtu/hr Boilers)

Category B.3a
Retrofit Technology Needed to Achieve Proposed Rule Limit of 2.5 ppmv by **2023**:

- SCR with anhydrous ammonia reagent system
- SCR with urea or aqueous ammonia reagent system and reagent vaporizer

Boilers and process heaters with a heat input greater than 75 MMBtu/hr require SCR retrofit to comply with the proposed 2.5 ppmv NOx limit. SCR systems require a reducing agent to reduce NOx emissions. Anhydrous ammonia is the least expensive reagent, but can be hazardous. Aqueous ammonia and urea are safer reagents, but are more expensive because they require additional processing equipment.

For units already equipped with a SCR system designed to meet a higher NOx limit, complying with a 2.5 ppmv NOx limit requires an additional layer of catalyst and more reagent, and may also require a new SCR housing.

Table C-31

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 7 ppmv to 2.5 ppmv Cost Effectiveness – *Anhydrous Ammonia Reagent*									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$689,000	$112,307	-$33,463	-$91,717	$7,260	$12,221	$6,608	3.61	$1,829
150	$689,000	$112,307	-$33,463	-$68,788	$5,445	$12,221	$27,722	2.71	$10,229
125	$689,000	$112,307	-$33,463	-$57,323	$4,537	$12,221	$38,279	2.26	$16,949
100	$627,000	$102,201	-$33,463	-$45,859	$3,630	$11,110	$37,619	1.81	$20,822
95	$627,000	$102,201	-$33,463	-$43,566	$3,448	$11,110	$39,731	1.72	$23,148
90	$627,000	$102,201	-$33,463	-$41,273	$3,267	$11,110	$41,842	1.63	$25,732
85	$570,000	$92,910	-$33,463	-$38,980	$3,085	$10,100	$33,653	1.54	$21,913
80	$570,000	$92,910	-$33,463	-$36,687	$2,904	$10,100	$35,764	1.45	$24,743
>75	$570,000	$92,910	-$33,463	-$34,394	$2,722	$10,100	$37,876	1.36	$27,951
							Average Cost Effectiveness		$19,257

Table C-32

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 9 ppmv to 2.5 ppmv Cost Effectiveness – *Anhydrous Ammonia Reagent*									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$689,000	$112,307	-$33,463	-$91,717	$7,260	$12,221	$6,608	5.19	$1,273
150	$689,000	$112,307	-$33,463	-$68,788	$5,445	$12,221	$27,722	3.89	$7,122
125	$689,000	$112,307	-$33,463	-$57,323	$4,537	$12,221	$38,279	3.24	$11,800
100	$627,000	$102,201	-$33,463	-$45,859	$3,630	$11,110	$37,619	2.60	$14,496
95	$627,000	$102,201	-$33,463	-$43,566	$3,448	$11,110	$39,731	2.47	$16,115
90	$627,000	$102,201	-$33,463	-$41,273	$3,267	$11,110	$41,842	2.34	$17,915
85	$570,000	$92,910	-$33,463	-$38,980	$3,085	$10,100	$33,653	2.21	$15,256
80	$570,000	$92,910	-$33,463	-$36,687	$2,904	$10,100	$35,764	2.08	$17,226
>75	$570,000	$92,910	-$33,463	-$34,394	$2,722	$10,100	$37,876	1.95	$19,460
							Average Cost Effectiveness		$13,407

Table C-33

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor **7 ppmv to 2.5 ppmv Cost Effectiveness – *32.5% Urea Reagent***									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$917,000	$149,471	-$33,463	-$91,717	$8,515	$12,221	$45,027	3.61	$12,461
150	$917,000	$149,471	-$33,463	-$68,788	$6,386	$12,221	$65,827	2.71	$24,289
125	$917,000	$149,471	-$33,463	-$57,323	$5,322	$12,221	$76,228	2.26	$33,752
100	$855,000	$139,365	-$33,463	-$45,859	$4,257	$11,110	$75,411	1.81	$41,738
95	$855,000	$139,365	-$33,463	-$43,566	$4,044	$11,110	$77,491	1.72	$45,147
90	$855,000	$139,365	-$33,463	-$41,273	$3,832	$11,110	$79,571	1.63	$48,934
85	$798,000	$130,074	-$33,463	-$38,980	$3,619	$10,100	$71,350	1.54	$46,460
80	$798,000	$130,074	-$33,463	-$36,687	$3,406	$10,100	$73,430	1.45	$50,803
>75	$798,000	$130,074	-$33,463	-$34,394	$3,193	$10,100	$75,510	1.36	$55,725
							Average Cost Effectiveness		$39,923

Table C-34

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor **9 ppmv to 2.5 ppmv Cost Effectiveness – *32.5% Urea Reagent***									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$917,000	$149,471	-$33,463	-$91,717	$8,515	$12,221	$45,027	5.19	$8,675
150	$917,000	$149,471	-$33,463	-$68,788	$6,386	$12,221	$65,827	3.89	$16,910
125	$917,000	$149,471	-$33,463	-$57,323	$5,322	$12,221	$76,228	3.24	$23,498
100	$855,000	$139,365	-$33,463	-$45,859	$4,257	$11,110	$75,411	2.60	$29,058
95	$855,000	$139,365	-$33,463	-$43,566	$4,044	$11,110	$77,491	2.47	$31,431
90	$855,000	$139,365	-$33,463	-$41,273	$3,832	$11,110	$79,571	2.34	$34,068
85	$798,000	$130,074	-$33,463	-$38,980	$3,619	$10,100	$71,350	2.21	$32,345
80	$798,000	$130,074	-$33,463	-$36,687	$3,406	$10,100	$73,430	2.08	$35,369
>75	$798,000	$130,074	-$33,463	-$34,394	$3,193	$10,100	$75,510	1.95	$38,796
							Average Cost Effectiveness		$27,794

Table C-35

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
7 ppmv to 2.5 ppmv Cost Effectiveness – *19.5% Aqueous Ammonia Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$917,000	$149,471	-$33,463	-$91,717	$29,466	$12,221	$65,978	3.61	$18,259
150	$917,000	$149,471	-$33,463	-$68,788	$22,100	$12,221	$81,541	2.71	$30,088
125	$917,000	$149,471	-$33,463	-$57,323	$18,417	$12,221	$89,322	2.26	$39,551
100	$855,000	$139,365	-$33,463	-$45,859	$14,733	$11,110	$85,887	1.81	$47,537
95	$855,000	$139,365	-$33,463	-$43,566	$13,997	$11,110	$87,443	1.72	$50,945
90	$855,000	$139,365	-$33,463	-$41,273	$13,260	$11,110	$88,999	1.63	$54,733
85	$798,000	$130,074	-$33,463	-$38,980	$12,523	$10,100	$80,255	1.54	$52,258
80	$798,000	$130,074	-$33,463	-$36,687	$11,787	$10,100	$81,811	1.45	$56,601
>75	$798,000	$130,074	-$33,463	-$34,394	$11,050	$10,100	$83,367	1.36	$61,523
							Average Cost Effectiveness		$45,722

Table C-36

SCR Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor
9 ppmv to 2.5 ppmv Cost Effectiveness – *19.5% Aqueous Ammonia Reagent*

Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$917,000	$149,471	-$33,463	-$91,717	$29,466	$12,221	$65,978	5.19	$12,712
150	$917,000	$149,471	-$33,463	-$68,788	$22,100	$12,221	$81,541	3.89	$20,947
125	$917,000	$149,471	-$33,463	-$57,323	$18,417	$12,221	$89,322	3.24	$27,535
100	$855,000	$139,365	-$33,463	-$45,859	$14,733	$11,110	$85,887	2.60	$33,095
95	$855,000	$139,365	-$33,463	-$43,566	$13,997	$11,110	$87,443	2.47	$35,468
90	$855,000	$139,365	-$33,463	-$41,273	$13,260	$11,110	$88,999	2.34	$38,105
85	$798,000	$130,074	-$33,463	-$38,980	$12,523	$10,100	$80,255	2.21	$36,382
80	$798,000	$130,074	-$33,463	-$36,687	$11,787	$10,100	$81,811	2.08	$39,406
>75	$798,000	$130,074	-$33,463	-$34,394	$11,050	$10,100	$83,367	1.95	$42,832
							Average Cost Effectiveness		$31,831

Rule 4320 Category C.3 (>75 MMBtu/hr Oil Field Steam Generators)

Retrofit Technology Needed to Achieve Proposed Rule Limit of 5 ppmv:

- New Ultra Low NOx (ULN) burner and Combustion Controls Upgrade

The proposed Rule 4320 NOx limit for oilfield steam generators with a heat input greater than 75 MMBtu/hr is 5 ppmv. These units are generally newer and have better control technology than smaller oilfield steam generators. All permitted units in this category already meet proposed Rule 4306 NOx limit of 7 ppmv. The cost analysis below is based on ULN burner retrofit.

Table C-37

ULN Retrofit Cost Effectiveness Calculation for Units at 80% Capacity Factor 7 ppmv to 5 ppmv Cost Effectiveness							
Size MMBtu/hr	Avg Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
85	$141,563	$23,075	$13,075	-	$36,149	0.71	$50,572
					Average Cost Effectiveness		

Rule 4320 Category D.3 and D.6 (>110 MMBtu/hr Petroleum Refinery Boilers and Heaters)

Retrofit Technology Needed to Achieve Proposed Rule Limit of 2.5 ppmv:

- Extra layer of catalyst, additional reagent, and tuning

The cost effectiveness analysis below is for the incremental retrofit costs for units with existing SCR systems to go from 5 ppmv to 2.5 ppmv. This is achieved by installing an extra layer of catalyst, using more reagent, and tuning the unit. If existing SCR housing cannot accept an additional layer of catalyst the units would require a new SCR housing which would increase costs

Table C-38

Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 5 ppmv to 2.5 ppmv Cost Effectiveness – *Anhydrous Ammonia Reagent*									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
250	$114,000	$18,582	$0	$0	$209	$6,722	$25,513	2.55	$10,021
200	$105,855	$17,254	$0	$0	$168	$6,111	$23,532	2.04	$11,554
150	$97,712	$15,927	$0	$0	$126	$6,111	$22,163	1.53	$14,509
125	$93,641	$15,263	$0	$0	$105	$6,111	$21,479	1.27	$16,873
							Average Cost Effectiveness		$13,239

Table C-39

Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 5 ppmv to 2.5 ppmv Cost Effectiveness – *32.5% Urea Reagent*									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$105,855	$17,254	$0	$0	$237	$6,111	$23,601	2.04	$11,588
150	$97,712	$15,927	$0	$0	$177	$6,111	$22,215	1.53	$14,543
125	$93,641	$15,263	$0	$0	$148	$6,111	$21,522	1.27	$16,907
							Average Cost Effectiveness		$14,346

Table C-40

Retrofit Cost Effectiveness Calculation for Units at 75% Capacity Factor 5 ppmv to 2.5 ppmv Cost Effectiveness – *19.5% Aqueous Ammonia Reagent*									
Size MMBtu/hr	Total Capital Cost $	Annualized Capital Cost	Incremental Electricity $/yr	Incremental Fuel $/yr	Reagent Cost $/yr	Catalyst Replacement $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
200	$105,855	$17,254	$0	$0	$1,281	$6,111	$24,646	2.04	$12,101
150	$97,712	$15,927	$0	$0	$961	$6,111	$22,998	1.53	$15,056
125	$93,641	$15,263	$0	$0	$801	$6,111	$22,175	1.27	$17,420
							Average Cost Effectiveness		$14,859

Direct PM2.5 Control Technology

Currently, there are a several produced gas fired steam generators operating in crude oil production facilities that are required by their permits to operate SOx scrubbers and ESPs (to reduce SOx emissions and visible emissions to burning high sulfur produced gas).

As illustrated below, electrostatic precipitator (ESP) and wet scrubber PM control technology are not a cost-effective option for this source category. The cost of the ESP technology does not include costs of retrofitting equipment and/or the facility or compliance monitoring costs, which would drive the cost-effectiveness up even more. In addition, the annualized costs provided by EPA for the wet scrubber system are in 2002 dollars, which means the value above would be even greater if it were adjusted to 2018 dollars.

PM Potential Emissions Reductions for an ESP and Scrubber

For the purposes of these calculations, the following assumptions were made:

1. For simplicity, the analysis will evaluate the cost-effectiveness of these technologies for total PM reductions from liquid fuel fired units.
2. The PM control efficiency of an ESP is 99%.
3. The PM control efficiency of a scrubber is 99%.

Potential Emissions Reductions$_{ESP}$ = (Total PM Emissions) x (Control Efficiency)
Potential Emissions Reduction$_{ESP}$ = 0.02 tons/year X 0.99
Potential Emissions Reduction$_{ESP}$ = 0.0198 tons/ year (tpy)

Potential Emissions Reductions $_{scrubber}$ = (Total PM Emissions) x (Control Efficiency)
Potential Emissions Reduction $_{scrubber}$ = 0.02 tons/year X 0.99
Potential Emissions Reduction $_{scrubber}$ = 0.0198 tons/ year (tpy)

Annualized Cost of an ESP and Wet Scrubber

The capital cost for the installation of an ESP for a 1-5 MMBtu/hr boiler ranges from \$90,000 - \$100,000 and the annual maintenance cost is \$1,000-\$2,000.[1] For the wet scrubber system, EPA estimated the annualized cost at \$5,300-\$102,000 per sm^3/sec at an average air flow rate of 0.7- 47 sm^3/sec.[2] The following assumptions in the cost-effectiveness calculations:

1. The capital cost of an ESP for a 5 MMBtu/hr boiler is assumed to be \$100,000.
2. The annual maintenance cost of an ESP for a 5 MMBtu/hr boiler is assumed to be \$2,000.
3. The annualized cost of a wet scrubber system is assumed to be the median of the range above (\$53,650 per sm^3/sec).
4. The average air flow rate for a wet scrubber system is assumed to be the median of the range above (23.85 sm^3/sec).
5. The total capital and maintenance cost of an ESP will be calculated by multiplying the cost of 1 unit by the total number of units.
6. The total annualized cost of a wet scrubber will be calculated by multiplying the annualized cost of 1 unit by the total number of units.
7. Lifetime of the ESP is 10 years at 10% interest. To account for this, the annualized capital cost will be calculated by multiplying the total capital cost by the capital recovery factor of 0.1627 and adding the annual maintenance costs.

Annual Cost$_{ESP}$ = (Total Capital Cost) x (0.1627) + (Annual Maintenance Cost x 62)
Annual Cost$_{ESP}$ = (\$100,000 x 62) x (0.1627) + (\$2,000 x 62)

[1] Catherine Roberts. (March 2009) *Information on Air Pollution Control Technology for Woody Biomass Boilers.* Environmental Protection Agency Office of Air Quality Planning and Standards and Northeast States for Coordinated Air Use Management.
[2] (2002). *Air Pollution Control Technology Fact Sheet: Spray-Chamber/Spray-Tower Wet Scrubber.* Environmental Protection Agency.

Annual $Cost_{ESP}$ = \$1,132,740/year

Annual $Cost_{scrubber}$ = (Annualized Cost of 1 unit) x (Number of Units) x (Average Flow Rate)
Annual $Cost_{scrubber}$ = (\$53,650/ sm^3/sec) x (62) x (23.85 sm^3/sec)
Annual $Cost_{scrubber}$ = \$79,332,255 year

<u>Cost-effectiveness of an ESP and Wet Scrubber</u>

Cost-effectiveness = Annual Cost / Annual Emissions Reductions

$Cost\text{-}effectiveness_{ESP}$ = (\$1,132,740/year) / (0.0198 tons/ year)
$Cost\text{-}effectiveness_{ESP}$ = \$57,209,091/ton of PM

$Cost\text{-}effectiveness_{scrubber}$ = (\$79,332,255/year) / (0.0198 tons/ year)
$Cost\text{-}effectiveness_{scrubber}$ = \$4,006,679,545/ton of PM

APPENDIX D

Socioeconomic Impact Analysis
For Proposed Amendments to Rules 4306 and 4320

December 17, 2020

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POTENTIAL AMENDMENTS TO RULES 4306 & 4320—BOILERS, STEAM GENERATORS, AND PROCESS HEATERS - PHASE 3, ADVANCED EMISSION REDUCTION OPTIONS FOR BOILERS, STEAM GENERATORS, AND PROCESS HEATERS GREATER THAN 5.0 MMBTU/HR

SOCIOECONOMIC IMPACT ANALYSIS

Final

December 9, 2020

Submitted to:

San Joaquin Valley Air Pollution Control District
1900 East Gettysburg Avenue
Fresno, CA 93726-0244

Submitted by:

Eastern Research Group, Inc. (ERG)
8950 Cal Center Drive, Suite 230
Sacramento, CA 95826

District Agreement No. CONT-00656

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1. EXECUTIVE SUMMARY

This report contains ERG's analysis of the socioeconomic impacts of potential amendments to the San Joaquin Valley Air Pollution Control District (SJVAPCD or District) Rules 4306 (Boilers, Steam Generators, and Process Heaters - Phase 3) and 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMbtu/hr). Potential amendments to Rules 4306 and 4320 would establish more strict NOx limits than in the existing rules. Also, facilities operating boilers, steam generators, or process heaters that do not meet those limits would be required to retrofit or replace the units to meet the specified emissions limits, comply with low use provision (fuel limit of ≤ 1.8 billion Btu/year), and/or pay annual Advanced Emissions Reduction Option (AERO) fees to the District (SJVAPCD, 2020a).

After providing an overview of demographic and economic trends in the District as a whole and describing how the COVID-19 pandemic has impacted the District economically, ERG estimates the impacts of the potential amendments on entities that would incur costs under the potential amendments by comparing compliance costs to profits.

As shown in Table 1, no affected sector would experience a significant adverse socioeconomic impact, defined as costs that amount to 10 percent or more of profits (Berck, 1995). The "Oil Producers" sector would incur both the highest average cost per facility and highest impacts. Note that the government facilities impacted by this rule are operated by local government agencies, which do not seek to maximize profits in the same way that private entities do, and therefore profit values are not shown in the following and subsequent tables. Local governments commonly raise fees to cover the compliance costs of regulations, and will likely plan for incurring these additional costs through their annual budgeting processes. Based on the average annualized cost per facility for the "Government" sector, there does not appear to be a significant impact to these types of facilities.

Table 1. Summary of Socioeconomic Impacts due to Potential Amendments to Rules 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

Sector	Affected Facilities	Total Annualized Cost [a]	Average Annualized Cost per Facility	Average Profits per Facility	Cost as % Profits
Oil Producers	49	$17,813,503	$363,541	$4,270,931	8.51%
Oil Refineries	4	$466,421	$116,605	$14,188,009	0.82%
Government [b]	7	$189,269	$27,038	—	—
Food Processing and Related Industries	137	$3,198,693	$23,348	$1,289,118	1.81%
Other Affected Sources	93	$1,313,620	$14,125	$5,020,940	0.28%
Total/Average	**290**	**$22,981,507**	**$79,247**	**$3,136,497**	**2.53%**

Sources: ERG estimates are based on SJVAPCD, 2020b; U.S. Census Bureau, 2015; U.S. Census Bureau, 2020b; U.S. Census Bureau 2020c; NASS, 2019; CA EDD, 2020a; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020d; U.S. Census Bureau, 2017a; U.S. Census Bureau, 2017b; BLS, 2020; IMPLAN, 2020a; OPM, 2017; IRS, 2016; RMA, 2020.

Notes:

[a] The total annualized cost is calculated by summing annualized one-time costs (annualized over a 10-year period using a 10 percent discount rate) and annual costs.

[b] Government agencies do not have profits, so profit values are not shown here.

As a secondary measure of impacts, ERG also used the IMPLAN (2020a) input-output model to assess how facilities with costs under the potential amendments might react by reducing employment, as well as a "ripple effect" felt if affected facilities reduce purchases from their suppliers, and their suppliers in turn reduce their own purchases. These impacts make up less than **0.01 percent** of District-wide revenue and employment.

ERG also conducted sensitivity analyses to assess how varying degrees of recovery from the effects of the COVID-19 pandemic might affect the results of the analysis. Impacts would change slightly with a full recovery (in fact increase slightly, as IMPLAN (2020a) data suggests that some of the affected sectors actually have higher revenues under the main analysis (with no recovery from the pandemic) than under full recovery).

2. INTRODUCTION AND BACKGROUND

This report provides economic data and analysis in support of the San Joaquin Valley Air Pollution Control District's (SJVAPCD or District) assessment of the socioeconomic feasibility of potential amendments to its existing rules for boilers, steam generators, and process heaters. This work was performed by ERG under District Agreement No. CONT-00656.

Facilities with boilers, steam generators, and process heaters subject to the District's rules represent a wide range of industries, including manufacturing and industrial processes, electrical utilities, oil and gas production, agricultural processing, and service and commercial facilities.

The potential amendments under consideration would affect two existing District rules:

- Rule 4306 (Boilers, Steam Generators, and Process Heaters - Phase 3)
- Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMbtu/hr)

Existing District Rule 4306 (last revised in 2008) is designed "to limit emissions of oxides of nitrogen (NOx) and carbon monoxide (CO) from boilers, steam generators, and process heaters" (SJVAPCD, 2008a).

Existing District rule 4320 (adopted in 2008) is designed "to limit emissions of oxides of nitrogen (NOx), carbon monoxide (CO), oxides of sulfur (SO2), and particulate matter 10 microns or less (PM10) from boilers, steam generators, and process heaters" (SJVAPCD, 2008b).

Both Rule 4306 and 4320 apply "to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a total rated heat input greater than 5 million Btu per hour" (SJVAPCD, 2008a; SJVAPCD, 2008b).

The potential amendments to these rules will satisfy commitments included in the *2018 PM2.5 Plan* to establish stricter NOx emission limits and lower the more stringent AERO limit for specific classes and categories of units (SJVAPCD, 2020a).

This analysis was prepared to meet the requirements of California Health and Safety Code §40728.5, which requires an assessment of the socioeconomic impacts of the adoption, amendment, or repeal of air district rules. It begins by providing an overview of demographic and economic trends in the District, and then estimates the economic impacts on specific entities subject to the potential rule amendments (including small entities), and how those economic impacts might affect the surrounding communities, including at-risk populations.

3. REGIONAL DEMOGRAPHIC AND ECONOMIC TRENDS

In this section ERG considers larger demographic and economic trends in the District, which includes eight counties that are home to over 4 million people.[1] These counties have become more populous over the last decade, and the median income (adjusted for inflation) has also increased. Utilities, wholesale and retail trade, and transportation, along with agriculture and oil and gas extraction, are the predominant industries within the District both in terms of establishments and employment.

3.1. REGIONAL DEMOGRAPHIC TRENDS

This section presents the demographic shifts within the District's jurisdiction over the past decade. The District has experienced greater population growth rate than the state as a whole, but the median income has lagged the state. The poverty rate throughout the district, while decreasing over time, is doing so at a slower pace than California as a whole.

The San Joaquin Valley contains almost 11 percent of the state of California's population. Table 2 shows how this population has changed over the last 10 years. Table 2 also shows the compound annual growth rate (CAGR) between 2010 and 2019. The CAGR is the constant rate the population would have changed annually to go from the 2010 level to the 2019 level.

The region has seen small amounts of population growth, an annual average growth rate marginally higher than the state of California. Kings and Madera counties, the two counties with the smallest population of the counties in the District, saw little growth in their populations from 2010 to 2019, and were the only counties to have population declines in any one year over the last ten years. San Joaquin County saw the most growth, increasing at 1.16 percent annually.

[1] While only part of Kern County falls into the District's boundaries, all of Kern County is included in the data presented in this section, as the data were only available at the county level.

Table 2. Population Trends by County

County	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR 2010-2019
Fresno	932,039	939,406	945,045	951,514	960,567	969,488	976,830	985,238	991,950	999,101	0.78%
Kern [a]	840,996	847,970	853,606	862,000	869,176	876,031	880,856	887,356	893,758	900,202	0.76%
Kings	152,370	151,868	150,991	150,337	149,495	150,085	149,382	149,665	151,382	152,940	0.04%
Madera	150,986	151,675	151,527	151,370	153,456	153,576	153,956	155,423	156,882	157,327	0.46%
Merced	256,721	259,297	260,867	262,026	264,419	266,353	267,628	271,096	274,151	277,680	0.88%
San Joaquin	687,127	694,354	699,593	702,046	711,579	722,271	732,809	743,296	752,491	762,148	1.16%
Stanislaus	515,145	517,560	520,424	523,451	528,015	533,211	539,255	544,717	548,126	550,660	0.74%
Tulare	442,969	446,784	449,779	452,460	455,138	457,161	459,235	462,308	464,589	466,195	0.57%
SJVAPCD [a]	**3,978,353**	**4,008,914**	**4,031,832**	**4,055,204**	**4,091,845**	**4,128,176**	**4,159,951**	**4,199,099**	**4,233,329**	**4,266,253**	**0.78%**
California	**37,319,502**	**37,638,369**	**37,948,800**	**38,260,787**	**38,596,972**	**38,918,045**	**39,167,117**	**39,358,497**	**39,461,588**	**39,512,223**	**0.64%**

Source: U.S. Census Bureau, 2020e.

Notes:

[a] While the SJVAPCD only includes a portion of Kern County, the data shown here are for the whole of the county.

Table 3 shows the median income by county for 2010 through 2018 (U.S. Census Bureau, 2019a). Median income growth rates varied across counties from 2010 to 2018, though the counties in the District[2] as a whole had a CAGR of 0.63 percent overall; this is significantly lower than the growth rate of median income for the state of California (1.60 percent). Kern and Tulare Counties experienced declines in median income (-0.17 percent and -0.26 percent respectively) while all other counties experienced some level of growth. Kings and Merced Counties have notably higher growth rates of 2.34 percent and 2.13 percent, respectively. These are the only two counties in the District where median income increased at a rate faster than the state.

[2] 2018 is the most recent data year currently available in the U.S. Census Bureau (2019a) median income data from the American Community Survey.

Table 3. Median Income by County [a]

County	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR 2010-2018
Fresno	$52,859	$49,014	$46,766	$48,496	$47,071	$50,369	$51,728	$53,987	$53,547	0.16%
Kern [b]	$53,213	$51,781	$51,578	$51,758	$51,647	$55,082	$52,990	$51,959	$52,478	-0.17%
Kings	$52,144	$57,645	$51,606	$50,538	$46,378	$49,078	$56,527	$59,985	$62,738	2.34%
Madera	$56,421	$53,323	$47,229	$43,896	$45,998	$50,585	$54,852	$53,448	$57,287	0.19%
Merced	$49,619	$45,863	$48,979	$44,921	$47,788	$45,056	$50,692	$49,750	$58,752	2.13%
San Joaquin	$58,458	$58,227	$56,984	$56,785	$55,999	$57,617	$63,199	$63,746	$65,237	1.38%
Stanislaus	$56,159	$50,467	$52,134	$52,954	$55,376	$56,177	$57,664	$62,027	$61,373	1.12%
Tulare	$50,727	$47,136	$45,277	$43,525	$46,191	$45,503	$48,719	$48,219	$49,668	-0.26%
SJVAPCD [b][c]	**$53,990**	**$51,459**	**$50,426**	**$50,318**	**$50,550**	**$52,467**	**$54,674**	**$55,614**	**$56,791**	**0.63%**
California	**$67,455**	**$65,594**	**$65,529**	**$66,454**	**$67,136**	**$69,198**	**$71,929**	**$74,837**	**$76,589**	**1.60%**

Source: U.S. Census Bureau, 2019a.

Notes:

[a] Inflated values to 2019$ using the BEA (2020) GDP deflator.

[b] While the SJVAPCD only includes a portion of Kern County, the data shown here are for the whole of the county.

[c] Median income for SJVAPCD is a weighted average by population.

Poverty rates by county for the same nine-year period are shown in Table 4. The poverty rate decreased in every county in the District in that time frame. Poverty rates within the District are higher than state average, and declining at a slower rate overall compared to the state of California's rate of -2.60 percent. Fresno and Tulare Counties consistently had the highest poverty rates while Stanislaus and San Joaquin Counties had the two lowest. San Joaquin and Stanislaus Counties were also the only two counties in the valley with CAGR lower than the states. Despite Merced County's notable CAGR of median household income, its poverty rate has declined at one of the slowest rates (-0.55 percent) in the valley.

Many the District's leading industries, including agriculture, transportation, and manufacturing, typically employ a higher percentage of low income and less educated employees, and have unstable or seasonal employment needs (Abood, 2014), likely leading to the higher rates of poverty seen in the District.

Table 4. Poverty Rate by County

County	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR 2010-2018
Fresno	26.8%	25.8%	28.4%	28.8%	27.7%	25.3%	25.6%	21.1%	21.5%	-2.72%
Kern [a]	21.2%	24.5%	23.8%	22.8%	24.8%	21.9%	22.7%	21.4%	20.6%	-0.36%
Kings	22.2%	20.5%	21.2%	21.4%	26.6%	23.6%	16.0%	18.2%	19.2%	-1.80%
Madera	21.0%	24.3%	23.6%	23.6%	22.2%	23.4%	20.3%	22.6%	20.9%	-0.06%
Merced	23.0%	27.4%	24.3%	25.2%	25.2%	26.7%	20.3%	23.8%	22.0%	-0.55%
San Joaquin	19.2%	18.1%	18.4%	19.9%	20.9%	17.4%	14.4%	15.5%	14.2%	-3.70%
Stanislaus	19.9%	23.8%	20.3%	22.1%	18.0%	19.7%	14.2%	13.5%	15.6%	-3.00%
Tulare	24.5%	25.7%	30.4%	30.1%	28.6%	27.6%	25.2%	24.6%	22.5%	-1.06%
SJVAPCD [a]	**22.5%**	**23.8%**	**24.2%**	**24.6%**	**24.3%**	**22.7%**	**20.6%**	**19.7%**	**19.3%**	**-1.91%**
California	**15.8%**	**16.6%**	**17.0%**	**16.8%**	**16.4%**	**15.3%**	**14.3%**	**13.3%**	**12.8%**	**-2.60%**

Source: U.S. Census Bureau, 2019b.

Notes:

[a] While the SJVAPCD only includes a portion of Kern County, the data shown here are for the whole of the county.

Table 5 shows the population below the poverty line from 2010 to 2018. While there has been a decline in the number of people below the poverty line from 2010 to 2018, the number has fluctuated during this period. The number of people in poverty grew by over 100,000 between 2010 and 2014, but has been in decline since 2014.

The CAGR of population below the poverty line varies across counties. Fresno County has the largest population below the poverty line as of 2018, which coincides with its large population and relatively higher poverty rate. Conversely, San Joaquin County has a notable decline in CAGR at -2.56 percent, one of three counties to see declines in poverty at a rate faster than the state (along with Fresno and Stanislaus Counties). Kern, Madera, and Merced Counties have positive CAGR and have seen an increase in population below the poverty over the nine-year period.

Table 5. Population Below Poverty Line by County

County	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR 2010-2018
Fresno	246,196	238,706	264,738	270,072	263,220	242,083	247,507	205,291	209,799	-1.98%
Kern [a]	171,950	201,230	196,625	189,484	208,388	186,501	193,133	184,619	178,239	0.45%
Kings	30,425	27,101	27,819	28,473	35,623	31,453	21,565	24,935	26,299	-1.81%
Madera	29,936	34,148	33,936	34,242	32,432	34,227	29,736	33,482	31,191	0.51%
Merced	58,360	70,243	62,448	64,552	65,405	70,118	53,314	63,485	59,283	0.20%
San Joaquin	128,748	123,258	126,610	137,663	146,601	123,817	103,399	113,136	104,622	-2.56%
Stanislaus	101,335	122,212	104,559	114,628	94,586	104,801	76,191	73,254	85,073	-2.16%
Tulare	107,660	113,515	135,194	135,066	129,485	125,728	114,290	112,524	103,711	-0.47%
SJVAPCD [a]	**874,610**	**930,413**	**951,929**	**974,180**	**975,740**	**918,728**	**839,135**	**810,726**	**798,217**	**-1.14%**
California	**5,783,043**	**6,118,803**	**6,325,319**	**6,328,824**	**6,259,098**	**5,891,678**	**5,525,524**	**5,160,208**	**4,969,326**	**-1.88%**

Source: U.S. Census Bureau, 2019b.

Notes:

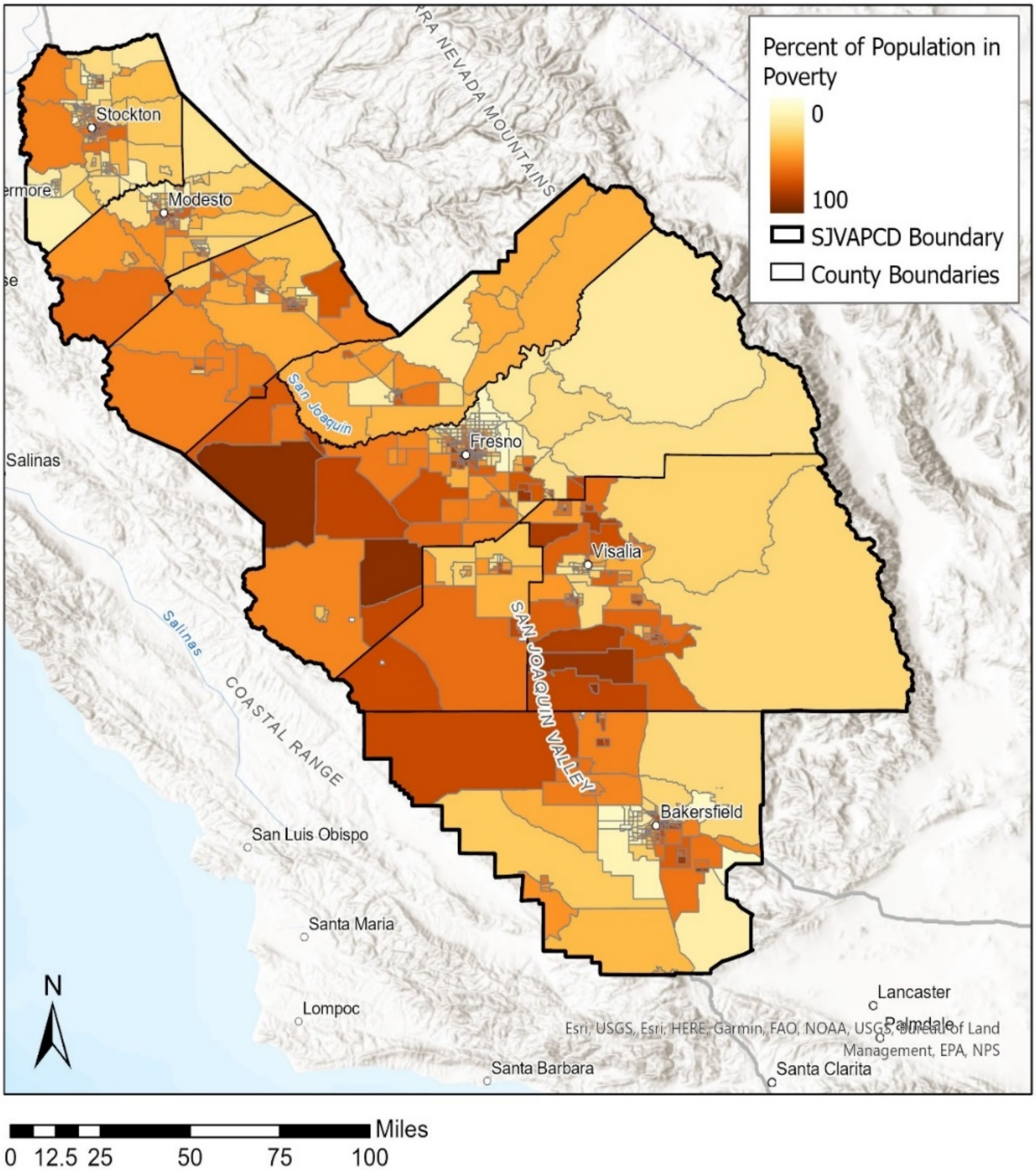
[a] While the SJVAPCD only includes a portion of Kern County, the data shown here are for the whole of the county.

Figure 1 shows where the population in poverty or at risk of poverty lives within the District[3] using CalEnviroScreen 3.0 (OEHHA, 2018) data on the percent of population living below two times the federal poverty limit. CalEnviroScreen poverty data is derived from the US Census Bureau's American Community Survey 5-year estimates for 2011 to 2015. CalEnviroScreen uses a poverty threshold of two times the poverty level to account for the higher cost of living in California compared to other parts of the country (OEHHA, 2017).

As shown in Table 4 above, roughly 20 percent of the District population is below the federal poverty limit, depending on the year. Using the higher CalEnviroScreen 3.0 threshold, nearly half (48.7 percent) of District residents are below twice the federal poverty limit (OEHHA, 2018), reflected in the high poverty rates in the map in Figure 1 below.

[3] Note that only the part of Kern County included in the SJVAPCD is shown. There are four census tracts on the eastern border of Kern County that are in the Eastern Kern Air Pollution Control District. The portions of these census tracts that fall outside of the SJVAPCD border are not shown.

Figure 1. Percentage of the Population Living below Two Times the Federal Poverty Level by Census Tract (2018)



Source: OEHHA, 2018.

3.2. REGIONAL ECONOMIC TRENDS

This section tracks the economic trends of the District over the past decade. Total employment growth in the District is slightly below that of California. Overall, employment, the number of establishments, and average pay have all increased across the District during that period.

Table 6 presents employment trends over the same 10-year span. During that period, overall employment throughout the District has also increased. The District as a whole saw a CAGR of 1.48 percent in employment over the last decade, slightly below that of the entire state of California (1.64 percent). No individual county experienced a decline in employment, although Kings County has a notably lower growth rate (0.72 percent) than the other counties in the region.

San Joaquin County was the only county in the District to experience an employment growth rate greater than that of California as a whole. This may be in part due to the California Central Valley Economic Development Corporation's (CCVEDC) efforts to encourage companies to locate within the District through tax credits and incentives and grants (CCVEDC, 2020). A few large employers (Amazon, Tesla, etc.) have moved to San Joaquin County in recent years, creating numerous job opportunities within the county. Some people have also moved from the more expensive Bay Area and Los Angeles-San Diego area to the Central Valley, with San Joaquin County being one of the more popular areas to relocate (Lillis, 2019).

Table 6. Employment Trends by County

County	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR 2010-2019
Fresno	366,200	370,200	373,500	379,800	387,500	395,700	402,700	407,400	412,783	418,092	1.48%
Kern [a]	313,400	325,700	340,400	347,200	351,700	350,500	348,000	349,500	354,892	360,783	1.58%
Kings	49,900	49,700	50,000	50,400	50,600	51,700	51,500	52,300	53,025	53,233	0.72%
Madera	51,400	52,000	53,500	54,400	54,900	53,500	55,400	56,100	56,958	57,642	1.28%
Merced	93,200	94,500	96,200	98,000	99,700	101,200	102,300	104,600	105,650	106,875	1.53%
San Joaquin	260,000	261,000	267,100	274,600	279,200	286,600	292,600	301,100	304,617	307,842	1.89%
Stanislaus	202,200	202,400	205,900	209,800	213,700	218,200	222,000	224,400	227,533	228,750	1.38%
Tulare	168,100	168,700	168,800	172,200	172,100	178,700	180,700	183,500	183,300	184,350	1.03%
SJVAPCD [a]	**1,504,400**	**1,524,200**	**1,555,400**	**1,586,400**	**1,609,400**	**1,636,100**	**1,655,200**	**1,678,900**	**1,698,758**	**1,717,567**	**1.48%**
California	**16,091,900**	**16,258,100**	**16,602,700**	**16,958,400**	**17,310,900**	**17,681,800**	**18,002,800**	**18,285,500**	**18,460,433**	**18,623,900**	**1.64%**

Source: CA EDD, 2020b.

Notes:

[a] While the SJVAPCD only includes a portion of Kern County, the data shown here are for the whole of the county.

Table 7 shows the economic trends by industry in the District by presenting three snapshots from 2009 to 2019 using data from the Bureau of Labor Statistics' (BLS, 2020) Quarterly Census of Employment and Wages (QCEW). The recent influx of new employers explains the continued growth in the utilities, trade and transportation industries. These industries have been the largest employers in the District for the last 11 years, followed closely by agriculture and oil and gas extraction. The education, health and social services industry has seen the greatest increase of establishments in the District over the past decade, although it is the one industry that has experienced a decrease in average pay over that same time frame. The information sector is the smallest industry in the district and has gotten smaller over the last 11 years.

Table 7. Economic Trends in the San Joaquin Valley, 2009-2019 [a]

NAICS	Sector	2009			2014			2019		
		Establish-ments	Employ-ment	Average Annual Pay [c]	Establish-ments	Employ-ment	Average Annual Pay [c]	Establish-ments	Employ-ment	Average Annual Pay
11, 21	Agriculture, Oil and Gas Extraction	7,789	189,766	$29,692	7,438	217,769	$33,068	7,430	217,649	$36,568
23	Construction	6,099	50,178	$55,144	5,377	56,011	$54,022	6,637	70,498	$59,475
31-33	Manufacturing	2,640	105,142	$52,640	2,531	107,702	$53,749	2,715	110,892	$55,863
22, 42, 44-45, 48-49	Utilities, Trade and Transportation	14,041	219,813	$40,871	14,500	246,596	$41,428	16,026	282,861	$43,587
51	Information	602	13,482	$59,608	510	11,035	$68,525	498	6,127	$60,315
52-53	Finance Activities	5,747	44,703	$52,430	5,652	41,123	$55,695	6,443	42,638	$59,747
54-56	Profession and Business Services	7,944	97,494	$45,994	8,391	106,412	$45,985	9,054	116,895	$50,424
61-62	Educational, Health and Social Services	7,503	140,416	$54,050	39,280	184,959	$47,321	53,489	223,552	$48,667
71-72	Leisure and Hospitality	5,960	97,885	$17,407	6,224	111,610	$16,859	7,424	130,279	$19,906
81	Other Services	38,938	53,413	$24,934	5,124	32,856	$33,084	5,603	24,860	$35,245
99	Unclassified	1,730	2,112	$34,651	1,917	3,006	$31,870	4	4	$25,752
SJVAPCD Total/Average [b]		**98,993**	**1,014,404**	**$40,664**	**96,944**	**1,119,079**	**$41,095**	**115,323**	**1,226,255**	**$43,903**

Source: BLS, 2020.

Notes:

[a] Includes all of Kern County.

[b] Annual average pay is a weighted average of the eight counties in the SJV APCD weighted by employment in sector.

[c] Annual average pay is adjusted to 2019 dollars using the BEA (2020) GDP deflator.

Table 8 presents the CAGR of the economic data from Table 7. The number of establishments, employment, and average annual pay have all increased over the last 11 years across the District. Health, education, and social services has seen the greatest growth in establishments and employment over that time frame, but it is the one industry that experienced a decrease in average pay (outside of the unclassified businesses). There are fewer establishments in the agriculture, oil, and gas extraction industry today than there were a decade ago, but employment and pay have both increased. The information industry has experienced the greatest decrease in employment across the District.

Table 8. Compound Annual Growth Rate of Establishments, Employment, and Annual Pay [a]

NAICS	Sector	Establishments			Employment			Average Annual Pay		
		2009-2014	2014-2019	2009-2019	2009-2014	2014-2019	2009-2019	2009-2014	2014-2019	2009-2019
11, 21	Agriculture, Oil and Gas Extraction	-0.92%	-0.02%	-0.47%	2.79%	-0.01%	1.38%	2.18%	2.03%	2.10%
23	Construction	-2.49%	4.30%	0.85%	2.22%	4.71%	3.46%	-0.41%	1.94%	0.76%
31-33	Manufacturing	-0.84%	1.41%	0.28%	0.48%	0.59%	0.53%	0.42%	0.77%	0.60%
22, 42, 44-45, 48-49	Utilities, Trade and Transportation	0.65%	2.02%	1.33%	2.33%	2.78%	2.55%	0.27%	1.02%	0.65%
51	Information	-3.26%	-0.48%	-1.88%	-3.93%	-11.10%	-7.58%	2.83%	-2.52%	0.12%
52-53	Finance Activities	-0.33%	2.65%	1.15%	-1.66%	0.73%	-0.47%	1.22%	1.41%	1.32%
54-56	Profession and Business Services	1.10%	1.53%	1.32%	1.77%	1.90%	1.83%	0.00%	1.86%	0.92%
61-62	Educational, Health and Social Services	39.25%	6.37%	21.70%	5.67%	3.86%	4.76%	-2.62%	0.56%	-1.04%
71-72	Leisure and Hospitality	0.87%	3.59%	2.22%	2.66%	3.14%	2.90%	-0.64%	3.38%	1.35%
81	Other Services	-33.34%	1.80%	-17.62%	-9.26%	-5.42%	-7.36%	5.82%	1.27%	3.52%
99	Unclassified	2.07%	-70.90%	-45.50%	7.31%	-73.40%	-46.58%	-1.66%	-4.17%	-2.92%
SJVAPCD Total/Average		**-0.42%**	**3.53%**	**1.54%**	**1.98%**	**1.85%**	**1.91%**	**0.21%**	**1.33%**	**0.77%**

Source: BLS, 2020.

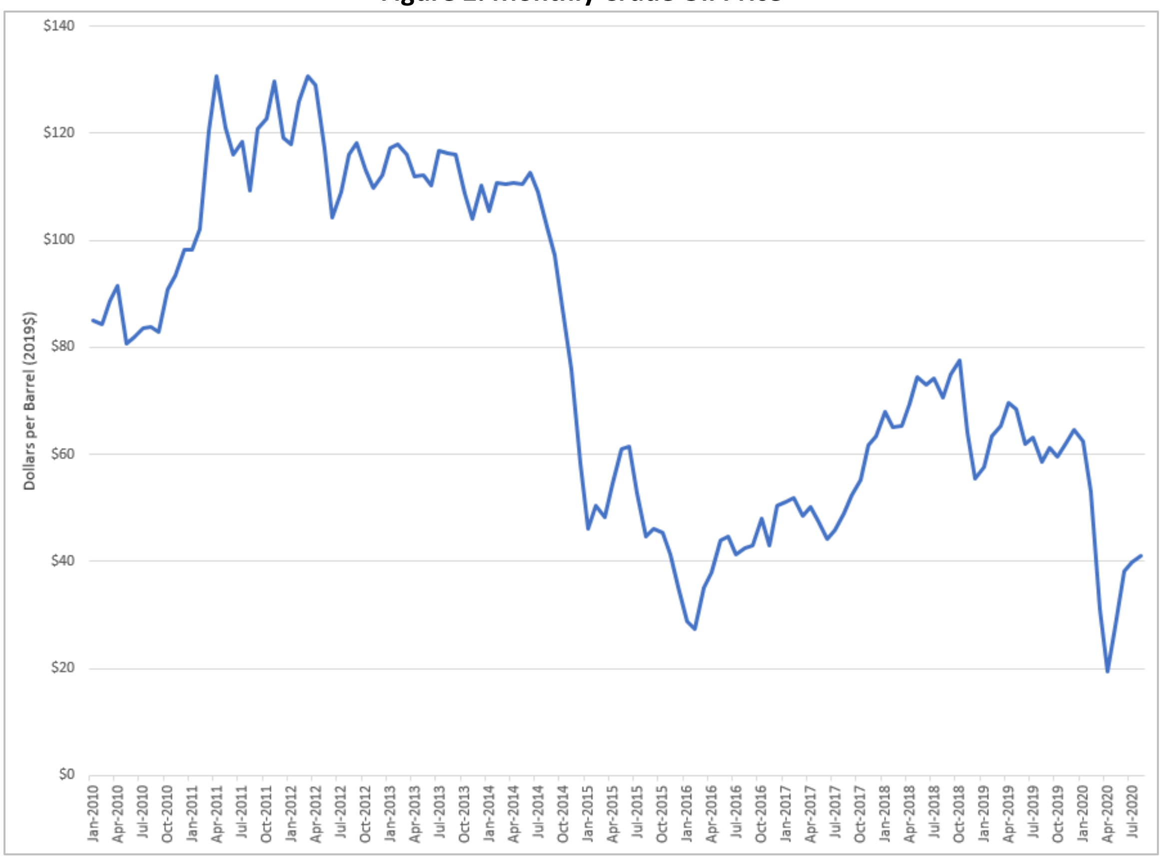
Notes:

[a] Includes all of Kern County.

This proposed rule amendments would in part impact oil and gas producers in the District. Industry-specific trends, including the price of crude oil, number of producing wells, and overall oil production, are provided below.

Based on U.S. Energy Information Administration (EIA) data, crude oil prices across California have generally increased over the last few years since a significant drop-off in prices at the end of 2014 and into 2015 (EIA, 2020a). In December 2019, the price for a barrel of crude oil was $64.51. This price is below the average monthly price from 2010 to 2019 of $80.74 but is significantly higher than that of January 2016 ($28.83), an increase of 124 percent. Monthly prices from 2010 through July 2020 are shown in Figure 2. Prices dipped considerably in the spring of 2020 (with the onset of the COVID-19 pandemic) but have since started to recover.

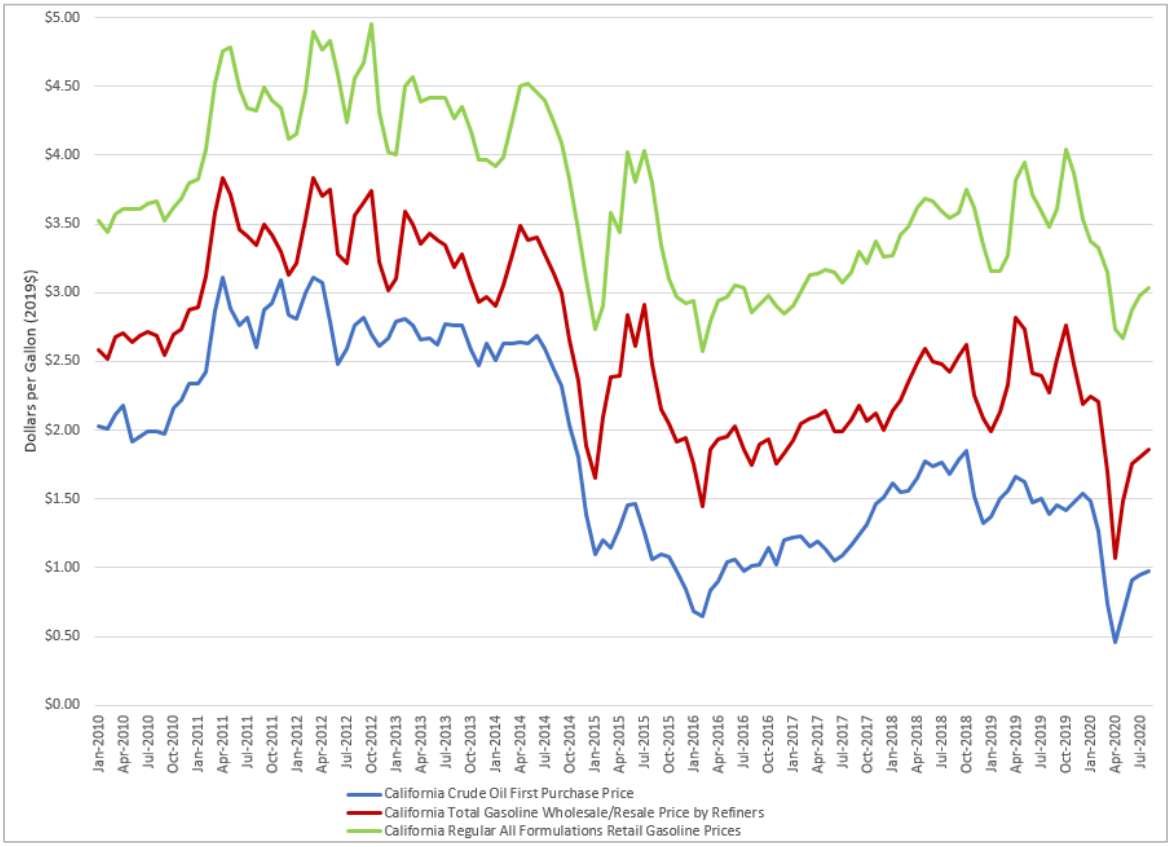
Figure 2. Monthly Crude Oil Price



Source: EIA, 2020a.

Figure 3 shows the same crude oil prices from above converted into dollars per gallon and also compares that price to the wholesale price of refined gasoline and the reformulated gas price from gas stations (in the state of California, all gasoline must be reformulated, so the “All Formulations” price presented in Figure 3 is the same as the reformulated price). The gross margins between the retail price and the wholesale price tend to be greater than those between the wholesale and crude prices. On average over this 10-year time frame, gas stations recognized a gross margin of $1.08 compared to the refineries’ gross margin of $0.77 per gallon (EIA, 2020a-c).

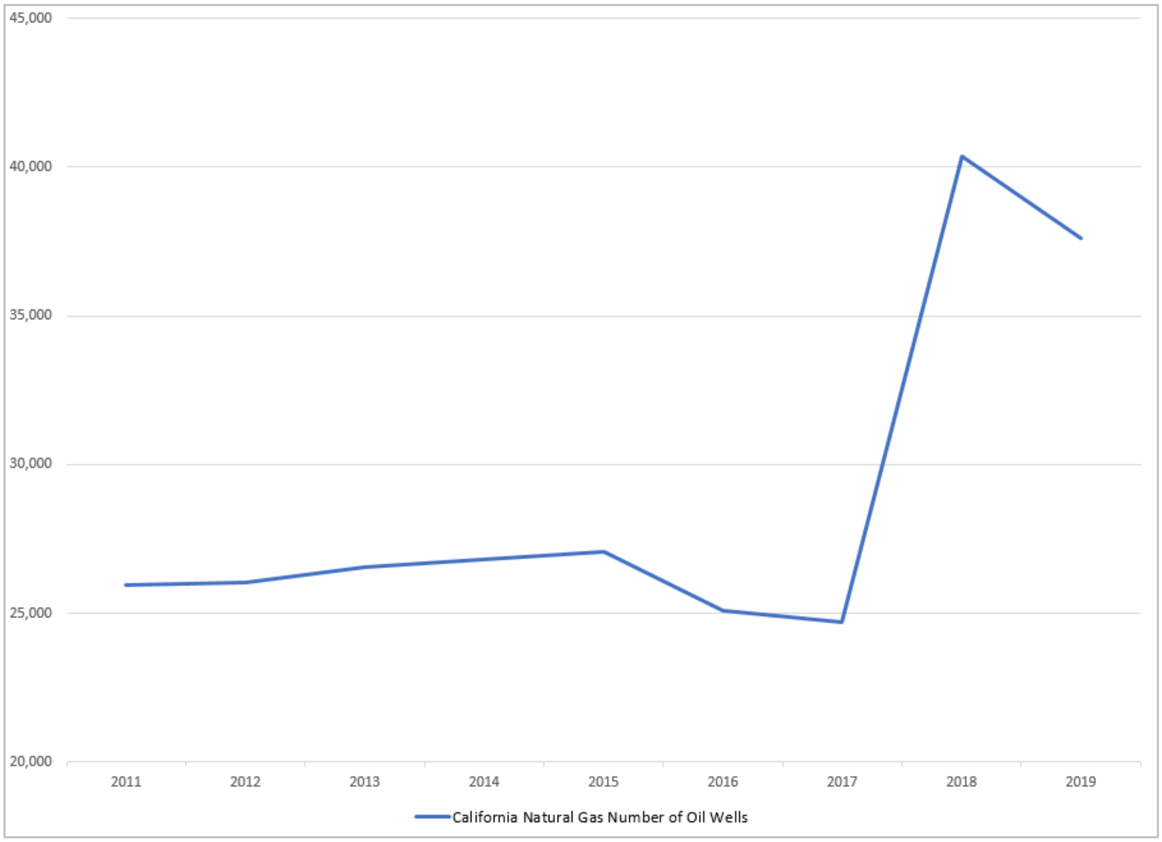
Figure 3. Comparison of California Monthly Price per Gallon of Oil



Source: EIA, 2020a-c.

As presented in Figure 4, the state of California saw a 63 percent increase in the number of oil wells in 2018 from the decade-low mark in 2017 (EIA, 2020d). The number of producing wells decreased in 2019 by 6 percent but is still much higher than at any other point in the last decade.

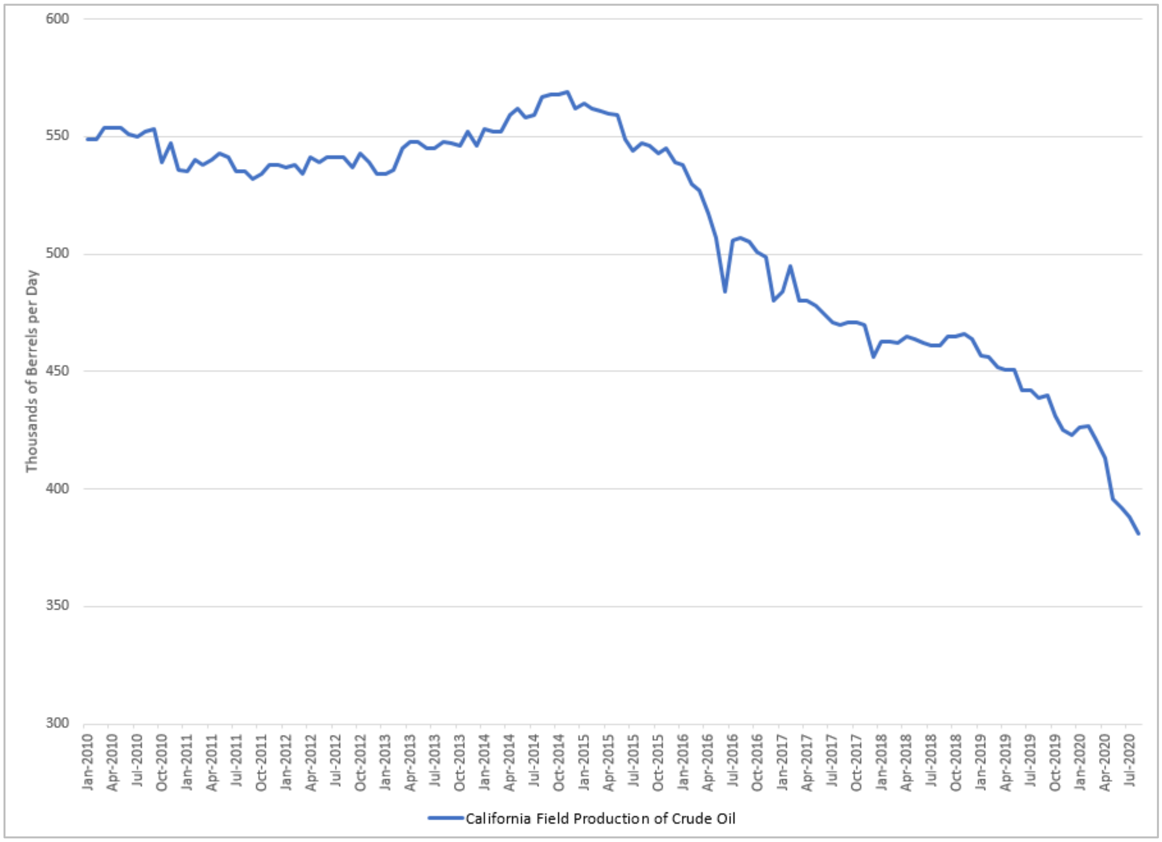
Figure 4. Number of Producing Wells in California



Source: EIA, 2020d.

Oil production has not necessarily coincided with the number of producing wells across California. Monthly crude oil production, as shown in Figure 5, has dropped significantly since a decade-high of 569,000 barrels per day in November 2014 (EIA, 2020e).

Figure 5. Monthly Crude Oil Production in California

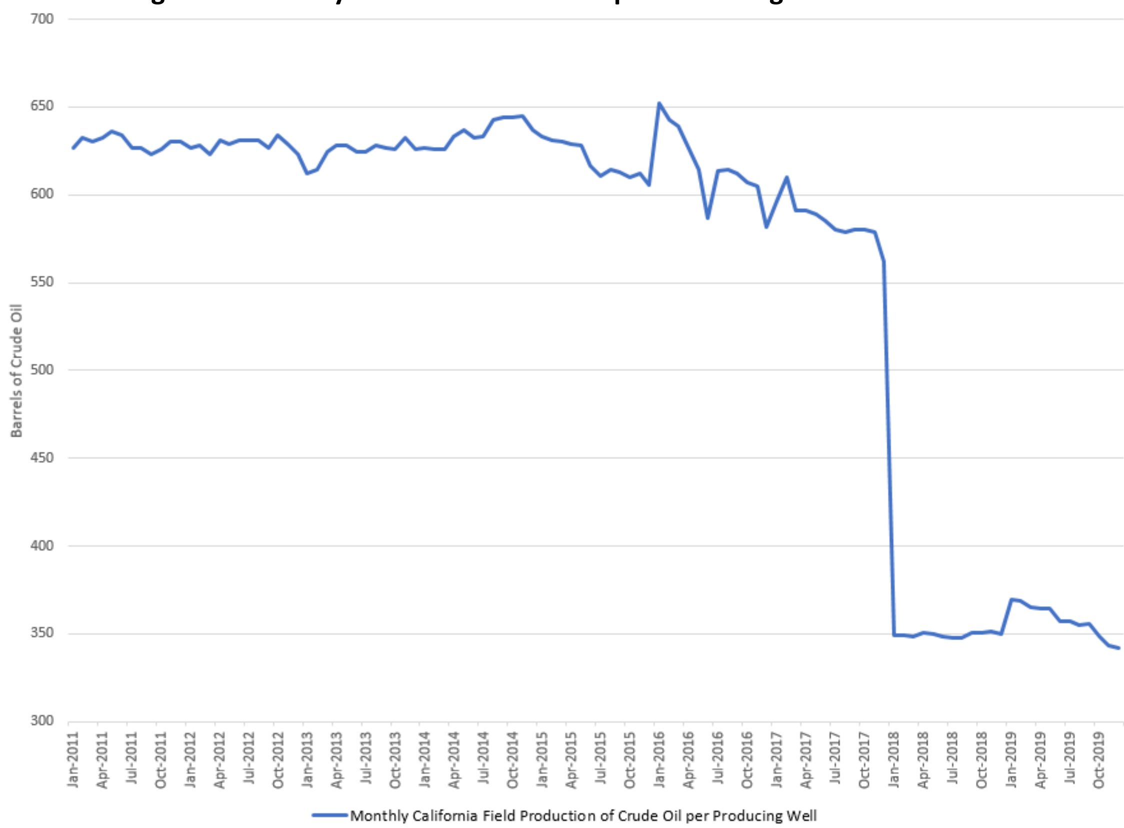


Source: EIA, 2020e.

From 2011 to 2019, oil production per well has generally decreased (EIA, 2020d-e). As shown in Figure 6, 2018 represented a dramatic downturn in per-well production, namely due to the sudden increase in the number of wells producing oil in California that year.

The downward trend since 2016 in both oil production and the number of producing wells seen in Figure 3 through Figure 5 represent the changing dynamics of the oil extraction industry. Fracking has become an increasingly deployed method of oil extraction, especially in top producing states like Texas, North Dakota, and New Mexico. The California state government places more restrictions on this practice than these other states, while some municipalities and counties have outright banned fracking (Nikolewski, 2018). In recent years, state policymakers have also pushed measures that promote renewable energy. California is also a more expensive state for oil companies to operate in. Extraction is more difficult since the oil in California is generally heavier. As a result, many companies have moved to other states such as Texas.

Figure 6. Monthly Crude Oil Production per Producing Well in California

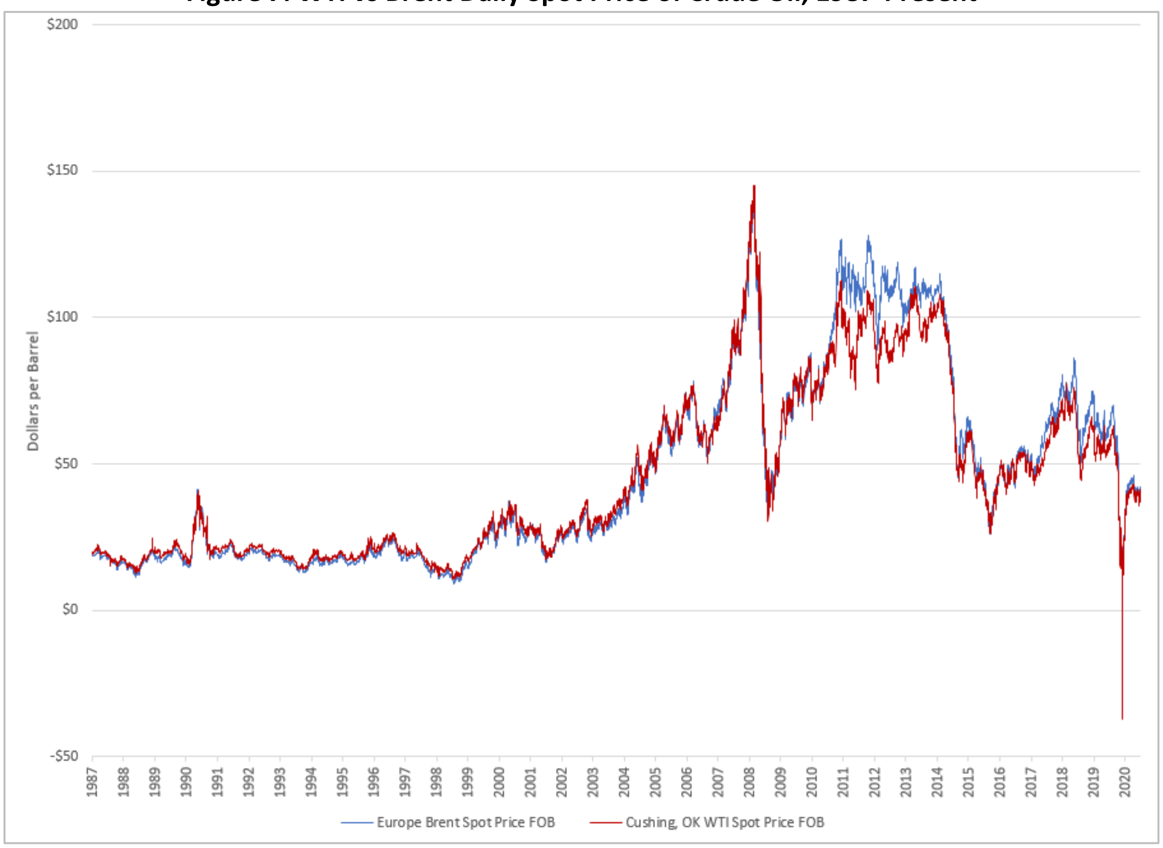


Source: EIA, 2020d-e.

Figure 7 shows daily spot prices for crude oil going back to 1987 (EIA, 2020f-g). There are two main spot price indicators used for crude oil trade: the West Texas Intermediate (WTI) spot price and the Brent Crude spot price. The WTI price is the benchmark in the United States since it refers to oil that is extracted from U.S. wells and sent via pipeline to Cushing, Oklahoma. At the same time, the EIA has determined that the price of Brent crude oil is a better indicator of prices throughout the U.S. than WTI (EIA, 2014). Brent crude oil is extracted from four oil fields in the North Sea and is the price used in nearly two-thirds of contracts globally, making it the global benchmark for crude oil prices (Bradfield, 2018). Of note, both the WTI and Brent spot indicators represent free on board (FOB) prices, which means that the buyer is liable for any damage to the goods while being shipped to them.

As can be seen in Figure 7, the WTI crude oil price dropped below zero for one day in April 2020, the first time this had ever happened. This was determined to be the result of weak demand (likely due to a decrease in travel across the country due to the COVID-19 pandemic), storage capacity reaching its limits, and unconstrained oil production (Wallace, 2020). It has since begun to recover, although not to 2019 levels.

Figure 7. WTI vs Brent Daily Spot Price of Crude Oil, 1987-Present



Source: EIA, 2020f-g.

3.3. IMPACTS OF THE COVID-19 PANDEMIC

The COVID-19 pandemic has affected virtually every industry, including those that would have costs under the potential amendments to Rules 4306 and 4320. For instance, the pandemic has changed how the food manufacturing industry operates. Workers in this industry are considered essential workers, requiring them to go to work in the production facilities. Some facilities, particularly meatpacking facilities, have experienced outbreaks resulting in temporary shutdowns of those facilities. Workers' safety in these facilities has become a main issue for the industry, with OSHA and the FDA creating a checklist for food manufacturing operators to adhere to (OSHA & FDA, 2020).

Despite these new safety protocols, food processors and manufacturers increased hiring in the early stages of the pandemic. This hiring spree was an effort to meet increased demand for food sold at retail establishments, since consumers were "panic buying" in the face of uncertainty about stay at home orders and the potential need to quarantine (Demetrakakes, 2020). These two developments in concert have given smaller manufacturers an advantage in maintaining social distancing protocols while still producing food for the country.

The early stages of the pandemic also saw the third oil price collapse that the oil and gas extraction industry has seen in just the last 12 years. This price shock, unlike the previous two, was swift, resulting in wide-ranging changes across the industry in a short period of time. Stay at home orders in California and around the world resulted in depressed demand for gas. Even as some of these restrictions have eased, a combination of job losses and remote work means that far fewer people are commuting. Travel for recreational activities is reduced as well, whether because facilities are closed or have restrictions in place or because people are reluctant to expose themselves to illness. Those who have lost their jobs as a result of the coronavirus are conscious of their expenses, including on travel.

The coronavirus-driven lack of demand coincided with a massive oversupply of oil that left the industry with very little storage space (Kasler, 2020). This combination of supply and demand mismatches resulted in an 87 percent drop in the Brent per-barrel price of oil from January to April of 2020 (McCarthy, 2020). Gas prices have also dropped nationwide. For instance, over a one month period from late February to late March 2020, the price of gas dropped significantly across California, going from $3.49 to $3.20 statewide, while the prices in the metro areas of Fresno and Madera-Chowchilla both dropped from about $3.33 to just under $3.00 over that same timeframe (Sheehan, 2020). The average price of regular unleaded gasoline in California in late September 2020 ($3.22) was about 70 cents cheaper than a year prior ($3.95) (AAA, 2020). Fresno and Merced have seen similar changes to their average gas prices, albeit with slightly lower prices than the statewide average.

Oil and gas companies started to slow down production in response to demand changes. The number of rigs operating across the country has dropped by more than 70 percent since the end of August 2019 (Flores, 2020). California has seen a similar drop in rigs within the state, going from 18 rigs in operation in late August of 2019 to just four at the end of August 2020 (Baker Hughes, 2020). California's oil and gas production is primarily centered in the San Joaquin Valley, in Kern County specifically. Before the pandemic began, nearly 10,000 people were employed in the oil and gas extraction industry in Kern County (Kasler, 2020). Each rig is associated with about 100 jobs, which means that the reduction in oil rigs operating in California over the past year could have resulted in the loss of approximately 1,400 jobs.

The pandemic also halted maintenance projects at refineries and pumps across the globe. With companies either shutdown or at limited working capacity, the supply of spare parts for repairs dwindled. Maintenance workers were unable to conduct reviews of equipment. There were anticipated to be a backlog of maintenance projects to complete as stay at home orders were lifted (Yagova, George, and Sharafedin, 2020). Typically, companies perform maintenance inspections during lulls in production, but they will need to conduct these inspections when production should be picking up. This could further delay crude production, slowing the industry's recovery.

Unlike previous economic hits to the industry, oil and gas extraction may not recover quickly from this downturn. Where some industries are hoping for a "V-shaped" recovery, oil and gas extraction is more likely to recover in a "U-shape," with a protracted downturn before recovery begins (Flores, 2020). The industry will likely be looking at flat or even decreased demand post-pandemic, as practices such as remote working continue (Barbosa et al, 2020).

The public sector's outlook has also drastically changed. State and local governments across the country are now experiencing significantly altered fiscal budgets. With the private sector struggling to attract business, the public sector has seen their projected budgets move into shortfall territory (McNichol & Leachman, 2020). The coronavirus-induced recession is estimated to cause greater budgetary shortfalls than the Great Recession of 2008. While the Coronavirus Aid, Relief, and Economic Security (CARES) Act granted state and local government federal aid to help offset these budgetary constraints, it is a fraction of their lost revenues. States in total also have about $75 billion in "rainy day" funds, but this also may not be enough to weather the shortage of government revenues.

Tax revenues are expected to diminish as a result of the pandemic. Income taxes will decrease with greater unemployment (Sheiner & Campbell, 2020). Revenues from sales taxes have also decreased because of reduced spending on entertainment and travel. As a result, state and local officials have started cutting funding for numerous programs. According to analysis from the League of California Cities, no matter their size, the vast majority of cities will have to cut spending on their public services. Even spending on core services will be cut, with between 78 and 90 percent of cities cutting public safety budgets and 71 to 90 percent cutting housing budgets (League of California Cities, 2020).

Public sector employment was also cut, particularly in the early stages of the pandemic. While most public sector job loss in education, local government workers lost approximately 523,000 jobs in non-education related areas from March through May of 2020 (NACo, 2020).

Because the COVID-19 pandemic has dramatically altered metrics used to estimate socioeconomic impacts, such as revenue and employment, ERG uses a "COVID-adjusted baseline" for these metrics, as discussed further in Section 4.1.2 below.

4. SOCIOECONOMIC IMPACT ANALYSIS

ERG calculated the direct impacts of the proposed rule amendments by comparing the costs of compliance to profits of affected facilities. ERG estimated potential employment impacts using IMPLAN's (2020a) input-output model. Additionally, ERG used the IMPLAN model to capture indirect and induced impacts (i.e., impacts that might arise if directly impacted entities reduce purchases from their suppliers and households adjust their spending as a result of changes in earnings).

4.1. DATA SOURCES AND METHODOLOGY

To estimate socioeconomic impacts, ERG compares the costs of compliance with the potential amendments with profits per facility. ERG sought to create a profile for each affected sector, including employment, revenue, profits, and average pay per employee. The process of estimating each of these endpoints also requires other data to be used (e.g., facility name, address).

This section describes the data sources used to create the baseline industry profile, how this profile was adjusted to capture the impacts of the COVID-19 pandemic, and how socioeconomic impacts were estimated.

The sections that follow detail the resulting profile of affected entities and the socioeconomic impacts of compliance with the potential rule amendments.

4.1.1. Baseline Industry Profile Estimates

SJVAPCD (2020b) provided ERG with an initial list of affected facilities, including fields for facility ID, facility description, Standard Industrial Classification (SIC) code, number of emissions sources, and unit location.

ERG identified additional data points for use in the analysis. For instance, SJVAPCD's (2020b) facility data includes a SIC code, and ERG converted these to the North American Industry Classification System (NAICS) codes that are used with other sources of economic data used in the analysis using a combination of U.S. Census Bureau (2020b) concordances.[4] Where a SIC code could map to multiple NAICS codes, ERG used information on companies' websites or other search tools about what type of industry they are engaged in to assign a NAICS code. (See Table A-2 for a list of the NAICS code(s) that mapped to each SIC code.)

Employment and revenue data for most private industries were drawn from the U.S. Census Bureau's (2020b) Economic Census, using 2017 data for California. Where data for certain industries

[4] SIC codes were last updated in 1987, and NAICS codes were first issued in 1997. The U.S. Census Bureau's (2020b) concordances map 1987 SIC codes to 1997 NAICS codes, and from there to the NAICS codes that are revised every five years (thus far in 2002, 2007, 2012, and 2017). SIC and NAICS codes are available at different levels of granularity. The SIC codes used in SJVAPCD's (2020a) data are 4-digit SIC codes, and ERG mapped these to 4-digit NAICS codes.

were not available,[5] ERG instead used estimates from the U.S. Census Bureau's (2015) Statistics of U.S. Businesses for 2012 for California or, if that was not available, the U.S. Census Bureau's (2020c) estimates for 2017 for the U.S.[6]

For the agricultural sector, revenue data are available in the United States Department of Agriculture (USDA) National Agricultural Statistics Service (NASS, 2019) Census of Agriculture for California for 2017, using the "market value of agricultural products sold." Employment data are drawn from the California Employment Development Department (CA EDD, 2020b) and are for California for 2017.

For state and local government entities, employment and revenue data are drawn from the U.S. Census Bureau's (2020d) Annual Survey of State and Local Government Finances, U.S. Census Bureau's (2017a) State and Local Government Employment and Payroll, and U.S. Census Bureau's (2017b) Government Units Survey, all using data for California for 2017. For federal entities, ERG used publicly-available estimates for the specific facilities included in the District's facility list (VA, 2019; IRS, 2020; ABC 30, 2016).

To estimate average payroll per employee, data for private entities by sector come from BLS' (2020) QCEW. For state and local government entities, data are from the U.S. Census Bureau's (2017a) State and Local Government Employment and Payroll and U.S. Census Bureau's (2017b) Government Units Survey. For federal entities, data are an Office of Personnel Management (OPM, 2017) estimate of the average base salary for full-time permanent employees.

ERG estimated profits for private industries by multiplying revenue figures by the average profit rate for each NAICS for 2010 through 2013 using data from the Internal Revenue Service (IRS, 2016) "SOI Tax Stats - Corporation Source Book." The profit rate was calculated as "Net Income (less deficit)" divided by "Total Receipts."[7] (See Appendix B for profit rates by NAICS code.) For agricultural industries (which are not included in the IRS data at a granular level) ERG used data from the Risk Management Association's (RMA, 2020 Annual Statement Studies, which are prepared standardized income statements from data submitted by individual enterprise to assess risk and evaluate financial performance relative to other enterprises in the same industry). For state and local government entities, although they are not profit-seeking, ERG calculates a "profit" rate as revenue minus expenditures divided by revenue, using data from the U.S. Census Bureau's (2020d) Annual Survey of State and Local Government Finances for 2017 for California.

4.1.2. COVID-19-Adjusted Baseline Industry Profile Estimates

To reflect the impact of the COVID-19 pandemic, ERG estimates **"COVID-adjusted" baseline**, which alters employment, revenue, and payroll figures for each facility using IMPLAN (2020a) data. IMPLAN's "Evolving Economy" data use economic data points from the second quarter of 2020 to reflect the impacts on the pandemic, taking into account industry losses, shifts in household spending and

[5] U.S. Census (2020b) Economic Census data were not available for California for NAICS 1151 Support Activities for Crop Production, 2212 Natural Gas Distribution, 2213 Water, Sewage and Other Systems, and 5324 Commercial and Industrial Machinery and Equipment Rental and Leasing.

[6] U.S. Census Bureau (2020c) Statistics of U.S. Businesses estimates for 2017 that include state-level revenue data will not be released until January 2021.

[7] 2013 is the most recent year for which profit rate data are available.

behavior, stimulus checks and unemployment benefits, and Paycheck Protection Program (PPP) loans (Demski, 2020). IMPLAN uses only the second quarter 2020 data, adjusts it for seasonality, and annualizes the single quarter of data to an entire year. This annualization approach means that IMPLAN models 2020 as if the entire year had an economy like in the early stages of the pandemic, without the relatively normal first quarter of 2020 and without any level of recovery later in the year (Clouse, 2020).

While the IMPLAN data for 2020 reflect the impacts of the COVID-19 pandemic and government response, it is important to note that it does not *only* capture the impacts of the pandemic, as other trends may also be captured in the changes between 2018 and 2020 (Clouse, 2020).

Using outputs of the IMPLAN model, ERG estimates the percentage change in employment, revenue, and payroll by NAICS between 2018 (the second-most recent year for which data are available) and 2020 (the "Evolving Economy" dataset, the most recent estimate). District-wide, this approach suggests that revenue contracted by 8 percent, and employment contracted by 9.9 percent (see Table 9). This likely underestimates the impacts of COVID because of continued economic growth through 2019 into the start of 2020. The impact of COVID is more appropriately against a baseline that incorporates this additional growth. Such a baseline would be higher than it was in 2018, and the economic decline in the second quarter of 2020 due to COVID shown in Table 9 would likely be even larger when compared against the later baseline (were such data available).

Table 9. District-Wide COVID-19 Impacts

	2018	2020 Q2 [a]	% Change
Revenue	$333.1 billion	$306.5 billion	-8.0%
Employment	2.0 million	1.8 million	-9.8%

Source: IMPLAN, 2020a.

Note:

[a] Data are modeled for an entire year as if it were like the second quarter of 2020 (i.e., the early stage of the pandemic.)

To estimate the impacts of the COVID-19 pandemic on individual industries, ERG multiplied the percentage change from 2018 to the second quarter of 2020 in the IMPLAN model by the baseline data to produce "COVID-adjusted" estimates for each NAICS code (which was then mapped onto SIC codes for use in conjunction with the cost data provided by SJVAPCD (2020c) on a SIC code basis).

In most industries, this results in a decrease in revenue and employment, but an *increase* in average payroll per employee, reflecting the fact that more workers in lower-paid occupations have been laid off than workers in higher-paid administrative and executive occupations (Clouse, 2020).

The industries with the largest decrease in revenue and employment between 2018 and the second quarter of 2020 include restaurants (a 46.7 percent decrease in revenue and 49.6 percent decrease in employment), support activities for crop production (a 32.2 percent decrease in revenue and 13.9 percent decrease in employment), and dry cleaning and laundry services (a 30.0 percent decrease in revenue and a 34.8 percent decrease in employment).

Notably, some sectors saw substantial revenue growth in 2019 through the first quarter of 2020, and thus appear to show less substantial impacts using the COVID-19-adjusted baseline. These sectors include oil and gas extraction (a 33.6 percent increase in revenue, state and local governments (a 15.0 and 9.6 percent increase in revenue, respectively), hospitals (a 7.4 increase in revenue), and the administrative and support and waste management and remediation service sector (between a 5 and 10 percent increase in revenue, depending on the specific industry).

This increase in revenue in the oil and gas industry and state and local governments is primarily the result of the forces driving economic growth prior to COVID-19. To account for this, IMPLAN's estimated the effect of growth in employment and increased labor productivity in these sectors between 2018 and 2020 prior to COVID-19, which, combined, suggest an increase in output (IMPLAN, 2020c). While IMPLAN's "Evolving Economy" dataset represents their best available estimate of the economy in 2020 based on the economic data that are currently released, the modeling approach has limitations. For instance, it is not possible to separate trends in an industry sector between 2018 and the second quarter of 2020 from the specific impacts of COVID-19 on the economy between the first and the second quarter of 2020. Using second quarter of 2020 data and applying it to the entire year also does not capture any lagging impacts of the COVID-19 pandemic that may take time to be seen in the data. Given the shortcomings of the dataset, IMPLAN suggests using both the 2018 and 2020 models to compare the results (Clouse, 2020). ERG has done this in the sensitivity analysis in Section 4.4.3 below.

While the pattern recovery from the COVID-19 pandemic will take is unknown, many sectors may have fully or partially recovered by the time compliance is required with the potential rule amendments. To capture this, while the primary analysis includes the worst-case scenario of no recovery, ERG also performed three sensitivity analyses assuming 30 percent, 70 percent, or 100 percent recovery (i.e., return to the 2018 baseline) (with the results presented in Section 4.4.3).

Note that the industries with lower revenue in 2018 than the second quarter of 2020 in the IMPLAN (2020a) data actually fare worse in terms of economic impacts under the COVID-19 recovery sensitivity analyses, because they are modeled as gradually returning to their (lower) 2018 revenue levels. This includes oil and gas extraction, one of the main industries affected by the potential amendments.

See Appendix C for detail on the revenue, employment, and payroll adjustments for the sectors affected by the potential amendments.

4.1.3. Estimating Impacts on Affected Entities

Cost estimates (i.e., the direct cost of the potential rule amendments by SIC code) were provided by SJVAPCD (2020b). Total costs were calculated by summing the one-time capital costs (annualized over a 10-year period using a 10 percent discount rate) and ongoing annual costs. (Note that this approach does not account for the fact that costs will not be incurred for several years, and thus resulting in greater cost and impacts estimates than an approach that takes into account the time value of money would.)

To estimate impacts, the direct costs of the rule (i.e., the cost of compliance with the rule) are compared to profits for each SIC code. Because each SIC code can include multiple NAICS codes, and because it is unknown which facilities are those with costs, ERG compared the costs of compliance with the proposed amendments to profits.

To estimate both direct employment impacts of the potential rule amendments and indirect and induced effects, ERG used IMPLAN's (2020a) input-output model. IMPLAN "is a regional economic analysis software application that is designed to estimate the impact or ripple effect (specifically backward linkages) of a given economic activity within a specific geographic area through the implementation of its Input-Output model" (IMPLAN Group LLC, 2020b).

Based on the costs to affected facilities, the IMPLAN model estimates how many jobs might be lost in reaction to the costs to affected firms. It also estimates indirect costs (i.e., the impact to affected firms' suppliers when the direct cost of rule compliance causes affected firms to reduce their purchases from those companies) and induced impacts (i.e., how households that have lost income in turn adjust their purchases).

4.1.4. Aggregating to the Sector Level

While the inputs to the analysis are estimated on a NAICS code or SIC code basis, the results are presented with those more granular industries aggregated into a smaller number of sectors:

- Oil Producers
- Oil Refineries
- Government[8]
- Food Processing and Related Industries
- Other Affected Sources
- Other Industries (those not directly affected by the rule, but that may see indirect or induced impacts).

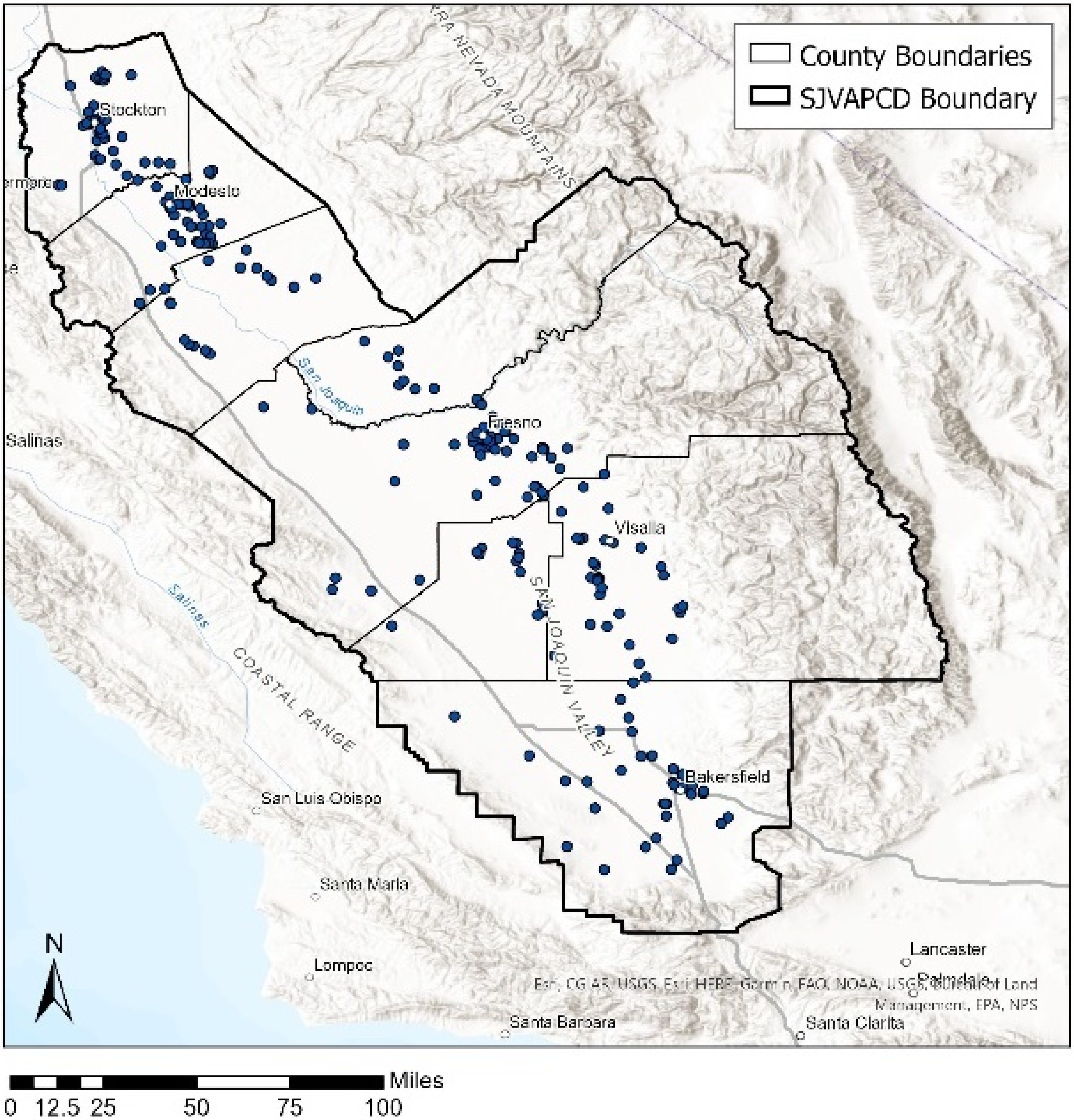
These SIC code to sector mappings were developed by SJVAPCD (2020d). See Appendix A for a concordance between SIC codes and sectors.

4.2. PROFILE OF AFFECTED ENTITIES

Figure 8 presents the facilities operating boilers, steam generators, and process heaters (whether affected by potential rule changes or not). Facilities were mapped using the geocoding function in ArcGIS Pro 2.6.0. Out of the 335 affected facilities, 271 were mapped while the remaining facilities did not have sufficient information to be displayed. Many of the unmapped facilities are likely in more rural areas where there was less information available for the address locator. However, the majority of facilities are concentrated in major metropolitan areas of the District. Madera County contains the least number of affected facilities (10) while the portion of Kern County within in the Districts contains the highest amount of affected facilities (68).

[8] Note that this sector does not include all government-operated facilities, as there are two local government facilities assigned SIC 4952 Sewerage Systems in the SJV APCD (2020b) data, and SIC 4952 is assigned to the "Other Affected Sources" sector in the SJV APCD (2020d) SIC to sector concordance. One of these two facilities is affected by the potential amendments.

Figure 8. Map of Facilities Operating Boilers, Steam Generators, and Process Heaters



Source data: SJVAPCD, 2020b; CARB, 2020; ERG estimates.
Map created by ERG using ArcGIS® software by Esri.

Table 10 includes a profile of facilities affected by the potential amendments to Rules 4306 and 4320 (i.e., those that will incur compliance costs). A total of 290 facilities will incur retrofit and/or AERO fee costs.

Table 10. Profile of Facilities Affected by Potential Amendments to Rules 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

Sector	Total Facilities	Affected Facilities	% Affected	Total		
				Employees	Revenue	Profits
Oil Producers	55	49	89.1%	1,806	$2,840,741,675	$209,275,625
Oil Refineries	4	4	100.0%	212	$840,428,115	$56,752,035
Government [a]	9	7	77.8%	1,437	$6,943,144,058	—
Food Processing and Related Industries	148	137	92.6%	7,502	$4,237,786,768	$176,609,213
Other Affected Sources	101	93	92.1%	32,295	$10,104,515,144	$466,947,385
Other Industries	18	0	0.0%	N/A	N/A	N/A
Total	**335**	**290**	**86.6%**	**43,251**	**$24,966,615,761**	**$909,584,258**

Sources: ERG estimates based on SJVAPCD, 2020b; U.S. Census Bureau, 2015; U.S. Census Bureau, 2020b; U.S. Census Bureau 2020c; NASS, 2019; CA EDD, 2020a; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020d; U.S. Census Bureau, 2017a; U.S. Census Bureau, 2017b; BLS, 2020; IMPLAN, 2020a; OPM, 2017; IRS, 2016; RMA, 2020.

Note:

[a] Government agencies do not have profits, so profit values are not shown here.

Table 11 shows the characteristics of the average facility affected by the potential amendments to Rules 4306 and 4320. (The exact characteristics of individual facilities could be either higher or lower than these average estimates.)

Table 11. Characteristics of Average Facilities Affected by Potential Amendments to Rules 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

Sector	Average per Facility			Average Annual Pay per Employee
	Employees	Revenue	Profits	
Oil Producers	37	$57,974,320	$4,270,931	$39,729
Oil Refineries	53	$210,107,029	$14,188,009	$58,992
Government [a]	205	$991,877,723	—	$58,259
Food Processing and Related Industries	55	$30,932,750	$1,289,118	$58,494
Other Affected Sources	347	$108,650,700	$5,020,940	$52,620
Average	**149**	**$86,091,778**	**$3,136,497**	**$53,319**

Sources: ERG estimates based on SJVAPCD, 2020b; U.S. Census Bureau, 2015; U.S. Census Bureau, 2020b; U.S. Census Bureau 2020c; NASS, 2019; CA EDD, 2020a; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020d; U.S. Census Bureau, 2017a; U.S. Census Bureau, 2017b; BLS, 2020; IMPLAN, 2020a; OPM, 2017; IRS, 2016; RMA, 2020.

Note:

[a] Government agencies do not have profits, so profit values are not shown here.

4.3. COMPLIANCE COST ESTIMATES

Compliance costs were estimated by SJVAPCD (2020c), and include:

- One-time costs for units retrofit by December 31, 2023.
- One-time costs for units retrofit by December 31, 2029.

- Annual operating and maintenance (O&M) costs for the units retrofit in 2023, beginning in 2023 and continuing indefinitely. (Note that for some facilities these costs may actually be cost savings, as the more efficient units result in decreased electricity and fuel usage.)
- Annual O&M costs (or cost savings) for the units retrofit in 2029, beginning in 2029 and continuing indefinitely.
- AERO fees paid annually to the District, beginning in 2025 on the basis of 2024 emissions.

Total costs are calculated by annualizing the one-time retrofit costs that will be incurred in either 2023 or 2029 over a 10-year period using a 10 percent interest rate, and then summing annualized one-time costs and annualized costs to yield the total.[9]

Table 12 shows the one-time, annual, and total annualized costs incurred by sector. Costs would total **$23.0 million**, with the majority of these incurred by the "Oil Producers" sector.

Table 12. Costs of Compliance with Potential Amendments to Rules 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

Sector	Retrofit Capital Costs [a]		Retrofit O&M Costs [b]		AERO Fees [c]	Total Annualized Costs [d]
	One-Time		Annual		Annual	Annualized One-Time + Annual
	2023	2029	2023+	2029+	2025+	—
Oil Producers	$53,498,510	$22,800	$2,088,349	$2,798	$7,012,010	$17,813,503
Oil Refineries	$217,440	$0	$12,257	$0	$418,777	$466,421
Government	$0	$525,960	$0	$82,888	$20,783	$189,269
Food Processing and Related Industries	$2,215,900	$38,409,984	-$51,328	-$4,243,880	$882,225	$3,198,693
Other Affected Sources	$957,600	$8,762,144	$175,056	-$680,207	$236,928	$1,313,620
Total	**$56,889,450**	**$47,720,888**	**$2,224,334**	**-$4,838,401**	**$8,570,724**	**$22,981,507**

Source: SJVAPCD, 2020c.

Notes:

[a] Includes one-time capital costs for retrofit in either 2023 or 2029 (depending on NOx emissions)

[b] Includes the costs to operate and maintain the retrofit unit (which for some facilities will be a cost savings due to decreased electricity and fuel usage).

[c] Includes AERO fees that are paid annually beginning in 2025 based on the previous year's emissions.

[d] The total annualized cost is calculated by summing annualized one-time costs (annualized over a 10-year period using a 10 percent discount rate) and annual costs.

4.4. IMPACTS ON AFFECTED ENTITIES

This section first discusses our primary impacts test, which compares compliance costs to profits for affected facilities. ERG then discusses indirect and induced impacts to related industries, and the results of sensitivity analyses that examine results under varying degrees of economic recovery from the COVID-19 pandemic.

[9] Note that this is a conservative cost estimate in the sense that costs that will not be incurred until 2023, 2025, or 2029 are not discounted to account for the time value of money.

4.4.1. Direct Impacts

One possible measure of determining economic feasibility is a comparison of total annualized costs to profits for affected facilities, with a threshold of 10 percent of profits indicating a finding of a finding of significant adverse impact (Berck, 1995). Therefore, ERG uses this comparison to aid in the District's determination of economic feasibility of the rule amendments.

As shown in Table 13, overall rule impacts are approximately **2.5 percent of profits.** The "Oil Producers" sector would face the highest impacts, at **8.5 percent** of profits, but no sector would be affected at a significant level.

Table 13. Economic Impacts for Entities Affected by Potential Amendments to Rule 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

Sector	Average Annualized Cost per Facility	Average Profits per Facility	Cost as % Profits
Oil Producers	$363,541	$4,270,931	8.51%
Oil Refineries	$116,605	$14,188,009	0.82%
Government [a]	$27,038	—	—
Food Processing and Related Industries	$23,348	$1,289,118	1.81%
Other Affected Sources	$14,125	$5,020,940	0.28%
Average	**$79,247**	**$3,136,497**	**2.53%**

Sources: ERG estimates are based on SJVAPCD, 2020b; SJVAPCD, 2020c; U.S. Census Bureau, 2015; U.S. Census Bureau, 2020b; U.S. Census Bureau 2020c; NASS, 2019; CA EDD, 2020a; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020d; U.S. Census Bureau, 2017a; U.S. Census Bureau, 2017b; BLS, 2020; IMPLAN, 2020a; OPM, 2017; IRS, 2016; RMA, 2020.
Note:
[a] Government agencies do not have profits, so profit values are not shown here.

4.4.2. Employment, Indirect, and Induced Impacts

In addition to the primary test of direct impacts on revenue (i.e., costs), ERG also assessed potential direct impacts on employment, indirect impacts, and induced impacts using IMPLAN's (2020a) input-output model. The IMPLAN model uses the direct costs of the rule to estimate "ripple effect (specifically backward linkages) of a given economic activity within a specific geographic area through the implementation of its Input-Output model" (IMPLAN, 2020b).

Outputs from the IMPLAN model include:

- **Direct employment impacts**, if facilities with compliance costs under the potential amendments were to attempt to offset these costs by reducing the number of employees.
- **Indirect revenue and employment impacts** that capture how directly affected firms might react to the direct cost of rule compliance by reducing purchases from their suppliers, and how those suppliers might in turn reduce employees.
- **Induced revenue and employment impacts** that capture how households will adjust their spending as a result of any changes in earnings.

Table 14 summarizes these impacts, which, taken together, could have a total impact on the District economy of **$25.4 million and 44 jobs.**

Table 14. Direct, Indirect, and Induced Impacts of Potential Amendments to Rules 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

Sector	Direct		Indirect		Induced		Total	
	Revenue (Costs)	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment
Oil Producers	$17,813,503	22	$396,071	1	$6,651	0	$18,216,225	23
Oil Refineries	$466,421	0	$76,437	0	$9,721	0	$552,580	0
Government	$189,269	1	$1,429	0	$2,155	0	$192,853	1
Food Processing and Related Industries	$3,198,693	7	$470,018	2	$62,086	0	$3,730,796	9
Other Affected Sources	$1,313,620	5	$185,818	1	$132,151	1	$1,631,590	7
Other Industries	$0	0	$784,261	2	$277,480	2	$1,061,741	4
Total	**$22,981,507**	**36**	**$1,914,034**	**5**	**$490,243**	**3**	**$25,385,784**	**44**

Sources: ERG estimates are based on SJVAPCD, 2020b; SJVAPCD, 2020c; U.S. Census Bureau, 2015; U.S. Census Bureau, 2020b; U.S. Census Bureau 2020c; NASS, 2019; CA EDD, 2020a; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020d; U.S. Census Bureau, 2017a; U.S. Census Bureau, 2017b; BLS, 2020; IMPLAN, 2020a; OPM, 2017; IRS, 2016; RMA, 2020.

Table 15 compares these impacts to the total size of the District's economy (as estimated in the IMPLAN model). These impacts represent **less than 0.01 percent** of revenue and employment District-wide.

Table 15. Comparison of Total Impacts against the District-Wide Economy for Potential Amendments to Rules 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

	Total Rule Impacts	Size of District Economy [a]	% of District Economy
Revenue	$25,385,784	$306,518,988,618	0.008%
Employment	44	1,806,161	0.002%

Source: ERG estimates based on IMPLAN, 2020a.

Note:

[a] While the SJVAPCD only includes a portion of Kern County, the data shown here include the whole of the county.

4.4.3. COVID-19 Sensitivity Analysis

As discussed in Section 4.1.2, the primary estimates used in this analysis reflect a "COVID-19-adjusted baseline" where the baseline economic indicators are adjusted using the percentage change between IMPLAN's (2020a) 2018 and second quarter of 2020 "Evolving Economy" model. ERG also conducted three sensitivity analyses that capture varying degrees of economic recovery from the pandemic (i.e., 30 percent, 70 percent, 100 percent).

Table 16 shows how the results of the analysis would vary under these three degrees of economic recovery. Counter-intuitively, costs as a percentage of profits would actually *increase* under the recovery scenarios. This is because the sector most heavily impacted by the rule, "Oil Producers," has higher revenue in IMPLAN's (2020a) model under the 2018-based 100 percent recovery scenario than under the second quarter of 2020 model used for the primary estimate.

Induced impacts also increase slightly with greater COVID-19 recovery, likely because IMPLAN's (2020a) 2020 model takes into account changes in household income and spending patterns (including stimulus checks, unemployment checks, and increased saving) that is removed in the recovery scenarios.

Table 16. Results of COVID-19 Sensitivity Analyses for the Impacts of Rules 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

Analysis	Recovery from COVID-19 Baseline	Direct			Indirect		Induced		Total	
		Revenue (Costs)	Costs % Profits	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment
Primary Estimate	0%	$22,981,507	2.527%	40	$2,058,502	5	$557,300	3	$29,141,975	49
Sensitivity Analysis 1	30%	$22,981,507	2.529%	39	$2,012,914	5	$580,194	4	$29,119,282	47
Sensitivity Analysis 2	70%	$22,981,507	2.532%	37	$1,952,130	5	$610,720	4	$29,089,023	46
Sensitivity Analysis 3	100%	$22,981,507	2.534%	36	$1,906,542	5	$633,614	4	$29,066,330	45

Sources: ERG estimates based on SJVAPCD, 2020b; SJVAPCD, 2020c; U.S. Census Bureau, 2015; U.S. Census Bureau, 2020b; U.S. Census Bureau 2020c; NASS, 2019; CA EDD, 2020a; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020d; U.S. Census Bureau, 2017a; U.S. Census Bureau, 2017b; BLS, 2020; IMPLAN, 2020a; OPM, 2017; IRS, 2016; RMA, 2020.

4.5. IMPACTS ON SMALL ENTITIES

The entities affected by the potential amendments may include small entities (i.e., small businesses and/or small government entities).

For private entities, small businesses are defined in the California Small Business Procurement and Contract Act (Cal. Gov't Code § 14837) as an independently owned and operated, non-dominant business with principal office located in California with fewer than 100 employees and earning less than $15 million in revenues.

For government entities, the Regulatory Flexibility Act definition is that "a small governmental jurisdiction is a government of a city, county, town, township, village, school district, or special district with a population of less than 50,000."

Because ERG did not estimate costs on a facility-specific basis, it is not possible to identify whether any small entities are among the facilities that will incur costs under the potential rule. To the extent that small entities face similar costs to large entities but have lower profits, compliance costs will make up a greater proportion of their profits. However, since many of the facilities that are anticipated to incur costs to comply with the rule are located at either oil and gas producing or food processing facilities, many of which are large employers, the impact of this rule on small businesses as defined above may not be significant.

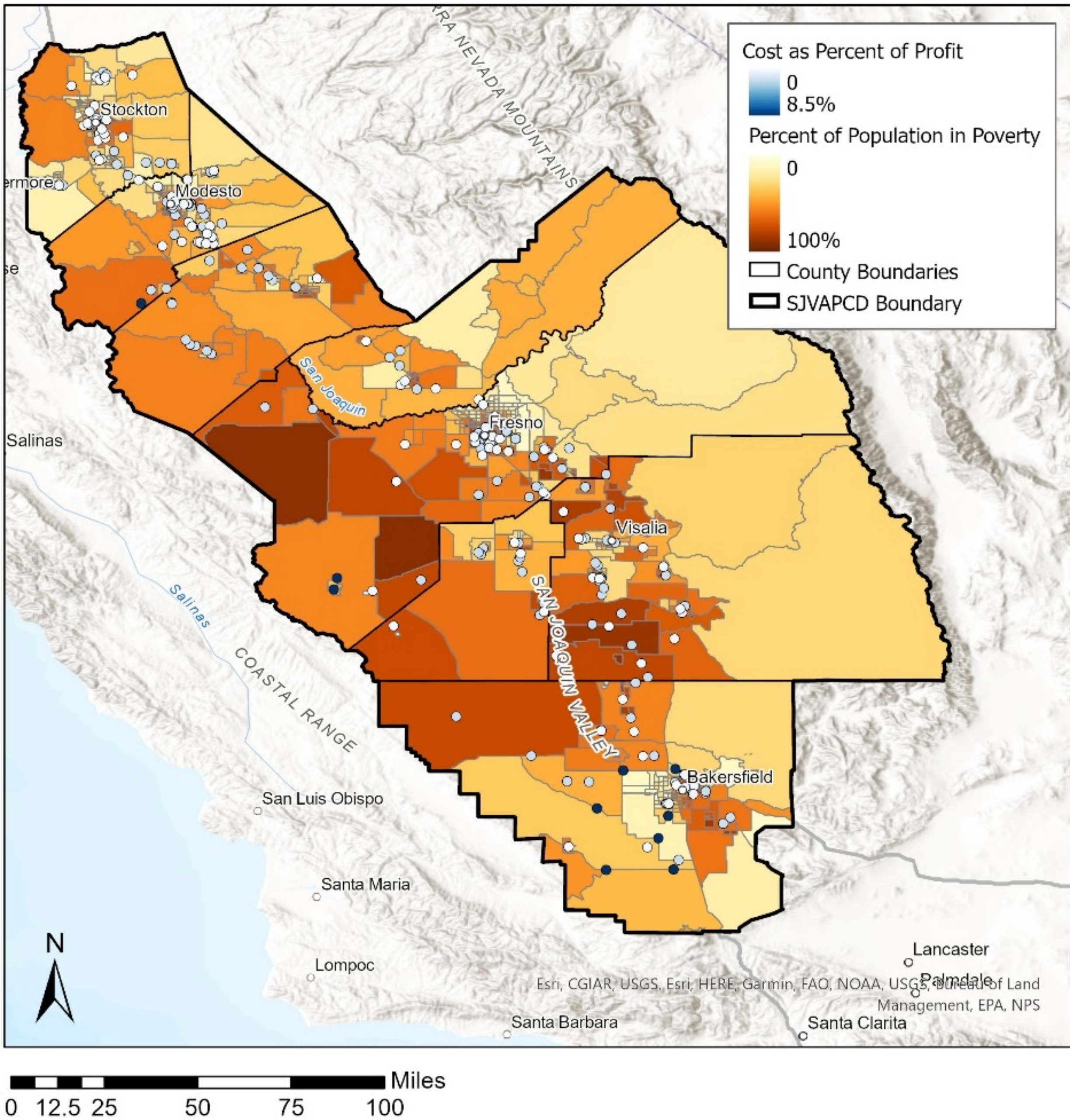
4.6. IMPACTS ON AT-RISK POPULATIONS

Cal. Gov't Code § 65040.12 defines environmental justice as "the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies."

The entities affected by the potential amendments may operate facilities in areas with a high number of at-risk populations. To help further the District's environmental justice goals, ERG overlaid data on the impacts of the rule with data on poverty using data from CalEnviroScreen 3.0 (OEHHA, 2018). (Note that not every facility in a given industry will necessarily be impacted by the rule, but this analysis does not include an assessment of impacts on individual facilities.)

Figure 9 presents a map of the potentially affected facilities overlying the percent of population living two times the federal poverty level. The facilities are colored in blue based on the estimated cost of compliance as a percent of profit. There is no correlation between the location of facilities and percent of the population living in poverty. However, the overall percentage of population living in poverty in the District is higher than the percentage for the state of California overall, and many potentially impacted facilities are located in areas with high poverty rates. The majority of facilities would likely face compliance costs of less than two percent of their profits. Impacts are highest for the "Oil Producers" sector, which are primarily facilities located in Kern County. This could impact vulnerable populations in Kern County, which is one of two counties that has experienced a decline in median income from 2010 to 2018 and experienced a smaller decline in poverty rate compared to the other counties in the district (see Table 5 above).

Figure 9. Map of Facilities in Relation to Population Living in Poverty



Source data: SJVAPCD, 2020b; CARB, 2020; ERG estimates; OEHHA, 2018
Map created by ERG using ArcGIS® software by Esri

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APPENDIX A. SECTOR, SIC CODE, AND NAICS CODE CONCORDANCES

Table A-1 shows the concordance between SIC codes and sectors developed by SJV APCD (SJVAPCD, 2020d). (SIC codes that were not in the original concordance but that might have indirect and induced impacts were assigned the sector "Other Industries.")

Table A-1. SIC Code to Sector Concordance used to Analyze the Impacts of 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

SIC Code	SIC Industry	Sector
0161	Vegetables and Melons	Food Processing and Related Industries
0191	General Farms, Primarily Crop	Food Processing and Related Industries
0723	Crop Preparation Services For Market, except Cotton Ginning - Other	Food Processing and Related Industries
1311	Crude Petroleum and Natural Gas	Oil Producers
1321	Natural Gas Liquids	Oil Producers
2011	Meat Packing Plants	Food Processing and Related Industries
2015	Poultry Slaughtering and Processing - Poultry Processing	Food Processing and Related Industries
2022	Natural, Processed, and Imitation Cheese	Food Processing and Related Industries
2023	Dry, Condensed, and Evaporated Dairy Products	Food Processing and Related Industries
2024	Ice Cream and Frozen Desserts	Food Processing and Related Industries
2026	Fluid Milk - Ultra-High Temperature	Food Processing and Related Industries
2032	Canned Specialties - Canned Specialties	Food Processing and Related Industries
2033	Canned Fruits, Vegetables, Preserves, Jams, and Jellies	Food Processing and Related Industries
2034	Dried and Dehydrated Fruits, Vegetables, and Soup Mixes - Dried and Dehydrated Fruits and Vegetables	Food Processing and Related Industries
2037	Frozen Fruits, Fruit Juices, and Vegetables	Food Processing and Related Industries
2041	Flour and Other Grain Mill Products	Food Processing and Related Industries
2043	Cereal Breakfast Foods - Coffee Substitute	Food Processing and Related Industries
2044	Rice Milling	Food Processing and Related Industries
2047	Dog and Cat Food	Other Affected Sources
2048	Prepared Feed and Feed Ingredients for Animals and Fowls, Except Dogs and Cats - Animal Slaughtering for Pet Food	Other Affected Sources
2062	Cane Sugar Refining	Food Processing and Related Industries
2064	Candy and Other Confectionery Products - Chocolate Confectionery	Food Processing and Related Industries
2068	Salted and Roasted Nuts and Seeds	Food Processing and Related Industries
2076	Vegetable Oil Mills, Except Corn, Cottonseed, and Soybeans - Vegetable Oilseed Processing, except Corn, Cottonseed, and Soybeans	Food Processing and Related Industries
2077	Animal and Marine Fats and Oils - Animal Fats and Oils	Other Affected Sources
2084	Wines, Brandy, and Brandy Spirits	Food Processing and Related Industries
2086	Bottled and Canned Soft Drinks and Carbonated Waters - Soft Drinks	Food Processing and Related Industries
2096	Potato Chips, Corn Chips, and Similar Snacks	Food Processing and Related Industries
2099	Food Preparations, NEC - Reducing Maple Sap to Maple Syrup	Food Processing and Related Industries
2273	Carpets and Rugs	Other Affected Sources

Table A-1. SIC Code to Sector Concordance used to Analyze the Impacts of 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

SIC Code	SIC Industry	Sector
2421	Sawmills and Planing Mills, General - Lumber Manufacturing from Purchased Lumber, Softwood Cut Stock, Wood Lath and Planing Mill Products	Other Affected Sources
2491	Wood Preserving	Other Affected Sources
2499	Wood Products, NEC - Mirror and Picture Frames	Other Affected Sources
2541	Wood Office and Store Fixtures, Partitions, Shelving, and Lockers - Wood Lunchroom Tables and Chairs	Other Affected Sources
2652	Setup Paperboard Boxes	Other Affected Sources
2653	Corrugated and Solid Fiber Boxes	Other Affected Sources
2656	Sanitary Food Containers, Except Folding	Other Affected Sources
2759	Commercial Printing, NEC - Screen Printing	Other Affected Sources
2869	Industrial Organic Chemicals, NEC - Aliphatics	Other Affected Sources
2875	Fertilizers, Mixing Only	Other Affected Sources
2879	Pesticides and Agricultural Chemicals, NEC	Other Affected Sources
2911	Petroleum Refining	Oil Refineries
2951	Asphalt Paving Mixtures and Blocks	Other Affected Sources
2952	Asphalt Felts and Coatings	Other Affected Sources
3086	Plastics Foam Products - Urethane and Other Foam Products	Other Affected Sources
3672	Printed Circuit Boards	Other Affected Sources
4221	Farm Product Warehousing and Storage	Other Affected Sources
4612	Crude Petroleum Pipelines	Oil Producers
4911	Electric Services - Hydroelectric Power Generation	Other Affected Sources
4931	Electric and Other Services Combined - Hydroelectric Power Generation When Combined with Other Services	Other Affected Sources
4952	Sewerage Systems	Other Affected Sources
4961	Steam and Air-Conditioning Supply	Other Affected Sources
5093	Scrap and Waste Materials	Food Processing and Related Industries
5141	Groceries, General Line	Food Processing and Related Industries
5142	Packaged Frozen Foods	Food Processing and Related Industries
5143	Dairy Products, Except Dried or Canned	Food Processing and Related Industries
5149	Groceries and Related Products, NEC - Bottling Mineral or Spring Water	Food Processing and Related Industries
5153	Grain and Field Beans	Food Processing and Related Industries
5169	Chemicals and Allied Products, NEC	Other Affected Sources
7216	Drycleaning Plants, Except Rug Cleaning	Other Affected Sources
7217	Carpet and Upholstery Cleaning	Other Affected Sources
7218	Industrial Launderers	Other Affected Sources
8062	General Medical and Surgical Hospitals	Other Affected Sources
9199	General Government, NEC	Government
9223	Correctional Institutions	Government
9999	Nonclassifiable	Government

Source: SJVAPCD, 2020d.

Table A-2 shows the NAICS codes that map to the SIC codes used in the analysis (limited to the NAICS codes assigned to the facilities in the District that may be affected by the potential amendments). This concordance was primarily developed using the U.S. Census Bureau's (2020a) SIC to NAICS concordances. Where multiple NAICS codes map to one SIC code, ERG used information on companies' websites or other search tools about what type of industry they are engaged in to assign a NAICS code.

Table A-2. SIC to NAICS Concordance for Facilities that may be Affected by Potential Amendments to Rule 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

SIC Code	SIC Industry	Corresponding NAICS
0161	Vegetables and Melons	1112 (Vegetable and Melon Farming)
0191	General Farms, Primarily Crop	1119 (Other Crop Farming)
0723	Crop Preparation Services For Market, except Cotton Ginning - Other	1151 (Support Activities for Crop Production), 3119 (Other Food Manufacturing)
1311	Crude Petroleum and Natural Gas	2111 (Oil and Gas Extraction)
1321	Natural Gas Liquids	2111 (Oil and Gas Extraction)
2011	Meat Packing Plants	3116 (Animal Slaughtering and Processing)
2015	Poultry Slaughtering and Processing - Poultry Processing	3116 (Animal Slaughtering and Processing)
2022	Natural, Processed, and Imitation Cheese	3115 (Dairy Product Manufacturing)
2023	Dry, Condensed, and Evaporated Dairy Products	3115 (Dairy Product Manufacturing)
2024	Ice Cream and Frozen Desserts	3115 (Dairy Product Manufacturing)
2026	Fluid Milk - Ultra-High Temperature	3115 (Dairy Product Manufacturing)
2032	Canned Specialties - Canned Specialties	3119 (Other Food Manufacturing)
2033	Canned Fruits, Vegetables, Preserves, Jams, and Jellies	3114 (Fruit and Vegetable Preserving and Specialty Food Manufacturing)
2034	Dried and Dehydrated Fruits, Vegetables, and Soup Mixes - Dried and Dehydrated Fruits and Vegetables	3114 (Fruit and Vegetable Preserving and Specialty Food Manufacturing)
2037	Frozen Fruits, Fruit Juices, and Vegetables	3114 (Fruit and Vegetable Preserving and Specialty Food Manufacturing)
2041	Flour and Other Grain Mill Products	3112 (Grain and Oilseed Milling)
2043	Cereal Breakfast Foods - Coffee Substitute	3112 (Grain and Oilseed Milling)
2044	Rice Milling	3112 (Grain and Oilseed Milling)
2047	Dog and Cat Food	3111 (Animal Food Manufacturing)
2048	Prepared Feed and Feed Ingredients for Animals and Fowls, Except Dogs and Cats - Animal Slaughtering for Pet Food	3111 (Animal Food Manufacturing)
2062	Cane Sugar Refining	3113 (Sugar and Confectionery Product Manufacturing)
2064	Candy and Other Confectionery Products - Chocolate Confectionery	3113 (Sugar and Confectionery Product Manufacturing)
2068	Salted and Roasted Nuts and Seeds	3119 (Other Food Manufacturing)
2076	Vegetable Oil Mills, Except Corn, Cottonseed, and Soybeans - Vegetable Oilseed Processing, except Corn, Cottonseed, and Soybeans	3112 (Grain and Oilseed Milling)
2077	Animal and Marine Fats and Oils - Animal Fats and Oils	3116 (Animal Slaughtering and Processing)
2084	Wines, Brandy, and Brandy Spirits	3121 (Beverage Manufacturing)
2086	Bottled and Canned Soft Drinks and Carbonated Waters - Soft Drinks	3121 (Beverage Manufacturing)
2096	Potato Chips, Corn Chips, and Similar Snacks	3119 (Other Food Manufacturing)

Table A-2. SIC to NAICS Concordance for Facilities that may be Affected by Potential Amendments to Rule 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

SIC Code	SIC Industry	Corresponding NAICS
2099	Food Preparations, NEC - Reducing Maple Sap to Maple Syrup	3119 (Other Food Manufacturing)
2273	Carpets and Rugs	3141 (Textile Furnishings Mills)
2421	Sawmills and Planing Mills, General - Lumber Manufacturing from Purchased Lumber, Softwood Cut Stock, Wood Lath and Planing Mill Products	3211 (Sawmills and Wood Preservation)
2491	Wood Preserving	3211 (Sawmills and Wood Preservation)
2499	Wood Products, NEC - Mirror and Picture Frames	3219 (Other Wood Product Manufacturing)
2541	Wood Office and Store Fixtures, Partitions, Shelving, and Lockers - Wood Lunchroom Tables and Chairs	3222 (Converted Paper Product Manufacturing)
2631	Paperboard Mills	3222 (Converted Paper Product Manufacturing)
2652	Setup Paperboard Boxes	3222 (Converted Paper Product Manufacturing)
2653	Corrugated and Solid Fiber Boxes	3222 (Converted Paper Product Manufacturing)
2656	Sanitary Food Containers, Except Folding	3222 (Converted Paper Product Manufacturing)
2759	Commercial Printing, NEC - Screen Printing	3231 (Printing and Related Support Activities)
2869	Industrial Organic Chemicals, NEC - Aliphatics	3251 (Basic Chemical Manufacturing)
2875	Fertilizers, Mixing Only	3253 (Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing)
2879	Pesticides and Agricultural Chemicals, NEC	3253 (Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing)
2911	Petroleum Refining	3241 (Petroleum and Coal Products Manufacturing), 3261 (Plastics Product Manufacturing)
2951	Asphalt Paving Mixtures and Blocks	3241 (Petroleum and Coal Products Manufacturing)
2952	Asphalt Felts and Coatings	3241 (Petroleum and Coal Products Manufacturing)
3086	Plastics Foam Products - Urethane and Other Foam Products	3261 (Plastics Product Manufacturing)
3672	Printed Circuit Boards	3329 (Other Fabricated Metal Product Manufacturing)
4221	Farm Product Warehousing and Storage	3111 (Animal Food Manufacturing), 3112 (Grain and Oilseed Milling)
4612	Crude Petroleum Pipelines	4861 (Pipeline Transportation of Crude Oil)
4911	Electric Services - Hydroelectric Power Generation	2211 (Electric Power Generation, Transmission and Distribution)
4931	Electric and Other Services Combined - Hydroelectric Power Generation When Combined with Other Services	2211 (Electric Power Generation, Transmission and Distribution)
4952	Sewerage Systems	9993 (Local Government)
4961	Steam and Air-Conditioning Supply	2213 (Water, Sewage and Other Systems)
5093	Scrap and Waste Materials	5629 (Remediation and Other Waste Management Services)

Table A-2. SIC to NAICS Concordance for Facilities that may be Affected by Potential Amendments to Rule 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

SIC Code	SIC Industry	Corresponding NAICS
5141	Groceries, General Line	3114 (Fruit and Vegetable Preserving and Specialty Food Manufacturing)
5142	Packaged Frozen Foods	4244 (Grocery and Related Product Merchant Wholesalers)
5143	Dairy Products, Except Dried or Canned	4244 (Grocery and Related Product Merchant Wholesalers)
5149	Groceries and Related Products, NEC - Bottling Mineral or Spring Water	3114 (Fruit and Vegetable Preserving and Specialty Food Manufacturing), 3121 (Beverage Manufacturing)
5153	Grain and Field Beans	4245 (Farm Product Raw Material Merchant Wholesalers)
5169	Chemicals and Allied Products, NEC	4249 (Miscellaneous Nondurable Goods Merchant Wholesalers)
7216	Drycleaning Plants, Except Rug Cleaning	8123 (Drycleaning and Laundry Services)
7217	Carpet and Upholstery Cleaning	8123 (Drycleaning and Laundry Services)
7218	Industrial Launderers	8123 (Drycleaning and Laundry Services)
8062	General Medical and Surgical Hospitals	6221 (General Medical and Surgical Hospitals)
9199	General Government, NEC	9991 (Federal Government), 9993 (Local Government)
9223	Correctional Institutions	5612 (Facilities Support Services), 9992 (State Government), 9993 (Local Government)
9999	Nonclassifiable	3115 (Dairy Product Manufacturing)

Source: ERG estimates based on SJVAPCD, 2020b; U.S. Census Bureau, 2020a.

APPENDIX B. PROFIT RATES BY NAICS INDUSTRY

Table B-1 shows the profit rates used for private industry, which were estimated using the average rate for 2000 through 2013 data from the Internal Revenue Service (IRS, 2016) "SOI Tax Stats - Corporation Source Book."

Table B-1. Profit Rate by NAICS Industry for Facilities Affected by Rule 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

NAICS	Industry	Average	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
1112	Vegetable and Melon Farming	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
1119	Other Crop Farming	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
1151	Support Activities for Crop Production	2.00%	1.04%	0.92%	-0.49%	1.06%	1.89%	3.36%	2.06%	2.84%	0.48%	0.87%	2.64%	2.33%	4.76%	4.31%
2111	Oil and Gas Extraction	7.33%	6.53%	5.55%	0.85%	5.50%	8.04%	14.89%	16.06%	11.11%	10.31%	2.50%	8.29%	5.99%	3.50%	3.50%
2211	Electric Power Generation, Transmission and Distribution	0.45%	7.39%	2.31%	2.53%	-1.37%	-0.14%	0.83%	4.84%	7.36%	0.54%	-2.62%	0.18%	-6.02%	-7.16%	-2.38%
2213	Water, Sewage and Other Systems	0.62%	4.82%	3.57%	-8.79%	-0.83%	0.43%	6.40%	4.36%	6.25%	-6.72%	-0.97%	-1.81%	-0.17%	-0.19%	2.38%
3111	Animal Food Manufacturing	4.06%	4.85%	2.75%	3.53%	2.10%	2.77%	5.38%	4.83%	5.11%	3.67%	4.37%	5.13%	3.47%	4.21%	4.66%
3112	Grain and Oilseed Milling	4.62%	3.36%	3.03%	3.33%	4.45%	4.40%	9.30%	7.06%	4.31%	3.66%	4.37%	5.13%	3.47%	4.21%	4.66%
3113	Sugar and Confectionery Product Manufacturing	8.23%	5.65%	7.03%	9.37%	6.34%	4.85%	7.97%	8.95%	6.89%	8.99%	6.98%	11.55%	8.24%	10.61%	11.74%
3114	Fruit and Vegetable Preserving and Specialty Food Manufacturing	5.97%	5.09%	6.15%	5.84%	4.75%	4.31%	7.36%	9.77%	5.17%	6.02%	6.23%	5.55%	5.55%	6.10%	5.71%
3115	Dairy Product Manufacturing	2.10%	2.64%	1.49%	1.89%	0.81%	0.78%	0.48%	2.61%	2.29%	2.52%	1.55%	2.60%	1.97%	4.35%	3.45%
3116	Animal Slaughtering and Processing	2.72%	1.69%	1.82%	1.69%	2.28%	2.05%	2.79%	1.43%	1.66%	0.84%	4.37%	5.13%	3.47%	4.21%	4.66%
3119	Other Food Manufacturing	4.61%	2.86%	2.47%	2.42%	3.20%	2.93%	13.21%	4.91%	5.28%	3.25%	5.00%	6.48%	3.16%	3.79%	5.50%
3121	Beverage Manufacturing	11.35%	9.13%	8.71%	7.57%	11.16%	8.99%	22.37%	10.84%	9.05%	8.36%	13.09%	11.80%	12.61%	11.59%	13.66%
3141	Textile Furnishings Mills	1.70%	1.19%	-1.02%	-0.84%	11.10%	0.56%	1.85%	1.90%	1.47%	-0.30%	-1.05%	1.46%	1.10%	2.78%	3.63%
3211	Sawmills and Wood Preservation	1.37%	1.88%	1.49%	0.66%	2.43%	4.25%	5.26%	2.27%	-0.43%	-2.35%	-4.63%	0.08%	0.55%	2.47%	5.28%
3219	Other Wood Product Manufacturing	1.37%	1.88%	1.49%	0.66%	2.43%	4.25%	5.26%	2.27%	-0.43%	-2.35%	-4.63%	0.08%	0.55%	2.47%	5.28%
3222	Converted Paper Product Manufacturing	7.09%	7.25%	4.44%	5.30%	4.22%	5.40%	12.53%	10.18%	7.60%	4.79%	7.83%	7.65%	5.27%	7.35%	9.47%
3231	Printing and Related Support Activities	2.82%	2.67%	1.69%	1.96%	2.26%	2.80%	4.10%	4.27%	3.77%	1.52%	0.64%	3.44%	1.84%	3.93%	4.55%

Table B-1. Profit Rate by NAICS Industry for Facilities Affected by Rule 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

NAICS	Industry	Average	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
3241	Petroleum and Coal Products Manufacturing	6.81%	8.77%	7.99%	3.83%	6.49%	7.96%	8.57%	7.99%	7.35%	6.22%	6.59%	6.95%	5.20%	6.05%	5.39%
3251	Basic Chemical Manufacturing	3.41%	1.93%	-1.88%	-0.92%	3.08%	1.16%	6.94%	5.82%	4.63%	2.18%	2.25%	5.76%	4.31%	5.71%	6.82%
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	9.71%	7.17%	6.83%	7.20%	8.32%	7.44%	20.64%	9.91%	9.08%	8.59%	13.43%	9.93%	8.63%	9.32%	9.51%
3261	Plastics Product Manufacturing	2.57%	2.49%	1.24%	1.57%	1.50%	2.51%	3.62%	2.17%	2.74%	1.24%	2.32%	2.84%	3.00%	4.68%	4.01%
3329	Other Fabricated Metal Product Manufacturing	6.09%	6.20%	3.31%	4.19%	4.07%	6.49%	9.50%	6.71%	7.38%	5.85%	3.71%	5.79%	6.81%	7.37%	7.84%
4244	Grocery and Related Product Merchant Wholesalers	2.66%	0.94%	0.92%	0.77%	0.89%	3.24%	2.64%	3.88%	4.15%	2.99%	2.47%	3.24%	3.12%	3.99%	3.98%
4245	Farm Product Raw Material Merchant Wholesalers	1.60%	1.22%	1.07%	0.78%	2.44%	2.08%	2.36%	2.17%	1.52%	0.76%	2.31%	2.33%	0.74%	1.64%	0.91%
4249	Miscellaneous Nondurable Goods Merchant Wholesalers	2.32%	1.52%	1.36%	1.68%	2.63%	2.74%	2.98%	2.31%	1.99%	2.12%	2.47%	2.78%	2.23%	2.94%	2.76%
4861	Pipeline Transportation of Crude Oil	8.89%	4.27%	2.45%	16.03%	10.39%	13.16%	11.98%	3.65%	12.16%	6.97%	7.85%	7.69%	3.74%	13.84%	10.25%
5612	Facilities Support Services	2.80%	0.45%	0.38%	1.43%	2.33%	2.47%	5.02%	3.70%	3.60%	3.03%	2.08%	3.61%	3.35%	3.85%	3.89%
5629	Remediation and Other Waste Management Services	3.47%	1.83%	2.78%	1.49%	-0.78%	3.05%	5.19%	-1.57%	6.69%	4.14%	6.25%	6.27%	4.23%	4.92%	4.13%
6221	General Medical and Surgical Hospitals	4.43%	1.68%	2.78%	3.59%	3.70%	4.00%	5.04%	4.89%	4.80%	4.68%	5.59%	5.37%	4.88%	5.70%	5.34%
8123	Drycleaning and Laundry Services	2.60%	-0.16%	-4.66%	2.16%	2.87%	1.85%	3.20%	4.09%	3.92%	2.41%	2.81%	3.71%	4.59%	4.85%	4.77%
9991	Federal Government	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
9992	State Government	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
9993	Local Government	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Source: ERG estimates based on IMPLAN, 2020a.

Note: Profit rate calculated as "Net Income (less deficit)" divided by "Total Receipts."

APPENDIX C. COVID-19 BASELINE ADJUSTMENTS BY NAICS INDUSTRY

Table C-1 shows the percentage change in revenue, employment, and average pay per employee by NAICS code, derived by comparing IMPLAN's (2020) datasets for 2018 and the "Evolving Economy" dataset developed using data for the second quarter of 2020.

Table C-1. COVID-19 Adjustments by NAICS Industry for Facilities Affected by Rule 4306 and 4320—Boilers, Steam Generators, and Process Heaters - Phase 3, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

NAICS	Industry	COVID-19-Adjusted Change in Baseline		
		Revenue	Employment	Average Pay
1112	Vegetable and Melon Farming	-17.46%	-13.79%	13.98%
1119	Other Crop Farming	-17.46%	-14.86%	13.76%
1151	Support Activities for Crop Production	-32.19%	-13.91%	13.78%
2111	Oil and Gas Extraction	33.55%	29.86%	6.47%
2211	Electric Power Generation, Transmission and Distribution	-3.97%	-7.25%	12.55%
2213	Water, Sewage and Other Systems	1.77%	-3.40%	9.68%
3111	Animal Food Manufacturing	-13.01%	-9.81%	4.41%
3112	Grain and Oilseed Milling	-17.68%	-14.07%	3.99%
3113	Sugar and Confectionery Product Manufacturing	-18.90%	-16.68%	12.61%
3114	Fruit and Vegetable Preserving and Specialty Food Mfg.	-19.07%	-14.99%	4.03%
3115	Dairy Product Manufacturing	-14.11%	-10.32%	8.13%
3116	Animal Slaughtering and Processing	-13.46%	-8.38%	13.85%
3119	Other Food Manufacturing	-7.81%	-2.06%	7.71%
3121	Beverage Manufacturing	-13.48%	-10.19%	4.23%
3141	Textile Furnishings Mills	-28.94%	-25.07%	4.14%
3211	Sawmills and Wood Preservation	-7.83%	-2.90%	6.76%
3219	Other Wood Product Manufacturing	-6.24%	-2.65%	-6.43%
3222	Converted Paper Product Manufacturing	-16.00%	-12.51%	4.47%
3231	Printing and Related Support Activities	-27.69%	-24.98%	3.50%
3241	Petroleum and Coal Products Manufacturing	-18.84%	-15.49%	4.32%
3251	Basic Chemical Manufacturing	-15.25%	-11.23%	3.86%
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Mfg.	-12.36%	3.67%	3.67%
3261	Plastics Product Manufacturing	-10.37%	-6.75%	9.43%
3329	Other Fabricated Metal Product Manufacturing	-17.49%	-4.27%	1.42%
4244	Grocery and Related Product Merchant Wholesalers	-6.17%	-10.33%	8.49%
4245	Farm Product Raw Material Merchant Wholesalers	-5.56%	-10.43%	6.83%
4249	Miscellaneous Nondurable Goods Merchant Wholesalers	-5.56%	-10.43%	6.83%
4861	Pipeline Transportation of Crude Oil	2.40%	0.15%	7.62%
5612	Facilities Support Services	4.69%	-2.34%	12.32%
5629	Remediation and Other Waste Management Services	9.90%	3.37%	7.41%
6221	General Medical and Surgical Hospitals	7.42%	0.14%	8.11%
8123	Drycleaning and Laundry Services	-30.05%	-34.82%	13.54%
9991	Federal Government	1.78%	0.58%	0.21%
9992	State Government	15.00%	9.87%	5.96%
9993	Local Government	9.59%	4.86%	5.84%

Source: ERG estimates based on IMPLAN, 2020a.

APPENDIX E

Rule Consistency Analysis
For Proposed Amendments to Rules 4306 and 4320

December 17, 2020

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RULE CONSISTENCY ANALYSIS FOR PROPOSED AMENDMENTS TO RULES 4306 AND 4320

I. REQUIREMENTS FOR RULE CONSISTENCY ANALYSIS

Pursuant to Section 40727.2 of the California Health and Safety Code, prior to adopting, amending, or repealing a rule or regulation, the District performs a written analysis that identifies and compares the air pollution control elements of the rule or regulation with corresponding elements of existing or proposed District and United States Environmental Protection Agency (EPA) rules, regulations, and guidelines that apply to the same source category. The rule elements analyzed are emission limits; monitoring and testing requirements; recordkeeping and reporting requirements; and operating parameters and work practice requirements.

II. ANALYSIS

A. District Rules

Facilities could be subject to other District rules including:

- Rule 1070 Inspections
- Rule 1081 Source sampling
- Rule 1100 Equipment Breakdown
- Rule 2010 Permits Required
- Rule 2201 New and Modified Stationary Source Review Rule
- Rule 2520 Federally Mandated Operating Permits
- Rule 4001 New Source Performance Standards
- Rule 4101 Visible Emissions
- Rule 4102 Nuisance
- Rule 4201 Particulate Matter Concentration
- Rule 4454 Refinery Process Unit Turnaround
- Rule 4623 Storage of Organic Liquids
- Rule 4624 Organic Liquid Loading
- Rule 4801 Sulfur Compounds

The above-listed rules are not in conflict with, nor are they inconsistent with the requirements of Proposed Rules 4306 and 4320.

B. Federal Rules, Regulations, and Policies

1. EPA Control Techniques Guideline (CTG) Document

Based on the EPA "Control Techniques Guidelines and Alternative Control Techniques Documents for Reducing Ozone-Causing Emissions" document[1], there are no EPA CTGs applicable to this source category and, therefore, no conflicts or inconsistencies with the proposed requirements of Rules 4306 and 4320.

2. EPA Alternative Control Techniques (ACT) Document

EPA-453/R-93-034 (ACT Document – NOx emissions from Process Heaters)

The District evaluated the requirements contained within the ACT for NOx Emissions from Process Heaters and found no requirements that were more stringent than those already in Rules 4306 and 4320.

EPA-453/R-94-022 (ACT Document – NOx Emissions from Industrial/Commercial/Institutional Boilers)

The District evaluated the requirements contained within the ACT for NOx Emissions from Industrial/Commercial/Institutional Boilers and found no requirements that were more stringent than those already in Rules 4306 and 4320.

EPA-453/R-94-023 (ACT Document – NOx Emissions from Utility Boilers)

The District evaluated the requirements contained within the ACT for NOx Emissions from Utility Boilers and found no requirements that were more stringent than those already in Rules 4306 and 4320.

3. EPA New Source Performance Standard (NSPS)

40 CFR 60 Subpart D (Standards of Performance for Fossil-Fuel Fired Steam Generators for which Construction Is Commenced After August 17, 1971)

The District evaluated the requirements contained within 40 CFR 60 Subpart D and found no requirements that were more stringent than those already in Rules 4306 and 4320.

40 CFR 60 Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units)

[1] Control Techniques Guidelines and Alternative Control Techniques Documents for Reducing Ozone-Causing Emissions. (2016). Retrieved November 5, 2020 from https://www.epa.gov/ground-level-ozone-pollution/control-techniques-guidelines-and-alternative-control-techniques

The District evaluated the requirements contained within 40 CFR 60 Subpart Db and found no requirements that were more stringent than those already in Rules 4306 and 4320.

40 CFR 60 Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units)

The District evaluated the requirements contained within 40 CFR 60 Subpart Dc and found no requirements that were more stringent than those already in Rules 4306 and 4320.

40 CFR Part 60 Subpart J (Standards of Performance for Petroleum Refineries)

The District evaluated the requirements contained within 40 CFR 60 Subpart J and found no requirements that were more stringent than those already in Rules 4306 and 4320.

40 CFR Part 60 Subpart Ja (Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

The District evaluated the requirements contained within 40 CFR 60 Subpart Ja and found no requirements that were more stringent than those already in Rules 4306 and 4320.

4. National Emission Standard for Hazardous Air Pollutants (NESHAP)

40 CFR 63 Subpart DDDDD (NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters)

40 CFR 63 Subpart DDDDD was amended on January 31, 2013 to include new emission limits for PM, CO, and total selective metals (TSM), replace numeric dioxin emission limits with work practice standards, add new subcategories of facilities, and add alternative monitoring approaches for compliance with the PM limit. The PM control requirements in District Rule 4320 are more stringent for liquid fuels because it only allows liquid fuels to be burned during PUC quality natural gas curtailment periods. Rule 4320 requirements are equivalent to that of the Subpart DDDDD for gaseous fuels used in the District permitted units except for the gaseous fuels that exceed 40 $\mu g/m^3$ of mercury.

III. CONCLUSION

Based on the above analysis, District staff found that the proposed amendments to Rules 4306 and 4320 would not conflict with any District or federal rules, regulations, or policies covering similar stationary sources.