San Joaquin Valley AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

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DATE: December 16, 2021

TO: SJVUAPCD Governing Board

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

RE: ITEM NUMBER 12: ADOPT PROPOSED AMENDMENTS TO RULE 4352 (SOLID FUEL FIRED BOILERS, STEAM GENERATORS, AND PROCESS HEATERS)

RECOMMENDATIONS:

1. Adopt proposed amendments to Rule 4352 (Solid Fuel Fired Boilers, Steam Generators, and Process Heaters).

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 these measures is a commitment from the District to seek additional emission reductions from solid fuel fired boilers, steam generators, and process heaters through amendments to District Rule 4352.

Today's proposed amendments to Rule 4352 include even more stringent nitrogen oxide (NOx) emission limits for solid fuel fired boilers, steam generators, and process heaters operating in the Valley, as well as establishing particulate matter (PM), and oxides of sulfur (SOx) emission limits. The proposed regulatory amendments satisfy the District's control measure commitment in the District's *2018 PM2.5 Plan*, to support expeditious attainment of the health-based federal PM2.5 and ozone air quality standards. In addition, the proposed amendments address commitments included in Board/CARB-approved South Central Fresno and Stockton Community Emissions Reduction Programs developed through the AB 617 community engagement process.

These amendments were developed through a public engagement process that solicited feedback from the public through a variety of forums, including workshops, meetings with affected sources and other interested parties, Citizens' Advisory Committee meetings, and community engagement through AB 617 steering committees.

The purpose of this item is to seek your Board's approval of the proposed amendments to District Rule 4352.

DISCUSSION:

Boilers, steam generators, and process heaters are used in a broad range of industrial, commercial, and institutional settings. The units currently operating in the Valley are fired on biomass and municipal solid waste (MSW). Although the output from units subject to the rule could be utilized in many settings, all of the operational solid fuel fired boilers in the Valley are currently used to generate electricity. There are currently two municipal solid waste-fired boilers permitted at one facility, and another ten biomass-fired boilers permitted at nine facilities within the District. However, five of the biomass-fired boilers are currently dormant and not operating. Emissions from these facilities are currently well controlled through the installation of control technologies required to meet the emissions limits currently contained in Rule 4352 and to comply with District permitting requirements.

Rule 4352 was adopted in September 1994, and has been amended several times, in October 1995, May 2006, and December 2011, to establish increasingly stringent NOx and carbon monoxide emission limits that units must comply with to operate in the District. As part of these regulatory efforts, units in the Valley have been equipped with the best available NOx control technologies. Through the requirements of Rule 4352, NOx emissions from solid fuel fired boilers, steam generators, and process heaters subject to Rule 4352 have been reduced by approximately 75% to date. As illustrated in the table below, the proposed amendments achieve significant additional emissions reductions by 2024.

Table 1 - Estimated Emission Reductions

	NOx	**PM10**	**PM2.5**	**SOx**
2024 Reduction Percentage - MSW	45.5%	24.5%	23.2%	64.7%
2024 Reduction Percentage - Biomass	8.7%	28.4%	25.4%	48.9%
2024 Emission Reduction (tons/day) - MSW	0.39	0.02	0.02	0.06
2024 Emission Reduction (tons/day) - Biomass	0.32	0.29	0.26	0.21
Total Emission Reductions by 2024 (tons/day)	**0.71**	**0.31**	**0.28**	**0.27**

Control Technology for Solid Fuel Fired Boilers, Steam Generators, and Process Heaters

Emissions from solid fuel fired boilers, steam generators, and process heaters have been reduced through a variety of control technologies. The two primary methods of controlling NOx emissions from solid-fuel fired boilers is 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 a post-combustion control system. The primary method of controlling particulate matter emissions (PM, PM10, PM2.5) from solid-fuel fired boilers is to capture the particulate matter before the particulate matter is emitted into the atmosphere. The primary method of controlling SOx emissions from solid fuel fired boilers is injecting a sorbent into the combustion exhaust stream. The sorbent adsorbs sulfur oxides and through a chemical reaction forms particulate, which is then captured using an electrostatic precipitator (ESP) or baghouse.

Currently, nearly all of the permitted solid-fuel fired boilers utilize a combination of selective non-catalytic reduction (SNCR) system and an electrostatic precipitator (ESP), or SNCR and a fabric filter baghouse for NOx and particulate matter control. Nearly all facilities located in the Valley currently control SOx with dry sorbent injection with sorbents such as limestone or sodium bicarbonate. The District evaluated the feasibility of achieving further emissions reductions with existing control equipment, as well as the availability and cost-effectiveness of alternative control technologies as a part of this rule development project.

Summary of Proposed Amendments to Rule 4352

The proposed rule amendments would lower emission limits for NOx, and would establish PM and SOx emission limits for solid fuel fired boilers, steam generators, and process heaters operating in the Valley. Emissions limits were proposed based on the results of a comprehensive review of the existing permit inventory in the Valley, the type of solid fuel utilized at the operation, available control technology, requirements in other air districts, and a cost-effectiveness analysis of requiring further controls for existing units (as further discussed in Appendix C of the attached Staff Report). The proposed emission limits for each pollutant are included in Table 2 of the rule, as presented below.

Table 2 - Proposed Rule 4352 NOx, CO, PM10, and SOx Emission Limits

<table>
<tr><th rowspan="2">Fuel Type</th><th colspan="4">Proposed Emission Limits effective on and after January 1, 2024</th></tr>
<tr><th>NOx Limit</th><th>CO Limit</th><th>PM10 Limit</th><th>SOx Limit</th></tr>
<tr><td>Municipal Solid Waste</td><td>110 ppmv corrected to 12% CO_2 A

90 ppmv corrected to 12% CO_2 C</td><td rowspan="3">400 ppmv corrected to 3% O_2 A</td><td>0.04 lbs/MMBtu
or
0.02 gr/dscf @ 12% CO_2</td><td>0.03 lbs/MMBtu C
or
12 ppmv @ 12% CO_2 C

0.064 lbs/MMBtu A
or
25 ppmv @ 12% CO_2 A</td></tr>
<tr><td>Biomass</td><td>65 ppmv corrected to 3% O_2 A</td><td>0.03 lbs/MMBtu</td><td>0.02 lbs/MMBtu B
0.035 lbs/MMBtu A</td></tr>
<tr><td>All Others</td><td>65 ppmv corrected to 3% O_2 A</td><td>0.03 lbs/MMBtu</td><td>0.02 lbs/MMBtu B
0.035 lbs/MMBtu A</td></tr>
</table>

A Block 24-hour average
B Rolling 30-day average
C Rolling 12-month average

The proposed amendments to Rule 4352 would also add language to clarify definitions, remove expired language, and establish compliance timelines. The timeframes established in the proposed rule for facilities to meet the proposed emissions limits reflect the time necessary for facilities to plan for full compliance with the proposed emission limits, including budgeting for any required modifications to the facility or facility operations, modifying existing controls or facility control practices, and installing any required further control technologies. The proposed compliance schedule would take place over two years, with full compliance with the proposed emissions limits required by January 1, 2024. Additionally, the 2024 compliance deadline supports fulfillment of the District's *2018 PM2.5 Plan* commitments.

Requirements would be added for continuous emissions monitoring systems for SOx. The existing test method references in the rule would be updated to reflect the latest version of test methodology available. Test methods were also added for PM10 and SOx.

As demonstrated in the *2018 PM2.5 Plan* and subsequent EPA action, Rule 4352 currently meets federal BACM (Best Available Control Measures) and Most Stringent Measures (MSM). Additionally, Rule 4352 also meets state BARCT (Best Available Retrofit Control Technology) requirements, including with respect to solid fuel fired boilers, steam generators, and process heaters under the proposed amendments. Based on District staff review of other air district requirements, the proposed updates would establish requirements that are more stringent than any other rule in nonattainment areas in California and in the nation. Adoption of the proposed amendments will ensure that Rule 4352 continues to meet or exceed BACM, MSM, and BARCT levels of emissions control.

Health Benefits of Implementing Plan Measures

Exposure to PM2.5 and ozone has 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. 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. Studies have shown that even short-term exposure of less than 24 hours can cause 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 and ozone.

As NOx emissions are a key precursor in the formation of both ozone and PM2.5, continuing to assess the feasibility of achieving additional NOx reductions across the Valley is critical to improving PM2.5 and ozone throughout the region. PM2.5 emissions are characterized by a unique combination of direct and indirectly formed constituents. NOx emissions are a precursor to the formation of ammonium nitrate, which is a large portion of total PM2.5 during the Valley's peak winter season. NOx is also a precursor to ozone, which is formed when heat and sunlight interact with NOx and VOCs. Harmful ozone is predominantly formed at the surface during the summer season in the Valley. The District has long worked to reduce NOx emissions as the primary precursor for the formation of ozone and PM2.5 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 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, the 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.

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
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 of the staff report.

Socioeconomic Impact Analysis
Pursuant to CH&SC Section 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 socioeconomic analysis has been used to further

refine the rule amendments. The final socioeconomic report is attached to the staff report as Appendix D.

Rule Consistency Analysis
Pursuant to CH&SC Section 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 the staff report.

Environmental Impacts
There are no other actions or rule requirements associated with this project. Based on the District's review, 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.

Rule Development Public Process

District staff conducted a public Scoping Meeting in December 2020, and held public workshops in September 2021, and November 2021. Information about public meetings was shared with members of the public, affected sources, manufacturers of control technologies, and other interested stakeholders. Information about the regulatory amendments and workshops were also made available at meetings of the Citizens' Advisory Committee, Environmental Justice Advisory Group, and AB 617 Community Steering Committees. Workshop announcements and public notices were provided in both English and Spanish, and interpretation services were made available upon request. At the public workshops, District staff presented the emission reduction and public health objectives of the proposed rulemaking project, and solicited feedback from the public on potential amendments. Initial draft amendments to Rule 4352 were published for public review on November 4, 2021, and an updated draft was published on November 16, 2021.

Throughout the rule development process, 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 4352. The comments received from the public, affected sources, and interested parties during the public outreach and workshop process were incorporated into the rule or addressed in the staff report as appropriate.

The proposed rule amendments and draft staff report with associated appendices were published for 30-day public review and comment prior to the public hearing to consider the adoption of the proposed amendments to Rule 4352 by the District Governing Board. 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 4352 (5 pages)
Attachment B: Proposed Amendments to Rule 4352 (8 pages)
Attachment C: Final Draft Staff Report for Proposed Amendments to Rule 4352 (109 pages)

San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
December 16, 2021

ADOPT PROPOSED AMENDMENTS TO RULE 4352 (SOLID FUEL FIRED BOILERS, STEAM GENERATORS, AND PROCESS HEATERS)

Attachment A:

Resolution for Proposed Amendments to Rule 4352
(5 PAGES)

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

IN THE MATTER OF: PROPOSED AMENDMENTS TO RULE 4352 (SOLID FUEL FIRED BOILERS, STEAM GENERATORS, AND PROCESS HEATERS)	**) 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 §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 ozone and 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 4352 (Solid Fuel Fired Boilers, Steam Generators, and Process Heaters) to further reduce oxides of nitrogen (NOx) emissions from this source category; and

WHEREAS, Sections 182(b)(2) and 182(f) of the federal Clean Air Act (CAA) require areas that are classified as moderate or above for ozone nonattainment to implement Reasonably Available Control Technology (RACT) for sources subject to U.S. Environmental Protection Agency (EPA) Control Techniques Guidelines (CTG) or for "major sources" of NOx and volatile organic compounds (VOC); 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 Rule 4352 on December 3, 2020, September 30, 2021, and November 4, 2021; and

WHEREAS, a public hearing for the adoption of proposed amendments to Rule 4352 was duly noticed for December 16, 2021 in accordance with CH&SC §40725.

NOW, THEREFORE, BE IT RESOLVED AS FOLLOWS:

1. The Governing Board hereby adopts the proposed amendments to Rule 4352 (Solid Fuel Fired Boilers, Steam Generators, and Process Heaters). Said rule shall become effective on December 16, 2021.

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. Amending Rule 4352 is necessary to meet the commitments of the SIP and requirements of the federal CAA and the California CAA. Said Rule amendments 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 the Rule amendment is written or displayed so that the meaning can be easily understood by those persons or industries directly affected by the Rule.

d. **CONSISTENCY.** The Governing Board finds that the Rule is 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 the Rule does not impose the same requirements as any existing state or federal regulation.

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 rule 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 rule to the California Air Resources Board for incorporation into the SIP.

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 rule.

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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 16th day of December 2021, to wit:

AYES:

NOES:

ABSENT:

SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL DISTRICT

By ______________________________
Craig Pedersen, Chair
Governing Board

ATTEST:
Deputy Clerk of the Governing Board

By ____________________
Michelle Franco

San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
December 16, 2021

ADOPT PROPOSED AMENDMENTS TO RULE 4352 (SOLID FUEL FIRED BOILERS, STEAM GENERATORS, AND PROCESS HEATERS)

Attachment B:

Proposed Amendments to Rule 4352
(8 PAGES)

RULE 4352 SOLID FUEL FIRED BOILERS, STEAM GENERATORS AND PROCESS HEATERS (Adopted September 14, 1994; Amended October 19, 1995; Amended May 18, 2006; Amended December 15, 2011; 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), oxides of sulfur (SOx), and particulate matter (PM10) from solid fuel fired boilers, steam generators and process heaters.

2.0 Applicability

This rule applies to any boiler, steam generator or process heater fired on solid fuel. Heat may be supplied by liquid or gaseous fuels for start-ups, shutdowns, and during other flame stabilization periods, as deemed necessary by the owner/operator.

3.0 Definitions

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

3.2 ARB: California Air Resources Board.

3.3 Block 24-hour Average: the arithmetic average of the hourly emission rates of a unit as measured over 24 one-hour periods, daily, from 12:00 AM to 11:59 PM, excluding periods of system calibration.

3.4 Boiler or Steam Generator: any combustion equipment fired directly or indirectly with any solid fuel used to produce hot water or steam.

3.5 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.

3.6 Carbon Monoxide (CO): emissions of carbon monoxide, a colorless and odorless gas resulting from incomplete combustion of fuel.

3.~~6~~7 EPA: United States Environmental Protection Agency.

3.~~7~~8 Flame Stabilization: any period in which supplemental use of a liquid or gaseous fuel is required in instances including control of one or more pollutants, or to alleviate or prevent unanticipated equipment outages or emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages.

3.~~8~~9 Gaseous Fuel: any fuel which is a gas at standard conditions.

3.10 gr/dscf: grains of particulate matter per dry standard cubic foot.

3.~~9~~11 Heat Input: the heat of combustion released due to burning a fuel in a unit, based on the higher heating value of the fuel, not including the sensible heat of incoming combustion air and fuel.

3.1~~0~~2 Higher Heating Value (~~hhv~~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.

3.1~~1~~3 Hot Standby Condition: a condition in which all fuel feed has been curtailed and the boiler is secured at a temperature greater than the current ambient temperature.

3.1~~2~~4 Liquid Fuel: any fuel which is a liquid at standard conditions.

3.1~~3~~5 NOx Emissions: the sum of oxides of nitrogen (NO) in the flue gas, collectively expressed as nitrogen dioxide.

3.1~~4~~6 Potential to Emit: as defined in Rule 2201 (New and Modified Stationary Source Rule).

3.17 PM10: as defined in Rule 1020 (Definitions).

3.1~~5~~8 Process Heater: any combustion equipment fired on solid fuel, which transfers heat from combustion gases to water or process streams. Process heaters exclude kilns or ovens used for drying, baking, cooking, calcining, heat treating or vitrifying.

3.1~~6~~9 Rated Heat Input (million Btu per hour or MMBtu/hr): 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.~~17~~20 Shutdown: the period of time during which a unit is taken from operational to non-operational status by allowing it to cool down from its operating temperature and pressure to an ambient temperature, or to a hot standby condition. Duration of shutdown shall not exceed 12 hours unless a longer time has been authorized under Section 5.3.4.

3.~~18~~21 Solid Fuel: any fuel which is a solid at standard conditions.

3.22 SOx: emissions of sulfur dioxide (SO_2).

3.~~19~~23 Standard Conditions: defined in Rule 1020 (Definitions).

3.2~~0~~<u>4</u> Start-up: the period of time during which a unit is heated to the operating temperature and pressure from a shutdown status or hot standby condition.

3.2~~1~~<u>5</u> Stationary Source: as defined in Rule 2201 (New and Modified Stationary Source Review Rule).

3.2~~2~~<u>6</u> Unit: any boiler, steam generator or process heater as defined in this rule. For the purpose of this rule, two boilers, two steam generators, or two process heaters may be considered as one unit, if, they are operated as one single unit sharing a single common stack and have been issued only one District Permit to Operate (PTO).

~~4.0 Exemptions~~

~~Except for complying with the recordkeeping requirements of Section 6.1, this rule shall not apply to units operated at a Stationary Source that has a potential to emit less than 10 tons per year of oxides of nitrogen (NOx) or volatile organic compounds (VOC).~~

~~5~~<u>4</u>.0 Requirements

~~5~~<u>4</u>.1 The owner/operator of a boiler, steam generator or process heater shall not operate such a unit in a manner that results in NOx<u>,</u> ~~and~~ CO<u>, PM10, and SOx</u> emissions exceeding the limits specified in Table 1<u> and Table 2</u>. The emission limits measured in parts per million by volume (ppmv)<u>, grains per dry standard cubic foot (gr/dscf), or pounds per million british thermal units (lbs/MMBtu)</u> are referenced at dry stack gas conditions and shall be corrected to the applicable percent O_2 or CO_2 specified in Table 1 <u>and Table 2</u> in accordance with EPA Method 19.

Table 1 - NOx and CO Emission Limits

Fuel Type	~~Emission Limits effective until December 31, 2012~~		Emission Limits effective until December 31, 2023~~ on and after January 1, 2013~~	
	~~NOx Limit~~	~~CO Limit~~	NOx Limit	CO Limit
Municipal Solid Waste	~~200 ppmv corrected to 12% CO_2~~	~~400 ppmv corrected to 3% O_2~~	165 ppmv corrected to 12% CO_2	400 ppmv corrected to 3% O_2
Biomass	~~115 ppmv corrected to 3% O_2~~		90 ppmv corrected to 3% O_2	
All Others	~~115 ppmv corrected to 3% O_2~~		65 ppmv corrected to 3% O_2	

Table 2 – NOx, CO, PM10, and SOx Emission Limits

Fuel Type	Emission Limits effective on and after January 1, 2024			
	NOx Limit	CO Limit	PM10 Limit	SOx Limit
Municipal Solid Waste	110 ppmv corrected to 12% CO_2 [A] 90 ppmv corrected to 12% CO_2 [C]	400 ppmv corrected to 3% O_2 [A]	0.04 lbs/MMBtu or 0.02 gr/dscf @ 12% CO_2	0.03 lbs/MMBtu [C] or 12 ppmv @ 12% CO_2 [C] 0.064 lbs/MMBtu [A] or 25 ppmv @ 12% CO_2 [A]
Biomass	65 ppmv corrected to 3% O_2 [A]		0.03 lbs/MMBtu	0.02 lbs/MMBtu [B] 0.035 lbs/MMBtu [A]
All Others	65 ppmv corrected to 3% O_2 [A]		0.03 lbs/MMBtu	0.02 lbs/MMBtu [B] 0.035 lbs/MMBtu [A]

[A] Block 24-hour average
[B] Rolling 30-day average
[C] Rolling 12-month average

~~5~~4.2 ~~All NOx and CO emission limits shall be based on a block 24-hour average.~~ A violation of the emission limits as measured by the test methods listed in Section ~~6~~5.3 shall constitute a violation of this rule.

~~5~~4.3 Start-up and Shutdown Provisions

The applicable emission limits of Section ~~5~~4.1 shall not apply during start-up or shutdown provided an operator complies with the requirements specified below.

~~5~~4.3.1 The duration of each shut down shall not exceed 12 hours, except as provided in Section ~~5~~4.3.4.

~~5~~4.3.2 Except as provided in Section ~~5~~4.3.4, the duration of each start-up shall not exceed 96 hours. If curing of the refractory is required after a modification to the unit is made, the duration of start-up shall not exceed 192 hours, except as provided in Section ~~5~~4.3.4.

~~5~~4.3.3 The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during start-up or shutdown.

~~5~~4.3.4 Notwithstanding the requirements of Section ~~5~~4.3.1 or Section ~~5~~4.3.2, the APCO, ARB, and EPA may approve a longer start-up or shutdown duration, if an operator submits an application for a Permit to Operate which provides a justification for the requested additional duration.

~~5~~4.3.4.1 The maximum allowable duration of start-up or shutdown will be determined by the APCO, ARB, and EPA.

~~5~~4.3.4.2 At a minimum, a justification for increased start-up or shutdown duration shall include the following:

~~5~~4.3.4.2.1 A clear identification of the control technologies or strategies to be utilized; and

~~5~~4.3.4.2.2 A description of what physical conditions prevail during start-up or shutdown periods that prevent the controls from being effective; and

~~5~~4.3.4.2.3 A reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions; and

~~5~~4.3.4.2.4 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~~4.3.4.2.5 A description of the material process flow rates and system operating parameters, etc., the owner/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~~4.3.4.2.6 Basis for the requested additional duration of start-up or shutdown.

~~5~~4.4 Monitoring Provisions

The owner/operator of any unit using ammonia injection as a NOx control technique, shall operate a Continuous Emissions Monitoring system (CEM) to monitor and record NOx concentrations, SOx concentrations, CO_2 or O_2 concentrations, as well as the NOx and SOx emission rates. Continuous Emission Monitoring systems shall be operated, maintained, and calibrated pursuant to the requirements of 40 CFR 60.7 (c) and 60.13. CEMs must also satisfy the Performance Specifications of 40 CFR 60 Appendix B and the Relative Accuracy Test Audit of Appendix F.

~~6~~5.0 Administrative Requirements

~~6~~5.1 Recordkeeping

~~6~~5.1.1 Except for municipal solid waste (MSW) fired units; the owner/operator of any unit subject to the requirements of this rule shall maintain, on a monthly basis, an operating log for each unit that includes the following information:

~~6~~5.1.1.1 Type and quantity of fuel used.

~~6~~5.1.1.2 The higher heating value (~~hhv~~HHV) of each fuel as determined by Section ~~6~~5.3, EPA Method 19, or as certified by a third party fuel supplier.

~~6~~5.1.2 The records required by Section ~~6~~5.1.1 shall be retained on site for a period of five years, and shall be made available to the APCO, ARB, and EPA upon request.

~~6~~5.2 Compliance Source Testing

~~6~~5.2.1 Each unit subject to the requirements of this rule shall be tested at least once every 12 months, to determine compliance with the applicable short term emission limit (i.e. the applicable emission limit with the shortest averaging period) requirements of Section ~~5~~4.0.

~~6~~5.2.2 All emission measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate.

~~6~~5.2.3 No compliance determination shall be established within two hours after a period in which fuel flow to the unit is zero, or is shut off for 30 minutes or longer.

~~6~~5.3 Test Methods

~~6~~5.3.1 Compliance with the requirements of Section ~~5~~4.0 shall be determined in accordance with the following source test procedures unless otherwise approved by the APCO, ARB, and EPA:

~~6~~5.3.1.1 Oxides of nitrogen (ppmv) – EPA Method 7E, or ARB Method 100.

~~6~~5.3.1.2 Carbon monoxide (ppmv) - EPA Method 10, or ARB Method 100.

~~6~~5.3.1.3 Stack gas oxygen - EPA Method ~~3 or~~ 3A, or ARB Method 100.

~~6~~5.3.1.4 NOx emission rate (Heat input basis) - EPA Method 19.

5.3.1.5 PM10 - EPA Method 201A/EPA Method 202, EPA Method 5/EPA Method 202, or EPA Method 5/CARB Method 5.

5.3.1.6 SOx – EPA Method 6, EPA Method 6C, EPA Method 8, or CARB Method 100.

~~6~~5.3.1.~~5~~7 Stack gas velocities - EPA Method 2.

~~6~~5.3.1.~~6~~8 Stack gas moisture content - EPA Method 4.

~~6~~5.3.1.~~7~~9 Solid fuel higher heating value (~~hhv~~HHV) - ASTM ~~Method~~ D 5865~~-10~~, ~~or~~ EPA Method 19, ASTM D2015, or ASTM E711.

~~6.3.1.8 Solid fuel higher heating value (hhv) - ASTM Method E 711-87.~~

~~6~~5.3.1.~~9~~10 Gaseous fuel higher heating value (HHV) - ASTM D 1826~~-94~~ or ASTM D-1945~~-96~~ in conjunction with ASTM D3588~~-98 for gaseous fuels~~.

5.3.1.11 Carbon dioxide - ARB Method 100 or EPA Method 3A.

6.0 Compliance Schedule

Solid fuel fired units subject to the requirements of Section 4 shall comply with applicable emission limits in accordance to the schedule below:

6.1 Emission Limits

Table 3: NOx, PM10 and SOx Compliance Schedule

Emission Level	Authority to Construct	Compliance Deadline
Emission Limits effective on and after January 1, 2024	June 1, 2022	January 1, 2024

6.2 As shown in Table 2, the columns labeled:

"Authority to Construct" identifies the date by which the operator shall submit an Authority to Construct (if needed) for each unit subject to Table 2 emission limits.

"Compliance Deadline" identifies the date by which the operator shall demonstrate that each unit is in compliance with Table 2 emission limits as applicable.

San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
December 16, 2021

ADOPT PROPOSED AMENDMENTS TO RULE 4352 (SOLID FUEL FIRED BOILERS, STEAM GENERATORS, AND PROCESS HEATERS)

Attachment C:

Final Draft Staff Report for Proposed Amendments to Rule 4352

(109 PAGES)

SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT

FINAL DRAFT STAFF REPORT

Proposed Amendments to Rule 4352 (Solid Fuel Fired Boilers, Steam Generators, and Process Heaters)

December 16, 2021

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I. SUMMARY

The San Joaquin Valley Unified Air Pollution Control District (District) is committed to protecting public health for all residents in the San Joaquin Valley (Valley) through efforts to meet health-based state and federal ambient air quality standards with efficient, effective, and entrepreneurial air quality management strategies. One such strategy includes a commitment in the District's *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards* (*2018 PM2.5 Plan*) to amend District Rule 4352 (Solid Fuel Fired Boilers) to reduce emissions of oxides of nitrogen (NOx) from units fired on municipal solid waste (MSW).

In support of this commitment, District staff have conducted a comprehensive technical evaluation of controls capable of further reducing emissions from solid fuel fired boilers operating in the Valley, as well as an in-depth review of air district, state, and federal regulations for this source category, and a robust public process. Proposed amendments to the rule include more stringent NOx for units fired on MSW, biomass, and other fuels, as well as establishing particulate matter (PM) and oxides of sulfur (SOx) control requirements. Full compliance with the proposed requirements would be required by 2024. The proposed amendments are applicable to all boilers, steam generators, and process heaters fired on solid fuel.

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 *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 key PM2.5 precursors like NOx. The attainment strategy 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 4352 (Solid Fuel Fired Boilers, Steam Generators, and Process Heaters) as a necessary measure for further reducing NOx and bringing the Valley into attainment with federal PM2.5 standards within the mandated federal deadlines. Solid-fuel fired boilers operating in the Valley account for 1.7% of the total NOx emissions inventory in the region, and contribute 12.1% of the NOx emissions coming from stationary sources under the regulatory jurisdiction of the District.

In addition, through the District's implementation of AB 617 and the development of the South Central Fresno Community Emissions Reduction Program (CERP) and Stockton CERP, the District heard concerns from community residents and other community stakeholders regarding solid fuel fired boilers, steam generators, and process heater operations. These discussions with the community led to specific measures being included within the South Central Fresno CERP and Stockton CERP to evaluate Rule 4352 for potential further emissions reductions. The proposed amendments to Rule 4352 address these measures within the CERPs for South Central Fresno and Stockton.

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 Rule 4352 to reduce emissions from solid fuel fired boilers, steam generators, and process heaters operating in the San Joaquin Valley. The proposed Rule 4352 goes 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.* In addition, the proposed amendments address commitments included in Board/CARB-approved South Central Fresno and Stockton Community Emissions Reduction Programs developed through the AB 617 community engagement process.

B. Health Benefits of Implementing Plan Measures

Exposure to PM2.5 and ozone has 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. 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. CARB explains that even short-term exposure of less than 24 hours can cause 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 and ozone.

As NOx emissions are a key precursor in the formation of both ozone and PM2.5, continuing to assess the feasibility of achieving additional NOx reductions across the Valley is critical to improving PM2.5 and ozone throughout the region. PM2.5 emissions are characterized by a unique combination of direct and indirectly formed constituents. NOx emissions are a precursor to the formation of ammonium nitrate, which is a large portion of total PM2.5 during the Valley's peak winter season. NOx is also a precursor to ozone, which is formed when heat and sunlight interact with NOx and VOC's. Harmful ozone is predominantly formed at the surface during the summer season in the Valley. The District has long worked to reduce NOx emissions as the primary precursor for the formation of ozone and PM2.5 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 Project

The District Governing Board first adopted Rule 4352 on September 14, 1994, and the rule has subsequently been amended three times, with the last amendment occurring in 2011. Rule 4352 currently limits NOx and carbon monoxide (CO) emissions from any boiler, steam generator or process heater fired on solid fuel. Through recent federal review, Rule 4352 has been found to implement or exceed RACT levels of control.[1] In February 2020, EPA also found that this rule implements Best Available Control

[1] U.S. Environmental Protection Agency: Air Plan Approval; California; San Joaquin Valley Unified Air Pollution Control District; Reasonably Available Control Technology Demonstration. August 2018.

Measures (BACM) and MSM, as further discussed in EPA's TSD for the approval of the *San Joaquin Valley PM2.5 Plan for the 2006 PM2.5 NAAQS*.[2]

During the development of the *2018 PM2.5 Plan,* the District evaluated all potential control technologies and all control technologies achieved in practice in other areas, as well as those included in other state implementation plans for this category. While the District rule currently meets or exceeds federal and state levels of emissions controls requirements for this source category, given the enormity of reductions needed to demonstrate attainment with the latest PM2.5 standards, the District committed in the *2018 PM2.5 Plan* to go beyond MSM and pursue the following potential opportunities to reduce NOx emissions for municipal waste-fired units, to the extent that additional controls are technologically and economically feasible, with commitments in the Plan to:

- Lower the existing NOx limit from 165 ppmv @ 12% CO_2 to 110 ppmv @ 12% CO_2 over 24-hr period and 90 ppmv @ 12% CO_2 over annual period
- Evaluate the feasibility of lower NOx emission levels

The proposed amendments to Rule 4352, which satisfy commitments in the *2018 PM2.5 Plan*, include lowering NOx emission limits for units fired on municipal solid waste and biomass, establishing PM10 and SOx emissions limits, clarifying definitions, and updating test methods. The proposed emissions limits and compliance timeframes have been established based on the results of a comprehensive technical evaluation, as further discussed later in this staff report and associated appendices. The limits proposed would require the installation of advanced combustion technology and permit modification. An evaluation was also conducted as to the feasibility of requiring alternative technologies.

Through the implementation of the proposed Rule 4352 amendments, from this source category an estimated 15% reduction of NOx, 28.2% reduction in PM2.5, 28% reduction of PM10, and a 51% reduction in SOx emissions will be achieved by 2024. The proposed rule amendments would result in estimated emissions reductions of 0.71 tpd NOx, 0.28 tpd PM2.5, 0.31 tpd PM10, and 0.27 tpd SOx being achieved by 2024. Emission reductions achieved through the proposed requirements of this rule amendment will contribute towards the Valley's attainment of the health-based federal PM2.5 and ozone standards, and satisfy the commitments in the *2018 PM2.5 Plan.*

D. Rule Development Process

District staff conducted a public Scoping Meeting in December 2020, and held public workshops in September 2021, and November 2021. Information about public meetings was shared with members of the public, affected sources, manufacturers of control technologies, and other interested stakeholders. Information about the regulatory amendments and workshops were also made available at meetings of the Citizens' Advisory Committee, Environmental Justice Advisory Group, and AB 617 Community

[2] U.S. Environmental Protection Agency: Technical Support Document for EPA's Technical Support Document "EPA Evaluation of BACM/MSM" for the San Joaquin Valley PM2.5 Plan for the 2006 PM2.5 NAAQA. February 2020.

Steering Committees. Workshop announcements and public notices were provided in both English and Spanish, and interpretation services were made available upon request. At the public workshops, District staff presented the emission reduction and public health objectives of the proposed rulemaking project, and solicited feedback from the public on potential amendments. Initial draft amendments to Rule 4352 were published for public review on November 4, 2021, and an updated draft was published on November 16, 2021.

Throughout the rule development process, 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 4352. The comments received from the public, affected sources, and interested parties during the public outreach and workshop process were incorporated into the rule or addressed in the staff report as appropriate.

The proposed rule amendments and draft staff report with associated appendices were published for 30-day public review and comment prior to the public hearing to consider the adoption of the proposed amendments to Rule 4352 by the District Governing Board. A summary of significant comments and District responses is available in Appendix A of the final draft staff report.

In addition, 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).

II. DISCUSSION

A. Source Category

Boilers, steam generators, and process heaters are used in a broad range of industrial, commercial, and institutional settings. The units currently operating in the Valley are fired on biomass and municipal solid waste (MSW). Although the output from units subject to the rule could be utilized in many settings, all of the operators within the San Joaquin Valley use the units' output to generate electricity. There are currently two municipal solid waste-fired boilers permitted at one facility, and another ten biomass-fired boilers permitted at nine facilities within the District. However, five of the biomass-fired boilers are currently dormant and not operating. Emissions from these facilities are currently well controlled through the installation of control technologies required to meet the emissions limits currently contained in Rule 4352 and to comply with District permitting requirements.

B. Solid Fuel Fired Boilers in the Valley

<u>Municipal Solid Waste</u>
One facility in the Valley operates two municipal solid waste-fired units in the Valley. Each unit is equipped with a baghouse for PM10 control, a dry lime scrubber for SOx control, and a selective non-catalytic reduction system for NOx control. This facility has been in operation since 1989 and has an electricity generating capacity of 22.5 megawatts. The two MSW fired units are capable of processing 800 tons of refuse per day that would alternately have been sent to local landfills. This helps the county that the facility is operated in to meet state requirements and policy goals to reduce landfill waste.

<u>Biomass</u>
There are currently five biomass fired units at five facilities operating in the District with a combined rating of 158 megawatts (MW). There are also an additional five units at four facilities that are non-operational, but have active permits with the District. The non-operational units have a combined rating of 130 MW.

Historically, the presence of biomass facilities in the Valley has played a vital role in reducing NOx and PM emissions from open burning practices. However, the biomass industry has indicated that given current energy policy in California there is concern that biomass power facilities are in jeopardy. Many biomass plants in the Valley are nearing, or have come to, the end of their long-term contracts with utilities and find themselves in a position where the power that they provide is not the type of power that utilities are seeking (base load vs. intermittent) and that the prices being offered for new contracts are too low to support their operations.

C. Emissions Control Technologies

Over the years, the District has adopted numerous generations of rules and rule amendments for solid fuel fired boilers that have significantly reduced emissions from this source category. As part of these regulatory efforts, solid fuel fired units in the Valley have been equipped with the best available NOx, SOx and PM control technologies.

The two primary methods of controlling NOx emissions from solid-fuel fired boilers is 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 a post-combustion control system. The primary method of controlling particulate matter emissions (PM, PM10, PM2.5) from solid-fuel fired boilers is to capture the particulate matter before the particulate matter is emitted into the atmosphere. The primary method of controlling SOx emissions from solid fuel fired boilers is injecting a sorbent into the combustion exhaust stream. The sorbent adsorbs sulfur oxides and through a chemical reaction forms particulate, which is then captured using an electrostatic precipitator or baghouse.

Currently, nearly all of the permitted solid-fuel fired boilers utilize a combination of selective non-catalytic reduction (SNCR) system and an electrostatic precipitator (ESP), or SNCR and a fabric filter baghouse for NOx and particulate matter control. Nearly all facilities currently control SOx with dry sorbent injection with sorbents such as limestone or sodium bicarbonate. A further description of the control technologies currently in-use by facilities operating in the Valley, including SNCR, ESP, Fabric Filter Baghouses, and Dry Sorbent Injection systems, is provided below, as well as further control technologies that District staff evaluated as a part of this rule development project.

NOx Emission Control Technologies

Selective Non-Catalytic Reduction

Selective non-catalytic reduction is a post-combustion control for NOx that involves injecting either ammonia or urea into the solid fuel-fired boiler at a location where the flue gas is between 1,400 and 2,000 °F. The injected ammonia reacts with NOx and O_2 in the flue gas to form molecular nitrogen and water. Nine of the currently permitted biomass-fired boilers utilize SNCR to reduce NOx emissions, and both of the permitted municipal solid-waste fired boilers are equipped with SNCR systems. Emission levels typically achieved through the installation of SNCR range from between 70 ppmv to 135 ppmv referenced at 3% O_2, depending on the type of boiler and fuel used in firing.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a post-combustion control for NOx that involves the injection of anhydrous ammonia, aqueous ammonia, or urea solution into the exhaust gas to reduce NOx emissions. Unlike SNCR, SCR uses a catalyst consisting of base metals (such as vanadium, molybdenum, or tungsten) to promote chemical reactions that reduce NOx emissions into N_2 and water. The chemical reactions in an SCR system can occur at temperatures between 450 to 800 °F, much lower than the temperatures used to reduce NOx in an SNCR system.

SCR systems for large boilers are quite costly, with costs varying widely depending on the scope of work required to install the control system at each facility. Generally, total capital costs to install an SCR system can range from $5 million to $15 million per solid-fuel fired boiler. Costs will be on the higher end of this range if the installation of the SCR system requires building modifications to accommodate the SCR systems' large footprint, or if the installation requires any modifications to the boiler tubes to accommodate the SCR unit. Additionally, SCR systems require adequate control of both PM10 and SOx to prevent plugging and fouling of the SCR catalyst materials, and may require the installation of an auxiliary burner to maintain the proper temperature of the exhaust gas for proper operation of the system.

Due to the cost and the complexity of retrofitting an existing unit with SCR, retrofits of existing solid-fuel fired boilers with an SCR is uncommon. Currently, one biomass boiler in the District operates with an SCR system to control NOx emissions; however, this was a new installation rather than a retrofit of an existing unit. For biomass-fired boilers, SCR systems can achieve emission rates as low as 65 ppmv NOx referenced to 3% O_2, while SCR systems can reduce emissions from municipal solid-waste fired boilers to levels as low as 50 ppmv NOx referenced to 12% CO_2.

Gore De-NOx Catalytic Filter Bags

Gore De-NOx catalytic filter bags is a retrofit control technology that effectually converts an existing pulse-jet baghouse into a selective catalytic reduction control system. The Gore catalytic filter bags consist of an outer layer ePTFE membrane for particulate removal, plus an inner layer of felt catalyst that promotes the same chemical reactions as the catalyst in an SCR system. The retrofit of an existing baghouse consists of removing the existing baghouse bags and replacing them with the Gore De-NOx filter bags. An additional ammonia injection is typically not required when retrofitting a solid-fuel fired boiler equipped with an SNCR system.

The capital cost to retrofit an existing solid-fuel fired boiler equipped with a pulse-jet baghouse and SNCR with the Gore De-NOx filters is generally much lower than retrofitting the same boiler with SNCR technology. However, on-going maintenance costs are generally higher than SNCR technology, due to more frequent replacement of costly catalytic filter bags. Furthermore, several of the solid-fuel fired boilers in the Valley are equipped with an electrostatic precipitator or reverse-air baghouse for control of particulate matter emissions. In order to utilize Gore De-NOx filter bags, it is necessary to convert the electrostatic precipitator/reverse-air baghouse into a pulse-jet baghouse. Furthermore, this control technology requires a minimum baghouse inlet temperature of at least 350 °F for the control technology to be effective, which some solid-fuel fired boilers do not achieve regularly. Finally, the boilers should be equipped with SOx controls that reduce raw SOx ppmv to less than 10 ppmv, in order to prevent fouling of the SCR catalyst materials. Larger SOx ppmv inlet concentrations are possible, but can decrease the catalyst life and result in more frequent replacement of the costly filter bags.

Combustion Modification – Covanta LN

Covanta Low-NOx (LN) is a proprietary retrofit control technology available for municipal solid-waste combustors that involves modifications to the combustion air system of a combustor, modifications to the combustion monitoring and control systems, and modifications to the existing SNCR system to reduce NOx emissions. This system is not applicable to boilers fired on other solid-waste streams.

Typical municipal solid waste combustion units use a moving grate with two sources of combustion air. Primary air (or underfire air) is supplied through plenums located under the moving grate and is used to dry and combust the waste. The level of primary air is typically adjusted to minimize excess air used in the combustion of the waste on the grate, while still ensuring full combustion of the carbon-containing waste. Secondary air (or overfire air) is injected into the combustor through nozzles located in the furnace waterwalls immediately above the moving grate. The secondary air provides the majority of the excess air to the combustion process, and provides turbulent mixing to complete the combustion process.

With the Covanta LN combustion modifications, a portion of the secondary air is diverted to a new series of tertiary nozzles, installed in the combustor waterwalls at a higher elevation in the furnace. The total air flow requirement for the furnace is not changed. The tertiary air further completes the combustion process and yields uniform flue gas temperature and velocity profiles which improves the performance and reliability of downstream boiler equipment. The primary, secondary, and tertiary streams are then controlled with an updated control system to minimize NOx and control combustion.

When used without an SNCR system, Covanta LN does not achieve lower NOx emissions rates than those currently required by District Rule 4352. However, Covanta LN can be paired with SNCR to meet NOx limits lower than the current District Rule 4352 limits. For facilities currently equipped with SNCR, the installation of Covanta LN requires relocation of the existing ammonia/urea injectors to enhance the reduction of NOx emissions. Additionally, the SNCR control system must be integrated with the Covanta LN combustion controls, allowing the operator to maximize the NOx reductions and minimize the ammonia slip. When paired with SNCR, Covanta LN can reduce NOx emissions to levels as low as 90 ppmvd @ 12% CO_2.

PM Emission Control Technology

Fabric Filter Baghouse

Baghouse dust collectors are a type of fabric filter air material separator used to filter and collect particulates before the particulate matter can be emitted into the atmosphere. Typically, an induced draft blower is used to pass particulate-laden gas stream through the fabric filters. The gasses pass through the filters, while the particulate is collected on the filter surface. Over time, the dust begins to build up and form a filter cake on the filter surface, eventually reducing the effectiveness of the filters. Thus, the filters must be periodically cleaned using a pulse-jet, shaker, or reverse-air-style filter cleaning process.

In solid fuel-fired boilers, pulse-jet and reverse-air cleaning mechanisms are the most common. Pulse-jet cleaning uses sequential pulses of compressed air in the reverse direction of filtering. To blow dust off the bag surface and drop the caked dust into a hopper at the base of the baghouse. Reverse-air baghouses work in a similar method, however, with much longer pulses of air with lower air pressures. Pulse-jet baghouses require stronger bags due to the shorter pulses and higher air pressures. Both pulse-jet and reverse-air baghouses typically achieve high levels of particulate control, with PM10 control efficiencies greater than 99%. Seven of the currently permitted biomass units and both of the municipal solid waste combustors are equipped with baghouses for particulate control.

Ceramic Filters

With traditional fabric baghouse filters described above, particulate matter is captured on the surface of the filter; however, some particulate matter penetrates deeply into the filter walls and the body of the fabric filter and may be emitted during the baghouse's internal filter cleaning process. Ceramic filters, such as Tri-Mer ceramic filters, have special qualities on the filter surface that result in all of the particulate matter being captured on the face of the filter tubes. This allows for complete cleaning of the filter surface with no emissions of deeply embedded particulate matter into the atmosphere during the filter cleaning process. Therefore, ceramic filters can generally achieve lower particulate matter emission rates than fabric filters. However, ceramic filters are much more expensive than fabric filters. Additionally, ceramic filter systems like the Tri-Mer system would require the existing baghouse/ESP to be removed and new ceramic filter modules to be installed.

Electrostatic Precipitator

An electrostatic precipitator (ESP) is a particulate control device that uses an electrostatic force to capture dust and other particles. The ESP consists primarily of wires and collection plates, with a high voltage applied from an electrostatic field between the wires and the collecting plate, charging the air electrically and ionizing them in the process. When airborne particles pass between the collecting plates, the particles become charged, which causes them to attach to the collecting plates. The particles that have been collected are then shaken loose from the collecting plates and collected below. Electrostatic precipitators are highly effective in controlling particulate matter, so long as the particulate matter can hold an electrical charge.

Three of the currently permitted biomass plants are equipped with electrostatic precipitators. These types of control technologies typically have PM10 control efficiencies greater than 99%.

SOx Emission Control Technology

Wet Fluid Gas Desulfurization (FGD)

Wet Fluid Gas Desulfurization controls SO_2 emissions using wet solutions containing alkali reagents such as limestone, lime, sodium-based alkaline, or dual alkali-based sorbents. Typically, the unit consists of sorbent storage and preparation equipment, an absorber vessel, a mist eliminator, and waste collection and treatment vessels. Wet FGD normally removes SO_2 by 98%. Wastewater generated by wet FGD systems often contain metal hazardous air pollutants (HAPS), as well as other HAPS and must be disposed of properly. Additionally, wet FGD systems can result in acid mist (H2SO4) in the flue gas, which is corrosive. Thus, retrofits with this technology may require corrosive resistant liners on downstream control equipment. In some cases the cost of corrosion resistant liners is more costly than replacing the existing equipment with new corrosion resistant equipment.

Semi-Dry Absorbers (SDA)

Semi-Dry Absorbers operate by mixing a small amount of water with the sorbent. These are considered to be dry scrubber units, since the sorbent is dry when the reaction takes place. Lime is usually the sorbent, but hydrated lime may be used and can provide greater SO_2 removal. A slurry containing lime and recycled solids is atomized and sprayed into the absorber. The SO_2 is absorbed into the slurry and reacts to form calcium salts. The scrubbed gas then passes through a particulate control (baghouse or electro static precipitator) downstream, where additional reactions and SO_2 absorption may occur. Typical SO_2 removal for an SDA control system is 95%.

Dry Sorbent Injection

Dry Sorbent Injection is not a standalone system, like the other systems mentioned above. In dry sorbent injection, dry sorbent is injected into the combustion unit itself, or the ductwork immediately following the combustor. The sorbent adsorbs the SO_2 and forms particulate, which is then captured using an electro static precipitator or baghouse. This type of system achieves between 50% to 70% SO_2 control, depending on operating conditions and parameters.

III. PROPOSED AMENDMENTS TO RULE 4352

A. Existing Rule 4352

District Rule 4352 was last amended in May 2006. Rule 4352 currently applies to any boiler, steam generator, or process heater fired on solid fuel that has a potential to emit more than 10 tons per year (tpy) of NOx or VOC. The rule places limits on NOx and CO based on three types of solid fuels, as summarized in Table 1. Facilities that emit less than 10 tpy are exempt from complying with the emission limits, but are required to keep records.

Operators are subject to monitoring, source testing, and reporting requirements to demonstrate ongoing compliance with the rule emission limits.

Table 1 Current Rule Emission Limits

Fuel Type	NOx Limit	CO Limit
Municipal Solid Waste	165 ppmv corrected to 12% CO_2	400 ppmv corrected to 3% O_2
Biomass using Multiple Hearth Furnace	90 ppmv corrected to 3% O_2	
All Others	65 ppmv corrected to 3% O_2	

B. Summary of Proposed Amendments to Rule 4352

As a result of the comprehensive regulatory analysis conducted in support of the commitments in the *2018 PM2.5 Plan*, District staff are recommending several amendments to existing Rule 4352. The following paragraphs detail the proposed modifications to existing rule language and requirements. For further information on how proposed limits were determined, please see the Incremental Cost Analysis in Appendix C. Additionally, in an effort to simplify rule language and clarify existing requirements, expired language would be removed in several sections of the rule. See Proposed Rule 4352 for exact language.

Purpose (Section 1.0)

This section will be updated to specify that this rule will now also establish emissions limits for particulate matter and sulfur oxides.

Applicability - Section 2.0

No changes proposed at this time.

Definitions (Section 3.0)

New definitions for Carbon Monoxide, PM10, SOx, and gr/dscf will be added, as well as minor clarifications to existing definitions. The new definitions included are as follows:

Carbon Monoxide (CO): emissions of carbon monoxide, a colorless and odorless gas resulting from incomplete combustion of fuel.

PM10: as defined in Rule 1020 (Definitions).

- Per Rule 1020: *PM-10: particulate matter with an aerodynamic diameter smaller than or equal to a nominal ten (10) microns as measured by the applicable state and federal reference test methods.*

SOx: emissions of sulfur dioxide (SO2).

gr/dscf: grains of particulate matter per dry standard cubic foot.

Exemptions (Existing Section 4.0)

The exemptions section is being removed. Units with the potential to emit less than 10 tons per year of NOx or volatile organic compounds (VOC) are no longer exempt from the requirements of Rule 4352. There are currently two facilities in the Valley that will be newly subject to the requirements of this rule through the removal of this exemption.

Requirements (Existing Section 5.0/Proposed Section 4.0)

Updates in this section specify the proposed updated emission limits for the pollutants controlled though the rule, including newly established proposed PM10 and SOx emissions limits for subject sources. The proposed emissions limits included in this section of the rule are based on an in-depth technical analysis and a thorough public process. District staff have found control technologies necessary to achieve the proposed limits to be reasonably available, economically feasible, and cost effective.

This section, and subsequent sections of the rule, will also be renumbered to reflect the deletion of the current rule Section 4.0.

Section 4.1 NOx, CO, PM10, and SOx Limits

Existing Table 1 has been modified to clarify that the NOx and CO limits are effective until December 31, 2023.

Table 2 has been added to the rule to specify the NOx, CO, PM10, and SOx emission limits effective on and after January 1, 2024. See the discussion below.

The NOx limit for units fired on municipal solid waste are proposed to be lowered from 165 ppmv, corrected to 12% CO_2, to 90 ppmv, corrected to 12% CO_2. The NOx limit for units fired on biomass will be lowered from 90 ppmv, corrected to 3% O_2, to 65 ppmv, corrected to 3% O_2.

New PM10 limits are proposed to be established for municipal solid waste units at 0.04 lbs/MMBtu or 0.02 gr/dscf at 12% O2, and for all other units at 0.03 lbs/MMBtu/hr. The proposed PM10 limits will also reduce PM2.5 emissions significantly, due to 90-95% of the PM10 emitted from solid fuel fired boilers being PM2.5.

New SOx limits are proposed to be established for municipal solid waste units at 0.03 lbs/MMBtu or 12 ppmv at 12% CO2 on a rolling 12-month average, and 0.064 lbs/MMBtu or 25 ppmv at 12% CO2 on a block 24-hour average, and for all other units at 0.02 lbs/MMBtu/hr on a rolling 30-day average, and 0.035 on a block 24-hour average.

The current CO limit included in the rule would be maintained for all categories. Keeping the existing CO emission limit in the current rule would allow operators the much-needed flexibility to be able to achieve more stringent NOx, SOx and PM10 emissions limits under varying field operating conditions and applications.

The emission limits proposed in Section 4.1 have been established based on a comprehensive review of available emissions control technology, the technological feasibility of further controls, and the cost-effectiveness of technologically feasible additional controls. The cost-effectiveness evaluation is further discussed in Appendix C of this staff report. The proposed emissions limits for NOx, CO, PM10, and SOx are summarized in Table 2.

Table 2 Proposed Rule 4352 Emission Limits				
Fuel Type	NOx Limit	CO Limit	PM10 Limit	SOx Limit
Municipal Solid Waste	110 ppmv corrected to 12% CO_2 [A] 90 ppmv corrected to 12% CO2 [C]	400 ppmv corrected to 3% O_2 [A]	0.04 lbs/MMBtu or 0.02 gr/dscf @ 12% CO_2	0.03 lbs/MMBtu [C] or 12 ppmv at 12% CO_2 [C] 0.064 lbs/MMBtu [A] or 25 ppmv at 12% CO_2 [A]
Biomass	65 ppmv corrected to 3% O_2 [A]		0.03 lbs/MMBtu	0.02 lbs/MMBtu [B] 0.035 lbs/MMBtu [A]
All Others	65 ppmv corrected to 3% O_2 [A]		0.03 lbs/MMBtu	0.02 lbs/MMBtu [B] 0.035 lbs/MMBtu [A]

[A] Block 24-hour average
[B] Rolling 30-day average
[C] Rolling 12-month average

SOx emissions limits are proposed to be established on both a short-term 24-hour basis, as well as on a longer averaging period of 30-days for biomass fired units, and annually for MSW fired units. This is to allow for variability in emissions that may result from different fuel sources on a short-term basis, while still requiring the units to achieve significantly lower SOx emissions on a longer term average.

The proposed emission limits for units fired on municipal solid waste are higher than the proposed emission limits for biomass (wood) fired units. Municipal solid waste is a lower quality fuel, as it is less energy dense than biomass. Additionally, municipal solid waste often includes materials that contain impurities that cause higher emissions, such as drywall which contains sulfur that is oxidized into SO2 when combusted. Due to the lower fuel quality and higher levels of materials with impurities, municipal solid waste plants have higher emission rates than biomass plants.

Section 4.4 Monitoring Provisions

Requirements were added to require the use of Continuous Emissions Monitoring Systems for SOx.

Administrative Requirements (Section 5.0)

Section 5.3 Test Methods
The existing test method references in the rule have been updated to reflect the latest version of test methodology available. Test methods were also added for PM10, SOx, and CO_2.

Compliance Schedule (Section 6.0)

This section is being added to the rule to establish a schedule for when operators must submit an authority to construct and a deadline for compliance with the proposed NOx, PM10, and SOx emission limits. A compliance schedule is necessary to identify the compliance dates for the emission limits on and after January 1, 2024. The compliance date for the proposed limits was determined based on the rule development commitment in the *2018 PM2.5 Plan.*

Timeframes established in the proposed rule reflect the time necessary for facilities to plan for full compliance with the proposed emission limits, including budgeting for any required modifications to the facility or facility operations, and modifying existing controls or facility control practices, and installing any required further control technologies. Along with the tables outlining the proposed compliance timeframes, language in this section has been added or modified to provide more clarity with the proposed changes to the rule, including definitions for Authority to Construct and Compliance Deadlines referenced in the compliance tables.

IV. 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. Emission Reduction Analysis

In order to determine the emission reductions associated with the proposed changes, District staff queried the District Permit Services Databases for all solid fuel fired units operating in the Valley, and then sorted the units into categories based on the types of fuel utilized (municipal solid waste and biomass). Based on existing permitted limits, District staff calculated the potential to emit for each affected unit, and then, based on the proposed new emissions limit for each pollutant, calculated the percent reduction that would be achieved through compliance with the proposed rule updates.

For State Implementation Plan (SIP) purposes, the percent reduction achieved through compliance with the proposed rule was applied to the baseline emissions inventory used in the District's *2018 PM2.5 Plan*. Based on these calculations, the SIP-creditable emission reductions estimated to be achieved from the proposed amendments to Rule

4352 are illustrated in the table below, in tons per day (tpd) on an annual average basis. Please see Appendix B of this draft staff report for further details.

Table 3 – Summary of NOx, PM10, PM2.5 and SOx Emission Reductions

	NOx	PM10	PM2.5	SOx
2024 Reduction Percentage - MSW	45.5%	24.5%	23.2%	64.7%
2024 Reduction Percentage - Biomass	8.7%	28.4%	25.4%	48.9%
2024 Emission Reduction (tons/day) - MSW	0.395	0.019	0.018	0.058
2024 Emission Reduction (tons/day) - Biomass	0.316	0.295	0.264	0.213
Total Emission Reductions by 2024 (tons/day)	**0.711**	**0.313**	**0.282**	**0.271**

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 of 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

Based on the District's assessment of the Rule Amendment, the District concludes that the Rule Amendment 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 CEQA Guidelines § 15378.

The Rule Amendment to Rule 4352 is estimated to reduce NOx emissions by 0.711 tons per day (tpd), PM10 emissions by 0.313 tpd, PM2.5 emissions by 0.282 tpd, and SOx emissions by 0.271 tpd. According to Section 15061 (b)(3) of the CEQA Guidelines, a project is exempt from CEQA if, "(t)he activity is covered by the general rule 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, substantial evidence supports the District's assessment that assuming the Rule Amendment is a "project" under CEQA, it will not have any significant adverse effects on the environment.

In Furthermore, the Rule Amendment is an action taken by a regulatory agency, the San Joaquin Valley Air Pollution Control 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. 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 Rule Amendment.

Therefore, for all the above reasons, the Rule Amendment is exempt from CEQA. Pursuant to Section 15062 of the CEQA Guidelines, District staff will file a Notice of Exemption upon Governing Board approval of Rule Amendment.

F. Most Stringent Measures (MSM) and Best Available Retrofit Control Technology (BARCT) Analyses

As previously discussed, on November 15, 2018, the District adopted the District's *2018 PM2.5 Plan* to satisfy Clean Air Act requirements for the PM2.5 national ambient air quality standards. As a part of the *2018 PM2.5 Plan*, the District demonstrated that Rule 4352 satisfies Best Available Control Measures (BACM) and performed a Most Stringent Measures (MSM) analysis for all rules that contain emission limits or requirements for NOx or PM. EPA defines MSM as, "*the maximum degree of emission reductions that has been required or achieved from a source or source category in any* *other attainment plans or in practice in any other states and that can feasibly be implemented in the area.*"

In February 2020, EPA published the *Technical Support Document - EPA Evaluation of BACM/MSM, San Joaquin Valley PM2.5 Plan for the 2006 PM2.5 NAAQS*,[3] and determined that, "*Rule 4352 implements BACM and MSM for this category at this time. We recommend that SJVUAPCD continue evaluating the technical and economic feasibility of the Covanta LN installation for MSW boilers.*"

In addition to federal control requirements, most existing stationary sources in California non-attainment areas such as the San Joaquin Valley have been subject to state Best Available Retrofit Control Technology (BARCT) requirements since the 1980s. California Health and Safety Code Section 40406 defines BARCT as follows:

> *"Best Available Retrofit Control Technology (BARCT) is an air emission limit that applies to existing sources and is the maximum degree of reduction achievable, taking into account environmental, energy and economic impacts by each class or category of source."*

As discussed above, EPA has determined that the requirements of Rule 4352 currently satisfy MSM and BACM/BACT (Best Available Control Technology). Furthermore, the proposed amendments to the municipal solid waste-fired boilers will require the use of Covanta LN, or a similar technology, to achieve the proposed emission limits, and require more stringent limits for biomass units operating in the Valley. Based on a review of requirements in other California air districts, District staff have found that the proposed rule implements BARCT levels of emissions control. Adoption of the proposed amendments will also ensure that Rule 4352 continues to meet or exceed BACM and MSM levels of emissions control.

[3] Technical Support Document - EPA Evaluation of BACM/MSM, San Joaquin Valley PM2.5 Plan for the 2006 PM2.5 NAAQS (February 2020)

APPENDIX A

Summary of Significant Comments and Responses
For Proposed Amendments to Rule 4352
(Solid Fuel Fired Boilers, Steam Generators, and Process Heaters)

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SUMMARY OF SIGNIFICANT COMMENTS
DRAFT AMENDMENTS TO RULE 4352
(SOLID FUEL FIRED BOILERS, STEAM GENERATORS, AND PROCESS HEATERS)
November 16, 2021

The District published the proposed rule November 16, 2021 for 30-day public review and comment.

No comments were received.

SUMMARY OF SIGNIFICANT COMMENTS
DRAFT AMENDMENTS TO RULE 4352
(SOLID FUEL FIRED BOILERS, STEAM GENERATORS, AND PROCESS HEATERS)
November 4, 2021

The District held a public workshop to present, discuss, and receive comments on the draft amendments to Rule 4352 on November 4, 2021. Summaries of significant comments received during the public workshop and associated comment period are summarized below.

Comments were received from the following:

Derek Furstenwerth, Consolidated Asset Management Services (CAMS)
Terry Coble, Covanta Holding Corporation (Covanta)

1. **COMMENT:** The SOx limit of 0.02 lbs/MMBtu for biomass fueled units is not supported by emissions data. Historical emissions data shows a significant number of 30-day rolling averages in excess of 0.02 lbs/MMBtu. (CAMS)

   RESPONSE: Based on the District's technical assessment and the feasible controls available, District staff found that the proposed emissions limits for SOx are technologically feasible and achievable. The proposed requirements were also found to be cost-effective.

2. **COMMENT:** We request that the 65 ppm NOx limit for biomass fueled units also be included as the equivalent limit in lbs/MMBtu. This would allow facilities to have certainty as to the applicable limits, regardless of whether they use O_2 or CO_2 diluent CEMS. (CAMS)

   RESPONSE: EPA Test Method 19 (Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Emission Rates) contains methodology for determining emission rates in ppm. O_2 or CO_2 concentrations and appropriate F factors (ratios of combustion gas volumes to heat inputs) are used to calculate pollutant emission rates from pollutant concentrations.

3. **COMMENT:** The draft rule proposes a new SOx limit of 0.03 lbs/MMBtu or 12 ppmv @ 12% CO_2 for units fired on municipal solid waste. Municipal solid waste is well documented as having heating values that are highly variable, and the proposed emission limit does not provide sufficient margin to ensure continuous compliance. We request a SOx emission limit of 0.04 lbs/MMBtu or 16 ppmv @ 12% CO_2. (Covanta)

   RESPONSE: Based on the District's technical assessment and the feasible controls available, District staff found that the proposed emissions limits for SOx are technologically feasible and achievable. The proposed requirements were also found to be cost-effective.

4. **COMMENT:** The draft rule proposes a PM10 limit of 0.04 lbs/MMBtu or 0.02 gr/dscf @ 12% CO_2. We request this limit be revised to 0.044 lbs/MMBtu or 0.022 gr/dscf. (Covanta)

   RESPONSE: Based on the District's technical assessment and the feasible controls available, District staff found that the proposed emissions limits for PM10 are technologically feasible and achievable. The proposed requirements were also found to be cost-effective.

SUMMARY OF SIGNIFICANT COMMENTS DRAFT AMENDMENTS TO RULE 4352 (SOLID FUEL FIRED BOILERS, STEAM GENERATORS, AND PROCESS HEATERS) September 30, 2021

The District held a public workshop to present, discuss, and receive comments on the draft amendments to Rule 4352 on September 30, 2021. Summaries of significant comments received during the public workshop and associated comment period are summarized below.

Comments were received from the following:

Derek Furstenwerth, Consolidated Asset Management Services (CAMS)
Dr. Catherine Garoupa, Central Valley Air Quality Coalition (CVAQ)
Theresa Zamora, Mi Familia Vota (MFV)
Matt Holmes, Little Manila Rising (LMR)
Thomas Helme, Valley Projects (VP)

5. **COMMENT:** We support the District's proposed emission limit for NOx, and propose a 0.025 lb/MMBtu SOx limit and a 0.04 lbs/MMBtu PM10 emissions limit in Rule 4352. (CAMS)

   RESPONSE: The District appreciates the recommendations for emission limits and have evaluated potential options for emission reductions. Proposed emissions limits have been established based on a comprehensive technical evaluation and cost-effectiveness evaluation.

6. **COMMENT:** While we support the proposed lower emissions limits for nitrogen oxides (NOx), particulate matter 10 (PM10), and sulfur oxides (SOx), we continue to encourage direct PM2.5 emissions control limits, particularly for industrial biomass facilities. With the fast-approaching deadline to meet federal air quality standards, it is essential that emission reduction strategies be applied to all pollutants. (CVAQ, MFV, LMR, VP)

   RESPONSE: The proposed Rule 4352 contains lower NOx emissions limitations (precursor to PM2.5), and establishes emissions limits for direct PM10 and SOx. The direct PM10 from solid fuel fired boilers is primarily PM2.5 (~90%), and SOx reductions also reduce the formation of secondary PM2.5. Therefore, the rule amendments will achieve significant reductions in direct PM2.5, as well as PM2.5 precursor emissions.

7. **COMMENT:** Rule 4352 currently contains an exemption in which the "rule does not apply to units at a Stationary Source that has a potential to emit less than 10 tons per year of NOx or volatile organic compounds (VOCs)." This exception

does not exist in other air districts and should no longer be included in this rule. (CVAQ, MFV, LMR, VP)

RESPONSE: The exemptions section is being removed. Therefore, units with the potential to emit less than 10 tons per year of NOx or VOC are no longer exempt from the requirements of Rule 4352.

8. **COMMENT:** We encourage continued analysis and use of industrial technologies such as SNCR, SCR, baghouses and electrostatic precipitators (ESP) as control technologies for industrial biomass facilities, particularly for facilities near sensitive receptors. (CVAQ, MFV, LMR, VP)

RESPONSE: All facilities subject to Rule 4352 currently control NOx, SOx, and direct particulate matter emissions through the use of multiple industrial control technologies, including SNCR, SCR, electrostatic precipitators, multiclones, baghouses, and other technologies. In support of the proposed regulatory amendments, the District conducted a comprehensive technical analysis of all available controls, including a combination of controls as feasible, and has proposed more stringent emission limits that are technologically feasible and cost-effective.

9. **COMMENT:** Consideration should be provided to public health and other adverse economic impacts of air pollution when weighing the technological and economic feasibility of rules with a particular focus on environmental justice implications. (CVAQ, MFV, LMR, VP)

RESPONSE: The District appreciates the comment and is proposing the regulatory amendments consistent with established state and federal requirements and guidance, and as part of ongoing efforts to meet health-based state and federal ambient air quality standards to protect public health in communities across the Valley.

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APPENDIX B

Emission Reduction Analysis for Proposed Amendments to Rule 4352 (Solid Fuel Fired Boilers, Steam Generators, and Process Heaters)

December 16, 2021

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I. SUMMARY

The District committed to amending Rule 4352 as part of the *2018 PM2.5 Plan*. This appendix details the calculations and assumptions used to estimate the NOx, PM10, PM2.5 and SOx emission reductions associated with the proposed amendments to Rule 4352.

Table B-1 summarizes the estimated emission reductions from each of these pollutants from the baseline emissions inventory in the *2018 PM2.5 Plan*. The calculation methodology is outlined in Section III of this appendix. When fully implemented, the proposed amendments are estimated to achieve 0.71 tons per day (tpd) of NOx emissions reductions (15.8% of baseline emission inventory), SOx emissions reductions of 0.27 tpd (51.4% of baseline emission inventory), PM10 emissions reductions of 0.31 tpd (27.9% of baseline emission inventory), and PM2.5 emissions reductions of 0.28 tpd (28.2% of baseline emission inventory). Since PM2.5 is a subset of PM10, and since the majority of PM10 emissions from solid fuel fired boilers are PM2.5 emissions, the emissions reduction estimates for PM2.5 are nearly the same as PM10. This is further described in Section III of this appendix.

Table B-1 – Estimated NOx, PM10, PM2.5, and SOx Emission Reductions Achieved by 2024

Fuel Type	NOx tpd	PM10 tpd	PM2.5 tpd	SOx tpd
MSW	0.395	0.019	0.018	0.058
Biomass	0.316	0.295	0.264	0.213
Total	**0.711**	**0.313**	**0.282**	**0.271**

Table B-2 shows the percent emission reductions estimated to be achieved from the baseline emissions for units fired on municipal solid waste (MSW), and units fired on biomass.

Table B-2 – Summary of NOx, PM10, PM2.5, and SOx Percent Reductions Achieved by 2024

Fuel Type	# of Units	% NOx	% PM10	% PM2.5	% SOx
MSW	2	45.5%	24.5%	23.2%	64.7%
Biomass	10	8.7%	28.4%	25.4%	48.9%

II. BACKGROUND

The San Joaquin Valley is home to 12 solid fuel fired boilers with active permits that are subject to Rule 4352. These units are located at 10 facilities that fuel their units on either municipal solid waste or biomass. For the purposes of this analysis, the boilers at each facility will be aggregated into a single calculation. This analysis will focus on the current annual permit emission limits as indicated in Table B-3.

Table B-3 – Affected Facility Annual Permitted Potential Emissions

Fuel Type	NOx Permitted Potential (tons/year)	PM10 Permitted Potential (tons/year)	SOx Permitted Potential (tons/year)
Municipal Solid Waste Facility	344.4	70.0	121.9
Biomass Facility	59.9	29.9	29.9
Biomass Facility	107.7	53.7	69.6
Biomass Facility	110.0	101.6	43.8
Biomass Facility	61.3	30.6	15.3
Biomass Facility	231.5	34.7	59.1
Biomass Facility	121.8	62.1	45.1
Biomass Facility	208.8	41.8	27.0
Biomass Facility	313.2	139.4	121.6
Biomass Facility	70.4	22.7	39.1

The District's *2018 PM2.5 Plan* emissions inventory from the 2016 California Emissions Projection Analysis Model (CEPAM) version 1.05 is used throughout this analysis, as this was the foundation for the *2018 PM2.5 Plan*. The 2024 emissions inventories for the two fuel types are shown in Table B-4.

Table B-4 – 2024 Emissions Inventory for Affected Facility Types

Fuel Type	NOx (tons/day)	PM10 (tons/day)	PM2.5 (tons/day)	SOx (tons/day)
MSW	0.868	0.076	0.072	0.089
Biomass	3.628	1.037	0.928	0.436

Source: CEPAM 2016 SIP Baseline Emission Projections, Version 1.05

III. Emissions and Emission Reduction Methodology

This section of the report outlines the procedures used to calculate the current emissions and the estimated emission reductions associated with the proposed amendments to Rule 4352.

The emissions reduction percentages resulting from this rule amendment can be applied directly to the baseline emissions inventory from the *2018 PM2.5 Plan*. These "SIP Currency" reductions (Table B-1) are being credited to the aggregate emissions reduction commitments from the *2018 PM2.5 Plan* (*2018 PM2.5 Plan* Table 4-3, page 4-12).

An emissions factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. These factors are usually expressed as the weight of pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant (e.g., pounds of NOx emitted per hour). Such factors facilitate an estimation of emissions from various sources of air pollution. In most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e., a population average).

In general, emissions can be calculated from the activity rate and emissions factor as:

$$E = A \times EF \quad (1)$$

Where:

E = emissions;
A = activity rate;
EF = emissions factor; and

For solid fuel-fired boilers, emissions factors will be determined from permit limits for existing permit units and compared to proposed rule limits in the proposed amended rule. This potential to emit was queried from the District's permits database, and will be used in place of A x EF.

For this analysis, Equation 1 shall be applied to each affected facility for the permitted activity rate at the current permit limit and at the proposed amended limit(s) to calculate potential emissions from each facility at each limit. The total potential current emissions and the total of the potential emissions at the proposed limits summed for each category will be used to determine a percent reduction for each pollutant from each affected category, as follows:

$$\%_{Reduced} = \frac{(\sum E_{Current} - \sum E_{Proposed})}{\sum E_{Current}} \quad (2)$$

Where:

$\%_{Reduced}$ = percent reduction;
$E_{Current}$ = current potential emissions; and
$E_{Proposed}$ = the potential emissions at proposed limits.

Finally, the emissions reductions will be calculated by multiplying the emissions inventory defined in Table B-4 by the calculated percent reductions determined as follows:

$$ER = EI \times \%_{Reduced} \quad (3)$$

Where:

ER = emission reduction;
EI = emission inventory; and
$\%_{Reduced}$ = calculated percent reductions.

A. NOx Emission Reduction Calculations

Proposed emission limits for NOx are 90 parts per million volume (ppmv) for units fired on municipal solid waste and 65 ppm for units fired on biomass. Table B-5 shows calculations for potential NOx emissions for each facility in ton/yr.

Table B-5 – NOx Emission Potentials for Affected Facilities

Fuel Type	Permitted NOx Limit (ppmv)	Permitted NOx Potential (tons/year)	Proposed NOx Limit (ppmv)	Proposed Permitted NOx Potential (tons/year)	NOx Percent Reduction
Municipal Solid Waste Facility	165	344.4	90	187.9	45.5%
Biomass Facility	65	59.9	65	59.9	0.0%
Biomass Facility	50	107.7	65	107.7	0.0%
Biomass Facility	65	110	65	110.0	0.0%
Biomass Facility	65	61.3	65	61.3	0.0%
Biomass Facility	65	231.5	65	231.5	0.0%
Biomass Facility	67	121.8	65	118.2	3.0%
Biomass Facility	90	208.8	65	150.8	27.8%
Biomass Facility	76	313.2	65	267.9	14.5%
Biomass Facility	70	70.4	65	65.4	7.1%

Table B-6 shows the total potential NOx emissions, summed by fuel type, and the percent reduced from the proposed NOx limits by applying Equation 2.

Table B-6 – Percent NOx Reductions

Fuel Type	Permitted NOx Potential (ton/yr)	Proposed Permitted NOx Potential (ton/yr)	NOx Percent Reduction
Municipal Solid Waste	344.4	187.9	45.5%
Biomass	1284.6	1172.6	8.7%

Table B-7 shows the results of Equation 3 with percent reductions in Table B-6 applied to the NOx emissions inventory in Table B-4.

Table B-7 – NOx Emission Reductions

Fuel Type	2024 NOx Emissions (tons/day)	% Reduction	2024 NOx Emission Reductions (tons/day)
Municipal Solid Waste	0.868	45.5%	0.395
Biomass	3.628	8.7%	0.316
Total	**4.496**		**0.711**

B. PM Emission Reduction Calculations

Particulate matter permit and rule limits for glass melting furnaces are for the size fraction of PM10. Since PM2.5 is directly proportional to and is a subset of PM10, the emissions controls to reduce PM10 will likewise reduce PM2.5. Within the emissions inventory established for the *2018 PM2.5 Plan*, a ratio is used to convert PM10 into PM2.5. For this analysis, Equation 1 and Equation 2 will use PM10 limits to determine a percent reduction, and will apply that percent reduction with Equation 3 to both the PM10 and PM2.5 planning inventories to determine emission reductions.

Proposed emission limits for PM10 are 0.04 pounds per metric million British thermal unit (lbs/MMBtu) for units fired on municipal solid waste and 0.03 lbs/MMBtu for units fired on biomass. Table B-8 shows calculations for potential PM10 emissions for each facility in ton/yr.

Table B-8 – PM10 Emission Potentials for Affected Facilities

Fuel Type	Permitted PM10 Limit (lbs/MMBtu)	Permitted PM10 Potential (tons/year)	Proposed PM10 Limit (lbs/MMBtu)	Proposed Permitted PM10 Potential (tons/year)	PM10 Percent Reduction
Municipal Solid Waste Facility	0.053	70	0.04	52.8	24.5%
Biomass Facility	0.04	29.9	0.03	22.4	25.0%
Biomass Facility	0.0214	53.7	0.03	53.7	0.0%
Biomass Facility	0.066	101.6	0.03	46.2	54.5%
Biomass Facility	0.04	30.6	0.03	23.0	25.0%
Biomass Facility	0.012	34.7	0.03	34.7	0.0%
Biomass Facility	0.045	62.1	0.03	41.4	33.3%
Biomass Facility	0.03	41.8	0.03	41.8	0.0%
Biomass Facility	0.045	139.4	0.03	92.9	33.3%
Biomass Facility	0.05	22.7	0.03	13.6	40.0%

Table B-9 shows the total potential PM10 emissions, summed by fuel type, and the percent PM10 reduced for each fuel type by applying Equation 2.

Table B-9 – Percent PM10 Reductions

Fuel Type	Permitted PM10 Potential (ton/yr)	Proposed PM10 Potential (ton/yr)	PM10 Percent Reduction
Municipal Solid Waste	70.0	52.8	24.5%
Biomass	516.5	369.7	28.4%

Table B-10 shows the results of Equation 3 with the percent reductions in Table B-9 applied to the PM10 emissions inventory in Table B-4.

Table B-10 – PM10 Emission Reductions

Fuel Type	2024 PM10 Emissions (tons/day)	% Reduction	2024 PM10 Emission Reductions (tons/day)
Municipal Solid Waste	0.076	24.5%	0.019
Biomass	1.037	28.4%	0.295
Total	**1.113**		**0.313**

Table B-11 shows the results of Equation 3 with the percent reductions in Table B-9 applied to the PM2.5 emissions inventory in Table B-4.

Table B-111 – PM2.5 Emission Reductions

Fuel Type	2024 PM2.5 Emissions (tons/day)	% Reduction	2024 PM2.5 Emission Reductions (tons/day)
Municipal Solid Waste	0.072	24.5%	0.018
Biomass	0.928	28.4%	0.264
Total	**1.00**		**0.282**

C. SOx Emission Reduction Calculations

Proposed emission limits for SOx are 0.03 pounds per metric million British thermal unit (lbs/MMBtu) for units fired on municipal solid waste and 0.02 lbs/MMBtu for units fired on biomass. Table B-12 shows calculations for potential SOx emissions using Equation 1 for each facility in ton/yr.

Table B-122 – SOx Emission Reduction Percentages for Affected Facilities

Fuel Type	Permitted SOx Limit (lbs/MMBtu)	Permitted SOx Potential (tons/year)	Proposed SOx Limit (lbs/MMBtu)	Proposed Permitted SOx Potential (tons/year)	SOx Percent Reduction
Municipal Solid Waste Facility	0.085	121.9	0.03	43.0	64.7%
Biomass Facility	0.04	29.9	0.02	15.0	50.0%
Biomass Facility	0.054	69.6	0.02	25.8	63.0%
Biomass Facility	0.03	43.8	0.02	29.2	33.3%
Biomass Facility	0.035	15.3	0.02	8.7	42.9%
Biomass Facility	0.04	59.1	0.02	29.6	50.0%
Biomass Facility	0.032	45.1	0.02	28.2	37.5%
Biomass Facility	0.063	27	0.02	8.6	68.3%
Biomass Facility Unit 1	0.033	68.6	0.02	41.6	39.4%
Biomass Facility Unit 2	0.038	53	0.02	27.9	47.4%
Biomass Facility	0.05	39.1	0.02	15.6	60.0%

Table B-13 shows the total potential SOx emissions, summed by fuel type, and the percent SOx reduced for each fuel type by applying Equation 2.

Table B-133 – Percent SOx Reductions

Fuel Type	Permit SOx Potential (ton/yr)	Proposed SOx Potential (ton/yr)	SOx Percent Reduction
Municipal Solid Waste	121.9	43.0	64.7%
Biomass	450.5	230.1	48.9%

Table B-14 shows the results of Equation 3 with the percent reductions in Table B-12 applied to the SOx emissions inventory in Table B-4.

Table B-144 – SOx Emission Reductions

Fuel Type	2024 SOx Emissions (tons/day)	% Reduction	2024 SOx Emission Reductions (tons/day)
Municipal Solid Waste	0.089	64.7%	0.058
Biomass	0.436	48.9%	0.213
Total	**0.525**		**0.271**

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APPENDIX C

Cost Effectiveness Analysis for
Proposed Amendments to Rule 4352
(Solid Fuel Fired Boilers, Steam Generators, and Process Heaters)

December 16, 2021

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APPENDIX C
COST EFFECTIVENESS ANALYSIS

I. SUMMARY

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.

Absolute cost effectiveness of a control option is the added annual compliance cost to meet the proposed rule requirements, in dollars per year ($/year), of a control technology or technique, divided by the emission reduction achieved in tons reduced per year. The costs includes capital equipment costs, engineering design costs, and labor and maintenance costs.

Incremental cost effectiveness (ICE) is intended to measure the change in costs (in $/year) and emissions reductions (in tons reduced/year) between two progressively more effective control options or technologies. ICE compares the differences in costs and the differences in emissions reductions of candidate control options. ICE does not reveal the emission reduction potential of the control options. Unlike the absolute cost effectiveness analysis that identifies the control option with the greatest emission reduction, ICE does not present any correlation between emissions reductions and cost effectiveness. Therefore, the relative values produced in the ICE analysis and the absolute cost effectiveness values are not comparable and cannot be evaluated in the same way as absolute cost effectiveness numbers.

Table 1 shows the summary of the cost effectiveness analysis for solid fuel fired boilers to comply with the proposed rule. The ‘cost effectiveness range’ shown in the table below represents the values for the technologies that are expected to be installed at solid fuel fired boilers, grouped by fuel type and pollutant, in the San Joaquin Valley.

Table C-1: Summary of Cost Effectiveness*

Compliance Scenarios (Current Permitted Limit to Proposed New Limit)	Cost Effectiveness Range ($/ton)
Municipal Solid Waste – NOx Limit	$26,269
Municipal Solid Waste – PM10 Limit	-
Municipal Solid Waste – SOx Limit	-
Biomass – NOx Limit	-
Biomass – PM10 Limit	-
Biomass – SOx Limit	$7,100 - $29,702

* *Where cost-effectiveness calculations are not shown, there are nominal costs expected. Associated costs would be related to maintaining and testing emissions, which are well controlled through currently installed control technologies, and permit modifications.*

Table 2 shows the total direct and indirect capital cost associated with the technologies required for subject facilities to comply with the proposed emission limits.

Table C-2: Estimated Capital Cost for Control Technology

Technology	Total Direct and Indirect Capital Costs
Municipal Solid Waste – Install Covanta LN	$12,100,000
Biomass – Install SOx CEMs	$2,323,317

**Costs do not include one time permit modification fees*

II. BACKGROUND

Proposed Rule 4352 would implement more stringent NOx limits, and establish PM10 and SOx limits for solid fuel fired boilers. To comply with the proposed requirements, the facility with units fired on municipal solid waste (MSW) will require a significant investment to install combustion modification equipment to meet the proposed NOx limit. Units fired on biomass are expected to be capable of achieving the proposed NOx limit with existing control equipment with nominal additional costs, which may including tuning of controls, testing, monitoring, as well as permit modifications. For the PM10 and SOx emissions limits, subject facilities are also expected to be capable of complying with the proposed updated limits with existing control equipment, and marginal associated costs which may include tuning of controls, testing, and monitoring costs, as well as the cost for permit modification to include permit conditions for the additional pollutants. Two biomass facilities will need to upgrade their continuous emission monitoring systems (CEMs) to monitor SO_2 emissions, and one facility would require the installation of a dry sorbent injection system to control SOx emissions. One additional facility with a biomass fired solid fuel fired boiler, which is currently in the permitting process, would require the installation of SO_2 CEMS and dry sorbent injection to comply with the proposed amendments to Rule 4352.

A. Estimated Compliance Cost

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, PM10, and SOx limits in Proposed Rule 4352. Specifically the data used in the analysis came from the following sources:

1. Covanta Stanislaus
2. Rio Bravo Fresno
3. Merced Power LLC
4. Ampersand Chowchilla
5. DTE Stockton
6. Mt. Poso Cogeneration
7. W. L. Gore & Associates, Inc.
8. Tracy Renewable Energy, LLC

Cost information submitted to the District was used to create the range of costs located in Tables C-4 through C-23.

III. SOLID FUEL FIRED BOILER STATUS RELATIVE TO PROPOSED EMISSION LIMITS

There are nine facilities that have active permits to operate solid fuel fired boilers within the District, and all nine will be impacted by this proposed rule amendment. These nine facilities operate a total of eleven furnaces – two are fired on municipal solid waste, and nine are fired on biomass. A summary of these facilities, their control equipment and their current permitted emission limits are shown in the table C-3 below:

Table C-3: Current Facility Control Technology, Size, and Emission Limits

Facility	Pollutant	Current Reduction Technology	Maximum Heat Input Rating (MMBtu/hr)	Current Permitted Emission Limits
Municipal Solid Waste – Facility 1	NOx	Selective Non-Catalytic Reduction (SNCR)	300	165 ppmv
	PM10	Baghouse		0.053 lbs/MMBtu
	SOx	Dry Sorbent Injection		0.085 lbs/MMBtu
Biomass – Facility 1	NOx	SNCR	185	65 ppmv
	PM10	Baghouse		0.04 lbs/MMBtu
	SOx	Dry Sorbent Injection		0.04 lbs/MMBtu
Biomass – Facility 2	NOx	Selective Catalytic Reduction (SCR)	780	50 ppmv
	PM10	Electrostatic Precipitator (ESP)		0.0214 lbs/MMBtu
	SOx	Dry Sorbent Injection		0.054 lbs/MMBtu
Biomass – Facility 3	NOx	SNCR	352	65 ppmv
	PM10	ESP		0.066 lbs/MMBtu
	SOx	Dry Sorbent Injection		0.03 lbs/MMBtu
Biomass – Facility 4	NOx	SNCR	185	65 ppmv
	PM10	Baghouse		0.04 lbs/MMBtu
	SOx	Dry Sorbent Injection		0.035 lbs/MMBtu
Biomass – Facility 5	NOx	SNCR	640	65 ppmv
	PM10	Baghouse		0.012 lbs/MMBtu
	SOx	Dry Sorbent Injection		0.04 lbs/MMBtu
Biomass – Facility 6	NOx	SNCR	317	65 ppmv
	PM10	Baghouse		0.045 lbs/MMBtu
	SOx	Dry Sorbent Injection		0.032 lbs/MMBtu
Biomass – Facility 7	NOx	SNCR	460	90 ppmv
	PM10	Baghouse		0.03 lbs/MMBtu
	SOx	Dry Sorbent Injection		0.063 lbs/MMBtu
Biomass – Facility 8 Unit 1	NOx	SNCR	400	76 ppmv
	PM10	Baghouse		0.045 lbs/MMBtu
	SOx	Dry Sorbent Injection		0.033 lbs/MMBtu
Biomass – Facility 8 Unit 2	NOx	SNCR	315	76 ppmv
	PM10	Baghouse		0.045 lbs/MMBtu
	SOx	Dry Sorbent Injection		0.038 lbs/MMBtu
Biomass – Facility 9	NOx	SNCR	198.6	70 ppmv
	PM10	Baghouse		0.05 lbs/MMBtu
	SOx	None		0.05 lbs/MMBtu

III. 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.

A. Absolute Cost Effectiveness

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.

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 4 percent and equipment life of 10 years.
2. Determine the annual electricity, fuel, and operation and maintenance costs of a control technology.
3. Calculate the total annual cost by adding the costs calculated in Step 1 and Step 2.
4. Calculate the emission reduction in tons/year. Appendix B provides a detailed explanation of the calculations performed to determine the emission reductions for the potential rule limits.
5. Calculate the absolute cost effectiveness by dividing the total annual cost in Step 3 by the emissions reduction in Step 4.

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 that were not considered cost effective. Due to the increased costs and marginal emission reductions, the ICE calculations typically show a much higher cost effectiveness than the absolute cost effectiveness values, and are therefore not directly comparable.

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

1. Identify the complying control options appropriate for 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.

For the ICE analysis, the emission reduction is the difference between the current rule emission limits to proposed emission limits.

IV. ABSOLUTE COST EFFECTIVENESS ANALYSIS

Absolute cost effectiveness of a control option is the added annual cost, in dollars per year, of a control technology or technique divided by the emission reductions achieved, in tons reduced per year. Compliance costs include both one-time costs and on-going annual costs. Examples of one-time costs are the purchase of equipment and installation costs. On-going costs are items like maintenance costs, operation costs, and insurance. In order to determine a single figure for costs, District staff use a capital recovery factor to allocate the one-time costs over the life of the equipment. For all cost analyses in this report, District staff used a 4 percent rate of return and a 10-year equipment life to convert the capital costs to equivalent annual cost.

1. NOx Compliance Costs

The District worked with the affected MSW facility operating in the Valley to determine the costs to install proprietary combustion modification technology, Covanta LN at the facility in Stanislaus County. The installation would also include an upgrade to the selective non-catalytic reduction system and an increased operation and maintenance cost (O&M) for the additional ammonia required to operate the system. All biomass facilities in the Valley already have selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR) to limit NOx emissions, and are expected to be able to meet the proposed limits without major modifications to the existing controls, or are already meeting the proposed emissions limits. Solid fuel fired boilers in the District are expected to be able to comply with the new PM10 emission limits without major modifications to their existing control equipment. The capital costs associated with the PM10 emission limits for biomass fired units are attributed to permit modification fees. Additional costs may be incurred by facilities to upgrade controls, test and monitor emissions to ensure compliance with the proposed emissions limits, but these costs are expected to be marginal.

Table C-4: NOx Compliance Costs

Fuel Type	Capital Cost	O&M ($/yr)	Annualized Cost ($/yr)	Emission Reductions (tons/year)	Cost Effectiveness ($/ton NOx)
Municipal Solid Waste	$12,121,000	$840,987	$2,355,397	144.0	$26,269

2. PM10 Compliance Costs

Most facilities subject to Rule 4352 are expected to be able to comply with the new PM10 emission limits without major modifications to their existing control equipment. All facilities already have the highest degree of control technology available, which include baghouses or electrostatic precipitators to limit particulate matter emissions. However, some facilities may require tuning of their current emission control equipment to ensure compliance with the lower emissions limits, with marginal associated costs.

3. SOx Compliance Costs

Most facilities subject to Rule 4352 are expected to be able to comply with the new SOx emission limits without major modifications to their existing control equipment, and with nominal costs or impacts to current operations. Potential compliance costs could include the cost of additional sorbent used in current control systems, permitting fees, and testing and monitoring costs. The majority of facilities have dry sorbent injection systems to control SOx. One dormant facility would require the installation of SOx control equipment should it become active again. Two facilities in the Valley do not currently have a CEMs channel for SOx. To demonstrate compliance with the proposed SOx limits, the facilities would be required to install a CEMs channel. This would include an initial cost to install the system, estimated at approximately $50,000 per facility, as well as annual costs to maintain the monitor. There is an expected O&M cost associated with the installation of the new CEMs channel of approximately $3,700 per facility annually. There is also one facility with two small biomass fired boilers, which is currently in the permitting process, that would require the installation of SOx CEMs and SOx control technology to comply with the proposed amendments to Rule 4352.

Table C-6: SOx Compliance Costs

Fuel Type	Capital Cost	O&M ($/yr)	Annualized Cost ($/yr)	Emission Reductions (tons/year)	Cost Effectiveness ($/ton SOx)
Biomass	$2,404,317	$783,487	$1,079,939	111.0	$9,729

V. ALTERNATIVE CONTROL TECHNOLOGIES EVALUATED

Selective Catalytic Reduction for Units Fired on MSW to Reduce NOx Emissions

Selective catalytic reduction systems are a post-combustion control for NOx that involves the injection of anhydrous ammonia, aqueous ammonia, or urea solution into the exhaust gas to reduce NOx emissions capable of achieving 50 ppm NOx. District staff evaluated the feasibility of installation of a SCR system at the MSW fired facility in the District to meet a potential 50 ppm limit, and found that this control option would involve very high capital and annual costs. Direct capital costs include the purchase of the SCR, retrofit of the existing structure to accommodate the system, additional ductwork, and installation of a natural gas pipeline for the duct burner. Indirect capital costs include engineering and retrofit downtime resulting in the loss of six months of electricity sales and tipping fees. Total capital cost are approximately $35 million. Annual operation and maintenance costs include periodic catalyst replacement, additional electricity required, insurance, and labor, with associated costs estimated at approximately $2 million annually. Establishing a 50 ppmv NOx emissions limit was not recommended due to the high capital cost and high cost per ton of NOx reduced.

Table C-7: Costs and Cost Effectiveness for Alternative Technology – SCR for Units fired on MSW

Selective Catalytic Reduction for Units Fired on MSW					
Total Capital Cost	Annualized Capital Cost	Annualized O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
$34,635,513	$5,635,198	$2,038,786	$7,673,984	156.9	$62,184

Gore De-NOx for Units Fired on MSW to Reduce NOx Emissions

Gore De-NOx catalytic filter bags is a retrofit control technology that effectually converts an existing pulse-jet baghouse into a selective catalytic reduction control system capable of achieving emissions levels as low as 60 ppm NOx. District staff evaluated the feasibility of installation of a Gore De-NOx system at the MSW fired facility in the District to meet a potential 60 ppm limit, and found that this control option would involve high capital and annual costs. Capital costs include the purchase of the initial Gore filter bags, freight, installation, and three weeks of retrofit downtime. Total capital cost are approximately $5.5 million. O&M costs include sorting of material, periodic catalyst bag replacement, insurance, and labor, with costs estimated at approximately $6.6 million annually. The major O&M cost is the cost to hand sort the municipal solid waste to remove high SOx materials like drywall. This is because Gore-DeNOx filter bags are susceptible to fouling by high levels of SOx. Another factor that led to the District not establishing a 60 ppm NOx limit is that Gore De-NOx technology has never been installed at a MSW facility in the United States.

Table C-8: Costs and Cost Effectiveness for Alternative Technology – Gore De-NOx for Units fired on MSW

Gore De-NOx for Units Fired on MSW					
Total Capital Cost	Annualized Capital Cost	Annualized O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
$5,449,933	$886,704	$6,647,262	$7,533,966	130.5	$88,462

Combined Selective Catalytic Reduction and Covanta LN for Units Fired on MSW to Reduce NOx Emissions

Combining SCR and Covanta LN combustion technology is capable of achieving 35 ppm NOx. District staff evaluated the feasibility of installation of a SCR system at the MSW fired facility in the District to meet a potential 35 ppm limit, and found that this control option would involve very high capital and annual costs. Direct capital costs include the purchase of the SCR, purchase of the Covanta LN combustion modification equipment, retrofit of the existing structure to accommodate the system, additional ductwork, and installation of a natural gas pipeline for the duct burner. Indirect capital costs include engineering and retrofit downtime resulting in the loss of six months of electricity sales and tipping fees. Total capital costs are approximately $42 million. Annual operation and maintenance costs include periodic catalyst bag replacement, additional electricity required, insurance, and labor, with costs estimated at approximately $3 million. Establishing a 35 ppmv NOx emissions limit was not recommended due to the high capital cost and high cost per ton of NOx reduced.

Table C-9: Costs and Cost Effectiveness for Alternative Technology – Combined SCR and Covanta LN for Units fired on MSW

Combined Selective Catalytic Reduction and Covanta LN for Units Fired on MSW					
Total Capital Cost	Annualized Capital Cost	Annualized O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
$42,368,248	$6,893,314	$2,904,021	$9,797,335	179.2	$67,268

Combined Gore De-NOx and Covanta LN for Units Fired on MSW to Reduce NOx Emissions

Combining Gore De-NOx and Covanta LN combustion technology is capable of achieving 45 ppm NOx. District staff evaluated the feasibility of installation of a Gore De-NOx and Covanta LN technologies at the MSW fired facility in the District to meet a potential 45 ppm limit, and found that this control option would involve high capital and annual costs. Capital costs include the purchase of the initial Gore filter bags, purchase of the Covanta LN combustion modification equipment, freight, installation, and three weeks of retrofit downtime. Total capital cost are approximately $5.5 million. Annual O&M costs include sorting of material, periodic catalyst bag replacement, insurance, and labor, with costs estimated at approximately $6.6 million. The major O&M cost is the cost to hand sort the municipal solid waste to remove high SOx materials like drywall. This is because Gore-DeNOx filter bags are susceptible to fouling by high levels of SOx. Another factor that led to the District not establishing a 45 ppm NOx limit is that Gore De-NOx technology has never been installed at a MSW facility in the United States.

Table C-10: Costs and Cost Effectiveness for Alternative Technology – Combine Gore De-NOx and Covanta LN for Units fired on MSW

Combined Gore Den-NOx and Covanta LN for Units Fired on MSW					
Total Capital Cost	Annualized Capital Cost	Annualized O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
$13,140,611	$2,137,977	$6,938,133	$9,076,110	170.2	$67,905

Selective Catalytic Reduction for Units Fired on Biomass to Reduce NOx Emissions

SCR is a post-combustion control for NOx that involves the injection of anhydrous ammonia, aqueous ammonia, or urea solution into the exhaust gas to reduce NOx emissions. SCR systems are capable of achieving emissions as low 50 ppm NOx. One recently installed biomass fired unit installed SCR and is meeting a 50 ppm NOx emissions limit. This new unit was subject to New Source Review (NSR), District Rule 2201 and therefore was required to install best available control technology (BACT). The other nine facilities with active permits would need to retrofit in order to meet a 50 ppm NOx limit. District staff evaluated the feasibility of installation of a SCR system at the biomass fired facilities in the District to meet a potential 50 ppm limit, and found that this control option would involve very high capital and annual costs. Direct capital costs include the purchase of the SCR, retrofit of the existing structure to accommodate the system, additional ductwork, and installation of a natural gas pipeline for the duct burner. Indirect capital costs include engineering and retrofit downtime resulting in the loss of 90 days of electricity sales minus the savings from not purchasing biomass during the retrofit. Total capital cost are approximately $72 million. Annual operation and maintenance costs include periodic catalyst replacement, additional electricity required, insurance, and labor. Annual O&M cost are approximately $13 million. Establishing a 50 ppmv NOx emissions limit was not recommended due to the high capital cost and high cost per ton of NOx reduced.

Table C-11: Costs and Cost Effectiveness for Alternative Technology – SCR for Units fired on Biomass

Selective Catalytic Reduction for Units Fired on Biomass					
Total Capital Cost	Annualized Capital Cost	Annualized O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
$72,001,257	$11,714,605	$13,027,490	$24,742,095	329.5	$75,090

Gore De-NOx for Units Fired on Biomass to Reduce NOx Emissions

Combining Gore De-NOx with a new, state of the art boiler is capable of achieving emissions as low as 50 ppm NOx. District staff evaluated the feasibility of installation of a Gore De-NOx system with a new boiler at the biomass fired facilities in the District to meet a potential 50 ppm limit, and found that this control option would involve very high capital and annual costs. Capital costs include the purchase of the initial Gore filter bags, purchase of the new boiler, freight, installation, and three weeks of retrofit downtime. Total capital cost are approximately $66 million. Annual O&M costs include periodic catalyst bag replacement, insurance, and labor. Annual O&M cost are approximately $8 million. Another factor that led to the District not establishing a 50 ppmv NOx emissions limit is that Gore De-NOx technology has never been installed at biomass facilities and never been installed in the United States, and therefore has not been demonstrated in practice for this type of unit.

Table C-12: Costs and Cost Effectiveness for Alternative Technology – Gore De-NOx for Units fired on Biomass

Gore De-NOx for Units Fired on Biomass					
Total Capital Cost	Annualized Capital Cost	Annualized O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
$65,614,626	$10,675,500	$7,998,587	$18,674,087	329.5	$56,674

Combined Selective Catalytic Reduction with a New Boiler for Units Fired on Biomass to Reduce NOx Emissions

Combining SCR with a new, state of the art boiler is capable of achieving 40 ppm NOx. District staff evaluated the feasibility of installation of a SCR system at the biomass fired facilities in the District to meet a potential 40 ppm limit, and found that this control option would involve very high capital and annual costs. Direct capital costs include the purchase of the SCR, retrofit of the existing structure to accommodate the system, additional ductwork, and installation of a natural gas pipeline for the duct burner. Indirect capital costs include engineering and retrofit downtime resulting in the loss of 90 days of electricity sales minus the savings from not purchasing biomass during the retrofit. Total capital cost are approximately $600 million. Annual O&M costs include periodic catalyst replacement, additional electricity required, insurance, and labor.

Annual O&M cost are approximately $17 million. Establishing a 40 ppmv NOx emissions limit was not recommended due to the high capital cost and high cost per ton of NOx reduced.

Table C-13: Costs and Cost Effectiveness for Alternative Technology – Combined SCR with a New Boiler for Units fired on Biomass

Combined Selective Catalytic Reduction with a New Boiler for Units Fired on Biomass					
Total Capital Cost	Annualized Capital Cost	Annualized O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
$600,951,595	$97,774,824	$16,585,626	$114,360,450	510.3	$224,104

Combined Gore De-NOx with a New Boiler for Units Fired on Biomass to Reduce NOx Emissions

Gore De-NOx catalytic filter bags is a retrofit control technology that effectually converts an existing pulse-jet baghouse into a selective catalytic reduction control system is capable of achieving 40 ppm NOx. District staff evaluated the feasibility of installation of a Gore De-NOx system at the biomass fired facilities in the District to meet a potential 40 ppm limit, and found that this control option would involve high capital and annual costs. Capital costs include the purchase of the initial Gore filter bags, purchase of the new boiler freight, installation, and three weeks of retrofit downtime. Total capital cost are approximately $575 million. O&M costs include periodic catalyst bag replacement, insurance, and labor, estimated to total approximately $8 million annually. Another factor that led to the District not establishing a 40 ppmv NOx emissions limit is that Gore De-NOx technology has never been installed at a MSW facility in the United States.

Table C-14: Costs and Cost Effectiveness for Alternative Technology – Combined Gore De-NOx with a New Boiler for Units fired on Biomass

Combined Gore De-NOx with a New Boiler for Units Fired on Biomass					
Total Capital Cost	Annualized Capital Cost	Annualized O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
$574,974,827	$93,548,404	$8,196,006	$101,744,410	510.3	$199,382

Ceramic Filters to Reduce PM10 Emissions

Ceramic filters can generally achieve lower particulate matter emission rates than fabric filters or electrostatic precipitators, as low as 0.02 lbs/MMBtu. Ceramic filters have the potential to be installed at facilities that are fired on municipal solid waste or biomass. However, these types of filters have not been installed or demonstrated at these types of facilities. With traditional fabric baghouse filters particulate matter is captured on the surface of the filter; however, some particulate matter penetrates deeply into the filter walls and the body of the fabric filter and may be emitted during the baghouse's internal filter cleaning process. Ceramic filters, such as Tri-Mer ceramic filters, have special qualities on the filter surface that result in all of the particulate matter being captured on the face of the filter tubes. However, ceramic filters are much more expensive than fabric filters. Additionally, ceramic filter systems like the Tri-Mer system would require the existing baghouse/ESP to be removed and new ceramic filter modules to be installed. District staff evaluated the feasibility of installation of ceramic filters at facilities in the District to meet a potential 0.02 lbs/MMBtu limit, and found that this control option would involve high capital and annual costs. Total capital costs are estimated to be approximately $63 million. Annual O&M costs include periodic catalyst bag replacement, insurance, and labor. Annual O&M costs are approximately $4 million. Establishing a 0.02 lbs/MMBtu PM10 emissions limit was not recommended due to the high capital cost and high cost per ton of PM10 reduced.

Table C-15: Costs and Cost Effectiveness for Alternative Technology – Ceramic Filters

Ceramic Filters						
Fuel Type	Total Capital Cost	Annualized Capital Cost	Annualized O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
MSW	$11,834,942	$1,925,545	$426,319	$2,351,864	43.6	$53,961
Biomass	$51,499,850	$8,379,028	$3,326,467	$11,705,495	187.6	$62,396

Semi-Dry Absorbers to Reduce SOx Emissions

Semi-dry absorbers (SDA) operate by mixing a small amount of water with the sorbent. These are considered dry scrubber units, since the sorbent is dry when the reaction takes place. Lime is usually the sorbent, but hydrated lime may be used and can provide greater SO_2 removal. SDAs can be installed at facilities that are fired on municipal solid waste or biomass and are capable of SOx emissions as low as 0.003 lbs/MMBtu. District staff evaluated the feasibility of installation of SDAs at facilities in the District to meet a potential 0.003 lbs/MMBtu limit, and found that this control option would involve high capital and annual costs. Total capital costs are approximately $310 million. Annual O&M cost are approximately $62 million. Establishing a 0.003 lbs/MMBtu SOx emissions limit was not recommended due to the high capital cost and high cost per ton of SOx reduced.

Table C-16: Costs and Cost Effectiveness for Alternative Technology – Semi-Dry Absorbers

Semi-Dry Absorbers						
Fuel Type	Total Capital Cost	Annualized Capital Cost	Annualized O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
MSW	$21,500,000	$3,498,050	$4,370,485	$7,868,535	118.0	$66,683
Biomass	$288,750,000	$46,979,625	$57,189,367	$104,168,992	402.3	$258,934

Wet Fluid Gas Desulfurization to Reduce SOx Emissions

Wet Fluid Gas Desulfurization (FGD) controls SO_2 emissions unit using wet solutions containing alkali reagents such as limestone, lime, sodium-based alkaline, or dual alkali-based sorbents. FGDs can be installed at facilities that are fired on municipal solid waste or biomass and are capable of SOx emissions as low as 0.001 lbs/MMBtu. District staff evaluated the feasibility of installation of FGDs at facilities in the District to meet a potential 0.001 lbs/MMBtu limit, and found that this control option would involve high capital and annual costs. Total capital costs are approximately $310 million. Annual O&M cost are approximately $62 million. Establishing a 0.001 lbs/MMBtu SOx emissions limit was not recommended due to the high capital cost and high cost per ton of SOx reduced.

Table C-17: Costs and Cost Effectiveness for Alternative Technology – Wet Fluid Gas Desulfurization

Wet Fluid Gas Desulfurization						
Fuel Type	Total Capital Cost	Annualized Capital Cost	Annualized O&M $/yr	Annualized Cost $/yr	NOx reduced tons/yr	CE $/ton NOx
MSW	$19,350,000	$3,148,245	$3,969,877	$7,118,122	120.6	$59,023
Biomass	$259,875,000	$42,281,663	$51,753,437	$94,035,100	433.5	$216,921

VI. INCREMENTAL COST EFFECTIVENESS ANALYSIS

Health and Safety Code section 40920.6 requires an incremental cost-effectiveness analysis for Best Available Retrofit Control Technology (BARCT) rules or emission reduction strategies when there is more than one control option that would achieve the emission reduction objective of the proposed amendments. The incremental cost effectiveness is the difference in cost between successively more effective controls divided by the additional emission reductions achieved. Incremental cost-effectiveness is calculated as follows:

$$\textit{Incremental cost-effectiveness} = (C_{alt}–C_{proposed}) / (E_{alt}–E_{proposed})$$

Where:
$C_{proposed}$ is the present worth value of the proposed control option;
$E_{proposed}$ are the emission reductions of the proposed control option;
C_{alt} is the present worth value of the alternative control option; and
E_{alt} are the emission reductions of the alternative control option

1. NOx Incremental Cost Effectiveness Analysis

The District evaluated several technology options to lower the NOx emissions at the municipal solid waste facility in the District. The proposed NOx limit of 90 ppm would require the installation of Covanta LN technology. Other more stringent control options included SCR, Gore De-NOx, Covanta LN with SCR, and Covanta LN with Gore De-NOx.

Table C-18: NOx Incremental Cost Effectiveness Analysis for Units fired on MSW

Evaluated Alternative Emissions Limit (ppm)	Potential Control Technology	Annualized Cost ($/year)	Annual Emission Reductions (tons/year)	Incremental Cost Effectiveness ($/ton)
60	Gore De-NOx	$7,533,966	130.5	$78,508
50	SCR	$7,673,984	156.9	$124,965
45	Covanta LN + SCR	$9,797,335	179.2	$82,634
35	Covanta LN + Gore De-NOx	$9,076,110	170.2	$82,911

The District evaluated several technology options to lower the NOx emissions for biomass fueled units. The proposed limit would require the establishment of a 65 ppm NOx limit. Other more stringent control options included SCR, Gore De-NOx, new boilers with SCR, and new boilers with Gore De-NOx.

Table C-19: NOx Incremental Cost Effectiveness Analysis for Units fired on Biomass

Evaluated Alternative Emissions Limit (ppm)	Technology	Annualized Cost ($/year)	Annual Emission Reductions (tons/year)	Incremental Cost Effectiveness ($/ton)
50	SCR	$24,742,095	329.5	$115,517
50	Gore De-Nox	$18,674,087	329.5	$86,972
40	New Boiler with SCR	$114,360,450	510.3	$289,568
40	New Boiler with Gore De-NOx	$101,744,410	510.3	$257,620

The incremental cost effectiveness analysis did not demonstrate that any of the alternative control technologies were more cost effective, therefore these control options were not chosen.

2. PM10 Incremental Cost Effectiveness Analysis

The District evaluated a technology option to lower the PM10 emissions for units fired on municipal solid waste. The proposed limit would require the establishment of a 0.04 lbs/MMBtu or 0.02 gr/dscf at 12% CO_2 PM10 limit. The other control option is the use of ceramic filters.

Table C-20: PM10 Incremental Cost Effectiveness Analysis for Units fired on MSW

Evaluated Alternative Emissions Limit (lbs/MMBtu)	Technology	Annualized Cost ($/year)	Annual Emission Reductions (tons/year)	Incremental Cost Effectiveness ($/ton)
0.02	Ceramic Filters	$2,351,864	43.6	$63,709

The District evaluated a technology option to lower the PM10 emissions for units fired on biomass. The proposed limit would require the establishment of a 0.04 lbs/MMBtu or 0.02 gr/dscf at 12% CO_2 PM10 limit. The other control option is the use of ceramic filters.

Table C-21: PM10 Incremental Cost Effectiveness Analysis for Units fired on Biomass

Evaluated Alternative Emissions Limit (lbs/MMBtu)	Technology	Annualized Cost ($/year)	Annual Emission Reductions (tons/year)	Incremental Cost Effectiveness ($/ton)
0.02	Ceramic Filters	$11,705,495	187.6	$127,263

The incremental cost effectiveness analysis did not demonstrate that the alternative control technology was more cost effective, therefore this control option was not chosen.

3. SOx Incremental Cost Effectiveness Analysis

The District evaluated several technology options to lower the SOx emissions for units fired on municipal solid waste. The proposed limit would require the establishment of a 0.03 lbs/MMBtu or 12 ppm at 12% CO_2 SOx limit. Other more stringent control options evaluated included semi-dry absorbers and wet fluidized gas desulfurization.

Table C-22: SOx Incremental Cost Effectiveness Analysis for Units fired on MSW

Evaluated Alternative Emissions Limit (lbs/MMBtu)	Technology	Annualized Cost ($/year)	Annual Emission Reductions (tons/year)	Incremental Cost Effectiveness ($/ton)
0.003	Semi-Dry Absorbers	$7,868,535	118.0	$201,732
0.001	Wet Fluid Gas Desulfurization	$7,118,122	120.6	$171,085

The District also evaluated technology options to lower the SOx emissions for units fired on biomass. The proposed limit would require the establishment of a 0.02 lbs/MMBtu or 12 ppm at 12% CO_2 SOx limit. Other more stringent control options evaluated included semi-dry absorbers and wet fluidized gas desulfurization.

Table C-23: SOx Incremental Cost Effectiveness Analysis for Units fired on Biomass

Evaluated Alternative Emissions Limit (lbs/MMBtu)	Technology	Annualized Cost ($/year)	Annual Emission Reductions (tons/year)	Incremental Cost Effectiveness ($/ton)
0.003	Semi-Dry Absorbers	$104,168,992	402.5	$357,287
0.001	Wet Fluid Gas Desulfurization	$94,035,100	433.5	$291,520

The incremental cost effectiveness analysis did not demonstrate that any of the alternative control technologies were more cost effective, therefore these control options were not chosen.

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APPENDIX D

Socioeconomic Impact Analysis
For Proposed Amendments to Rules 4352
(Solid Fuel Fired Boilers, Steam Generators, and Process Heaters)

December 16, 2021

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POTENTIAL AMENDMENTS TO RULE 4352—SOLID FUEL-FIRED BOILERS, STEAM GENERATORS AND PROCESS HEATERS

SOCIOECONOMIC IMPACT ANALYSIS

Final

December 9, 2021

Submitted to:

San Joaquin Valley Air Pollution Control District
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District Agreement No. 21-4-22

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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) Rule 4352—Solid Fuel-Fired Boilers, Steam Generators, and Process Heaters. Potential amendments to Rules 4352 would decrease nitrogen oxide (NOx), particulate matter (PM), and sulfur oxide (SOx) emissions for boilers fired on solid fuel.

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, the one facility in the Municipal Solid Waste sector may experience a significant adverse socioeconomic impact, defined as costs that amount to 10 percent or more of profits (Berck, 1995). Conversely, the Biomass sector is expected to experience very little impact as a result of Rule 4352.

Table 1. Summary of Socioeconomic Impacts due to Potential Amendments to Rule 4352—Solid Fuel-Fired Boilers, Steam Generators and Process Heaters

Sector	Total Facilities	Facilities w/ Costs	Total Annualized Cost [a]	Average Annualized Cost per Facility	Average Profits per Facility	Cost as % Profits
Municipal Solid Waste	1	1	$390,267	$390,267	$1,078,583	36.18%
Biomass	5	5	$14,664	$2,933	$518,638	0.57%
Total/Average	**6**	**6**	**$404,931**	**$67,489**	**$611,962**	**11.03%**

Sources: ERG estimates based on SJVAPCD, 2021; NAICS.com, 2021; PG&E, 2011; Ampersand Chowchilla Biomass, LLC and Merced Power, LLC v. The United States; U.S. Census Bureau, 2020d; RMA, 2021; IMPLAN, 2021; U.S. Census Bureau, 2020f.
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.

As a secondary measure of impacts, ERG also used the IMPLAN (2021) 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 a sensitivity analysis 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 less than 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 existing Rule 4352 for solid fuel-fired boilers, steam generators, and process heaters. This work was performed by ERG under District Agreement No. 21-4-22.

Facilities with solid fuel-fired boilers, steam generators, and process heaters in the District are fired on municipal solid waste or biomass (SJVAPCD, 2020). The potential amendments would revise existing District Rule 4352 (last revised in 2011), which limited oxides of nitrogen and carbon monoxide (CO) emissions from solid fuel-fired boilers, steam generators, and process heaters. (SJVAPCD, 2011). The potential amendment to Rule 4352 would satisfy the commitments included in the *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards* to reduce NOx emissions for municipal waste-fired units by further reducing the current NOx limits (SJVAPCD, 2020).

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 a 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 at which the population would have changed annually to increase from the 2010 level to the 2019 level.

Overall, the region has seen annual average population growth 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, 2020a.

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 2019 (U.S. Census Bureau, 2020b). Median income growth rates varied across counties from 2010 to 2019, though the counties in the District as a whole had a CAGR of 1.32 percent overall; this is lower than the growth rate of median income for the state of California (2.23 percent). Kern County is the only county that experienced a decline in median income (-0.03 percent) while all other counties experienced some level of growth. Merced County has a notably higher growth rate of 2.66 percent. It is the only county in the District where median income increased at a rate faster than the state.

Table 3. Median Income by County

County	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR 2010-2019
Fresno	$53,461	$49,572	$47,299	$49,049	$47,607	$50,988	$52,357	$54,645	$54,217	$58,215	1.07%
Kern [a]	$53,820	$52,371	$52,165	$52,348	$52,235	$55,759	$53,633	$52,592	$53,136	$53,710	-0.03%
Kings	$52,738	$58,302	$52,194	$51,114	$46,907	$49,682	$57,213	$60,716	$63,524	$59,161	1.45%
Madera	$57,064	$53,930	$47,767	$44,396	$46,522	$51,206	$55,518	$54,099	$58,004	$65,612	1.76%
Merced	$50,184	$46,385	$49,537	$45,433	$48,332	$45,610	$51,308	$50,356	$59,488	$61,908	2.66%
San Joaquin	$59,124	$58,890	$57,633	$57,432	$56,637	$58,325	$63,967	$64,523	$66,054	$69,833	2.10%
Stanislaus	$56,799	$51,042	$52,728	$53,557	$56,007	$56,868	$58,364	$62,782	$62,142	$63,801	1.46%
Tulare	$51,305	$47,673	$45,793	$44,021	$46,717	$46,062	$49,311	$48,807	$50,290	$58,391	1.63%
SJVAPCD [a]	**$54,605**	**$52,046**	**$51,001**	**$50,891**	**$51,126**	**$53,112**	**$55,339**	**$56,292**	**$57,503**	**$60,627**	**1.32%**
California	**$68,224**	**$66,341**	**$66,275**	**$67,211**	**$67,136**	**$70,049**	**$72,803**	**$75,748**	**$77,549**	**$81,414**	**2.23%**

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

Notes:

[a] Inflated values to 2020$ 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 SJV is a weighted average by population

Poverty rates by county for the last decade are shown in Table 4. The poverty rate decreased in every county in the District in that time frame. The poverty rate within the District is higher than the state average and declining at a slower rate overall compared to the state of California's rate of -3.58 percent. Fresno and Tulare Counties have consistently had among the highest poverty rates in the District while Stanislaus and San Joaquin Counties have had the two lowest. These two counties, plus Kings and Merced Counties, have CAGRs lower than the state rate. Despite its notable CAGR of median household income, Merced County had high poverty rates for most of the past decade. That trend changed in 2019, with the county poverty rate dropping from 22.0 percent in 2018 to 16.8 percent in 2019.

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	2019	CAGR 2010-2019
Fresno	26.8%	25.8%	28.4%	28.8%	27.7%	25.3%	25.6%	21.1%	21.5%	20.6%	-3.24%
Kern [a]	21.2%	24.5%	23.8%	22.8%	24.8%	21.9%	22.7%	21.4%	20.6%	19.1%	-1.30%
Kings	22.2%	20.5%	21.2%	21.4%	26.6%	23.6%	16.0%	18.2%	19.2%	15.2%	-4.62%
Madera	21.0%	24.3%	23.6%	23.6%	22.2%	23.4%	20.3%	22.6%	20.9%	17.6%	-2.18%
Merced	23.0%	27.4%	24.3%	25.2%	25.2%	26.7%	20.3%	23.8%	22.0%	16.8%	-3.85%
San Joaquin	19.2%	18.1%	18.4%	19.9%	20.9%	17.4%	14.4%	15.5%	14.2%	13.7%	-4.13%
Stanislaus	19.9%	23.8%	20.3%	22.1%	18.0%	19.7%	14.2%	13.5%	15.6%	12.7%	-5.46%
Tulare	24.5%	25.7%	30.4%	30.1%	28.6%	27.6%	25.2%	24.6%	22.5%	18.8%	-3.26%
SJVAPCD [a]	**22.5%**	**23.8%**	**24.2%**	**24.6%**	**24.3%**	**22.7%**	**20.6%**	**19.7%**	**19.3%**	**17.3%**	**-3.25%**
California	**15.8%**	**16.6%**	**17.0%**	**16.8%**	**16.4%**	**15.3%**	**14.3%**	**13.3%**	**12.8%**	**11.8%**	**-3.58%**

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

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 2019. While there has been an overall decline in the number of people below the poverty line from 2010 to 2019, the number has fluctuated during this period. The number of people in poverty grew by over 100,000 between 2010 and 2014, but has declined by 256,000 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 2019, which coincides with its large population and relatively higher poverty rate. Conversely, the poverty rate in Stanislaus, Kings, and Merced Counties has declined at a faster rate than California as a whole.

Table 5. Population Below Poverty Line by County

County	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR 2010-2018
Fresno	246,196	238,706	264,738	270,072	263,220	242,083	247,507	205,291	209,799	202,698	-2.40%
Kern [a]	171,950	201,230	196,625	189,484	208,388	186,501	193,133	184,619	178,239	166,768	-0.38%
Kings	30,425	27,101	27,819	28,473	35,623	31,453	21,565	24,935	26,299	21,063	-4.49%
Madera	29,936	34,148	33,936	34,242	32,432	34,227	29,736	33,482	31,191	26,093	-1.70%
Merced	58,360	70,243	62,448	64,552	65,405	70,118	53,314	63,485	59,283	45,396	-3.09%
San Joaquin	128,748	123,258	126,610	137,663	146,601	123,817	103,399	113,136	104,622	101,591	-2.92%
Stanislaus	101,335	122,212	104,559	114,628	94,586	104,801	76,191	73,254	85,073	69,572	-4.59%
Tulare	107,660	113,515	135,194	135,066	129,485	125,728	114,290	112,524	103,711	86,315	-2.72%
SJVAPCD [a]	**874,610**	**930,413**	**951,929**	**974,180**	**975,740**	**918,728**	**839,135**	**810,726**	**798,217**	**719,496**	**-2.41%**
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**	**4,552,837**	**-2.95%**

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

Notes:

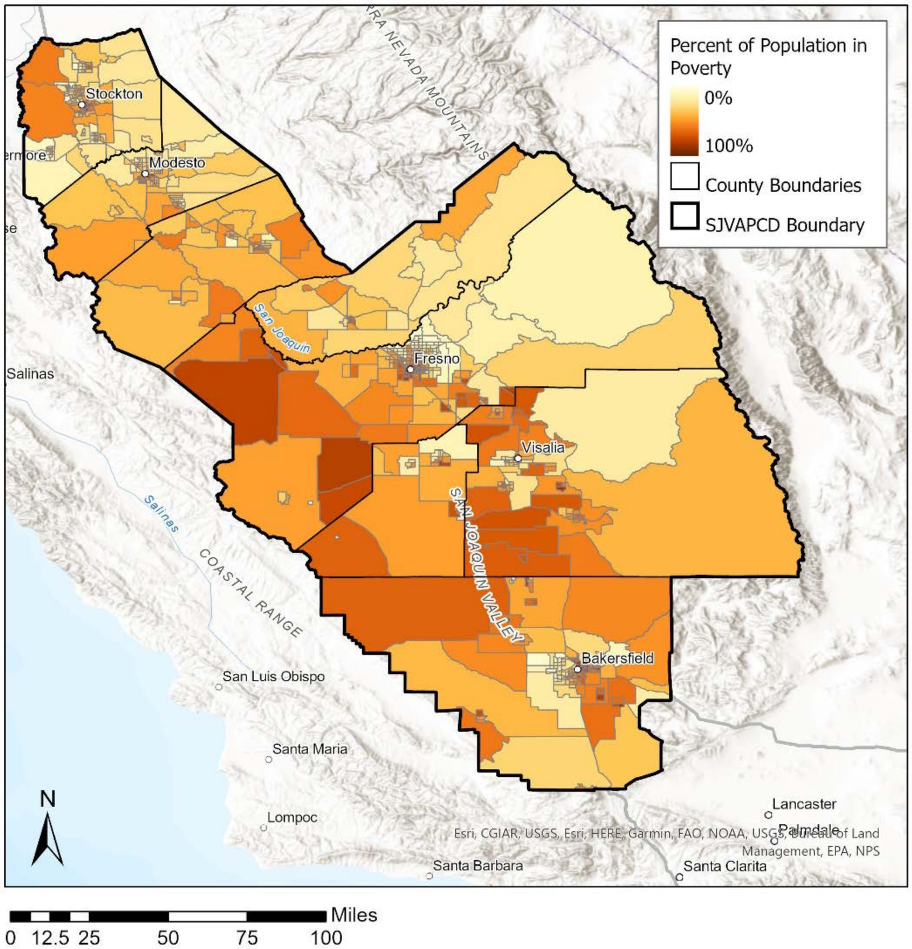
[a] While the SJVAPCD only includes a portion of Kern County, the data shown here are for the whole of the county.

Figure 1 shows where the population in poverty or at risk of poverty lives within the District[2] using CalEnviroScreen 4.0 (OEHHA, 2021a) 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 2015 to 2019. 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, 2021b).

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 4.0 threshold, nearly half (44.9 percent) of District residents are below twice the federal poverty limit (OEHHA, 2021a-b), reflected in the high poverty rates in the map in Figure 1 below.

[2] 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 (2015–2019)



Source: OEHHA, 2021a.
Map created by ERG using ArcGIS® software by Esri.

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 (0.71 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	379,900	387,500	395,300	402,400	406,900	412,800	418,100	1.48%
Kern [a]	313,400	325,700	340,400	347,200	351,700	350,100	347,700	349,100	354,900	360,800	1.58%
Kings	49,900	49,700	50,000	50,400	50,600	51,600	51,400	52,200	53,000	53,200	0.71%
Madera	51,400	52,000	53,500	54,400	54,900	53,500	55,400	56,000	57,000	57,700	1.29%
Merced	93,200	94,500	96,200	98,000	99,700	101,100	102,200	104,500	105,600	106,900	1.54%
San Joaquin	260,000	261,000	267,100	274,600	279,200	286,400	292,400	300,700	304,600	307,900	1.90%
Stanislaus	202,200	202,400	205,900	209,800	213,700	218,000	221,800	224,100	227,500	228,800	1.38%
Tulare	168,100	168,700	168,800	172,200	172,100	178,500	180,500	183,200	183,300	184,400	1.03%
SJVAPCD [a]	1,504,400	1,524,200	1,555,400	1,586,500	1,609,400	1,634,500	1,653,800	1,676,700	1,698,700	1,717,800	1.48%
California	16,091,900	16,258,100	16,602,700	16,958,400	17,310,900	17,660,700	17,980,100	18,257,100	18,460,700	18,627,400	1.64%

Source: CAEDD, 2021.

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.

3.3. REGIONAL TRENDS IN MUNICIPAL SOLID WASTE AND BIOMASS ENERGY

The number of municipal solid waste incinerators has decreased both nationally and regionally, declining from 200 in the early 1990s to 77 in 2016, with more than half of those in the northeast U.S. (DOE, 2019). California had three facilities until the closure of the Los Angeles-area Commerce Refuse-to-Energy Facility in 2018 (Rosengren, 2018, DOE, 2019), with one of the remaining two California facilities in the District. Reasons for the decline in municipal solid waste incinerators include (Rosengren, 2018, DOE, 2019):

- The expiration of long-term power purchase agreements with guaranteed rates higher than current market rates.
- Higher costs to generate power from municipal solid waste than other sources.

The number of biomass power plants has also decreased, from a high of 66 facilities with a combined capacity of 800 megawatts in California in the early 1990s to around 30 direct-combustion biomass facilities with a combined capacity of 640 megawatts now (CEC, 2021). Six of the biomass facilities in the District have closed since 2012, with five currently operating (SJVAPCD, 2020).

Reasons for the closure of biomass facilities include (CEC, 2021; Souza, 2015; SJVAPCD, 2020):

- The expiration of government price support.
- Several 25- and 30-year contracts entered into in the 1980s between biomass plants and utility companies not being renewed because electricity produced from biomass costs more per kilowatt than electricity produced from natural gas or renewable sources.
- A preference on the part of investor-owned utilities for solar and wind power to meet the renewable energy purchase requirements under California's Renewable Portfolio Standard.

3.4. IMPACTS OF THE COVID-19 PANDEMIC

The COVID-19 pandemic has affected virtually every industry to some degree, including the municipal solid waste and biomass energy producers that would have costs under the potential amendments to Rule 4352.

One of the facilities subject to Rule 4352 operates a power plant fueled on municipal solid waste from the adjacent landfill, and also recovers metal from the waste stream for recycling (Board of Supervisors of the County of Stanislaus, 2012). In the waste management industry, the overall volume of refuse did not appear to change during the pandemic, but the balance shifted away from commercial waste and toward residential waste because of the shift to remote working (Toto, 2020).

The company that operates the municipal solid waste energy facility subject to Rule 4352 reported experiencing relatively moderate direct impacts from the COVID-19 pandemic, such as a delay in scheduled maintenance activities from the first to the second half of 2020 and reduced volume in the waste market that rebounded after the second quarter of 2020. Overall, as of the end of 2020, "cash receipts to date remain[ed] generally consistent with pre-pandemic levels." However, the pandemic resulted in volatility in the energy and recycled metal markets and a general sense of uncertainty about future economic conditions (Covanta Holding Corporation, 2021).

Like many industries, the electric power sector faced a high degree of uncertainty early in the pandemic. Some facilities temporarily paused non-critical activities and kept critical employees sequestered at the facility to protect their health (Annand, 2020; DTE Energy, 2021). Employees able to do so transitioned to working remotely, and companies saw higher operation and maintenance costs for the additional personal protective equipment and other safety measures needed for those staying on site (DTE Energy, 2021).

The electric power sector also saw shifts in power consumption early in the pandemic due to shelter in place orders and the transition to remote working (Annand, 2020). In California, the electricity sector experienced a greater than 4 percent drop in average weekday demand in March 2020 compared to March 2019. Demand decreased 9 percent from April 2019 to April 2020 (CEC, 2020a). In the first week of April in 2020, residential energy use increased by 9 to 12 percent as compared to the same week in 2019. At the same time, there were substantial decreases in commercial and industrial demand (CEC, 2020a). During the summer of 2020, cooling demand increased by 9 percent in California, while non-cooling demand was down 5 percent, again representing the significant shift to at-home work and slowed industrial output (CEC, 2020b).

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 (2021) 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 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 (2021) 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 converted the SIC codes to the North American Industry Classification System (NAICS) codes that are used with other sources of economic data used in the analysis using U.S. Census Bureau (2020d) concordances.[3] (See Table A-2 for a list of the NAICS codes that mapped to each SIC code.)

ERG estimated facility revenues and profits using the same method the District has used for prior analyses. Dividing industry "sales, value of shipments, or revenues" by "number of employees taken from the 2017 Economic Census for the relevant NAICS codes results in estimated output per employee. This was inflated to represent 2020 dollars using the U.S. Bureau of Economic Analysis (BEA) gross domestic product implicit price deflator (BEA, 2021). The data used for these calculations are presented in Appendix B. Multiplying output per employee by the number of employees in each facility results in estimated facility revenues.

ERG estimated profits for private industries by multiplying revenue figures by the average profit rate for each NAICS for 2015 through 2020 (see Appendix B). The profit rate was calculated using 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.

[3] SIC codes were last updated in 1987, and NAICS codes were first issued in 1997. The U.S. Census Bureau's (2020d) 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 6-digit NAICS codes.

4.1.2. COVID-19-Adjusted Baseline Industry Profile Estimates

To reflect the impact of the COVID-19 pandemic, ERG considered using a **"COVID-adjusted" baseline**, which alters employment, revenue, and payroll figures for each facility using IMPLAN (2021) data. IMPLAN's "Evolving Economy" data use economic data points from the third quarter of 2020 to reflect the impacts on the pandemic, taking into account industry losses, shifts in household spending and behavior, stimulus checks and unemployment benefits, and Paycheck Protection Program (PPP) loans (Demski, 2021). IMPLAN uses only the third quarter 2020 data, adjusts it for seasonality, and annualizes the single quarter of data to an entire year.

Using outputs of the IMPLAN model, ERG estimates the percentage change in employment, revenue, and payroll by NAICS between 2019 (the most recent full year for which data are available) and 2020 Q3 (the "Evolving Economy" dataset, the most recent estimate). District-wide, this approach suggests that revenue contracted by 4.5 percent, and employment contracted by 8.9 percent (see Table 9).

Table 9. District-Wide COVID-19 Impacts

	2019	2020 Q3 [a]	% Change
Revenue	$345.0 billion	$329.5 billion	-4.5%
Employment	2.0 million	1.8 million	-8.9%

Source: IMPLAN, 2021

Note:

[a] Data are modeled for an entire year as if it were like the third quarter of 2020.

To estimate the impacts of the COVID-19 pandemic on individual industries, ERG multiplied the percentage change from 2019 to the third 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 (2021)).

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 2019 and the third quarter of 2020 include restaurants (a 30.6 percent decrease in revenue and 33.6 percent decrease in employment) and dry cleaning and laundry services (a 44.6 percent decrease in revenue and a 77.1 percent decrease in employment).

Notably, some sectors saw revenue and employment *growth* when comparing 2019 and the third quarter of 2020. These sectors include oil and gas extraction (a 74.5 percent increase in revenue and 69.5 percent increase in employment), dog and cat food manufacturing (an 84.9 percent increase in revenue and 22.5 percent increase in employment), and tree nuts (an 11.1 percent increase in revenue and 71.6 percent increase in employment).

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, using third quarter of 2020 data and applying it to the entire year does not capture any lagging impacts of the COVID-19 pandemic that may take time to be seen in the data (for example, companies that were able to stay open for much of the pandemic but ultimately closed). Given the shortcomings of the dataset, IMPLAN suggests using both the pre-pandemic (2019) and 2020 data to compare the results (Clouse, 2020). ERG has done this in the sensitivity analysis in Section 4.4.3 below.

However, while the pattern recovery from the COVID-19 pandemic will take is unknown, many sectors will have recovered significantly by the time this analysis is performed and even more so by the time compliance is required with the potential rule amendments. Therefore, ERG started with a baseline assuming 100 percent recovery from COVID-19 (i.e., return to the 2019 baseline), but also performed a sensitivity analysis assuming 70 percent recovery (with the results presented in Section 4.4.3).

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 (2021). Total costs were calculated by summing the one-time capital costs and one-time permit costs (annualized over a 10-year period using a 4 percent discount rate) with ongoing annual costs. 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.

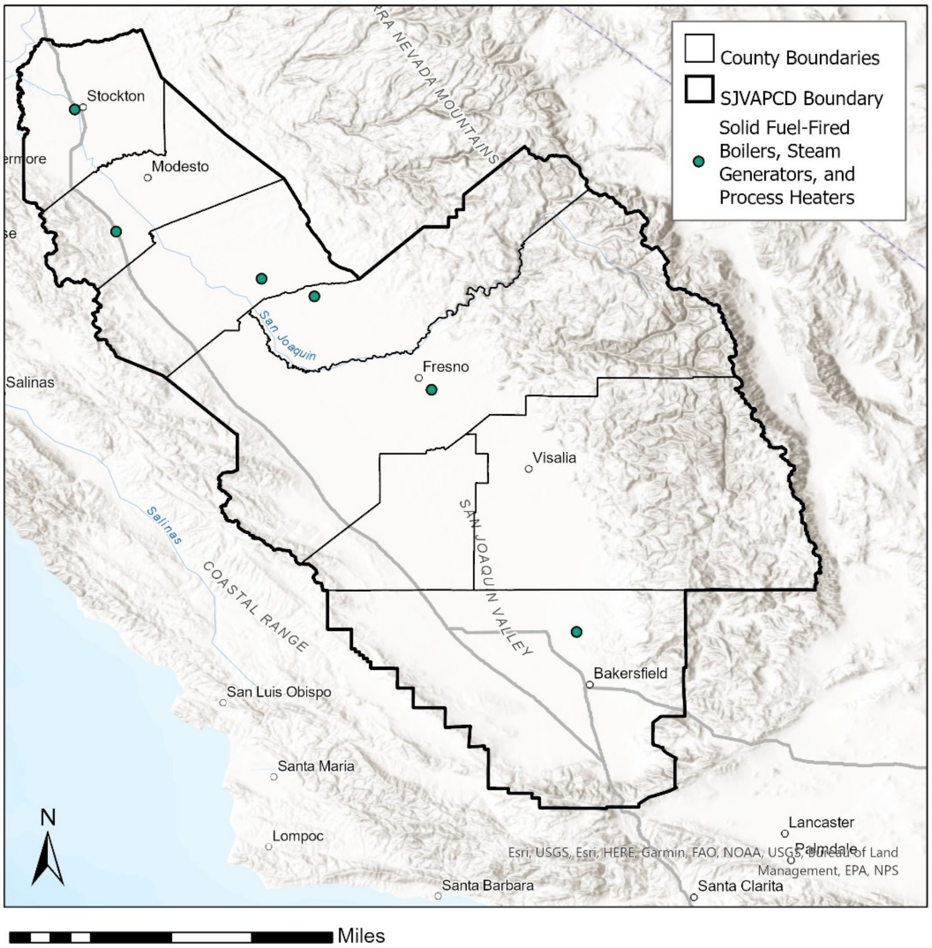
To estimate both direct employment impacts of the potential rule amendments and indirect and induced effects, ERG used IMPLAN's (2021) input-output model. IMPLAN "is a regional economic analysis software application that is designed to estimate the impact or ripple effect (specifically backward linkages) of a given economic activity within a specific geographic area through the implementation of its Input-Output model" (IMPLAN, 2020).

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).

4.2. PROFILE OF AFFECTED ENTITIES

Figure 2 presents the facilities operating solid fuel-fired 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. The majority of facilities are located outside of major metropolitan areas. No county has more than one facility. There are no affected facilities in Kings and Tulare Counties.

Figure 2. Map of Facilities Operating Solid Fuel-Fired Boilers, Steam Generators, and Process Heaters



Source data: SJVAPCD, 2021.
Map created by ERG using ArcGIS® software by Esri.

Table 10 includes a profile of facilities affected by the potential amendments to Rule 4352 (i.e., those that will incur compliance costs). A total of 6 facilities will incur retrofit and permit fee costs.

Table 10. Profile of Facilities Affected by Potential Amendments to Rule 4352—Solid Fuel-Fired Boilers, Steam Generators and Process Heaters

Sector	Total Facilities	Facilities w/ Costs	% w/ Costs	Total, All Facilities		
				Employees	Revenue [a]	Profits [b]
Municipal Solid Waste	1	1	100%	47	$22,812,672	$1,078,583
Biomass	5	5	100%	113	$54,847,488	$2,593,189
Total	**6**	**6**	**100%**	**160**	**$77,660,160**	**$3,671,772**

Sources: ERG estimates based on SJVAPCD, 2021; NAICS.com, 2021; U.S. Census Bureau, 2020f; U.S. Census Bureau, 2020d; U.S. Census Bureau, 2020e; RMA, 2021.
[a] Calculated from the 2017 Economic Census as estimated revenues per employee for NAICS 221117 (U.S. Census Bureau, 2020e), inflated to 2020 dollars (BEA 2021); see Appendix B for details. Revenue per employee multiplied by the number of facility employees (NAICS.com, 2021).
[b] Calculated as facility revenue multiplied by average profit rates from 2015 to 2020 (RMA, 2021); see Appendix B for details.

Table 11 shows the characteristics of the average facility affected by the potential amendments to Rule 4352. (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 Rule 4352—Solid Fuel-Fired Boilers, Steam Generators and Process Heaters

Sector	Average per Facility			Average Annual Pay per Employee
	Employees	Revenue [a]	Profits [b]	
Municipal Solid Waste	47	$22,812,672	$1,078,583	$43,587
Biomass	23	$10,969,498	$518,638	$43,587
Average	**27**	**$12,943,360**	**$611,962**	**$43,587**

Sources: ERG estimates based on SJVAPCD, 2021; NAICS.com, 2021; U.S. Census Bureau, 2020f; U.S. Census Bureau, 2020d; U.S. Census Bureau, 2020e; RMA, 2021.

4.3. COMPLIANCE COST ESTIMATES

Compliance costs were estimated by SJVAPCD (2021), and include:

- One-time costs for units retrofit by December 31, 2023.
- One-time permit costs.
- Annual operating and maintenance (O&M) costs for the units retrofit in 2023, beginning in 2023 and continuing indefinitely.

Total costs are calculated by annualizing the one-time retrofit costs and permit that will be incurred in 2023 over a 10-year period using a 4 percent interest rate, and then summing annualized one-time costs and annualized costs to yield the total.

Table 12 shows the one-time, annual, and total annualized costs incurred by sector. Annualized costs would total **$404,931** per year over 10 years, with the majority of costs incurred by the "Municipal Solid Waste" sector.

Table 12. Costs of Compliance with Potential Amendments to Rule 4352—Solid Fuel-Fired Boilers, Steam Generators and Process Heaters

Sector	Capital Costs [a]	O&M Costs [b]	Permit Modification [c]	Total Annualized Costs [d]
	One-Time	Annual	One-Time	Annualized One-Time + Annual
	2023	2023	2023	2023
Municipal Solid Waste	$2,598,082	$68,987	$8,100	$390,267
Biomass	$49,996	$3,700	$40,500	$14,664
Total	**$2,648,078**	**$72,687**	**$48,600**	**$404,931**

Source: SJVAPCD, 2021.

Notes:

[a] Includes one-time capital costs in 2023.

[b] Includes the costs to operate and maintain the new equipment.

[c] Includes costs to modify the permit to reflect actual 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.

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 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 11 **percent of profits.** The "Municipal Solid Waste" sector may face significant impacts, with costs representing **36.18 percent of profits**. The biomass sector would incur impacts of only **0.6 percent of profits**.

Table 13. Economic Impacts for Entities Affected by Potential Amendments to Rule 4352—Solid Fuel-Fired Boilers, Steam Generators and Process Heaters

Sector	Average Annualized Cost per Facility	Average Profits per Facility	Cost as % Profits
Municipal Solid Waste	$390,267	$1,078,583	36.18%
Biomass	$2,933	$518,638	0.57%
Average	**$67,489**	**$611,962**	**11.03%**

Sources: ERG estimates based on SJVAPCD, 2021; NAICS.com, 2021; U.S. Census Bureau, 2020f; U.S. Census Bureau, 2020d; U.S. Census Bureau, 2020e; RMA, 2021.

4.4.2. Employment, Indirect, and Induced Impacts

In addition to the primary test of direct impacts of costs on revenue, 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 **$405,108 in revenue, with no jobs lost.**

Table 14. Direct, Indirect, and Induced Impacts of Potential Amendments to Rule 4352—Solid Fuel-Fired Boilers, Steam Generators and Process Heaters

Sector	Direct		Indirect		Induced		Total	
	Revenue	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment
Municipal Solid Waste	$390,267	0	$87	0	$1	0	$390,356	0
Biomass	$14,664	0	$87	0	$1	0	$14,752	0
Total	**$404,931**	**0**	**$174**	**0**	**$2**	**0**	**$405,108**	**0**

Sources: ERG estimates based on SJVAPCD, 2021; NAICS.com, 2021; U.S. Census Bureau, 2020f; U.S. Census Bureau, 2020d; U.S. Census Bureau, 2020e; RMA, 2021.

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 Rule 4352—Solid Fuel-Fired Boilers, Steam Generators and Process Heaters

	Total Rule Impacts	Size of District Economy [a]	% of District Economy
Revenue	$405,108	$329,543,696,694	0.000%
Employment	0	1,844,909	0.000%

Source: ERG estimates based on IMPLAN, 2021.

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 (2021) 2019 and third quarter of 2020 "Evolving Economy" model. ERG also conducted a sensitivity analysis that assumes 70 percent economic recovery from the pandemic.

Table 16 shows how the results of the analysis would vary under these economic recovery scenarios. Both indirect and induced cost impacts increase with a lower level of economic recovery, as would be expected. Costs comprise a greater portion of profits with a lower level of recovery from the pandemic, another expected outcome.

Table 16. Results of COVID-19 Sensitivity Analyses for the Impacts of Rule 4352—Solid Fuel-Fired Boilers, Steam Generators and Process Heaters

Analysis	Recovery from COVID-19 Baseline	Direct			Indirect		Induced		Total	
		Revenue	Costs % Profits	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment
Primary Estimate	100%	$404,931	11.03%	0	$174	0	$2	0	$405,108	0
Sensitivity Analysis 1	70%	$404,931	11.87%	0	$167	0	$3	0	$405,100	0

Sources: ERG estimates based on SJVAPCD, 2021; NAICS.com, 2021; U.S. Census Bureau, 2020f; U.S. Census Bureau, 2020d; RMA, 2021; IMPLAN, 2021.

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. Although the average facility values presented in Table 11 suggest some facilities may be small, the only facility expected to be significantly impacted is owned by a large multinational corporation.

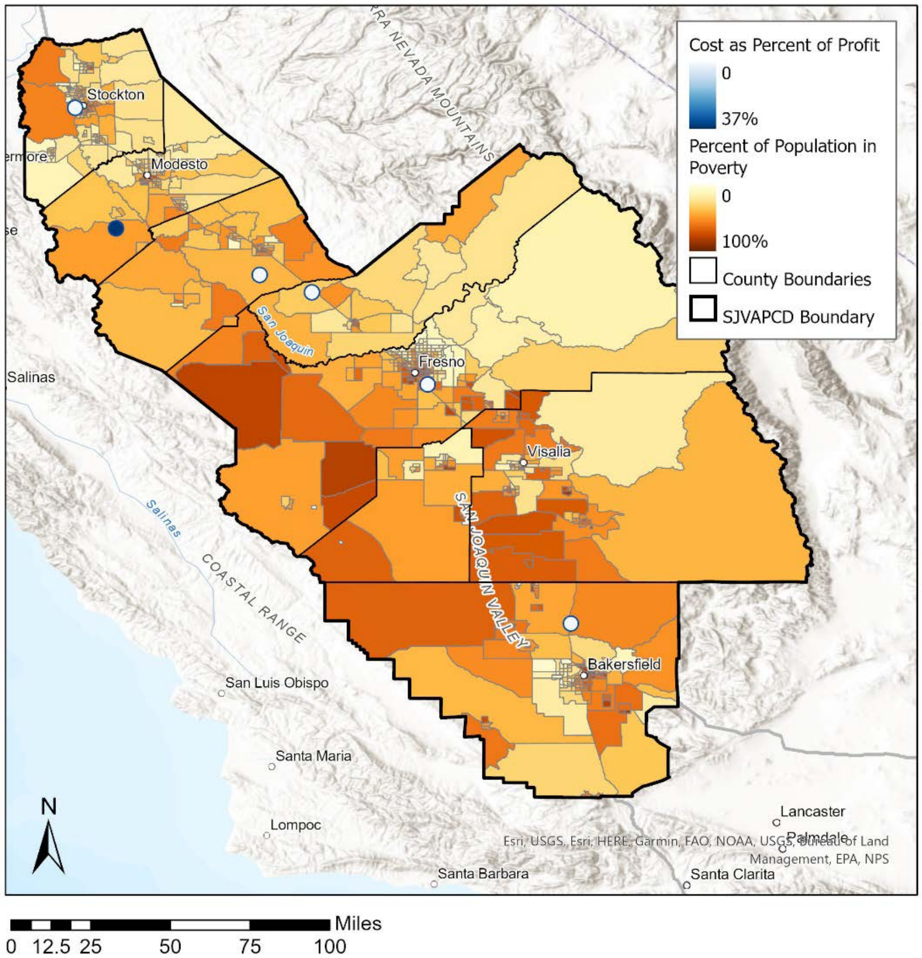
4.6. IMPACTS ON AT-RISK POPULATIONS

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 4.0 (OEHHA, 2021a). (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 3 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 one percent of their profits. Impacts are highest for the “Municipal Solid Waste” sector, of which there is one facility located in Stanislaus County. Projected impacts to this sector are estimated to exceed 36 percent of profits and may affect vulnerable populations in the County.

Figure 3. Map of Facilities in Relation to Population Living in Poverty



Source data: SJVAPCD, 2021; ERG estimates; OEHHA, 2021a
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 Rule 4352—Solid Fuel-Fired Boilers, Steam Generators and Process Heaters

SIC Code	SIC Industry	Sector
4911	Electric Services	Biomass
4931	Electric and Other Services Combined	Municipal Solid Waste

Source: SJVAPCD, 2021.

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 (2020d) 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 4352—Solid Fuel-Fired Boilers, Steam Generators and Process Heaters

SIC Code	SIC Industry	Corresponding NAICS
4911	Electric Services	2211 Electric power generation, transmission, and distribution
4931	Electric and Other Services Combined	2211 Electric power generation, transmission, and distribution

Source: SJVAPCD, 2021.

[a] Because a separate NAICS code for converting Municipal Solid Waste to electric power was not specified within NAICS 22111, ERG chose to classify it as NAICS 221117 for the purposes of calculating output per employee.

Both SIC codes 4911 and 4931 are assigned to 4-digit NIACS code 2211, electric power generation, transmission, and distribution. Within that NAICS code, the 5-digit code 22111, electric power generation, is further broken down into 6-digit codes for electric power generation from hydroelectric, fossil fuel, nuclear, solar, wind, geothermal, biomass, and other sources. Because of the wide variety of energy sources included, with an equally wide variety of cost structures, ERG chose to characterize establishments in both SIC codes as NAICS 221117, biomass electric power generation.

APPENDIX B. REVENUE AND PROFIT RATES BY NAICS INDUSTRY

Table B-1 presents the 2017 U.S. Economic Census data for biomass electric power generation (NAICS 201117) along with the calculation of revenue per employee used to estimate revenue per establishment for these facilities in the District.

Table B-1. Number of U.S. Firms, Establishments, Revenue, Payroll and Employees for NAICS 221117, Biomass Electric Power Generation, 2017

NAICS	Industry	Geographic Region	Number of Firms	Number of Estab.	Sales, value of shipments, or revenue ($1,000)	Annual Payroll ($1,000)	Number of Employees	Revenue per Employee*
221117	Biomass Electric Power Generation	U.S.	73	141	$905,622	$163,226	1,968	$460,174

Source: U.S. Census Bureau, 2002e

* ERG calculation.

Table B-2 tabulates the GDP implicit price deflator used to convert the Economic Census 2017-dollar values to the 2020-dollar values used in this analysis.

Table B-2. GDP Implicit Price Deflator, 2017 - 2020

Year	GDP Implicit Price Deflator Index (2012 = 100)	Multiplier to Convert to 2020 Value
2017	107.747	1.055
2018	110.321	1.030
2019	112.294	1.012
2020	113.648	1.000

Source: BEA, 2021

Table B-3 shows the profit rates used for private industry, which were estimated using the average rate for 2015 through 2020 data from RMA (2021).

Table B-3. Calculation of Average Profit Rate, NAICS 2211, 2015 - 2020

NAICS	Industry	Average	2015	2016	2017	2018	2019	2020
2211	Electric Power Generation, Transmission and Distribution	4.73%	4.18%	5.83%	2.95%	5.47%	4.61%	5.33%

Source: RMA, 2021

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 (2021) datasets for 2019 and the "Evolving Economy" dataset developed using data for the third quarter of 2021.

Table C-1. COVID-19 Adjustments by NAICS Industry for Facilities Affected by Rule 4352—Solid Fuel-Fired Boilers, Steam Generators and Process Heaters

NAICS	Industry	COVID-19-Adjusted Change in Sensitivity Analysis		
		Revenue	Employment	Average Pay
2211	Electric Power Generation, Transmission and Distribution	-7.07%	7.72%	-1.83%

Source: ERG estimates based on IMPLAN, 2021.

APPENDIX E

Rule Consistency Analysis for
Proposed Amendments to Rule 4352
(Solid Fuel Fired Boilers, Steam Generators, and Process Heaters)

December 16, 2021

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RULE CONSISTENCY ANALYSIS FOR
PROPOSED AMENDMENTS TO RULE 4352
(SOLID FUEL FIRED BOILERS, STEAM GENERATORS, AND PROCESS HEATERS)

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 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 United States Environmental Protection Agency (EPA) rules, regulations, and guidelines that apply to the same source category. The elements analyzed are emission standards, monitoring and testing, and recordkeeping and reporting requirements.

II. RULE CONSISTENCY ANALYSIS

A. District Rules

Facilities subject to District Rule 4352 could be subject to other District rules including:

- Rule 2201 New and Modified Stationary Source Review
- Rule 2020 Exemptions
- Rule 2520 Federally Mandated Operating Permits
- Rule 4101 Visible Emissions
- Rule 4301 Fuel Burning Equipment
- Rule 4305 Boilers, Steam Generators, and Process Heaters – Phase 2
- Rule 4306 Boilers, Steam Generators, and Process Heaters – Phase 3
- Rule 4307 Boilers, Steam Generators, and Process Heaters – 2.0 MMBtu/hr to 5.0 MMBtu/hr
- Rule 4308 Boilers, Steam Generators, and Process Heaters – 0.075 MMBtu/hr to less than 2.0 MMBtu/hr
- Rule 4351 Boilers, Steam Generators, and Process Heaters – Phase 1
- Rule 4601 Architectural Coatings
- Rule 4801 Sulfur Compounds
- Rule 8011 General Requirements
- Rule 8021 Construction, Demolition. Excavation, Extraction, and Other Earthmoving Activities
- Rule 8031 Bulk Materials
- Rule 8041 Carryout and Trackout
- Rule 8051 Open Areas
- Rule 8061 Paved and Unpaved Roads
- Rule 8071 Unpaved Vehicle/Equipment Traffic Areas

The above-listed rules are not in conflict with, nor are they inconsistent with the requirements of Proposed Rule 4352.

B. Federal EPA Rules and Regulations

1. 40 CFR 60 Subpart D (Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction Commenced After August 17, 1971)

   40 CFR 60 Subpart D applies to fossil fuel-fired, and fossil fuel and wood residue-fired steam generating units of more than 250 MMBtu/hr that commenced construction or modification after August 17, 1971. Subpart D establishes the emission standards for NOx, SOx, and PM. Since Rule 4352 applies to units that are fired on solid fuel, the rule consistency analysis focused only on the NOx standards established in 40 CFR 60 Subpart D for similar type of fuel.

   NOx limits:
   - Wood residue, or gaseous fossil fuel and wood residue – 0.30 lb/MMBtu
   - Solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse) – 0.70 lb/MMBtu
   - Lignite, or lignite and wood residue – 0.60 lb/MMBtu
   - Lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit – 0.80 lb/MMBtu

   In general, the applicability, emission limits, and monitoring requirements of Rule 4352 are more stringent than those specified for units that are subject to 40 CFR 60 Subpart D.

2. 40 CFR 60 Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units)

   40 CFR 60 Subpart Db applies to steam generating units with a heat input capacity of greater than 100 MMBtu/hr that commence construction, modification, or reconstruction after June 19, 1984. Steam generating units, as defined in 40 CFR 60 Subpart Db, do not include process heaters. Rule 4352 applies to solid fuel fired units so the rule consistency analysis focused only on the NOx standards established in 40 CFR 60 Subpart Db for similar type of fuel.

   NOx limits:
   - Mass-feed stoker – 0.50 lb/MMBtu
   - Spreader stoker and fluidized bed combustion – 0.60 lb/MMBtu
   - Pulverized coal – 0.70 lb/MMBtu
   - Lignite – 0.60 lb/MMBtu

- Lignite mined in ND, SD, MT, and combusted in a slag tap furnace – 0.80 lb/MMBtu
- Coal-derived synthetic fuels – 0.50 lb/MMBtu

In general, the applicability, emission limits, and monitoring requirements of Rule 4352 are more stringent than those specified for units that are subject to 40 CFR 60 Subpart Db.

3. 40 CFR 60 Subpart Cb (Emissions Guidelines and Compliance Times for Large Municipal Waste Combustors That are Constructed on or Before September 20, 1994)

   40 CFR 60 Subpart Cb applies to each municipal waste combustor unit with a combustion capacity greater than 250 tons per day of municipal solid waste for which construction was commenced on or before September 20, 1994. Rule 4352 applies to solid fuel fired units so the rule consistency analysis focused only on the NOx standards established in 40 CFR 60 Subpart Cb for similar type of fuel.

   NOx limits:
   - Mass burn waterwall – 205 ppm at 7% O2
   - Mass burn rotary waterwall – 250 ppm at 7% O2
   - Refuse-derived fuel combustor – 250 ppm at 7% O2
   - Fluidized bed combustor – 240 ppm at 7% O2
   - Mass burn refractory combustors - no limit
   - Fluidized bed combustor – 180 ppm at 7% O2

   In general, the applicability, emission limits, and monitoring requirements of Rule 4352 are more stringent than those specified for units that are subject to 40 CFR 60 Subpart Cb.

4. 40 CFR 63 Subpart DDDDD (NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters)

   40 CFR 63 Subpart DDDDD establishes emission limits and work practice standards for boilers and process heaters to regulate hazardous air pollutants such as arsenic, cadmium, chromium, hydrogen chloride, hydrogen fluoride, lead, manganese, mercury, and nickel, as well as CO and filterable particulate matter. NESHAP applies to any boiler process or heaters located at a major source. Existing units are units that commenced construction on or before June 4, 2010; new units are units that commenced construction after June 4, 2010.

5. EPA –453/R-94-022 “Alternative Control Techniques (ACT) Document – NOx Emissions from Industrial/Commercial/Institutional Boilers”, dated March 1994.

The ACT discusses the different control techniques for controlling NOx emissions from boilers with heat input capacities from 0.4 to 1,500 MMBtu/hr. The ACT also presented the achievable emission levels of several control techniques based on the type of boiler and the type of fuel used. The ACT contains cost effectiveness estimates for different control techniques. However, the ACT does not prescribe the specific emission limits that should be used in developing a regulation to control NOx emissions from boilers.

6. EPA Control Techniques Guideline (CTG) Document

There is no EPA CTG for boilers, steam generators, and process heaters.

7. EPA Policy on Start-up or Shutdown

Section 5.3 of Rule 4352 establishes certain operational standards that must be met during start-up or shutdown of boilers, steam generators, and process heaters. District staff believe that the proposed start-up or shutdown provisions are consistent with the EPA policy as discussed in an EPA memorandum, dated February 15, 1983, “Policy on Excess Emissions During Start-up, Shutdown, Maintenance and Malfunctions” which prohibits automatic exemption during periods of start-up or shutdown of a unit.

8. EPA Policy on Recordkeeping

The recordkeeping requirement in Section 6.1 of Rule 4352 is consistent with EPA’s policy to keep and maintain records for at least five years.

III. CONCLUSION

Based on the above analysis, District staff found that the proposed amendments to Rule 4352 would not conflict with federal rules, regulations, or policies covering similar stationary sources.