TECHNICAL MEMORANDUM

TO: Docket for Rulemaking, "Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards" (EPA-HQ-OAR-2021-0668)

DATE: March 15, 2023

SUBJECT: Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs

***** This revised document replaces the version posted to EPA's website the morning of March 15, 2023. This corrected version is the final document in the rulemaking docket. *****

I. Background

For the February 28, 2022 *Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards* (proposed FIP), the EPA developed an analytical framework to facilitate decisions about industries and emissions unit types for including emissions units in the non-electric generating unit "sector" (non-EGUs) in a proposed FIP for the 2015 ozone national ambient air quality standards (NAAQS) transport obligations. A February 28, 2022 memorandum, titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (Non-EGU Screening Assessment), documents the analytical framework that the EPA used to identify industries and emissions unit types included in the proposed FIP.[1]

To further evaluate the industries and emissions unit types identified and to establish the proposed emissions limits, the EPA reviewed Reasonably Available Control Technology (RACT) rules, New Source Performance Standards (NSPS) rules, National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules, existing technical studies, rules in approved state implementation plan (SIP) submittals, consent decrees, and permit limits. That evaluation is detailed in the EPA's December 2021 technical support document for the proposed FIP entitled *Technical Support Document (TSD) for the Proposed Rule, Non-EGU Sectors TSD* (Non-EGU Sectors TSD).[2]

Finally, in the proposed FIP the EPA proposed to find, based on the most recent information available from the EPA's August 2016 *Final Technical Support Document (TSD) for the Final Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Assessment of Non-EGU NO_X Emissions Controls, Cost of Controls, and Time for Compliance Final TSD* (CSAPR Update Non-EGU TSD),[3] that controls on all of the non-EGU emissions units could not be installed by the 2023 ozone season. The proposed FIP estimated controls could be installed on non-EGU emissions units by the 2026 ozone season. For this final rule, the EPA prepared a report entitled *NOx Emission Control Technology Installation Timing for Non-EGU Sources* (Non-EGU Control Installation Timing Report)[4] that includes estimates of the amount of time needed to install the control equipment identified in the

[1] The Non-EGU Screening Assessment is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150.
[2] The Non-EGU Sectors TSD is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145.
[3] The CSAPR Update Non-EGU TSD is available here: https://www.epa.gov/csapr/assessment-non-egu-NO_X-emission-controls-cost-controls-and-time-compliance-final-tsd.
[4] The Non-EGU Control Installation Timing Report is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668.

EPA's final rule and associated *Technical Support Document (TSD) for the Final Rule, Non-EGU Sectors TSD* (Final Non-EGU Sectors TSD).[5] All stages of the process to install control equipment, including but not limited to time for contract award, permitting, construction, and actual installation, are included in the control equipment installation time estimate. In addition, we included information on materials and labor needed to complete installation, including equipment vendor capacity.

This memorandum summarizes the emissions unit types, applicability criteria, emissions limits, estimated list of emissions units captured by the applicability criteria, and estimated emissions reductions and costs for the year 2026 associated with the final *Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards*. The remainder of this memorandum includes the following sections:

II. Applicability Criteria for Non-EGU Emissions Units Subject to the Final Rule
III. Emissions Limits for the Final Rule
IV. Assumed Control Technologies that Meet the Emissions Limits in the Final Rule
V. Estimating Emissions Units, Emissions Reductions, and Costs

II. Applicability Criteria for Non-EGU Emissions Units Subject to the Final Rule

The EPA is finalizing rate-based limits and production-based limits to directly control emissions of nitrogen oxides (NO_X) from the types of non-EGU emissions units identified in the proposed FIP. In addition, in Section V.B.3.b of the preamble for the proposed FIP, the EPA included a discussion of the potential for NOx emissions reductions from municipal waste combustors (MWCs) and solicited comment on whether these units should be included in a final FIP to address the 2015 ozone NAAQS transport obligations. The EPA is including these units in the final rule. For all of the non-EGU emissions units, the EPA developed emissions control requirements using applicability criteria based on size and type of unit and, in some cases, emissions thresholds. Table 1 below (Table II.A-1 of the final rule preamble) lists the nine non-EGU industries covered by the rule, identified by North American Industry Classification System (NAICS) codes. Table 2 below summarizes the industries, emissions unit types, and applicability requirements.

Table 1. Industries and NAICS Codes Covered by Rule

Industry	NAICS
Pipeline Transportation of Natural Gas	4862
Cement and Concrete Product Manufacturing	3273
Iron and Steel Mills and Ferroalloy Manufacturing	3311
Glass and Glass Product Manufacturing	3272
Metal Ore Mining[6]	2122
Basic Chemical Manufacturing	3251
Petroleum and Coal Products Manufacturing	3241
Pulp, Paper, and Paperboard Mills	3221
Solid Waste Combustors and Incinerators	562213

[5] The Final Non-EGU Sectors TSD is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668.

[6] The analytical framework applied in the Non-EGU Screening Assessment did not identify any boilers in the Metal Ore Mining industry with > 100 tpy NOx emissions. As such, no boilers were reflected in the proxy results from the screening assessment for proposal. The proposed and final applicability criterion for boilers is not based on tpy and is based on design capacity ≥100 MMBtu/hour. Metal Ore Mining has a few boilers with a design capacity of ≥100 MMBtu/hour that could be subject to the final emissions limits. See Section II.A., Table II.A-1 of the final rule preamble.

Table 2. Summary of Industries, Non-EGU Emissions Unit Types, and Applicability Requirements

Industry	Emissions Unit Type	Applicability Requirements
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engines	Nameplate rating of ≥1000 braking horsepower (bhp)
Cement and Concrete Product Manufacturing	Kilns	Directly emits or has the potential to emit 100 tpy or more of NO_X
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	Directly emits or has the potential to emit 100 tpy or more of NO_X
Glass and Glass Product Manufacturing	Furnaces	Directly emits or has the potential to emit 100 tons per year (tpy) or more of NO_X
Iron and Steel Mills and Ferroalloy Manufacturing Metal Ore Mining Basic Chemical Manufacturing Petroleum and Coal Products Manufacturing Pulp, Paper, and Paperboard Mills	Boilers	Design capacity of ≥100 mmBtu/hr
Solid Waste Combustors and Incinerators	Combustors or Incinerators	Design capacity ≥ 250 tons of waste/day

Any emissions unit that meets the applicability criteria in the final rule (as summarized in Table 2) and is located at a facility within one of the industries listed in Table 1 in any of the 20 states with non-EGU emissions control obligations[7] is subject to the final emissions limits. A detailed discussion of the applicability criteria for non-EGU sources is provided in Section VI.C of the preamble to the final rule.

III. Emissions Limits for the Final Rule

Establishing emissions limits for emissions units based on size and type of unit and, in some cases, emissions thresholds, will achieve the necessary reductions commensurate with the EPA's analysis of non-EGU industries and emissions units at Step 3 of the interstate transport framework. Between the proposal and this final rule, the EPA made several adjustments to the proposed emissions limits for the emissions units in non-EGU industries.

- For Pipeline Transportation of Natural Gas, the EPA is finalizing the emissions limits as proposed; however, the EPA is adjusting the applicability criteria to exclude emergency engines. Additionally, the final rule allows source owners/operators to request EPA approval of facility-wide emissions averaging plans on a case-by-case basis, where specified criteria are met. An approved facility-wide averaging plan would allow the source to install controls on the engines with the largest potential for emissions reductions at cost-effective thresholds.
- For Cement and Concrete Product Manufacturing, in the final rule the EPA has removed the daily source cap limit, which could have resulted in an artificially restrictive NO_X emissions limit for affected cement kilns due to lower operating periods resulting from to the COVID-19 pandemic.
- For Iron and Steel and Ferroalloy Manufacturing, the EPA is finalizing only a test-and-set requirement for reheat furnaces premised on the installation of low-NO_X burners. Based on commenters' concerns regarding the proposed requirements for other unit types in this industry, the EPA is not finalizing the proposed emissions limits for other emissions units in this industry.
- For Glass and Glass Product Manufacturing, the EPA is finalizing alternative requirements that may apply during startup, shutdown, and idling conditions.
- For boilers in Iron and Steel and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills,

[7] The EPA is requiring emissions reductions from non-EGU sources to address interstate transport obligations for the 2015 ozone NAAQS for the following 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia.

the EPA is finalizing a low-use exemption to eliminate the need to install controls on low-use boilers that would have resulted in relatively small reductions.

More details on the bases for these changes can be found in the Section VI.C of the preamble to the final rule and in the Final Non-EGU Sectors TSD. Table 3 summarizes the industries, emissions unit types, the form of the final emissions limits, and the final emissions limits.

Table 3. Summary of Non-EGU Industries, Emissions Unit Types, Form of Final Emissions Limits, and Final Emissions Limits

Industry	Emissions Unit Type	Form of Final Emissions Limits	Final Emissions Limits
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engines	Grams per horsepower per hours (g/hp-hr)	Four Stroke Rich Burn: 1.0 g/hp-hr Four Stroke Lean Burn: 1.5 g/hp-hr Two Stroke Lean Burn: 3.0 g/hp-hr
Cement and Concrete Product Manufacturing	Kilns	Pounds per ton (lbs/ton) of clinker	Long Wet: 4.0 lb/ton Long Dry: 3.0 lb/ton Preheater: 3.8 lb/ton Precalciner: 2.3 lb/ton Preheater/Precalciner: 2.8 lb/ton
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	lbs/mmBtu[a]	Test and set limit based on installation of Low-NOx Burners
Glass and Glass Product Manufacturing	Furnaces	lbs/ton glass produced	Container Glass Furnace: 4.0 lb/ton Pressed/Blown Glass Furnace: 4.0 lb/ton Fiberglass Furnace: 4.0 lb/ton Flat Glass Furnace: 7 lb/ton
Iron and Steel Mills and Ferroalloy Manufacturing Metal Ore Mining Basic Chemical Manufacturing Petroleum and Coal Products Manufacturing Pulp, Paper, and Paperboard Mills	Boilers	lbs/mmBtu[a]	Coal: 0.20 lb/mmBtu Residual Oil: 0.20 lb/mmBtu Distillate Oil: 0.12 lb/mmBtu Natural Gas: 0.08 lb/mmBtu
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ppmvd on a 24-hour averaging period and ppmvd on a 30-day averaging period	110 ppmvd on a 24-hour averaging period 105 ppmvd on a 30-day averaging period

[a] Heat input limit.

IV. Assumed Control Technologies that Meet the Final Emissions Limits

Because the EPA does not have complete information on the operating characteristics of every emissions unit potentially captured by the applicability criteria (e.g., existing emissions limit), the EPA made assumptions for each industry and emissions unit type about the control technology needed to meet the final emissions limits. Table 4 summarizes the industries, emissions unit types, and assumed control technologies that the EPA anticipates will meet the final emissions limits. The estimated emissions reductions and costs presented in Section V below reflect these assumed control technologies. A more detailed discussion of the EPA's basis for concluding that these assumed control technologies would meet the final emission limits is included in Section VI.C of the preamble to the final rule and in the Final Non-EGU Sectors TSD, both located in the docket.

Table 4. Summary of Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies that Meet Final Emissions Limits

Industry	Emissions Unit Type	Assumed Control Technologies that Meet Final Emissions Limits
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engines	Layered Combustion (2-cycle Lean Burn)[a] SCR (4-cycle Lean Burn) NSCR (4-cycle Rich Burn)
Cement and Concrete Product Manufacturing	Kilns	SNCR
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB
Glass and Glass Product Manufacturing	Furnaces	LNB
Iron and Steel Mills and Ferroalloy Manufacturing Metal Ore Mining Basic Chemical Manufacturing Petroleum and Coal Products Manufacturing Pulp, Paper, and Paperboard Mills	Boilers	LNB + FGR (Natural Gas, No Coal or Oil) SCR (Any Coal, Any Oil)
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ANSCR[b] LN[tm] and SNCR [b,c]

[a] Several emissions units, or engines, in the 2019 inventory had Source Classification Codes (SCC) indicating that the units were reciprocating without specifying the type of engine. We assumed NSCR or layered combustion as the control for these emissions units.
[b] *Municipal Waste Combustor Workgroup Report*, prepared by the Ozone Transport Commission Stationary and Area Sources Committee, Revised April 2022.
[c] Covanta has developed a proprietary low NOx combustion system (LN^{TM}) that involves staging of combustion air. The system is a trademarked system and Covanta has received a patent for the technology.

V. Estimating Emissions Units, Emissions Reductions, and Costs

With the exception of Solid Waste Combustors and Incinerators (also referred to as Municipal Waste Combustors or MWCs), for each industry and emissions unit type, using a 2019 inventory prepared from the emissions inventory system (EIS) the EPA first estimated a list of emissions units captured by the applicability criteria for the final rule.[8] For Solid Waste Combustors and Incinerators, the EPA estimated the list for MWCs using the 2019 inventory and the NEEDS-v6-summer-2021-reference-case workbook.[9] Appendix A introduces the inventory data used and the general steps taken to filter the inventory data to estimate an initial list of units. In addition, there is an Excel workbook with a worksheet containing information for each industry, as well as for reciprocating internal combustion engines, boilers, and MWCs available in the docket.[10] Using the 2019 inventory from the EIS, the EPA reviewed permits for the estimated emissions units in the Cement and Concrete Product Manufacturing, Glass and Glass Product Manufacturing, and Iron and Steel Mills and Ferroalloy Manufacturing industries. Because the number of estimated emissions units for reciprocating internal

[8] Using a projected emissions inventory for 2026 introduces challenges associated with the growth of emissions at sources over time. The EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-term emissions reductions. For additional discussion of the 2019 inventory, please see the *2019 National Emissions Inventory Technical Support Document: Point Data Category* available in the docket. In using the 2019 inventory, however, we did not account for any growth or decrease in emissions that might occur at individual units.
[9] Available here: https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6.
[10] The Excel workbook is titled *Non-EGU Facilities and Units_Final.xlsx* and is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668.

combustion engines and boilers was larger, the EPA reviewed a smaller set of permits for those units. For boilers, the EPA also reviewed the database used in the July 2022 revised Boiler MACT.

Each workbook includes a worksheet labeled *README* with the detailed steps taken to estimate the list of emissions units captured by the applicability criteria (these steps are included in Appendix A). In developing the list, we assumed that the information in the 2019 inventory was accurate unless we updated that information through the permit reviews, information found in a dataset from the July 2022 revised boiler MACT rule, or information from other existing emissions inventories. In addition, each workbook includes a worksheet labeled *Units Will Need Controls* that represents the initial list of emissions units the EPA estimates could need the assumed controls to meet the emissions limits in the final rule.

For the final rule, the EPA did not run the Control Strategy Tool (CoST) to estimate emissions reductions and costs, as we did for the proposed rule, and instead programmed the assessment using R.[11] Using with the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies identified in Table 4, and information on control efficiencies and default cost/ton values from the control measures database (CMDB)[12], the EPA then estimated emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions (not potential to emit) from the 2019 emissions inventory. It is not clear what the impact of using actual emissions is on the estimated emissions reductions. As an example, if these emissions units were not subject to the emissions limits in this rule and their actual emissions were lower than their potential to emit, they could have increased emissions in 2026 (compared to actual emissions in 2019), resulting in greater estimated emissions reductions.

There were a few cases where an emissions unit had an existing control indicated in the inventory, but we estimated that the existing control might not enable the unit to meet the emissions limit and additional emissions reductions could be needed for the unit to meet the applicable emissions limit. When running CoST, the EPA can specify that a replacement control be applied if it achieves a specified, additional percent emissions reduction. In this analysis, we assumed a replacement control would need to result in 11% more emissions reductions than the control currently on an emissions unit. Lastly, when incorporating additional information on existing controls from other existing emissions inventories or when assessing replacement controls, we identified existing controls on some emissions units. In some cases, after identifying an existing control on an emissions unit, the control we assumed was needed to meet the final emissions limit actually was not.[13]

Finally, in the assessment the EPA matched emissions units by Source Classification Code (SCC) from the inventory to the applicable control technologies in the CMDB.[14,15] We modified SCC codes as necessary to match control technologies to inventory records. For each emissions unit type and industry, the following summarizes the approach used and data modifications made to estimate emissions reductions and costs.

[11] R is a free software environment for statistical computing and graphics. Additional information is available here: https://www.r-project.org/.

[12] More information about the Control Strategy Tool (CoST) and the control measures database (CMDB) can be found at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.

[13] As a result, the number of emissions units in the *Units Will Need Controls* worksheet may be larger than the number of emissions units in the Excel results workbook titled *Non-EGU Results – 11-17-2022.xlsx* (available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668).

[14] The control measures in the CMDB have applicable SCC codes associated with them, facilitating the matching of inventory SCCs to control measure SCCs.

[15] The 2019 emissions inventory data, the control measure and default cost/ton data in the CMDB used to prepare the emission reduction and cost estimates, and the R code that processed these data are available upon request.

- For reciprocating internal combustion engines in the Pipeline Transportation of Natural Gas industry – The EPA used the control efficiencies and default cost/ton values from the CMDB for the assumed control and calculated emissions reductions and costs reflecting information on existing controls gathered from the review of a smaller set of permits, where available. The default cost/ton values from the CMDB may result in lower cost/ton values than is likely for some lower emitting units. We made some modifications where the inventory record and the CMDB had incompatible SCC codes or the CMDB had a gap in SCC coverage. For the inventory records with SCC codes specified as *Reciprocating*, we applied *NSCR or Layered Combustion.* Also, for two records with SCCs 20100202 and 20300201, we expanded the *NSCR or Layered Combustion* control in the CMDB to cover these SCCs.

- For the kilns in Cement and Concrete Product Manufacturing – The EPA reviewed permits and public comments on the proposed FIP to identify existing control information, where available, and estimated reductions using this information. The EPA used the control efficiency and default cost/ton values from the CMDB for the assumed control.

- For the reheat furnaces in Iron and Steel and Ferroalloy Manufacturing – The EPA reviewed permits to identify existing control information, where available, and estimated reductions using this information. The EPA used the control efficiency and default cost/ton values from the CMDB for the assumed control. We made some modifications where the inventory record and the CMDB had incompatible SCC codes or the CMDB had a gap in SCC coverage. For inventory records, we replaced SCC codes for all reheat furnaces with 30390003. Lastly, for the LNB control, the CMDB currently has two low NOx burner controls and to be conservative we used the control with a lower control efficiency.

- For the furnaces in Glass and Glass Product Manufacturing – The EPA reviewed permits to identify existing control information, where available, and estimated reductions using this information. The EPA used the control efficiency and default cost/ton values from the CMDB for the assumed control. For one inventory record, we changed an SCC code (30501401) and applied the LNB control measure.

- For boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills industries – The EPA used the control efficiencies and default cost/ton values from the CMDB for the assumed control and calculated emissions reductions and costs reflecting information on existing controls gathered from the review of a smaller set of permits or information found in a dataset from the July 2022 revised boiler MACT rule, where available. The default cost/ton values from the CMDB may result in lower cost/ton values than is likely for some lower emitting units. In addition, the default control efficiency in the CMDB for LNB for boilers is 50 percent and the default control efficiency for LNB+FGR is 61%. In assessing replacement controls, we assumed boilers that already have LNB will find another way to comply with the final emissions limits and not install FGR.

  We made some modifications where the inventory record and the CMDB had incompatible SCC codes or the CMDB had a gap in SCC coverage. For several inventory records, we replaced SCC codes for *Electric Generation: Boilers* and *Commercial/Industrial: Boilers* with *Industrial: Boilers* SCC codes for the same fuel type to assign control technology consistently across the industries. In the process level emissions inventory file, emissions can sometimes be below the 25 tpy threshold for which a default cost/ton gets used for LNB+FGR. We used the default cost/ton for the LNB+FGR control measure for some processes below the 25 tpy threshold.

- For combustors or incinerators in Solid Waste Combustors and Incinerators – The EPA estimated reductions by comparing current emissions limits to the final rule's emissions limits and multiplied the percent difference by a unit's actual emissions. We assumed ANSCR or low NOx technology (LN^{TM}) and SNCR would meet final rule emissions limits and used costs for those technologies from the *Municipal Waste Combustor Workgroup Report*, prepared by the Ozone Transport Commission Stationary and Area Sources Committee, Revised April 2022.[16] See Appendix B for a summary of information from the *Municipal Waste Combustor Workgroup Report* used to estimate costs for waste combustors or incinerators.

Table 5 summarizes the industries, emissions unit types, assumed control technologies, and number of control installations expected to meet the final rule emissions limits. Table 6 summarizes the industries, emissions unit types, assumed control technologies, and estimated average cost/ton values. Table 7 summarizes the industries, emissions unit types, assumed control technologies, estimated total annual costs, and estimated ozone season NOx emissions reductions in 2026. Table 8 summarizes the industries, emissions unit types, estimated total annual costs, and estimated annual and ozone season NOx emissions reductions in 2026.

The data used in this assessment is sufficient to inform the EPA's identification of which emissions from non-EGU industries and emissions units are "significant" under Step 3 of the 4-step interstate transport framework. Further, this assessment for the final rule reflects comments we received regarding the relationship between EPA's Step 3 and Step 4 analyses for non-EGU industries and emissions units at proposal. In this assessment the EPA has more directly incorporated into the analysis at Step 3 the emissions controls that we estimate would likely be installed at these emissions units. This allows the EPA to assess whether these controls could result in emissions reductions and air quality benefits at downwind receptors that are relatively cost-effective when compared with the control strategies for EGUs (see Section V.D.2 of the preamble for a more detailed discussion).

The estimates presented below using the 2019 inventory and information from the CMDB identify proxies for emissions units, as well as emissions reductions, and costs associated with the assumed control technologies that would meet the final emissions limits. Emissions units subject to the final rule emissions limits may be different than those estimated in this assessment; the estimated emissions reductions from and costs to meet the final rule emissions limits may be different than those estimated in this assessment. The costs do not include monitoring, recordkeeping, reporting, or testing costs. In the regulatory provisions that implement these emissions limits at Step 4, the EPA has incorporated mechanisms that are designed to accommodate unique circumstances on a unit-specific basis, such as allowing for an extension of time to install controls or developing an alternative emissions limit where it can be established to be necessary. See Section VI.C. of the preamble for further discussion.

[16] The *Municipal Waste Combustor Workgroup Report*, prepared by the Ozone Transport Commission Stationary and Area Sources Committee, Revised April 2022 is available here: https://otcair.org/upload/Documents/Reports/MWC%20Report_revised%2020220425.pdf.

Table 5. Summary of Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies that Meet Final Emissions Limits, Estimated Number of Control Installations

Industry/Industries	Emissions Unit Type	Assumed Control Technologies that Meet Final Emissions Limits	Estimated Number of Units Per Assumed Control
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engines	NSCR or Layered Combustion (Reciprocating)	323
		Layered Combustion (2-cycle Lean Burn)	394
		SCR (4-cycle Lean Burn)	158
		NSCR (4-cycle Rich Burn)	30
Cement and Concrete Product Manufacturing	Kiln	SNCR	16
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	19
Glass and Glass Product Manufacturing	Furnaces	LNB	61
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers	LNB + FGR (Natural Gas, No Coal or Oil)	151
Metal Ore Mining		SCR (Any Coal, Any Oil)	15
Basic Chemical Manufacturing Petroleum and Coal Products Manufacturing			
Pulp, Paper, and Paperboard Mills			
Solid Waste Combustors and Incinerators[a]	Combustors or Incinerators	ANSCR	57
		LN™ and SNCR	4
		Total	1,228

[a] Twelve MWCs have existing controls, and we estimated these units will use more reagent in those controls to meet the final emissions limits.

Table 6. Summary of Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies, Estimated Average Cost/Ton (2016$)

Industry/Industries	Emissions Unit Type	Assumed Control Technologies that Meet Final Emissions Limits	Average Cost/Ton Values (2016$)
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engine	NSCR or Layered Combustion, Layered Combustion, SCR, NSCR	4,981
Cement and Concrete Product Manufacturing	Kiln	SNCR	1,632
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	3,656
Glass and Glass Product Manufacturing	Furnaces	LNB	939
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers	SCR or LNB + FGR	8,369
Metal Ore Mining			14,595
Basic Chemical Manufacturing			11,845
Petroleum and Coal Products Manufacturing			14,582
Pulp, Paper, and Paperboard Mills			14,134
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ANSCR or LN™ and SNCR[a]	7,836
		Overall Average Cost/Ton	5,339

Table 7. Summary of Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies, Estimated Total Annual Costs (2016$), Ozone Season NOx Emissions Reductions in 2026

Industry/Industries	Emissions Unit Type	Assumed Control Technologies that Meet Final Emissions Limits	Annual Costs (2016$)	Ozone Season Emissions Reductions
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engine	NSCR or Layered Combustion, Layered Combustion, SCR, NSCR	385,463,197	32,247
Cement and Concrete Product Manufacturing	Kiln	SNCR	10,078,205	2,573
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	3,579,294	408
Glass and Glass Product Manufacturing	Furnaces	LNB	7,052,088	3,129
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers	SCR, LNB + FGR	8,838,171	440
Metal Ore Mining			621,496	18
Basic Chemical Manufacturing			49,697,848	1,748
Petroleum and Coal Products Manufacturing			5,128,439	147
Pulp, Paper, and Paperboard Mills			62,268,540	1,836
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ANSCR or LN™ and SNCR	38,949,560	2,071
		Totals	571,676,839	44,616

Table 8. Summary by Industries, Estimated Total Annual Costs (2016$), Annual and Ozone Season NOx Emissions Reductions in 2026

Industry/Industries	Emissions Unit Type	Annual Costs (2016$)	Annual Emissions Reductions	Ozone Season Emissions Reductions
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engine	385,463,197	77,392	32,247
Cement and Concrete Product Manufacturing	Kiln	10,078,205	6,174	2,573
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	3,579,294	979	408
Glass and Glass Product Manufacturing	Furnaces	7,052,088	7,510	3,129
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers	8,838,171	1,056	440
Metal Ore Mining		621,496	43	18
Basic Chemical Manufacturing		49,697,848	4,196	1,748
Petroleum and Coal Products Manufacturing		5,128,439	352	147
Pulp, Paper, and Paperboard Mills		62,268,540	4,406	1,836
Solid Waste Combustors and Incinerators	Combustors or Incinerators	38,949,560	4,971	2,071
	Totals	571,676,839	107,077	44,616

In addition, Table 9 summarizes annual cost, estimated annual and ozone season NOx emissions reductions in 2026, and average cost/ton by state and by industry, and Table 10 summarizes annual cost, estimated annual and ozone season NOx emissions reductions in 2026, and average cost/ton by state. Figure 1 shows the geographical distribution of estimated ozone season NOx reductions, along with the summary of reductions by state and by industry. Note that while Nevada is a linked state in 2026, we did not estimate that any emissions units would need to apply the assumed control technologies to meet the final emissions limits.

Table 9. By State And By Industry, Estimated Annual Cost (2016$), Estimated Annual and Ozone Season NOx Emissions Reductions in 2026, and Estimated Average Cost/Ton (2016$)

State	NAICS Description	Annual Cost (2016$)	Annual Reductions	OS Emissions Reductions	Average Cost/Ton (2016$)
AR	Basic Chemical Manufacturing	1,632,223	208	87	7,851
AR	Glass and Glass Product Manufacturing	123,157	90	37	1,376
AR	Iron and Steel Mills and Ferroalloy Manufacturing	309,447	85	35	3,656
AR	Pipeline Transportation of Natural Gas	13,129,973	2,555	1,065	5,139
AR	Pulp, Paper, and Paperboard Mills	9,518,419	774	323	12,290
CA	Cement and Concrete Product Manufacturing	3,486,679	2,725	1,135	1,279
CA	Glass and Glass Product Manufacturing	296,407	383	160	774
CA	Pipeline Transportation of Natural Gas	2,414,437	512	213	4,718
CA	Waste Treatment and Disposal	2,271,068	221	92	10,271
IL	Basic Chemical Manufacturing	588,959	24	10	24,690
IL	Glass and Glass Product Manufacturing	551,552	712	297	775
IL	Petroleum and Coal Products Manufacturing	1,952,466	148	62	13,221
IL	Pipeline Transportation of Natural Gas	20,610,074	4,664	1,943	4,419
IN	Cement and Concrete Product Manufacturing	3,192,728	1,148	478	2,782
IN	Glass and Glass Product Manufacturing	727,048	528	220	1,376
IN	Iron and Steel Mills and Ferroalloy Manufacturing	3,579,696	697	291	5,133
IN	Petroleum and Coal Products Manufacturing	564,315	80	33	7,031
IN	Pipeline Transportation of Natural Gas	9,272,053	1,768	737	5,243
IN	Waste Treatment and Disposal	1,706,754	520	217	3,282
KY	Glass and Glass Product Manufacturing	130,692	52	22	2,493
KY	Iron and Steel Mills and Ferroalloy Manufacturing	111,147	30	13	3,656
KY	Pipeline Transportation of Natural Gas	32,782,561	6,297	2,624	5,206
KY	Pulp, Paper, and Paperboard Mills	394,020	16	7	24,690
LA	Basic Chemical Manufacturing	19,965,275	1,886	786	10,584
LA	Glass and Glass Product Manufacturing	614,449	276	115	2,229
LA	Petroleum and Coal Products Manufacturing	497,471	20	8	24,690
LA	Pipeline Transportation of Natural Gas	72,118,746	14,880	6,200	4,847
LA	Pulp, Paper, and Paperboard Mills	1,045,465	79	33	13,221
MD	Pipeline Transportation of Natural Gas	164,447	30	13	5,457

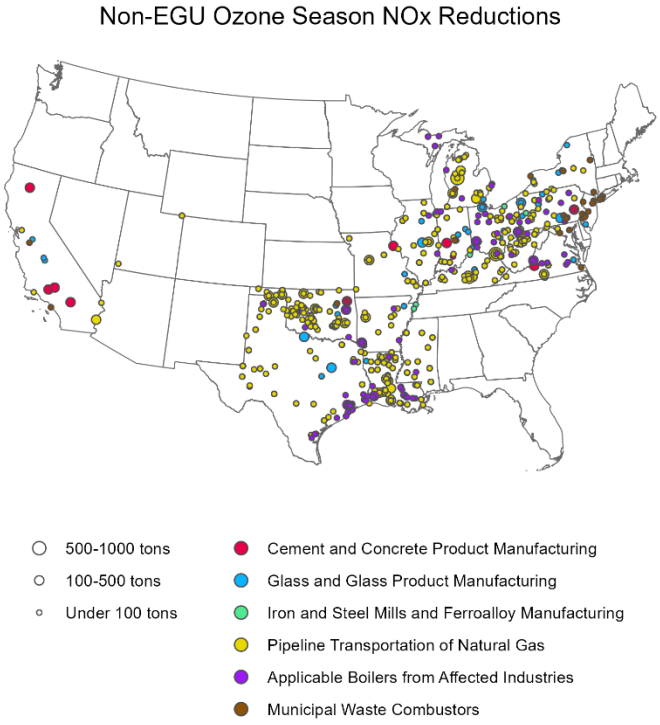
MD	Waste Treatment and Disposal	2,069,959	347	145	5,965
MI	Basic Chemical Manufacturing	649,287	26	11	24,690
MI	Glass and Glass Product Manufacturing	35,459	65	27	549
MI	Metal Ore Mining	621,496	43	18	14,595
MI	Pipeline Transportation of Natural Gas	31,429,866	6,329	2,637	4,966
MI	Pulp, Paper, and Paperboard Mills	5,896,625	559	233	10,551
MI	Waste Treatment and Disposal	1,137,836	142	59	8,002
MO	Cement and Concrete Product Manufacturing	759,911	273	114	2,782
MO	Glass and Glass Product Manufacturing	249,721	182	76	1,376
MO	Pipeline Transportation of Natural Gas	22,471,530	4,501	1,875	4,993
MS	Pipeline Transportation of Natural Gas	29,429,138	5,828	2,428	5,050
MS	Pulp, Paper, and Paperboard Mills	3,468,462	170	71	20,424
NJ	Glass and Glass Product Manufacturing	59,949	44	18	1,376
NJ	Waste Treatment and Disposal	6,776,981	538	224	12,596
NY	Glass and Glass Product Manufacturing	349,137	191	80	1,826
NY	Iron and Steel Mills and Ferroalloy Manufacturing	82,491	23	9	3,656
NY	Pipeline Transportation of Natural Gas	2,698,676	553	230	4,884
NY	Pulp, Paper, and Paperboard Mills	1,956,608	278	116	7,031
NY	Waste Treatment and Disposal	10,195,093	1,255	523	8,125
OH	Basic Chemical Manufacturing	1,820,887	88	37	20,635
OH	Glass and Glass Product Manufacturing	861,166	660	275	1,305
OH	Iron and Steel Mills and Ferroalloy Manufacturing	6,109,926	874	364	6,993
OH	Petroleum and Coal Products Manufacturing	195,795	8	3	24,690
OH	Pipeline Transportation of Natural Gas	27,466,909	5,386	2,244	5,100
OH	Pulp, Paper, and Paperboard Mills	6,568,693	436	182	15,049
OK	Cement and Concrete Product Manufacturing	891,978	663	276	1,346
OK	Glass and Glass Product Manufacturing	334,023	243	101	1,376
OK	Pipeline Transportation of Natural Gas	42,845,192	8,631	3,596	4,964
OK	Pulp, Paper, and Paperboard Mills	7,406,196	754	314	9,827
OK	Waste Treatment and Disposal	1,706,754	240	100	7,104
PA	Cement and Concrete Product Manufacturing	526,032	411	171	1,279
PA	Glass and Glass Product Manufacturing	1,268,316	1,899	791	668
PA	Iron and Steel Mills and Ferroalloy Manufacturing	1,607,318	239	99	6,735

PA	Pipeline Transportation of Natural Gas	6,599,932	1,377	574	4,792
PA	Pulp, Paper, and Paperboard Mills	4,446,769	197	82	22,540
PA	Waste Treatment and Disposal	10,809,443	1,118	466	9,670
TX	Basic Chemical Manufacturing	20,677,319	1,549	645	13,353
TX	Glass and Glass Product Manufacturing	1,144,406	1,963	818	583
TX	Petroleum and Coal Products Manufacturing	1,918,392	96	40	20,047
TX	Pipeline Transportation of Natural Gas	38,681,714	7,611	3,171	5,082
TX	Pulp, Paper, and Paperboard Mills	1,010,352	41	17	24,690
UT	Pipeline Transportation of Natural Gas	2,848,769	604	252	4,717
VA	Basic Chemical Manufacturing	362,998	15	6	24,690
VA	Cement and Concrete Product Manufacturing	1,220,878	954	398	1,279
VA	Glass and Glass Product Manufacturing	306,606	223	93	1,376
VA	Iron and Steel Mills and Ferroalloy Manufacturing	617,441	88	37	7,031
VA	Pipeline Transportation of Natural Gas	12,732,010	2,326	969	5,473
VA	Pulp, Paper, and Paperboard Mills	20,150,279	1,084	452	18,583
VA	Waste Treatment and Disposal	2,275,672	589	246	3,862
WV	Basic Chemical Manufacturing	4,000,899	400	167	10,004
WV	Pipeline Transportation of Natural Gas	17,767,169	3,540	1,475	5,019
WV	Pulp, Paper, and Paperboard Mills	406,652	16	7	24,690
	Totals	571,676,839	107,077	44,616	5,339

Table 10. By State, Annual Cost (2016$), Estimated Annual and Ozone Season NOx Emissions Reductions in 2026, and Estimated Average Cost/Ton (2016$)

State	Annual Cost (2016$)	Annual Reductions	OS Emissions Reductions	Average Cost/Ton (2016$)
AR	24,713,219	3,711	1,546	6,659
CA	8,468,591	3,841	1,600	2,205
IL	23,703,051	5,547	2,311	4,273
IN	19,042,595	4,742	1,976	4,015
KY	33,418,421	6,396	2,665	5,225
LA	94,241,407	17,141	7,142	5,498
MD	2,234,405	377	157	5,924
MI	39,770,569	7,164	2,985	5,552
MO	23,481,162	4,955	2,065	4,739
MS	32,897,600	5,998	2,499	5,485
NJ	6,836,929	582	242	11,755
NY	15,282,005	2,299	958	6,646
OH	43,023,376	7,452	3,105	5,773
OK	53,184,143	10,530	4,388	5,051
PA	25,257,811	5,241	2,184	4,819
TX	63,432,182	11,259	4,691	5,634
UT	2,848,769	604	252	4,717
VA	37,665,883	5,279	2,200	7,135
WV	22,174,720	3,956	1,649	5,605
Total	571,676,839	107,077	44,616	5,339

Figure 1. Geographical Distribution of Ozone Season NOx Reductions in 2026 and Summary of Estimated Reductions by Industry and by State



State	Cement and Concrete Product Manufacturing	Glass and Glass Product Manufacturing	Iron and Steel Mills and Ferroalloy Manufacturing	Pipeline Transportation of Natural Gas	Applicable Boilers from Affected Industries	Municipal Waste Combustors	Total
LA	0	115	0	6,200	827	0	7,142
TX	0	818	0	3,171	702	0	4,691
OK	276	101	0	3,596	314	100	4,388
OH	0	275	114	2,244	472	0	3,105
MI	0	27	0	2,637	262	59	2,985
KY	0	22	13	2,624	7	0	2,665
MS	0	0	0	2,428	71	0	2,499
IL	0	297	0	1,943	71	0	2,311
VA	398	93	0	969	495	246	2,200
PA	171	791	9	574	173	466	2,184
MO	114	76	0	1,875	0	0	2,065
IN	478	220	228	737	96	217	1,976
WV	0	0	0	1,475	174	0	1,649
CA	1,135	160	0	213	0	92	1,600
AR	0	37	35	1,065	409	0	1,546
NY	0	80	9	230	116	523	958
UT	0	0	0	252	0	0	252
NJ	0	18	0	0	0	224	242
MD	0	0	0	13	0	145	157

Lastly, because the estimated number of emissions units for the reciprocating internal combustion engines and the boilers was large, the EPA reviewed a smaller set of permits to gather or confirm information on existing controls on engines and boilers.[17] To consider the potential impact this limited review could have on the estimated emissions reductions and costs for engines and boilers, the EPA prepared a sensitivity assessment. The sensitivity assessment included subsets of the engines and boilers for which the limited review was conducted because we determined these subsets of engines and boilers would need controls.[18] We estimated the emissions reductions and costs for these engines and boilers both without (i.e., based only on information in the emissions inventory) and with the supplemental information (i.e., based on information in the emissions inventory, supplemented with information from the limited permit review or found in a dataset from the July 2022 revised boiler MACT rule). We calculated the percent differences in the emissions reductions and costs between those two estimates.

For reciprocating internal combustion engines when comparing the estimates (i) the estimated emissions reductions (annual and ozone season) using the supplemental information were 12 percent lower, and (ii) the estimated annual costs using the supplemental information were 10 percent lower. For boilers, when comparing

[17] The limited permit review was completed for approximately 330 engines and 40 boilers.

[18] The subset of engines reviewed that were identified in the *Units Will Need Controls* worksheet were approximately 135 engines. The subset of boilers reviewed that were identified in the *Units Will Need Controls* worksheet were approximately 28 boilers.

the estimates (i) the estimated emissions reductions (annual and ozone season) using the supplemental information were 25 percent lower, and (ii) the estimated annual costs using the supplemental information were approximately 22 percent higher.

The reason the estimated costs are higher and reductions are lower for boilers is that we are accounting for the increment of emission reduction beyond any existing control identified in supplemental information that was not reflected in the emissions inventory. These additional tons are likely more expensive, so as a conservative estimate we calculated the cost of the control based on the total tons reduced by that control if the source was uncontrolled. However, so as to not overstate the potential emission reduction, we report only the incremental emission reduction.

Appendix A – Using 2019 Inventory Data to Identify Emissions Units

Boilers -- Steps taken to filter 2019 NEI data to estimate a list of boilers captured by the applicability criteria for the final rule.

1. Filter to 23 States
2. Remove any units that for any process associated with the unit lists an SCC Code that has SCC Level-4 equal to "< 10 Million BTU/hr", "10-100 Million BTU/hr", or "Boiler < 100 Million BTU, except tangential"
3. Limit boilers to units in the following NAICS:
   Tier 1 Industries
   - 3311 - Iron and Steel Mills and Ferroalloy Manufacturing

   Tier 2 Industries
   - 2122 - Metal Ore Mining
   - 3274 - Lime and Gypsum Product Manufacturing
   - 3221 - Pulp, Paper, and Paperboard Mills
   - 3241 - Petroleum and Coal Products Manufacturing
   - 3251 - Basic Chemical Manufacturing
4. Remove any processes that do not list Unit Type equal to "Boiler" or "Unclassified".
5. Remove any processes that do not have SCC Level-2 equal to "Commercial/Institutional: Boilers", "Electric Generation: Boilers", or "Industrial: Boilers"
6. Remove any processes that do not have SCC Level-3 equal to "Natural Gas", "Residual Oil", "Distillate Oil", or "Bituminous/Subbituminous Coal" and re-confirm that SCC Level-4 is not equal to "< 10 Million BTU/hr", "10-100 Million BTU/hr", or "Boiler < 100 Million BTU, except tangential"
7. Select units from the EIS unit-level file that have processes that were not filtered out during Step 1-6 (559 Units)
8. Remove any units with actual NOx emissions less than 7.5 tpy (380 units after removals)
9. Remove any units with Design Capacity UOM="E6BTU/HR" and Design Capacity<100, unless Design Capacity is default value of 0.1 or 0.01 (329 units after removals)
   Note: The default values may need to be expanded.
10. Remove any units where Facility Status="PS" or Unit Status="PS" (323 units after removals)
11. Added in 2 with Design Capacity default of 1 (325 units).
12. Removed recovery boilers/furnaces and process heaters by reviewing SCC codes or the Unit Level Description (Column AI).

For other industries and reciprocating internal combustion engines, -- Steps taken to filter 2019 NEI data to estimate units captured by the applicability criteria for the final rule.

1. Rely on NAICS Codes, SCC Codes, and Unit Types in NEI Data
2. Combine 2019 NEI data with other available data from comments, previous data collections, limited permit review to fill in missing design capacity where possible
3. Conduct permit reviews to fill in missing information to determine applicability (boiler and engine design capacity, MWC PTE and tons/day, and PTE for remaining industries)
4. Review available data and permits to determine controls currently installed on emissions units
5. Narrow the list of applicable units to only include those that will need to install controls (e.g., remove low utilization boilers)

Appendix B – *Municipal Waste Combustor Workgroup Report* -- Information Used to Estimate Costs for Waste Combustors or Incinerators

1. Cost/ton values were taken from the *Municipal Waste Combustor Workgroup Report*, prepared by the Ozone Transport Commission Stationary and Area Sources Committee, Revised April 2022 (https://otcair.org/upload/Documents/Reports/MWC%20Report_revised%2020220425.pdf).

2. For units that need to install ASNCR or low NOx technology (LN™) and SNCR
    a. The annual cost of ASNCR -- the *Municipal Waste Combustor Workgroup Report* cited $1,812,930 total annual costs (operating and capital) to install ASNCR at an MWC with 3 incinerators. We divided the value by 3 to derive an estimated annual cost of $604,310 per incinerator to install ASNCR.
    b. The annual cost of Covanta's LN™ and SNCR -- the *Municipal Waste Combustor Workgroup Report* cited total annual costs (operating and capital) for 1 incinerator ranging from $297,679 to $580,181. Using this information, we conservatively assumed $580,181 for any incinerator type that Covanta has indicated can install LN™ and SNCR.
3. For units that already have ASNCR or LN™ and SNCR installed
    a. The annual costs for facilities that already have ASNCR installed -- The *Municipal Waste Combustor Workgroup Report* cited $995,000 for the annual operating costs of ASNCR at an MWC with 3 incinerators. Because these facilities already have ASNCR installed, we did not include the capital costs. We divided the value by 3, to derive an estimated annual operating cost of $331,667 per incinerator to operate ASNCR. We believe this estimate is conservative because these units are already operating the installed ASNCR at a lower reagent usage and paying a portion of the $331,667 annual operating costs.
    b. For annual cost for facilities that already have Covanta LN™ and SNCR installed -- The *Municipal Waste Combustor Workgroup Report* cited annual operating costs for 1 incinerator ranging from $181,146 to $401,243. Because these facilities already have LN™ and SNCR installed, we did not include the capital costs. Using this information, we conservatively assumed $401,243 for the additional operating costs. We believe this estimate is conservative because these units are already operating the installed LN™ and SNCR at a lower reagent usage and paying a portion of the $401,243 annual operating costs.