# APPENDIX D:

# Reasonably Available Control Technology Analysis for Major Sources

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2B: NAFB RACT Supplemental
3A: Caesars RACT
3B: Caesars Supplemental

4: MGMRI RACT
5A: Calnev Pipeline LVT RACT
5B: Calnev Pipeline LVT Supplemental
6A: CertainTeed Gypsum Manufacturing RACT
6B: CertainTeed Gypsum Manufacturing Supplemental
7A: NV Energy Las Vegas Generating Station RACT
7B: NV Energy Clark Generating Station RACT
7C: NV Energy Sunpeak Generating Station RACT
7D: NV Energy Supplemental
8A: Saguaro Power Company RACT
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## ACRONYMS AND ABBREVIATIONS

**Acronyms**

| | |
|---|---|
| AFR | air-to-fuel injection ratio |
| AQR | Clark County Air Quality Regulation |
| ARA | Air Register Adjustment |
| BACT | Best Available Control Technology |
| BF | biased firing |
| BOOS | burner out of service |
| BT | burner tuning |
| CAM | compliance assurance monitoring |
| CCB | cyclonic combustion burner |
| CGS | Clark Generating Station |
| CCM | combined combustion modification |
| CCU | combined cycle units |
| CE | cost effectiveness |
| CEMS | continuous emission monitoring system |
| CEPCI | Chemical Engineering Plant Cost Index |
| CFB | ceramic fiber burners |
| CI | compression ignition |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| CT | combustion turbine |
| CTG | Control Techniques Guidelines (EPA) |
| DAQ | Division of Air Quality |
| DEFR | domed external floating roof |
| DES | Department of Environment and Sustainability |
| DLN | dry low $NO_x$ |
| DLNC | dry low $NO_x$ combustor |
| EAR | excess air reduction |
| EFRT | External Floating Roof Tank |
| EGR | exhaust gas recirculation |
| EPA | U.S. Environmental Protection Agency |
| EPMS | Engine Performance Management System |
| EU | emission unit |
| FBR | fluidized bed reactor |
| FGR | flue gas recirculation |
| FIR | forced internal recirculation |
| FIR2 | fuel-induced recirculation |
| FRT | floating roof tank |
| GACT | Generally Available Control Technology |
| GCP | good combustion practices |
| GFFM | gas flow fuel modifier |
| GHG | greenhouse gases |
| GMP | good maintenance practices |
| HA | hydrographic area |

| | |
|---|---|
| HAP | hazardous air pollutants |
| HC | hydrocarbons |
| HRSG | heat recovery steam generator |
| IFR | internal floating roof |
| ITR | injection timing retard |
| LAER | lowest achievable emission rate |
| LEA | low excess air |
| LNB | low NOx burner |
| LVT | Las Vegas Terminal |
| MAT | manifold air temperature |
| MACT | Maximum Achievable Control Technology |
| MGMRI | MGM Resorts International |
| NAAQS | National Ambient Air Quality Standards |
| NAFB | Nellis Air Force Base |
| NAICS | North American Industrial Classification System |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NGR | natural gas reburning |
| NMHC | nonmethane hydrocarbon |
| $NO_2$ | nitrogen dioxide |
| $NO_x$ | nitrogen oxide(s) |
| NRDC | Natural Resources Defense Council, Inc. |
| NSCR | non-selective catalytic reduction |
| NSPS | New Source Performance Standards |
| NSR | New Source Review |
| $O_2$ | Oxygen |
| OC | oxidation catalyst |
| O&M | operations and maintenance |
| OFA | overfired air |
| OP | (Title V) Operating Permit |
| OT | Oxygen Trim |
| PTE | potential to emit |
| RACM | reasonably available control measure |
| RACT | reasonably available control technology |
| RAP | reduced air preheat |
| RBLC | RACT / BACT / LAER Clearinghouse (database) |
| RCB | radiant ceramic burner |
| REA | reduce excess air |
| RICE | reciprocating internal combustion engine |
| RVP | Reid vapor pressure |
| SCA | Staged Combustion Air |
| SCR | selective catalytic reduction |
| SIC | Standard Industrial Classification |
| SLN | SoLoNOx |
| SNCR | selective non-catalytic reduction |
| SOx | sulfur oxide(s) |
| SPC | Saguaro Power Company |

| | |
|---|---|
| SPGS | Sun Peak Generation Station |
| SVE | soil vapor extraction |
| TCI | total capital investment |
| TVP | true vapor pressure |
| ULNB | ultra-low NOx burner |
| VOC | volatile organic compound |
| VRU | vapor recovery unit |
| WFR | water-to-fuel ratio |
| WSI | water/steam injection |

**Abbreviations**

| | |
|---|---|
| bbl | barrels (of oil) |
| hp | horsepower |
| hr | hour |
| kPa | kilopascal |
| kW | kilowatt |
| lb | pound |
| MM Btu | million Btu (heat input) |
| MM Btu/hr | million Btu per hour |
| $O_2$ | percent oxygen |
| Pa | pascal |
| Ppm | parts per million |
| ppmvd | parts per million volume dry |
| psi(a) | pounds per square inch (absolute) |
| tpd | tons per day |
| tpy | tons per year |

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# 1.0 INTRODUCTION

In 2015, the U.S. Environmental Protection Agency (EPA) revised the 8-hr National Ambient Air Quality Standard (NAAQS) for ozone to 0.070 parts per million (ppm). On June 4, 2018, EPA designated a portion of Clark County (Hydrographic Area (HA) 212) a "marginal" nonattainment area for the 2015 8-hr ozone NAAQS based on a design value that exceeded the standard (83 FR 25776).

HA 212, which is centrally located in Clark County, includes the Las Vegas Valley (Figure 1). After the area failed to attain the NAAQS by the August 3, 2021, deadline, EPA reclassified it to "moderate" nonattainment on January 5, 2023 (88 FR 775), then to "serious" nonattainment on January 21, 2025 (89 FR 103657). Under Section 182(c)(1) of the Clean Air Act (the Act) (42 U.S.C. 7401 et seq.), serious nonattainment areas are required to implement reasonable available control technology (RACT) for all major sources of volatile organic compounds (VOCs) and nitrogen oxides ($NO_x$). Appendix D contains RACT determinations for major sources in HA 212 and satisfies serious nonattainment area State Implementation Plan (SIP) requirements.

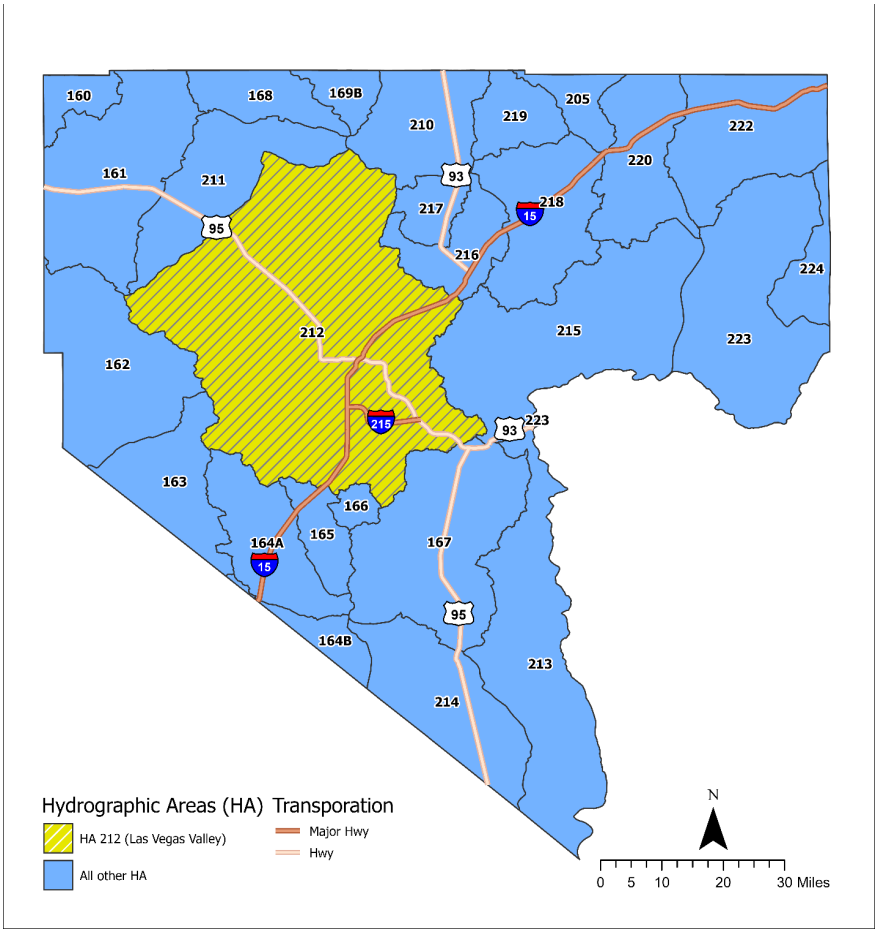



**Figure 1. Nonattainment Area (HA 212) in Clark County, NV.**

# 2.0 OZONE IN CLARK COUNTY

Both $NO_x$ and VOC emissions are precursors to the formation of ozone. The predominant source of $NO_x$ emissions in HA 212 is on-road mobile sources, while the predominant source of VOC emissions is biogenic. Point sources for both $NO_x$ and VOC emissions make up a small portion of the total emissions inventory for HA 212: in 2023, $NO_x$ point sources contributed 1,074 tons to the $NO_x$ emissions inventory and VOC point sources contributed 674 tons to the VOC emissions inventory (Appendix A). Of these, $NO_x$ major sources represented only one third of the 2023 inventory and VOC major sources represented only one fifth. During a typical summer day in 2023, $NO_x$ major stationary sources collectively emitted less than 2 tons of $NO_x$ and VOC major sources collectively emitted less than half a ton.

# 3.0 ATTAINMENT DATE REQUIREMENTS

The effective date of the nonattainment designation for HA 212 was August 3, 2018. EPA's implementation rule for the 2015 ozone NAAQS (40 CFR Part 51.1300, Subpart CC) provides that a marginal nonattainment area must achieve attainment within 3 years of the effective date of the nonattainment designation. Clark County was required to bring HA 212 into attainment with the 2015 8-hr ozone NAAQS by August 3, 2021 (attainment date).

Under Section 181(b) of the Act, EPA shall reclassify an ozone nonattainment area to the next higher classification if the area fails to achieve attainment by the attainment date. HA 212 did not achieve attainment by August 3, 2021, resulting in its reclassification from "marginal" to "moderate" nonattainment for the 2015 8-hr ozone NAAQS (88 FR 775). The attainment date for the moderate nonattainment area was August 3, 2024; after failing to attain the standard by that date, EPA reclassified HA 212 as a "serious" ozone nonattainment area effective January 21, 2025, with a new attainment deadline of August 3, 2027 (89 FR 103657).

Under Section 182(b) of the Act, major sources in an area classified as "moderate nonattainment" for the ozone NAAQS must demonstrate RACT. A major source under the "moderate" classification is any stationary source with the potential to emit (PTE) 100 tons per year (tpy) or more of VOCs or $NO_x$. Upon reclassification as a "serious" nonattainment area, the major source thresholds lower to 50 tpy, expanding RACT applicability to stationary sources not subject to it under the moderate classification. The present RACT evaluation builds on the prior moderate-area determinations by incorporating sources now classified as major due to the reduced threshold and reevaluating sources categorized as major under the previous threshold, ensuring compliance with the expanded requirements mandated by the Act and EPA's implementation rule (40 CFR Part 51.1312(a)).

# 4.0 RACT UNDER EXISTING LOCAL REGULATIONS VERSUS NONATTAINMENT AREA RACT

The Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ)'s definition of RACT is consistent with EPA's (44 FR 53761).[1] Section 0 of the Clark County Air Quality Regulations (AQRs) defines RACT as:

> "the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available, considering technological and economical feasibility..."

The AQRs already include several types of RACT requirements. Under AQRs 12.1.3.6 and 12.4.3, RACT applies to a stationary source proposing to construct or modify an emission unit and increase potential emissions at a minor stationary source by equal to or greater than significant levels, and to a major stationary source increasing potential emissions by equal to or greater than the minor New Source Review (NSR) Significant Level for a pollutant. The $NO_x$ and VOC RACT significance levels are 20 tpy for minor sources and 12.5 tpy for major sources (AQRs 12.1.1 and 12.4.2.1).

Beyond these construction and modification triggers, Section 182(b)(1)(A)(ii)(II) of the Act requires RACT for all major sources of ozone precursors; Section 182(f) extends this requirement to major sources of $NO_x$. For serious ozone nonattainment areas such as HA 212, "major source" is defined as a stationary source that emits or has a PTE of at least 50 tpy of either VOC or $NO_x$. To implement this federal requirement, AQR 120 requires owners and operators of VOC or $NO_x$ major sources in ozone nonattainment areas ("affected sources") to submit a major source RACT demonstration[2] within 120 days of being notified by the Control Officer. In April 2025, DAQ issued a notice to all affected sources requiring compliance with AQR 120, including any emission unit with a VOC or $NO_x$ PTE of 5 tpy or more ("affected unit"). DAQ used information from the affected sources to evaluate RACT, along with its previous RACT determinations for the Moderate SIP (codified in AQR 121). This previous analysis was updated to establish source-specific RACT requirements in AQR 122 for the serious nonattainment area, superseding AQR 121.

Another type of RACT requirement is Control Techniques Guidelines (CTG) RACT. Section 172(c)(1) of Part D of the Act requires an ozone nonattainment area to adopt reasonably available control measures (RACM), including RACT requirements for certain stationary sources. Under Section 182(b) of the Act, a moderate or higher ozone nonattainment area must apply RACT to each VOC source category for which EPA has issued a CTG. Sources falling into a category for which EPA has published a CTG are referred to as "CTG sources."

[1] Neither the Act nor EPA rules contain a codified definition of RACT for the purpose of implementing the Act's Part D RACT requirements. Instead, EPA has defined RACT as "the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility" (Strelow 1976).

[2] In this document, the term "demonstration" refers to RACT analyses performed by affected sources subject to AQR 120 requirements. The term "determination" describes DAQ's own analyses and decisions, which may be based in part on the information supplied in affected sources' demonstrations.

CTGs provide the "presumptive norm" for minimum control requirements for specific categories of sources. EPA recommends that air pollution control agencies adopt regulations that are consistent with the applicability thresholds and control levels in the CTGs, but allows agencies to "judge the feasibility of imposing the recommended controls on particular sources, and adjust the controls accordingly" (44 FR 53761).

DAQ established CTG RACT requirements for the moderate nonattainment area in AQRs 101–107, which cover industrial adhesive operations; gasoline dispensing facilities; metal and plastic parts coating operations; industrial cleaning solvent operations; metal solvent degreaser operations; offset lithographic, letterpress, and flexible package printing, and other graphic arts operations; and cutback asphalt operations. In AQRs 13.3 and 14.2, DAQ incorporated by reference the federal New Source Performance Standards (NSPS) at 40 CFR Part 60, Subparts K, Ka, and Kb and National Emission Standards for Hazardous Air Pollutants (NESHAP) at 40 CFR Part 63, Subpart BBBBBB for petroleum storage, along with the NSPS at 40 CFR Part 60, Subparts XX and XXa and the NESHAP at 40 CFR 63, Subpart BBBBBB for bulk gas plants and terminals.

EPA does not issue CTGs for $NO_x$ emissions from source categories, thus no CTG RACT requirements apply. EPA has instead put forth Alternative Control Techniques (ACT) guidance for $NO_x$ source categories. Rather than establishing a presumptive level of emissions control, ACT documents provide information on potential control measures and costs. They constitute an additional resource for determining RACM requirements and RACT for individual major sources.

EPA codified requirements for implementing the 2015 ozone NAAQS in 40 CFR Part 51, Subpart CC.. The remaining sections of this document describe DAQ's process for satisfying the RACT requirements for all CTG sources, and for $NO_x$ and VOC major sources, in Sections 172(c) and 182(b) of the Act.

# 5.0 CONTROL TECHNIQUES GUIDELINES ANALYSIS OVERVIEW

Appendix C provides a detailed CTG analysis. DAQ conducted a comprehensive evaluation of VOC sources within HA 212 by identifying pertinent CTG source categories and confirming the presence of operating stationary sources in each one. The process included (1) reviewing emissions inventory data for sources emitting above EPA's recommended CTG applicability threshold; (2) consolidating and screening business license databases from Las Vegas, North Las Vegas, Henderson, and unincorporated Clark County; (3) consulting permitting records; and (4) performing targeted internet searches using CTG source category key terms. DAQ promulgated new regulations for every CTG source with an affected facility in HA 212 after considering presumptive RACT in the CTG.

This comprehensive search identified 13 CTG source categories operating in HA 212. DAQ established CTG rules for 11 of them for the Moderate SIP: AQRs 101–107, 13.3, and 14.2. These regulations remain in effect locally and have been submitted to EPA for final action and inclusion into the SIP.

Since submittal of the Moderate SIP, DAQ has identified a newly permitted source engaged in fabric coating operations and confirmed the continued operation of a paper coating source identified during preparation of the Moderate SIP. To address both sources, DAQ is promulgating AQR 108 to establish CTG RACT requirements for paper, film, foil, fabric, and vinyl coating operations consistent with EPA's 1977 and 2007 CTG guidance.

Appendix C contains a complete description of the CTG review and new CTG rules. These new regulations ensure all applicable source categories operating in HA 212 are subject to CTG RACT requirements.

# 6.0 RACT FOR VOC AND $NO_X$ MAJOR SOURCES

Section 182(b) of the Act requires RACT for major stationary sources of VOC; Section 182(f) requires RACT for major stationary sources of $NO_x$. EPA guidance allows an air pollution control agency to establish a general RACT rule that applies to a category of stationary sources or to determine RACT for each major source on a case-by-case basis. EPA also allows averaging between major sources to demonstrate that a RACT level of control is achieved on the whole within the nonattainment area.

Through a review of operating permits, DAQ identified 23 major sources that might be subject to VOC or $NO_x$ RACT requirements under the "serious" classification and notified each on April 3, 2025, of their status (Attachment 1). Once DAQ issued the notification, the sources had 120 days to comply with AQR 120 requirements for all affected units. As the notice explained, an affected unit under the "serious" area classification included any emission unit with a $NO_x$ or VOC PTE equal to or greater than 5 tpy (EPA allows states to establish a de minimis level in implementing RACT (Helms 1995)).

Of the 23 major sources that received notices:

- 9 submitted RACT demonstrations;
- 12 submitted permit applications to become synthetic minor sources and avoid RACT requirements, and
- 2 were not subject to RACT requirements because each individual emission unit's PTE is less than 5 tpy of $NO_x$ or VOC.

Since so few major sources are located in HA 212, DAQ chose to address RACT for existing sources on a case-by-case basis. This approach involved three steps: initial information collection, technical analysis, and final determination of RACT, including an achievable emissions limitation using the reasonably available control.

*Step 1: Collect Information*

Pursuant to AQR 120, all affected sources, regardless of prior RACT determination, must submit a RACT demonstration for all affected units no later than 120 days after the Control Officer provides written notice. In April 2025, DAQ issued such notice to all affected sources in HA 212 requesting RACT demonstrations for emission units with a PTE of 5 tpy or greater of VOC or $NO_x$. Affected sources had to comply with the following AQR 120 requirements:

1. Identify all available control technologies pertaining to the affected unit.
2. Determine the technical feasibility of the available control technologies.
3. Determine the cost-effectiveness of technically feasible control technologies.
4. Identify other pollutants that would be emitted when using the proposed control technologies.

5. Discuss the environmental, energy, and other impacts (benefits and disbenefits) of the technologies.

6. Identify a control technology that is proposed as major source RACT for each affected unit.

7. Propose a RACT emissions limitation that the affected unit can achieve using the proposed major source RACT.

8. Identify a proposed schedule for complying with a RACT analysis.

9. Propose testing, monitoring, recordkeeping, and reporting efforts that meet periodic or compliance assurance monitoring requirements, including during periods of startup, shutdown, and malfunction.

To ensure consistency in cost estimates for RACT analyses, AQR 120.5(a)(3) and (b) require that major sources use a 6% interest rate and a 30-year life expectancy for either the affected unit or the control technology, with baseline emissions based on the unit's PTE. Affected sources can propose alternative values for the interest rate or life expectancy, provided they submit a supporting rationale to the Control Officer.

*Step 2: Verify Collected Information*

DAQ reviewed each demonstration for completeness and reliability in accordance with AQR 120, then issued letters to affected sources found initially deficient in meeting the requirements that gave them an opportunity to submit supplemental information.

Next, DAQ performed a technical evaluation of each RACT demonstration to verify reported data, cost assumptions, and the reasonableness of key analytical parameters. This review included assessments of available control technologies, engineering feasibility, proposed emissions limits, environmental impacts, and supporting documentation. When necessary, DAQ supplemented facility-supplied information with a review of the RACT/Best Available Control Technology (BACT)/Lowest achievable emission rate (LAER) Clearinghouse (RBLC), as well as relevant EPA guidance documents (ACTs, CTGs) and recent technical literature, to ensure DAQ considered all plausible RACT options in its own RACT determination.

An essential element of RACT evaluations is an assessment of cost-effectiveness (CE). DAQ confirmed that sources properly applied cost methodologies, used appropriate inflation adjustments, employed reasonable input parameters, and prioritized site-specific data when available. When DAQ identified control technologies the source had not evaluated, it performed preliminary CE screening to determine whether such technologies warranted further consideration. If the preliminary screening indicated that a control technology was potentially cost-effective (at or below $5,500/ton of VOC or $NO_x$) and technically feasible, DAQ requested the source conduct a detailed evaluation of it.

DAQ evaluated CE and technical feasibility based on its own precedents, EPA guidance, and thresholds utilized by other air pollution control agencies. If this more detailed CE analysis for a given control option remained below the established threshold of $5,500/ton, DAQ considered

that technology RACT. In all cases, DAQ ensured that RACT determinations were transparent, well-documented, and based on the best available technical and economic information.

DAQ provided its preliminary RACT analysis to each affected source for review, and to comment on any changes proposed to the source's original RACT demonstration. This collaborative approach helped identify site-specific considerations that potentially affected RACT implementation and ensured the determination was both technically sound and achievable in practice.

*Step 3: Establish Requirements*

Once DAQ identified control measures qualifying as RACT, it then determined RACT emissions limitations. These limitations represent the lowest achievable emissions level with which the emission unit(s) can continuously comply using the proposed control option. The proposed emissions limitations included requirements for startup, shutdown and malfunction periods (SSM). The provisions can be included in a single RACT emission limitation, or can act as a separate emissions limitation when including them in a generally applicable emissions limitation would make that limitation too lax during periods of normal operations. DAQ also considered work practice requirements when a numerical emissions limitation was not feasible.

DAQ assessed RACT requirements for affected sources and determined that the most efficient regulatory approach was to develop a source-specific RACT regulation (AQR 122), rather than establishing individual permit conditions for each affected source. DAQ hereby submits AQR 122 to EPA for approval into the SIP.

# 7.0 MAJOR OZONE PRECURSOR SOURCES IN THE NONATTAINMENT AREA

DAQ evaluated a total of eight major sources for $NO_x$ and three major sources for VOCs within HA 212, two sources being major for both pollutants. Table 1 presents each source's current permitted PTE, along with reported actual emissions from the 2023 emission inventory. These major sources reflect a range of industrial and commercial sectors, including four electric utility facilities, one bulk petroleum distribution terminal, and one gypsum manufacturing plant. The remaining three sources are classified as miscellaneous: two multi-location casino chains (each covered under a single permit) and Nellis Air Force Base (NAFB), each having such typical equipment as engines, small boilers, and other miscellaneous emission units. DAQ did not include three major $NO_x$ sources (two Switch, Ltd. and Jasmin Development LLC) in its RACT determinations because they do not operate affected units.

Table 1 presents each facility's total PTE, which qualifies it as a major source, along with its actual emissions reported in the SIP emission inventory (Appendix A).

**Table 1. Affected Sources in HA 212 Nonattainment Area**

| Facility ID | Facility Name | Total Facility NOx PTE (tpy) | 2023 EI Emissions (tpy) | 2023 EI Emissions (tpd) |
|---|---|---|---|---|
| **$NO_x$ Major Source** | | | | |
| 4 | CertainTeed | 84.86 | 26.57 | 0.073 |
| 7 | Clark Generating Station | 2,467.22 | 97.14 | 0.250 |
| 114 | Nellis AFB | 188.01 | 19.97 | 0.055 |
| 257 | Caesars Consolidated Properties | 439.96 | 88.95 | 0.244 |
| 329 | Las Vegas Generating Station | 94.66 | 20.15 | 0.055 |
| 393 | Saguaro Power Company | 135.18 | 32.45 | 0.089 |
| 423 | Sun Peak Generating Station | 249.42 | 26.32 | 0.072 |
| 825 | MGM Resorts International | 784.60 | 65.04 | 0.178 |
| **VOC Major Sources** | | | | |
| 7 | Clark Generating Station | 217.24 | 17.85 | 0.049 |
| 13 | Calnev Pipeline LLC | 188.01 | 98.00 | 0.269 |
| 114 | Nellis AFB | 66.52 | 7.30 | 0.020 |

# 8.0 MISCELLANEOUS, ENGINE, AND SMALL BOILER RACT

## 8.1 INTRODUCTION

This section explains DAQ's $NO_x$ (and in some cases VOC) case-by-case RACT determinations for each of the major sources in HA 212 that operate diesel engines (mostly emergency engines) and /or commercial boilers.[3] In making its own RACT determination, DAQ relied on information provided in the major sources' RACT demonstrations, supplementing these analyses when appropriate. For example, when one major source's RACT analysis identified additional potential control technologies for a similar type of equipment, DAQ used cost and emissions reduction information from that source for other determinations. In some cases, in accordance with AQR 120, DAQ adjusted the life expectancy to 30 years in cost calculations when a source did not provide any basis for a shorter life expectancy.

This section summarizes each source's RACT demonstration and highlights key information critical to DAQ's own RACT determinations. Attachments 2 through 10 provide the full scope of information that DAQ considered in making a RACT determination for each major source.

## 8.2 POTENTIALLY AVAILABLE $NO_X$ CONTROL TECHNOLOGIES FOR ENGINES AND BOILERS

Engines and boilers are widely used across HA 212. This section highlights several of the most common and relevant $NO_x$ control technologies for industrial, commercial, and institutional stationary internal combustion engines and boilers. This analysis drew on information from EPA's RBLC and ACT documents; more detailed analysis and consideration of additional control measures tailored to each source's configuration and operational context is provided below.

For the major sources reviewed, many engines operate as emergency engines to provide power in case of disruption or for peak demand. Such engines must run less than 500 hours annually, and are typically powered by natural gas or diesel fuel. Add-on controls for emergency engines are generally not cost-effective due to their limited or intermittent use. Instead, owners or operators follow operational limits and manufacturer-recommended work practices to minimize emissions. Further evaluation of emergency engine applications is provided in Section 8.3.

### 8.2.1 Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a post-combustion treatment of engine or boiler exhaust that involves injecting a nitrogen-based reagent (e.g., ammonia or urea) into the flue gas stream. In the presence of a catalyst, the reagent reacts selectively with $NO_x$ to convert it into nitrogen and water vapor. The effectiveness of SCR depends on several factors, including exhaust gas temperature (typically optimal between 480°F and 800°F), the amount and distribution of the reagent, injection grid design, and catalyst activity. SCR can result in $NO_x$ reductions of up to 70–90% (EPA 2020).

[3] See Sections 5 and 6 for the remaining major source RACT determinations.

Engines that must meet EPA's Tier 4 (40 CFR Part 1039) manufacturer certification standards are built with SCR systems. EPA regulations phased in Tier 4 requirements from 2008–2015, depending on engine size (40 CFR Part 1039). Engines manufactured prior to the applicable Tier 4 requirements can be retrofitted with SCR, but the engine's exhaust temperature will impact its effectiveness as an emissions control device. At too low a temperature, SCR efficiency decreases. Figure 2 presents an efficiency curve for SCR operation at various temperatures. Extrapolating beyond the curve for a boiler or emergency engine with a 400°F flue gas temperature yields a $NO_x$ removal efficiency of less than 5%.

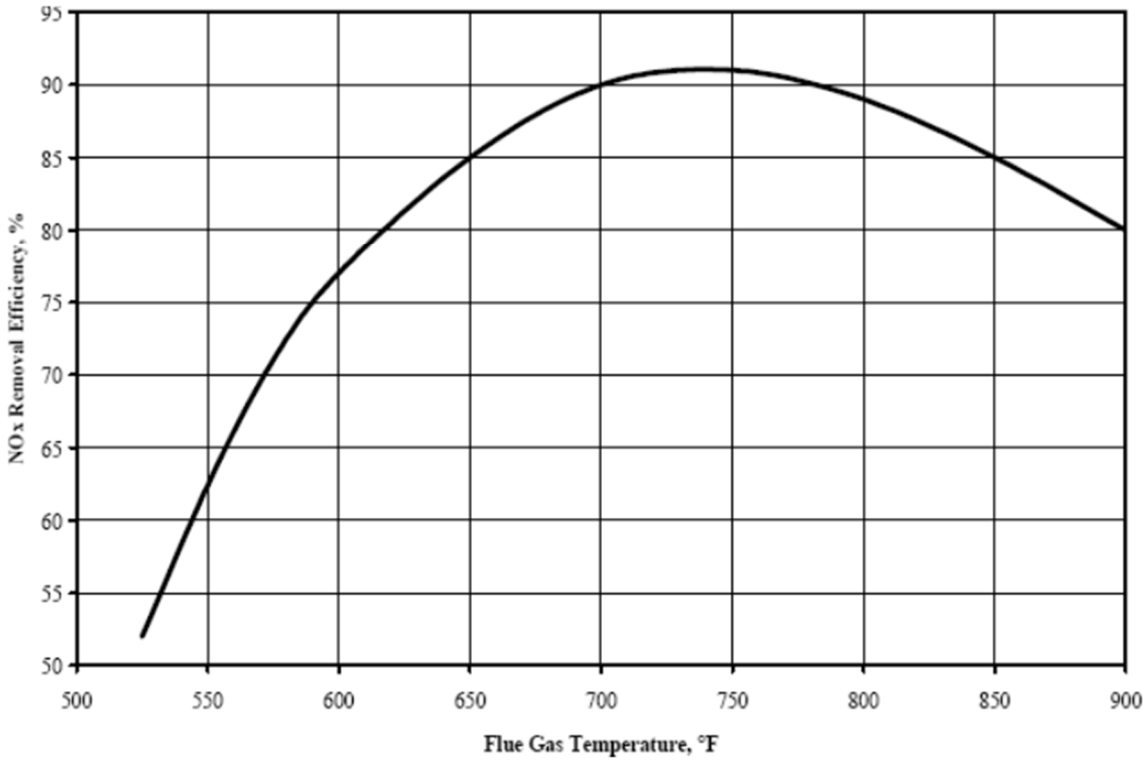



**Figure 2. SCR-$NO_x$ Removal versus Temperature (Sorrels 2016).**

For emergency engines in particular, intermittent operation results in average exhaust gas temperature below the temperature required for the catalytic reaction. This makes the application of SCR to most emergency engines economically unreasonable because the costs far exceed the emissions reduction benefit. SCR on small boilers, especially if the boilers are used intermittently (e.g., for hot water), are also not generally cost-effective. For example, a search of the RACT/BACT/LAER Clearinghouse for $NO_x$ control determinations for small boilers shows a 2021 BACT determination for the Lansing, Michigan, Board of Water and Light (MI-0447) for a 50 MMBtu/hour natural gas-fired boiler of 30 ppm $NO_x$ at 3% $O_2$ using a low-$NO_x$ burner (LNB) and flue gas recirculation (FGR) , which is generally more stringent than required for RACT. The cost-effectiveness of SCR for the boiler was calculated at $18,527, which was determined to be unreasonable for that facility.

### 8.2.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is a post-combustion $NO_x$ control technology that works by injecting a reducing agent (e.g., ammonia or urea) into the boiler exhaust stream at temperatures between approximately 1,400°F and 1,600°F. Within this temperature range, the injected reagent reacts with $NO_x$ in the flue gas stream, converting it primarily into molecular nitrogen and water vapor. SNCR systems typically achieve $NO_x$ reductions of up to 50%, although actual performance depends on achieving optimal temperature and mixing conditions for the reaction (Sorrels 2019).

SNCR is less costly than SCR, so the control technology is more cost-effective. However, like SCR, SNCR efficiency for $NO_x$ emissions reduction decreases when not operated at optimal temperatures, where the optimal range of SNCR is between 920°C and 1,095°C (1,688°F and 1,940°F). At a 400°F to 700°F exhaust temperature, SNCR has a control efficiency of near 0%. Figure 3 presents an efficiency curve for SNCR operations at various temperatures: the Y axis is % $NO_x$ control and the X axis is temperature in degrees Celsius.

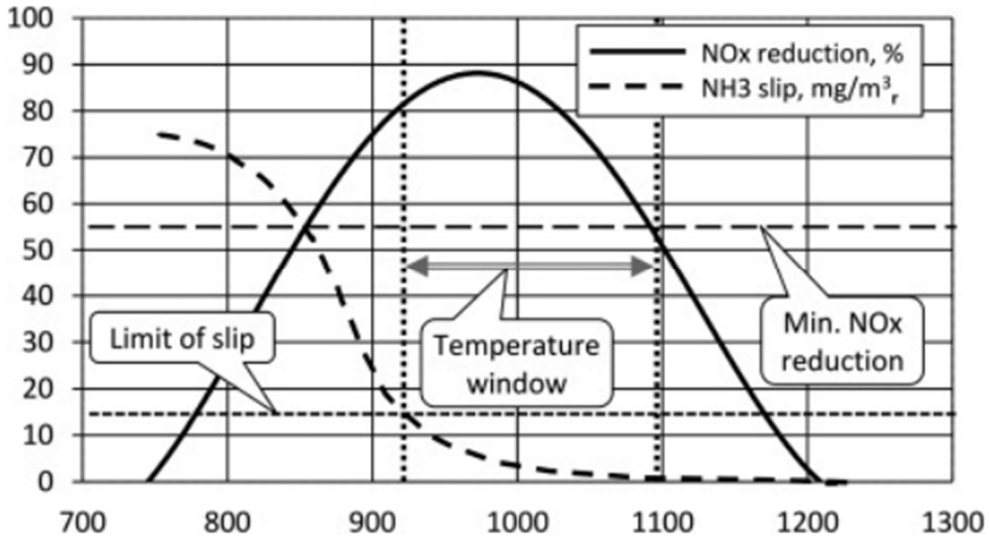



**Figure 3. Exhaust Gas Temperature and $NO_x$ Control Using SNCR (Pronobis 2020).**

### 8.2.3 Low $NO_x$ Burners

LNBs are commonly applied to boilers to reduce $NO_x$ formation during combustion by precisely managing the air-to-fuel mixing process in stages, lowering peak flame temperatures and thereby suppressing thermal $NO_x$ generation. Modern boiler burners are frequently equipped with at least basic LNB features. The two primary types used in natural gas boilers are staged air burners and staged fuel burners, which were both designed to optimize combustion conditions for $NO_x$ reduction (EPA 1992b).

### 8.2.4 Good Combustion and Maintenance Practices

Good combustion practice (GCP) and good maintenance practice (GMP) involve operating the engine or boiler to maximize energy output or thermal efficiency while maintaining optimized

oxygen levels to ensure complete combustion. GCP and GMP can also involve running equipment in accordance with the manufacturer's recommended settings and preventative maintenance schedules.

### 8.2.5 Ultra-Low NOx Burners for Boilers or Low Emission Control for Engines

Recent advancements in combustion technology have led to the development of ultra-low $NO_x$ burners (ULNB), which achieve higher levels of emissions control than traditional LNB. This technology can reduce $NO_x$ concentrations in boiler exhaust from 30 ppm to 9 ppm at 3% $O_2$ (see Attachment 3A). However, the reduced $NO_x$ emissions level comes at the expense of increased carbon monoxide (CO) emissions (EPA 1993b). Many existing LNB cannot be fine-tuned to reach ULNB levels, so replacing the burners in a boiler is necessary to achieve ULNB control levels.

Similar advances in combustion design have resulted in low emission control (LEC) engines. LEC, however, requires replacing the existing engine with a new one. DAQ did not require engine replacement as a viable option for RACT, since RACT is determined based on the design of the existing emission unit; however, engine replacement may be pursued at the discretion of the source.

### 8.2.6 Flue Gas Recirculation

FGR when applied to boilers reduces $NO_x$ emissions in two ways by recirculating a portion of the flue gas from the stack to the burner. First, the recirculated flue gas acts primarily as a dilutant to reduce combustion temperatures, thus suppressing thermal $NO_x$ formation. Second, it also lowers the oxygen concentration in the primary flame zone, reducing the availability of oxygen to react with nitrogen to form $NO_x$. FGR systems are normally used in combination with low $NO_x$ burners to achieve a 60–90% reduction in $NO_x$ emissions (EPA 1998b). It may not be possible to equip all boiler types with this technology, and retrofitting may be infeasible due to existing space constraints.

### 8.2.7 Exhaust Gas Recirculation

Exhaust gas recirculation (EGR) can reduce $NO_x$ by 40% on low-load mobile diesel engines, but EPA notes that EGR requires external hardware retrofits, some additional controls, and possibly cooling/cleaning of the exhaust. Other downsides include substantial fouling of heat exchanger and flow passages, increased maintenance, substantial increases in CO and smoke, and increased wear. As of 1993, EGR was not offered for production compression ignition (CI) or spark-ignition (SI) engines (EPA 1993b). In addition, a National Resources Defense Council (NRDC) study reported that EGR results in fuel penalties of 0–5%, is among the costliest of available control options, and results in increased particulate matter (PM) emissions (Kassel and Bailey 2004).

### 8.2.8 Injection Timing Retardation

Injection timing retardation (ITR) is a good combustion practice for engines. This technology reduces maximum combustion temperature and pressure, which decreases $NO_x$ formation. Its use

for $NO_x$ emissions reduction comes with tradeoffs because ITR degrades the performance and longevity of the engine and increases CO, PM, $CO_2$, and hydrocarbon (HC) emissions. EPA literature identifies these concerns, including a 3% fuel penalty, which means that the engines require more fuel to produce the same level of output (EPA 1978b, p. 4-67).

### 8.2.9 Air to Fuel Injection Ratio

Air-to-fuel injection ratio (AFR) can be used to control $NO_x$ emissions from some types of engines. Literature indicates that even if it is available, however, it comes with substantial fuel penalties (up to 5%) and increases in HC and CO emissions, and is not very effective for diesel engines (EPA 1978b, p. 4-66).

### 8.2.10 Derating/Increasing Speed

EPA has identified drawbacks to this option, noting that derating (reducing an engine's maximum power output by operating it at lower load or modifying operating parameters) results in substantial increases in brake-specific fuel consumption, to the point that additional units would be required to compensate for the loss in output and HC and CO emissions from the derated units would increase. Increasing engine speed is equivalent to derating in loss of power and is not a feasible option for existing units (EPA 1978b, p. 4-63). EPA also points out that the reduction in $NO_x$ emissions may be no more than the equivalent reduction in output, and that $NO_x$ emissions are less responsive to derating for turbocharged engines (EPA 1993d).

### 8.2.11 Inlet Manifold Air Temperature Adjustment/Aftercooler

Decreasing inlet manifold air temperature (MAT) reduces peak engine temperature, which reduces $NO_x$ formation. When air is turbocharged, aftercooling can be used to cool the pressurized air before it enters the engine; however, aftercooling requires additional hardware. An engine can be either air-cooled or water-cooled, which requires a cooling tower, but ambient temperatures may limit the amount of reduction that can be achieved, especially for air-cooled engines. At least one study indicated that cooling intake air is an effective technique to reduce $NO_x$ emissions, showing a reduction of more than 50% $NO_x$ in some operating conditions (Lashkarpour et al. 2011). With a built-in air-cooling aftercooler, the engine temperature dropped from 356°F to 122°F, a delta of 234°F (Komatsu Technical Report 2003).

Air cooling requires less hardware than water cooling, but either option can be used. Temperatures in Clark County can reach 115°F in the summer, but can drop to 30°F in the winter. This variation in ambient temperature makes it more difficult to determine control efficiency; however, EPA's 1978 control technology review indicates that for turbocharged diesels, the reduction in $NO_x$ is approximately 0.3 • (ΔT°F)% (EPA 1978b, Table 4-20).[4] Using this equation and a delta of 234°F yields a control efficiency of 70% (0.3 • 234 = 70%).

The cost of using this control technology depends on whether there is a cooling tower and water available for cooling the air following the turbocharger. Assuming there is (or that air cooling is

[4] The level of control varies from 0.1 to 0.4 • (ΔT°F)%, depending on whether the engine is a 2- or 4-cylinder, so 0.3 was selected as a conservative value.

used), the cost is mainly a factor of the hardware (i.e., heat exchanger, piping) needed to cool the air following the turbocharger and the associated operating costs. There may also be a slight fuel penalty, but since that is difficult to determine, it was not included in DAQ's cost analysis for this control technology.

### 8.2.12 Water Injection (Direct Water Injection/Steam Injection)

According to EPA, water injection reduces peak combustion temperature and results in significant $NO_x$ emissions reductions. Additional hardware is needed to inject water directly into the inlet manifold or cylinder, which can result in deposit buildup, degradation of lube oil, and cycling control problems. EPA indicates that at a 50% water/fuel ratio, there is a 25–35% decrease in $NO_x$ with a 2–4% fuel penalty (EPA 1993d, Table 3.4-6). An increase in HC emissions also results from the lower peak temperature. NAFB indicated a problem with water destroying the protective oil film on the cylinders, but that can be prevented by using water vapor rather than water droplets (Attachment 2A). However, the work required to create an injection system for different engine types makes this approach more suited for the original equipment manufacturer (OEM) parts rather than a retrofit. A water/fuel emulsion is a better route, according to studies, and is outlined in more detail below (Majewski 2002).

Water can be introduced into the diesel combustion process using any of the following methods:

- Emulsified fuel,
- In-cylinder water injection, or
- Water injection into the intake air (fumigation).

An emulsion is a system consisting of two immiscible liquids, one of which is finely dispersed in the other. In all water/diesel fuel emulsions of practical importance, water is dispersed in the form of fine droplets in the continuous diesel fuel phase: this type of emulsion is often referred to as a "water-in-fuel" emulsion. In the opposite configuration, where fuel is dispersed in the continuous water phase, water would be much more likely to contact the cylinder liner surface and other metal parts, leading to corrosion and engine problems.

In practice, running an engine on a water-fuel emulsion makes it possible to reduce $NO_x$ by up to about 50%, with the required water quantity being about 1% for each percentage point of $NO_x$ reduction (Majewski 2002). The limiting factor for water emulsions is the delivery capacity of the injection system. If emulsions are used without engine modifications (e.g., to substitute regular fuel in existing engines), the maximum quantity of water and the degree of $NO_x$ reduction are both limited to around 10–20%. Even then, the engine may not be able to reach its rated power, running in effect at a slightly derated condition.

Emulsions are distinguished from other methods of water addition because water, being incorporated into the fuel spray droplets themselves, is introduced directly into the combustion flame area where emissions are formed. In addition to the $NO_x$ benefit, which in all methods is attributed primarily to the water lowering the combustion temperature, emulsions result in enhanced fuel spray atomization and mixing. Enhanced mixing that extends throughout the diffusion flame can bring impressive reductions of PM emissions. As a result, water-fuel emulsions

are one of the rare diesel emissions control strategies that can simultaneously reduce $NO_x$ and PM emissions with a small (or no) fuel economy penalty. Reduction of PM emissions by emulsions has not been as thoroughly researched as $NO_x$ reduction, but the achievable effectiveness of PM reduction appears to be more than twice that of $NO_x$ reduction.

In-cylinder injection of water requires a separate, fully independent injection system, preferably under electronic control. This method offers the capability to inject very large quantities of water without the need to derate the engine. The system also allows operators to switch the water injection on and off as needed without affecting engine reliability. Direct water injection (DWI) needs to be carefully optimized with respect to injection timing, water consumption, emissions, and other parameters. Its flexibility in optimizing parameters allows this control approach to achieve $NO_x$ reductions similar to those seen in emulsion systems, despite the fact that water is not introduced directly into the diesel flame area as an integral part of the spray. However, any PM emissions reductions do not match those seen with emulsified fuels. The complex development work required for water injection systems in different engine types makes this approach more suited for OEM parts than retrofit applications.

Fumigation, meaning the introduction of water into the intake air, is the simplest method of water addition. This method offers very little control over injection parameters, such as timing or spatial coordinates; for this reason, observed $NO_x$ reductions tend to be lower than with emulsions or direct injection. Fumigation typically reduces $NO_x$ emissions by 10% for each 20% addition of water to the fuel (Holtbecker 1998).[5]

If fumigated water does not completely evaporate in the intake air, it will impinge on the cylinder walls, causing disintegration of the lube oil film and engine damage. A safer approach is to fumigate water vapor rather than water liquid. Water vapor may be generated using waste heat from the engine, such as from the exhaust gas and/or compressed charge air. Another possibility is steam, which may be available in certain stationary engine applications (Majewski 2002).

In-cylinder injection is more suitable for OEM parts and requires development to retrofit existing engines. It is likely not economically reasonable for existing emission units. For boilers,

> "[b]ecause of low initial cost, this technique is considered particularly effective for small single burner packaged boilers operated infrequently. In these applications, the oil gun positioned in the center of the natural gas ring burner is used to inject the water at high pressure. The amount of water injected normally varies between 25 and 75 percent of the natural gas feed rate, on a mass basis. However, the technique has some important environmental and energy impacts. For example, CO emissions increase because of the quenching effect on combustion, and the thermal efficiency of the boiler decreases because the moisture content of the flue gas increases, contributing to greater thermal losses at the stack. Another concern related to this technique is its potential for unsafe combustion conditions that can result from poor feed rate control" (EPA 1994, p. 5-43).

[5] Majewski, W.A. 2002. "Water in Diesel Combustion." *DieselNet Technology Guide*. Dieselnet.com/tech/engine_water.php.

A literature search produced no information on the potential available in adding water or steam injection to boilers with LNB—and whether the amount of $NO_x$ reduction would be less, since LNB already reduces emissions—and very little cost information. One study is cited for package fire-tube boilers: for a 33.5 MMBtu/hr boiler with a capacity factor of 0.33, the CE in 1992 dollars is \$3,903/ton $NO_x$ removed (EPA 1994, p. D-3). The study includes both oxygen trim and water/steam inject systems but does not separate out the costs between the two, since both are needed to get the reported $NO_x$ reductions. Correcting that to 2022 costs using the Chemical Engineering Plant Cost Index (CEPCI), $CE_{2022} = \$3{,}903_{1992} \bullet (\$824.5_{2022}/\$358.2_{1992}) = \$8{,}984$/ton.

### 8.2.13 Water/Fuel Emulsions

The literature indicates water/fuel emulsions as a viable option, even more than water injection; one source indicates that $NO_x$ control is limited to 20% without engine modifications, but reductions of 50% are possible with modifications (Majewski 2002). Another study indicates that emissions reductions up to 80% are possible (Issa et al. 2019, Table 5). Calculated costs for large engines can range from \$4.4/kW to \$19.2/kW, with a higher per-kW cost for smaller engines.

Emulsified diesel fuel cost about 4.4% more than regular diesel fuel in Europe in 2015, so that cost differential is assumed: for example, if diesel costs \$5/gal, then emulsified diesel was assumed to cost \$5.22/gal. The gallons of fuel used per year can be estimated using the size of the engine and hours of operation;[6] taking the gallons per year times a delta of \$0.22/gallon yields the cost of using emulsified diesel (Tyrovola et al. 2015).

The stability of the emulsion used could be an issue. Only 10% water emulsion is stable over fairly long periods, i.e., at least 35 days with no water separation (Scarpete 2013). This might require replacing unused fuel, resulting in additional expense and fuel waste.

#### 8.2.13.1 Engine Performance Management System

The U.S. Nuclear Regulatory Commission (NRC) points out that manufacturers' monitoring and maintenance guidance is based on long periods of running time and is, at times, unhelpful and/or damaging if followed for emergency engines (NRC 2011).[7] In this way, an engine performance management system (EPMS) is different from GCP and GMP. NRC recommends (or, in some cases, mandates) more extensive monitoring and different maintenance procedures than a comprehensive EPMS for emergency diesel engines; their guidance includes monitoring temperatures, quality of fuel (diesel degrades after a year), and CO emissions that indicate the degree of combustion, among other requirements.

EPMS alone does not appear to reduce $NO_x$ emissions, and DAQ found no data estimating improved efficiency or $NO_x$ emissions reduction potential. Because the degree of emissions reductions achievable through this work practice is unknown and appears negligible, DAQ does not consider it a viable technology for RACT.

[6] Diesel Service & Supply, www.dieselserviceandsupply.com.

[7] This data release contains 14 chapters addressing use of emergency diesel engines at nuclear plants, with emphasis on making certain the units will start and operate as expected in an emergency. Chapter 12 focuses on the parameters to monitor and why they are important.

#### 8.2.13.2 High-Pressure Fuel Injection

A literature review found some articles indicating $NO_x$ reductions may occur when using increasing injection pressure with retarded timing and other injection techniques. Generally, higher injection pressure (using larger-area nozzles) promotes mixing and shortens combustion time, resulting in higher combustion chamber temperatures. Increased combustion temperature increases $NO_x$ emissions. In addition, ultra-high-pressure injection is more appropriate for manufacturers to build into their engines than for retrofit (Fayad 2019). DAQ therefore does not consider it viable technology for RACT.

### 8.2.14 Operating Restrictions

RACT should be based on the actual or potential operations of the affected unit; therefore, DAQ generally did not consider emissions or operating restrictions a viable control technology for RACT unless the major source identified the approach in its own RACT demonstration.

## 8.3 EMERGENCY ENGINES

Emergency engines are specialized stationary engines designed to supply electrical or mechanical power exclusively when primary utility service is disrupted, such as during power outages, natural disasters, unusually high demand, or emergencies beyond a facility's control. These engines are permitted only limited hours of operation under major source operating permits (OPs), further reinforcing their role as critical but infrequently used backup devices.

Due to emergency engines' restricted usage (intermittent) and vital nature (rapid start design necessary to quickly stabilize the power supply), not all industry-standard emissions controls are technically or economically reasonable. EPA's 2010 Maximum Achievable Control Technology (MACT)/Generally Available Control Technology (GACT) review for Reciprocating ICE (RICE) supports this conclusion, stating:

> "Because these engines are typically used only a few number of hours per year, the costs of emission control are not warranted when compared to the emission reductions that would be achieved" (King 2010).

Similarly, the California Air Resources Board (CARB) does not recommend additional emission controls for emergency engines, acknowledging the practical limitations and essential nature of these engines during emergencies. Therefore, many advanced control technologies considered for major source RACT are not evaluated for emergency engines. This exemption is consistent with federal and state guidelines, and ensures reliable emergency power for public safety and critical infrastructure.

In Clark County, emergency engines typically operate less than 500 hours a year, 100 hours of which may be used for maintenance and testing and 50 hours of which may be used in nonemergency situations.[8] Typical operation of an emergency engine includes weekly, biweekly, or monthly 30-minute maintenance and testing operations with low or no load to ensure the engine is operating properly (CARB 2010). Furthermore, the electricity grid in Clark County is very reliable. From 2019–2023, customers in Nevada experienced an average interruption duration of about 185 minutes per year, with power being interrupted approximately 1 to 1.2 times per year, according to EIA-861 reliability data (EIA 2025). This low frequency of emergency engine use reduces the justification for expensive or complex control technologies; therefore, DAQ eliminated further consideration of more expensive add-on controls, and controls requiring infrastructural improvements or resulting in collateral disbenefits, from RACT analyses for emergency engines. Table 2 summarizes DAQ conclusions with respect to certain emissions controls for emergency engines.

**Table 2. Technology Controls Not Further Reviewed for Emergency Engines**

| Control | RACT for Emergency Engines | Explanation |
|---|---|---|
| SCR | No | SCR requires high exhaust temperature to be effective, usually only reached at higher, steady loads. The short testing or short-term use of emergency engines does not make it suitable for SCR because there is a delay between engine activation and when the engine exhaust reaches the required exhaust temperatures, which substantially narrows or eliminates the duration over which SCR could be used. Therefore, DAQ excludes SCR analysis for emergency engines because the cost is prohibitive relative to small annual emissions benefits (CARB 2010). |
| SNCR | No | Literature indicates SNCR is not available for diesel engines because it operates best between 1,600°F and 2,000°F, and diesel engine exhaust gas ranges from 800° F to 1,200° F (Pronobis 2020, Chapter 4.4.2). SNCR also needs a fuel-rich engine operation or the use of reducing agents; CI diesel engines are generally lean burning. In addition, lower exhaust gas temperatures make SNCR unsuitable (EPA 1993d, p. 2-18). DAQ finds that SNCR does not qualify as RACT because it is not an available control technology for emergency engines. |
| EGR | No | DAQ concludes that the potential energy penalty and collateral pollutant disbenefits outweigh the benefit of $NO_x$ emission reductions (Section 8.2.7). Therefore, DAQ finds that EGR is not RACT for emergency engines. |
| DWI | No | Environmental impacts associated with increased water use and infrastructure construction and potential collateral pollutant disbenefits outweigh potential emissions reductions. Therefore, DAQ finds that DWI is not RACT for emergency engines. |
| Conversion to natural gas (NG) (from diesel) | No | Conversion offers emission benefits, but onsite storage of natural gas is logistically complex, expensive, and potentially risky for emergency applications (e.g., supply interruptions during disasters). Diesel storage is preferred for reliability due to a long shelf life and safe on-site containment. NG retrofit is not practical in most permitted emergency engines setups. Therefore, DAQ finds that conversion to natural gas is not RACT for emergency engines. |

[8] Emergency engines are typically permitted for 500 hours per year to establish PTE. This approach is consistent with EPA guidance in the Seitz memo, which recognizes that emergency engines may be limited to 500 hours per year for PTE calculations rather than assuming continuous operation (EPA 1995). NSPS and NESHAP standards (40 CFR Parts 60 and 63) separately allow emergency engines to operate up to 100 hours per year for maintenance and testing, and up to 50 hours per year for nonemergency demand response.

## 8.4 NELLIS AIR FORCE BASE

NAFB (Source ID: 00114) is permitted as a major (Part 70) source for $NO_x$ and VOC; a synthetic minor for course particulate matter ($PM_{10}$), fine particulate matter ($PM_{2.5}$), CO, and hazardous air pollutants (HAPs); and a minor source for sulfur dioxide ($SO_2$). It is also a source of greenhouse gases (GHGs). The facility includes a stationary source category that, as of August 7, 1980, was regulated under Section 111 of the Act ("Asphalt Plants"); therefore, fugitive emissions from the asphalt plant were included in the source status determination. All activities and emission units (EUs) at NAFB are classified as Standard Industrial Classification (SIC) code 9711 and North American Industry Classification System (NAICS) code 928110, both titled "National Security."

Although it is treated as a single stationary source for permitting purposes, NAFB's emission units and activities are divided into three geographic areas that vary in size and purpose. Area I, the Main Base, consists of the flight line and a wide variety of commercial and industrial operations that support the base's mission. Area II, located east of the Main Base, includes the munitions storage area and the Red Horse Squadron complex (along with its mineral processing, asphalt batch plant, and concrete batch plant activities). Area III is a 1.9-square-mile portion north of the Main Base that includes the bulk fuels storage area, Security Police Squadron facilities, open space, and support facilities.

DAQ issued the latest permit for NAFB on May 1, 2025, with PTEs for $NO_x$ of 188.01 tpy and for VOC of 66.52 tpy.

NAFB has submitted a revision to lower the PTE of a spray booth to below 5 tpy of VOC and asked to remove one engine from its permit; these emission units were therefore not reviewed for RACT determinations. NAFB submitted an updated RACT analysis that addressed only the affected units not included in its RACT analysis for the Moderate SIP. This latest submittal included only one new emission unit, G194. In the earlier RACT analysis, NAFB evaluated $NO_x$ RACT for one nonemergency stationary engine (A032), seven emergency-use stationary engines (G009, G010, G032, G033, G041, G176, and G188), and two aircraft engine test cells (N001 and N002). One unit (G141) was incorrectly sized when purchased, so rather than operate it, NAFB uses it for spare parts. This engine is not included in the analysis. All engines evaluated were diesel-fired standby units permitted for limited use and operated at significantly lower levels than their maximum allowed hours.

In its RACT analysis for the Moderate SIP submittal, NAFB noted A032 was not used in 2021 and there were no plans to use it in 2022. DAQ requested that NAFB review A032 with updated PTE calculations for this Serious SIP demonstration. NAFB has decided to remove A032 from the permit; therefore, DAQ did not review A032 in this demonstration.

DAQ's RACT analysis builds on NAFB submissions, supplemented as needed to comply with updated requirements. The previous NAFB analysis for the Moderate SIP used actual emissions in the cost calculations; DAQ subsequently promulgated AQR 120 and now requires the use of PTE.

Most of NAFB's RACT analysis for the Moderate SIP concerned engines. NAFB used a more complete list of potential $NO_x$ control retrofit technologies than most facilities, including the replacement of existing engines. Replacing an entire emission unit, however, is not required in RACT analyses, which are limited to controls available for the existing emission unit, so DAQ eliminated further consideration of that option for this RACT analysis. Even if replacement were a required option, the CE analyses conducted by NAFB for replacing current engines with lower-emitting ones demonstrated that the cost (in $/ton $NO_x$ decrease) was far higher than the threshold of $5,500/ton.

### 8.4.1 $NO_x$ RACT analysis

#### 8.4.1.1 Emergency Engines

##### *8.4.1.1.1 Control Technology Analysis*

NAFB operates eight emergency engines with a PTE above 5 tpy, and included specifications for each of these engines in their previous and 2025 RACT analyses. The eight emergency units are G176, G009, G010, G032, G033, G041, G188, and G194. EUs: G176, G188, and G194 are newer engines that are EPA Tier 2, in accordance with 40 CFR Part 60, Subpart IIII.

Since the eight emergency engines are similar in size and planned operation, DAQ performed a single analysis for all eight. Attachments 2A and 2B contain the NAFB RACT analysis, which includes an analysis of EU: G194. DAQ included the potentially available control technologies identified by NAFB from its current and previous RACT analyses for its eight emergency engines in Table 3. The table also provides DAQ's analysis of information provided by NAFB, with supplemental information on the availability and cost of the emissions controls and DAQ's conclusion on whether a control qualifies as RACT. Attachment 9 has detailed cost calculations.

**Table 3. DAQ $NO_x$ RACT Analyses for NAFB's Emergency Engines**

| CT # | Control Tech | RACT | Discussion |
|---|---|---|---|
| 1 | DLN and SLN | No | NAFB indicates these technologies are primarily for turbines, and no examples for emergency engines were found. DAQ could not find articles, documents, or websites showing either technologies used on diesel engines. DAQ thus finds DLN and SLN are not commercially available for emergency engines. |
| 2 | Turbocharging | Yes | NAFB's RACT analysis indicates that these emergency engines are currently equipped with turbochargers.[9] DAQ finds this control technology qualifies as RACT as it is available and cost-effective. |
| 3 | GCP and GMP | Yes | These are the most common RACT determinations in the RBLC and are already implemented on these units through the OP.[10] |

[9] The NAFB RACT analysis states that all these emergency engines are equipped with turbochargers.
[10] Condition 1.3.2.2 of the operating permit: "The permittee shall operate and maintain all generators in accordance with the manufacturer's O&M manual for emissions-related components."

| CT # | Control Tech | RACT | Discussion |
|---|---|---|---|
| 4 | Pre-stratified charge | No | According to NAFB, the manufacturer says this technology is not applicable or available. EPA documents support NAFB's analysis, indicating this technique is for spark ignition engines, not compression engines (EPA 1993b). DAQ agrees this control technology does not qualify as RACT because it is not available. |
| 5 | ITR | No | The NAFB RACT analysis concludes ITR is not a desirable control technology because it degrades engine performance and longevity. The literature supports this, indicating increases in CO, PM, and HC emissions, and a fuel penalty of 3%. [11] DAQ concludes that ITR does not qualify as RACT for the units because the energy and collateral pollutant disbenefits outweigh potential emission reductions. |
| 6 | AFR adjustments | No | NAFB states that this technology would reduce power capability, which Air Force mission requirements would not allow. DAQ makes no finding on the availability of this control technology, but finds that it does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the benefits of the potential emissions reductions. |
| 7 | Derating/increasing speed | No | DAQ finds that this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the potential $NO_x$ emission reductions. |
| 8 | MAT adjustment/ aftercooler | Yes | NAFB is required to use air cooling on these emergency engines.[12] DAQ concludes that air cooling qualifies as RACT because it is available and cost-effective. |
| 9 | Water/fuel emulsions | No | DAQ concludes that emulsified diesel is technically feasible and DAQ estimated this CE at $1,323/ton at 10% water in emulsion. However, there are environmental and operational concerns with this control option. Because emulsified fuel has lower heating value than conventional diesel, additional fuel is required to generate the same power output compared to pure diesel and the water content can promote corrosion of engine components (Issa et al., 2019). Further, EPA ACT states there is no documentation of this control technique in stationary internal combustion engines and engine manufacturers that were contacted stated that water/fuel emulsions are not an option for their engines (EPA 1993b). Some studies show that water-emulsified diesel as fuel led to a significant increase of CO and VOC emissions (Syu et al. 2014). DAQ concludes that emulsified diesel does not qualify as RACT for the other units because the energy and collateral pollutant disbenefits outweigh potential emission reductions. |
| 10 | EPMS | No | DAQ finds this control technology does not qualify as RACT because the amount of additional $NO_x$ emissions reductions through use of an EPMS system is likely negligible. |
| 11 | High-pressure fuel injection | No | The effect on reducing $NO_x$ emissions and ability to retrofit the technology for existing emission units is highly uncertain. DAQ, therefore, finds this control technology does not qualify as RACT because it is not available. |
| 12 | Conversion to natural gas from diesel | No | NAFB's security directive prohibits reliance on natural gas for standby generation (Attachment 2A). DAQ finds this control technology does not qualify as RACT because it is not technically feasible. |
| 13 | Conversion to dual fuel (diesel/ natural gas) | No | NAFB's security directive prohibits reliance on natural gas for standby generation or mission-essential standby generation. Therefore, use of dual fuel using natural gas is removed from further considerations for emergency engines for NAFB, because it is technically infeasible for this major source. |

[11] Based on data from EPA's ACT for $NO_x$ emissions from ICE engines, p. 2-42, Table 2-14.
[12] AQR 121.

| CT # | Control Tech | RACT | Discussion |
|---|---|---|---|
| 14 | Alternative fuels (other than natural gas) | No | NAFB states that alternative fuels are not demonstrated or available for these engines, and the literature supports this conclusion. Methanol and LNG are the main alternatives besides emulsions. Methanol has serious corrosive and toxic problems, is costly, can be readily contaminated with water, and can increase GHG emissions. LNG requires significant investments for storage and installation and increases CO emissions (Issa et al. 2019). DAQ concludes that these alternative fuels are not RACT because the collateral pollutant emissions disbenefits for both outweigh potential emissions reduction benefits. |

NAFB included emission unit replacement as a potentially available control technology option; however, DAQ does not consider engine replacement an available control technology because RACT is defined relative to the emission unit under review, and replacement does not result in emissions control for an existing unit. DAQ thus eliminated all engine replacement options as RACT.[13]

#### *8.4.1.1.2 RACT Emissions Limitation*

NAFB concluded that RACT is the existing engine design, with no additional add-on $NO_x$ emissions controls, and proposed to require existing built-in controls along with GCP and GMP to satisfy RACT requirements. For the reasons discussed in Table 3, DAQ finds the existing emissions controls, consisting of turbocharging and aftercooler, qualify as RACT. It is not feasible to establish an emissions limitation for use of either control technology. DAQ proposes that NAFB continue to operate G009, G010, G032, G033, G041, G176, G188, and G194 with turbochargers and aftercoolers. No additional $NO_x$ emissions reductions are expected from compliance with RACT requirements.

### 8.4.1.2 Aircraft Engine Test Cells (N001 and N002)

Also termed "hush houses," these test cells are used to conduct off-wing aircraft engine diagnostics and testing. $NO_x$ emissions come from firing the aircraft engines, which are the F100 series: a twin spool, axial flow, afterburning turbofan engine. It has a three-stage fan driven by a two-stage low-pressure turbine, and a ten-stage compressor driven by a two-stage high-pressure turbine. $NO_x$ PTE emissions are 46.42 tpy for the combination of the test cells.

NAFB reviewed the RBLC data and found three similar facilities with RACT determinations of no additional controls or practices besides "preventive requirement of good management practices." No control measures were found for aircraft engine testing or similar sources in EPA's Menu of Control Measures (EPA 2013). NAFB therefore determined that RACT is no additional controls.

An online search on hush house controls showed that at least one company offered an SCR to control $NO_x$ emissions (Peerless-Aarding 2024). DAQ found no information specific to hush house SCR control size or cost. Compared to diesel engine exhaust, the exhaust from F100 turbofan engines is hotter (up to 3,000°F), which is above the effective operating range of SCR

[13] Although DAQ finds replacing an existing emission unit and reducing hours of operation are not control technology options for RACT, a major source could opt to use these strategies to meet certain emissions limitations established based on RACT or to avoid applicability by reducing PTE.

without causing catalyst degradation (Aaron 2009). The exhaust gas is also mixed with cooler air to avoid damaging the noise reduction equipment, which results in a higher volume, especially in the afterburner phase of operation. Reported exhaust mass ranges are 18.8, 22.32, and 167.688 kg/sec at the three main test modes (idle, military, and afterburner) (Merkisz, Markowski, and Pielecha 2013). While designing an SCR reactor sized to handle the large and transient exhaust flows (i.e., test cells run intermittently rather than continuously like a power plant) is technically possible, it is prohibitively expensive. In addition, a large reactor raises concerns related to space constraints and the hazard of ammonia use in an enclosed space occupied by personnel. Given these concerns, DAQ concludes the SCR is not cost-effective and does not represent RACT for aircraft engine test cells. Therefore, RACT is the current OP requirement of applying best management practices.[14]

### 8.4.2 VOC RACT Analysis

#### 8.4.2.1 Gasoline Dispensing Facility

NAFB has two storage tanks (EU J001 and J004) that are used for gasoline dispensing operations, with a throughput of 3,000,000 gallons each. Unit J004 is an underground storage tank with a capacity of 25,000 gallons and a PTE of 5.04 tpy. Unit J001 is an aboveground storage tank with a capacity of 20,000 gallons and a PTE of 6.00 tpy. Both are required to have Phase I vapor recovery with a control efficiency of 95.0%.[15] NAFB stated that its current controls satisfy AQR 102, but did not provide a further RACT review.

DAQ reviewed control measures for gasoline storage tank dispensing operations to determine if NAFB's current Phase I vapor recovery systems satisfy RACT, including applicable EPA guidance like "Design Criteria for Stage I Vapor Control Systems – Gasoline Service Stations" (EPA 1975). EPA's CTG identifies Phase I vapor recovery systems as the recommended control technology for gasoline dispensing facilities and suggests control efficiencies of greater than 90% are achievable with common design elements. The current technology at EU J001 and J004 achieves 95% control efficiency, which is above EPA's CTG recommendations.

DAQ also considered enhanced vapor recovery. AQR 102 requires that if HA 212 fails to make attainment, gasoline dispensing facilities (GDFs) are required to use CARB-certified Enhanced Vapor Recovery (EVR). HA 212 failed to make attainment; therefore, GDFs with gasoline throughput of 120,000 gallons or more must comply with CARB-certified EVR control standards upon modifying, replacing, or newly installing any affected facility no later than 180 days from the Control Officer's written notice. CARB-certified EVR must achieve a minimum vapor control volumetric efficiency of 98% for underground storage tanks and 95% for aboveground storage tanks for all affected facilities. Since EU J001 is an aboveground storage tank currently achieving 95% control efficiency, adding EVR would not improve the control efficiency. EU J004 is an underground storage tank and must achieve 98% control efficiency through CARB-

[14] Condition 1.4.2.2: "The permittee shall implement best management practices that result in compliance, at a minimum, with AQR 26, 40, and 43. *[AQR 12.5.2.6(a)]"* The operating permit also contains emissions limits, fuel limits, testing requirements, and monitoring and reporting requirements.

[15] Condition 1.1.2.2.7(a): "The Phase I vapor recovery system shall be rated with at least 95.0% control efficiency when in operation. This system shall be certified by an industry-recognized certification body, i.e., California Air Resources Board (CARB) or equivalent."

certified EVR upon modification, replacing or newly installing the affected facility no later than 180 days from the Control Officer's written notice. DAQ determined that replacing the current control system for a 3% efficiency gain was not cost-effective, therefore EVR is not RACT for this unit.

DAQ determines that the existing control of Phase I vapor recovery systems at 95% control efficiency represents RACT for EUs J001 and J004.

## 8.5 CAESARS ENTERTAINMENT

Caesars (Source ID: 257) owns and operates several adjacent and contiguous hotels, casinos, and a convention center. DAQ reviewed the following properties for this RACT analysis:

- Harrah's Las Vegas, 3475 S. Las Vegas Blvd.
- Flamingo Las Vegas, 3555 S. Las Vegas Blvd.
- Horseshoe Las Vegas, 3645 S. Las Vegas Blvd. (formerly Bally's)
- Caesars Palace, 3570 S. Las Vegas Blvd.
- The Cromwell Hotel, 3595 S. Las Vegas Blvd.
- Paris Las Vegas, 3655 S. Las Vegas Blvd.
- The LINQ, 3535 S. Las Vegas Blvd.
- High Roller (observation wheel in the LINQ complex), 3545 S. Las Vegas Blvd.
- Planet Hollywood Las Vegas, 3667 S. Las Vegas Blvd.
- Battista's Hole in the Wall restaurant, 4041 Audrie St.
- Caesars Forum conference center, 3911 Koval Lane.

Caesars's PTE for the consolidated properties is 439.96 tons per year of $NO_x$ emissions and 27.23 tons per year of VOC emissions. Only $NO_x$ emissions exceed the 50 tpy major source threshold; therefore, DAQ limited the RACT analysis to those. Attachments 3A and 3B contain the proposed RACT analysis from Caesars, which includes a complete list of emission units potentially subject to RACT requirements. These consist only of natural gas-fired boilers. DAQ followed Caesars's RACT analysis in grouping emission units with similar ratings or emissions concentrations.

### 8.5.1 Boiler $NO_x$ RACT

Caesars owns and operates five boilers (EUs: CP01–CP05) subject to $NO_x$ RACT review. Each boiler is located at Caesars Palace and is approximately 34–35 MMBtu/hr in size. These boilers are classified as industrial, commercial, or institutional boilers because they include steam and hot water generators with heat input capacities from 0.4 to 1,500 MMBtu/hr (EPA 1994). According to Caesars' analysis, the Hurst and Burnham boilers are 3-pass fire-tube, 800-bhp boilers; the Riello burners associated with all five boilers include LNB designs and cannot be modified to lower $NO_x$ emissions, i.e., to the level achievable with ULNB. All the boilers fire natural

gas and have $NO_x$ emissions limits of 29–30 ppm at 3% $O_2$, imposed through New Source Review Authority to Construct permits. There are no limits on fuel use or operating hours.

Caesars' RACT analysis reviewed five possible control technologies for the boilers (FGR, Radiant Ceramic burner, ULNB, SCR, and SNCR). Only the replacement of existing burners with ULNB was found technically feasible, so Caesars obtained a cost estimate for retrofitting the five boilers with ULNB and conducted a cost estimate for each boiler. It concluded that adding ULNB to the boilers would cost $6,330–$6,460/ton, far above DAQ's threshold for CE.

#### 8.5.1.1 DAQ Control Technology Analysis

DAQ reviewed other technologies beyond those Caesars provided in its RACT submittal and requested more information from Caesars to determine the technical feasibility of available controls. Table 4 shows DAQ's RACT analyses for the Caesars boilers, based on information from Caesars' RACT demonstration and the other documents indicated.

**Table 4. DAQ's $NO_x$ RACT Determinations for Caesars' Boilers**

| CT # | Control Tech | RACT | Discussion |
|---|---|---|---|
| 1 | SCR | No | Caesars rejected SCR because the boiler exhaust gas temperatures are too low; flue-gas temperatures of a typical boiler range from 300°F –500°F, and Caesars reports exhaust temperatures of less than 400°F, which is below the effective operating range of the SCR (typically optimal between 480°F and 800°F) (U.S. Department of Energy's Industrial Technologies Program). Figure 2 confirms the flue gas temperatures are too low for effective SCR operation. DAQ concludes that this control technology is not RACT because it is not technically feasible for this type of boiler. |
| 2 | SNCR | No | Although having lower capital and operating cost, SNCR is not available for this size industrial boiler. It operates best at temperatures of 1,600°F to 2,000°F, but boiler flue gas temperatures are less than 400°F (204°C) (EPA 1994) (Figure 3). DAQ determines SNCR is not technically feasible for these boilers. |
| 3 | LNB | Yes | The boilers are equipped with LNB and are required to operate at or below 30 ppm $NO_x$. DAQ finds that LNB qualifies as RACT. |
| 4 | ULNB | No | This category includes metal mesh burners (as well as ceramic burners—see CT#14). For metal mesh burners or equivalent ULNB, DAQ calculated a CE of $6,330/ton to upgrade the burners to ULNB. This cost estimate is based on Caesars' cost figures using a 70% control efficiency for ULNB and adjusting Caesars' estimate for a 30-yr life expectancy. DAQ finds that ULNB is not RACT because it is not cost-effective.[16] |
| 5 | GCP and GMP | Yes | These practices are the most common RACT determinations in the RBLC and are already being implemented on these units through the OP (Condition III.A.4.b). DAQ finds that GCP and GMP are RACT. |
| 6 | FGR | No | Caesars rejected FGR because of retrofit problems identified by its boiler maintenance contractor: the units cannot be retrofitted because of the configuration of the components for the combustion air supply for the burners.[17] Caesars indicates that the boilers already have LNB installed and some LNB include FGR to some extent as part of the |

[16] ULNB can reduce $NO_x$ concentrations to 9 ppm from the current 29 to 30 ppm. Caesars's RACT analysis included a vendor quote showing a capital cost of around $330K; Caesars used a 30-yr life removal.

[17] From the Caesars previous RACT analysis: "According to the Caesars boiler maintenance contractor, the existing boilers with Riello burners cannot be retrofitted with FGR due to the configuration of the components for the combustion air supply for the burners. Therefore, an FGR retrofit is not technically feasible for these boilers. An FGR retrofit in conjunction with burner replacement is potentially feasible but since it would not represent a significant improvement in the amount of control possible when compared to retrofitting an ultra-low $NO_x$ burner alone, this control option is not considered to be an alternative control strategy to an ultralow $NO_x$ burner."

| CT # | Control Tech | RACT | Discussion |
|---|---|---|---|
| | | | design (even more so with ULNB) (Richards 2000)(p. 7-4). Therefore, much of the $NO_x$ reductions associated with FGR may already be realized by the LNB, which are keeping $NO_x$ exhaust gas concentrations at 30 ppm or less. DAQ concludes that FGR is not a feasible control technology for these boilers based on their design. |
| 7 | Excess Air Reduction (EAR) / Low Excess Air (LEA) | No | Boilers are generally run with 10–20% excess air (EA) to ensure full combustion (to minimize smoke, PM, and VOC, and for safety). Reducing EA is an "easy" approach (Richards 2000) (p. 6-8) that can reduce $NO_x$ emissions by 5-10% (Energy Solutions Center)[18] or 16-20% (by going to 2-7% EA) (Richards 2000) (p. 6-9). Often this is done by changing burners, so the cost and CE would be similar to that of installing a ULNB ($6330/ton). DAQ concludes this control technology is not RACT because it is not cost-effective. |
| 8 | Burner Out of Service (BOOS) | No | BOOS is available only for multi-burner boilers; the Caesars' boilers are single burner models (based on information from manufacturer websites). With BOOS, one or more burners are taken out of service, meaning they do not burn fuel and instead are used to inject air or flue gas. It has a similar effect and cost to FGR or OFA. DAQ concludes that this control technology is not RACT because it is not technically feasible based on the boilers' design. |
| 9 | Overfire Air (OFA) | No | OFA is often used in conjunction with LNB, and may already be a part of the Caesars boilers. If not, OFA requires modifications to the boiler and is not available for some boiler configurations (Richards 2000) (p. 6-10).[19] The emissions reductions available are estimated at 30–58% (Richards 2000) (p.7-5).[20] DAQ assumed 50% control efficiency and the CE is $2,516 /ton $NO_x$. DAQ requested that Caesars assess OFA further for technical feasibility and cost-effectiveness. Caesars reviewed OFA and noted that the maintenance contractor stated that this technology is not common practice for fire-tube boilers and the physical layout does not allow for this application. Therefore, DAQ determined this technology is RACT because it is not technically feasible. |
| 10 | Air Register Adjustment (ARA) | No | Air registers control the distribution and control of high-volume combustion air. By adjusting the register door positioner, the air can be rotated in a clockwise or counter-clockwise direction. This rotating combustion air creates a thorough mixing of the fuel and air before it enters the combustion zone, resulting in complete, efficient combustion with low excess air. Single zone air registers are used on units up to ~120 MMBtu/hr, mainly in conjunction with OFA, when the angle of the air flow can be adjusted. Since OFA is not technically feasible, DAQ eliminated ARA as also not technically feasible. |
| 11 | Reduced Air Preheat (RAP) | No | Combustion air preheat is never used for fire-tube boiler configurations (EPA 1994) (p. 2-4), so there is no air preheat to reduce. When available, RAP can reduce $NO_x$ emissions by 15–25% (Richards 2000) (p. 6-18 and 6-19), but is seldom used due to efficiency penalties (Oland 2002) (p. 5-5). DAQ determined this control technology is not RACT because it is not technically feasible for these types of boilers. |
| 12 | Fuel conversion | No | Fuel conversion is often addressed for several different pollutants, such as PM and sulfur oxides ($SO_x$), when a fuel such as coal or oil is used. A fuel lower in nitrogen will produce less $NO_x$ (EPA 1994) (p. 5-4). The best fuel in terms of nitrogen content is natural gas, which the boilers already use, so switching is not an option. DAQ finds that fuel conversion is not RACT because it will not result in additional emissions reductions. |
| 13 | Water / Steam Injection (WSI) | No | One study is cited for WSI for package fire-tube boilers. For a 33.5 MMBtu/hr boiler and a capacity factor of 0.33, the CE in 1992 dollars is $3,903/ton $NO_x$ removed (EPA |

[18] However, this source also states that it is better to select a control technology that has little effect on excess air.

[19] "Overfire air combustion modifications require the penetration of the boiler wall by new air ducts and usually requires changes to the air handling system in order to deliver the air to the secondary combustion zone. Furthermore, there must be sufficient space above the burners and before the heat exchange area of the boiler to provide sufficient time for the combustion reactions. Because of this limitation, this approach is not possible on some existing coal-, oil-, and gas-fired suspension type boilers."

[20] This is in conjunction with LNB, but yields reductions of 30-58% based on reducing emissions of 0.3 to 0.5 lb $NO_x$/MM Btu down to 0.21 lb/MM Btu. (e.g., (0.5-0.21)/0.5 = 0.58 or 58%)

| CT # | Control Tech | RACT | Discussion |
|---|---|---|---|
| | | | 1994) (p. D-3). This includes both oxygen trim and water/steam injection, and does not separate out the costs between the two because both are needed to get the reported $NO_x$ reductions. Correcting that to 2024 costs using the CEPCI, $CE_{2024}$ = $\$3{,}903_{1992}$ x ($\$796.16_{2024}/\$358.2_{1992}$) = $8,675/ton. DAQ concludes that water injection is not RACT because it is not cost-effective and has energy and safety disbenefits that outweigh the potential for $NO_x$ emissions reductions. |
| 14 | Ceramic Fiber Burners (CFB) / Radiant Ceramic Burners (RCB) / Metal mesh burners | No | These burners are a type of LNB. "The fiber burner is a burner using a ceramic fiber matrix as the combustion surface ~ Premixed gaseous fuel and air enter the burner plenum, pass through the fiber surface, and are ignited. Once the burner is operating steadily, the surface glows without visible flame at ,800° F and typical emissions are 20 ppm CO,15 ppm $NO_x$, and 2 ppm HC" (Kesselring, Kendall, and Schreiber 1984). $NO_x$ emissions as low as 10 ppm have been achievable. The burners can often be fitted into the same space as the original burners in fire-tube boilers, extending along the tube, and use the same auxiliary equipment as other burners, keeping the capital costs relatively low. CFB have an additional advantage: thermal efficiency is increased by 1–2%, resulting in a savings of as much as 5% natural gas. However, ceramic burners to date have been applied only in boilers of 16 MM Btu/hr or less, so are not yet demonstrated as feasible for the Caesars' boilers, which are 30+ MM Btu/hr. Therefore, DAQ determined that this is not an available control for this size boiler, and therefore not RACT. Metal mesh burners, like ceramic burners, are ultra-low $NO_x$ burners (ULNB) and can reduce emissions substantially—in this case, down to 9 to 15 ppm. The metal mesh burners, in contrast to ceramic burners, are suitable for larger boilers up to over 100 MMBtu/hr, but the cost is much higher (an estimated $250,000, since metal mesh burners are custom-designed and built for each boiler make and model) and there are no fuel savings, so DAQ concludes the metal mesh burner technology are not cost effective for these boilers. Since ceramic fiber burners are not available for these emission units and metal mesh burners are not cost effective, DAQ concludes that the existing controls constitute RACT for these boilers. |
| 15 | LNB/FGR | No | The most commonly demonstrated $NO_x$ combination control for boilers is LNB with FGR. Retrofit of combined LNB and FGR controls to existing packaged boilers is often more feasible than using FGR alone. Also, combined retrofit of FGR and LNB to ICI boilers is considered by some to be a way of meeting stringent $NO_x$ control regulations without using flue gas treatment controls. Field data for 101 natural gas-fired, 44 distillate oil-fired, and 13 residual oil-fired water tube boilers (primarily in California) show that LNB/FGR retrofits achieve $NO_x$ reduction efficiencies ranging from 55% to 84% for natural gas units (EPA 1994) (p.5-60). However, these results are predominantly from larger water tube boilers, not smaller firetube designs as found at the Caesars facility, where technical constraints, including burner design, furnace geometry, and achievable recirculation rates, may preclude the use of LNB/FGR as a feasible retrofit. Therefore, DAQ has determined that LNB/FGR is not RACT for the Caesars firetube boilers, as it is not technically feasible for these units based on site- and boiler-specific considerations. |
| 16 | Gas Fuel Flow Modifiers (GFFM) | No | The gas turbulator has been demonstrated to reduce $NO_x$ formation in natural gas-fired packaged boilers. Originally designed to produce savings in fuel consumption, the turbulator is a small stainless-steel venturi incorporating strategically placed fins. The turbulator is inserted in the gas pipe directly upstream of the burner, creating highly turbulent fuel flow. This turbulence facilitates the bonding of hydrocarbon particles with the oxygen molecules of the combustion air, resulting in increased combustion efficiency. Fuel savings typically range from 2–10% but have been as high as 35%. From the standpoint of $NO_x$ emissions reductions, the more efficient turbulent mixing of fuel and air results in lower excess air requirements for efficient combustion, producing lower levels of $NO_x$. At one site, the use of a turbulator raised full-load boiler efficiency by 3% and the improved air-fuel mixing reduced the required excess oxygen by 27%. $NO_x$ emissions were reduced from 58 to 35 ppm at 3% $O_2$, a 40% decrease (EPA 1994) (p. 5-69). The Caesars' boilers are already equipped with LNB, which incorporate air-fuel mixing strategies and are already emitting at only 30 ppm or less, so this technique likely will have little or no effect in further reducing emissions. However, DAQ calculated CE using 15% reduction in $NO_x$ and half the cost of installing ULNB. The CE was |

| CT # | Control Tech | RACT | Discussion |
|---|---|---|---|
| | | | $14,769, so DAQ concludes that GFFM is not cost-effective for RACT. |
| 17 | Forced Internal Recirculation (FIR) Burners | No | FIR burners use a combination of premixing, staging, and interstage heat removal to control $NO_x$ and CO formation by (1) premixing sub-stoichiometric combustion air and significant internal recirculation of partial combustion products in the first stage to achieve stable, uniform combustion that minimizes peak flame temperature and high oxygen pockets; (2) enhancing heat transfer from the first stage to reduce combustion temperatures in the second stage; and (3) controlling second-stage combustion to further minimize peak flame temperature. Burners based on this concept have no moving parts and avoid the need for external FGR (Oland 2002) (p. 5-9). These are classified as ULNB, since they can reach single digit $NO_x$ concentrations (in ppm at 3% $O_2$). Assuming that the costs are the same as for generic ULNB burners (see CT #4 above), the CE would be $6,330/ton. DAQ finds that FIR is not RACT because it is not cost-effective. |
| 18 | Fuel-Induced Recirculation (FIR2) | No | FIR2 "involves the recirculation of a portion of the boiler flue gas and mixing it with the gas fuel at some point upstream of the burner. Although FIR has not yet been widely applied, it has been demonstrated commercially in an industrial unit in California, achieving $NO_x$ emission readings as low as 17 ppm with little adverse effect on CO emissions" (EPA 1994) (p. 5-56). Reductions of 48–68% have been demonstrated on a utility boiler (Reese et al. 1994); cost information is difficult to find, but the Reese study indicated that capital costs are low. It is difficult to determine whether the existing units can be readily modified for FRI2, and whether the reductions LNB already achieved mean the reductions FRI2 can achieve would be lower. Assuming the cost is about the same as that of an FGR retrofit (estimated at $94,920) and the reduction achievable is 43% (assuming a reduction from 30 ppm down to 17 ppm), the CE is $2,926/ton. DAQ requested that Caesars review FIR2 to assess technical feasibility. Caesars' boiler maintenance contractor determined that the existing boilers with Riello burners cannot be retrofitted with FIR due to the configuration of the combustion air supply components. The burners would need to be replaced for this technology to be implemented. The cost of burner replacement for FIR2 implementation would be equivalent to the cost of installing ULNB. Therefore, DAQ concludes that FIR2 is not cost effective for these units and therefore is not RACT. |
| 19 & 20 | Oxygen Trim (OT) and Burner Tuning (BT) | No | OT and BT are two relatively simple operational modifications that can be performed to limit the amount of excess oxygen available for combustion. In certain cases, these adjustments can reduce $NO_x$ emissions by as much as 15%, but the actual degree of $NO_x$ reduction depends on the fuel characteristics and burning conditions. For LNBs equipped with automatic rather than manual OT, it is sometimes possible to achieve excess air levels of 5% or less without adversely affecting boiler performance (Oland 2002) (p. 5-5). An EPA publication mentions specific installations and 15–25% control (EPA 1994) (p. 5-64). These techniques, which are a form of LEA control, are often done in conjunction with other control techniques. Since the Caesars' boilers are already equipped with LNB, which are designed for LEA, there may be little or no benefit trying to use OT or BT to further reduce excess air. There is little cost information, but one publication (EPA 1994) (p. 2-17) mentions an OT retrofit costing $100 per MMBtu/hr in 1992 dollars. For a 33-MMBtu/hr burner, that is a $3,300 capital cost, which in 2024 dollars would be $3,300 x ($796.165$_{2024}$/$358.2$_{1992}$) = $7,335. DAQ requested that Caesars evaluate the technical feasibility of OT and BT. Caesars determined that OT would not achieve additional NOx reductions and that BT is not feasible because the burners have outdated components with obsolete parts. The burners may be replace for OT and BT, however the cost of burner replacement would be equivalent to ULNB . Therefore, DAQ concludes that OT/BT is not cost effective for these units. |
| 21 | Biased Firing (BF) | No | BF is a process of biasing the fuel flow to different burners to create a lower peak temperature. Since the Caesars' boilers have only one burner, DAQ concludes this technology is not RACT because it is not a technically feasible. |
| 22 | Natural Gas Reburning (NGR) | No | NGR is a process of adding natural gas to combustion gases at a later stage of combustion. It has been demonstrated to be effective in reducing $NO_x$ emissions from coal and oil burners by as much as 60% (Oland 2002) (p. 5-7). However, a literature search did not result in any articles or reports on the use of NGR in natural gas-fired boilers |

| CT # | Control Tech | RACT | Discussion |
|---|---|---|---|
| | | | (just coal-fired). DAQ concludes this technology is not an available control technology for gas-fired boilers. |
| 23 | Cyclonic Combustion Burner (CCB) | No | CCB is another type of LNB, so cost is addressed under LNB/ULNB above (CT #3 and 4). In cyclonic combustion, high tangential velocities are used in the burner to create a swirling flame pattern in the furnace. This causes intense internal mixing as well as recirculation of combustion gases, diluting the temperature of the near- stoichiometric flame and lowering thermal $NO_x$ formation. The tangential flame causes close contact between combustion gases and the furnace wall, adding a convective component to the radiant heat transfer within the furnace. The increased heat transfer and low excess air operation of the cyclonic burner result in increased boiler efficiency (EPA 1994) (p. 5-54). To achieve ultra-low $NO_x$ emissions levels, a small quantity of low-pressure steam is injected into the burner, which further reduces the local flame temperature and $NO_x$ formation. Testing revealed that $NO_x$ emissions during natural gas firing could be reduced from 70 ppm to less than 20 ppm without affecting burner stability, low excess air operation, or turndown performance. However, the use of steam results in a boiler heat efficiency loss of roughly 5%. The cyclonic burner is available as a stand-alone retrofit burner with a bolt-on feature, but no retrofit emissions data were found in an online search. Since achieving 20 ppm requires steam injection at the cost of efficiency, while other ULNB can achieve 9–10 ppm without using steam injection, DAQ finds that CCB is not RACT because it is not cost-effective and also has a collateral energy disbenefit. |

Caesars reviewed the most recent 5 years of RACT determinations in the RBLC and found none that were relevant, so it considered the following $NO_x$ RACT control options for industrial boilers: FGR, ULNB, SCR, and SNCR. DAQ expanded the search by conducting a 10-year review of the RBLC; it also reviewed control options identified during the 2024 RACT determination for the Moderate SIP and considered additional control options in EPA's *Alternative Control Techniques (ACT) Document for $NO_x$ Emissions from Industrial/Commercial/Institutional (ICI) Boilers* (EPA 1994).

Natural gas-fired boiler $NO_x$ control techniques are divided into combustion and post-combustion controls. LNB are already installed on the Caesars' boilers, which are in the first category and usually employ elements of more than one combustion control technique (e.g., the burner could be designed to reduce excess air [REA] or include FGR). For the Table 4 analyses, DAQ assumed the Caesars LNB design included combustion controls.

Staged Combustion Air (SCA) is an umbrella term covering several different techniques for injecting a portion of the total combustion air downstream of the fuel-rich primary combustion zone, including burner out of service (BOOS), Biased Firing (BF), adjusting burners lean and rich, overfired air (OFA), and LNB and ULNB when the burner design incorporates staged combustion. Up to 50% $NO_x$ emissions reductions are achievable, depending on the technique used and the type and size of boiler (Oland 2002). Generally, LNB that incorporate SCA are used on small package boilers. Other than as a part of LNB and ULNB, SCA is not considered viable for existing fire-tube boilers because of the retrofit modifications required (EPA 1994).

The $NO_x$ boiler control techniques are identified and discussed in Table 4. Some techniques, such as load reduction, reduced air preheat, and low excess air firing, are not considered independent or viable control technologies. Fuel switching from coal to oil or gas and from high-nitrogen residual oil to lighter oil fractions or gas has been considered in regional and seasonal $NO_x$ compliance options (EPA 1994). Fuel switching refers to a change to a "cleaner" fuel; since

the Caesars boilers already use natural gas, the cleanest of the fossil fuels, this option is not available even if it is considered a control technology.

Out of 23 boiler control technologies evaluated by DAQ, nothing beyond current LNB controls were found to be both technically and economically feasible. Therefore, current controls of LNB qualify as RACT.

#### 8.5.1.2 RACT Emissions Limitation

DAQ finds that RACT is LNB in combination with GCP for CP01 through CP05. DAQ proposes the following emissions limitations and corresponding monitoring, recordkeeping, and reporting requirements for these emission units based on RACT.

**Table 5. Caesars Proposed RACT-Based $NO_x$ Emission Limitations**

| Emission unit | $No_x$ RACT-based Emission Limitation |
|---|---|
| CP01, CP02 | 29 ppm corrected to 3% $O_2$<br>Operate and maintain boiler in accordance with manufacturer's O&M. |
| CP03, CP04, CP05 | 30 ppm corrected to 3% $O_2$<br>Operate and maintain boiler in accordance with manufacturer's O&M. |

## 8.6 MGM RESORTS INTERNATIONAL

### 8.6.1 Background

MGM Resorts International (MGMRI, Source ID: 825) owns a group of hotels within HA 212. DAQ issued a renewed operating permit (OP) to MGMRI on May 19, 2022 (revised on February 12, 2025), that includes requirements for the following hotels, referred to as "MGMRI": MGM Grand, New York-New York, Park MGM, The Signature at MGM Grand, Mandalay Bay, The Four Seasons, Luxor, Excalibur, Bellagio, CityCenter, T-Mobile Arena, and the Cosmopolitan of Las Vegas. MGMRI is currently a major source of $NO_x$, with a stationary source-wide PTE of 784.60 tpy, but not a major source of VOC, with a stationary source-wide PTE of 48.64 tpy.

MGMRI listed all emission units potentially subject to RACT (those with a PTE of 5 tpy or more) in a table in Attachment B of its RACT demonstration (Attachment 4 of this document). These include 49 diesel-fired engines driving emergency engines and one spray booth. Since the last RACT analysis performed for the Moderate SIP, MGMRI removed the boilers that were subject to RACT control requirements under AQR 121.11.1(a); the remaining diesel-fired emergency engines range from 1,180–3,701 hp. These engines are classified as Large Internal Combustion Engines (>500 hp), subject to existing NSPS for stationary CI engines (40 CFR Part 60, Subpart IIII). Attachment 4 contains MGMRI's RACT demonstration for these affected units. MGMRI indicated that it identified available control technologies via the RBLC, surveying agencies, engineering experience, vendors, and available literature. The RBLC search was conducted for the most recent 10 years.

At the time of its initial RACT demonstration, MGMRI was a major source for VOC; however, a recent permitting action lowered stationary source-wide PTE VOCs below the major source

level. The initial determination included a spray booth that emitted above 5 tpy VOC. On further review, DAQ determined the unit was insignificant and removed it from the RACT analysis.

### 8.6.2 Emergency Engines

The RACT analysis was conducted on the 49 emergency engines at various MGMRI properties that met the criteria for review. The diesel engines are rated from 1,180–3,701 hp, all from the same manufacturer. $NO_x$ PTE for the engines ranges from 7.08–15.12 tpy. For all 49 units, the OP assumes 500 operating hours per year per emergency engine, with 100 hours per year available for nonemergency purposes and only 50 of those available for nonemergency purposes other than testing and maintenance.[21] All 49 units are required to follow the manufacturer's operations and maintenance (O&M) guidance, which is generally accepted as constituting GCP.[22] In addition, these units must all have turbochargers and aftercoolers except:

- Turbochargers only: EX007-EX010 and NY27-NY29.
- Neither turbochargers nor aftercoolers: TM01 and CO07-CO09.
- TM01, LX024, LX025 and CO07-CO09, which are required to meet EPA Tier Certification in accordance with 40 CFR Part 60, Subpart IIII.[23]

Compressing the air and/or exhaust gas that goes to the inlet heats up the gas, which raises the maximum temperature in the cylinders unless it is cooled back down with an aftercooler. Adding an aftercooler to the units that require only turbochargers should reduce $NO_x$ emissions.

#### 8.6.2.1 MGMRI RACT Demonstration

MGMRI listed (1) EPA Tier Certification, where the engine, based on the date of manufacture and construction, is certified to comply with EPA Tier Emission Standards per 40 CFR Part 60, Subpart IIII; and (2) GCP as the only technically feasible control technologies. Six MGMRI units (including the largest, TM01 at T-Mobile Arena) are Tier Certified in accordance with 40 CFR Part 60, Subpart IIII; all the units are subject to GCP and adhere to the manufacturer's O&M guidance. MGMRI found any add-on controls, like SCR, not technically feasible, based on the lack of any RACT determinations in the RBLC and on an EPA statement regarding use of SCR and other add-on controls for emergency engines. Specifically, during its evaluation for emergency RICE under MACT/GACT, EPA concluded for emergency RICE that "[b]ecause these engines are typically used only a few hrs/yr, the costs of add-on emission control are not warranted when compared to the emission reductions that would be achieved" (King 2010).

[21] For example, Condition 1.1.3.1.: "The permittee shall limit the operation of the emergency engines (EUs: MG17 through MG23) for testing and maintenance purposes to 100 hours per calendar year. The permittee may operate the emergency engines up to 50 hours per calendar year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per calendar year for nonemergency situations cannot be used for peak shavings or to generate income for the facility." These hourly limits are what distinguish an emergency engine from other engines, per 40 CFR 60.4211.

[22] For example, 1.1.2.2.: "The permittee shall operate and maintain all diesel generators and fire pumps in accordance with the manufacturer's O&M manual for emissions-related components (EUs: MG17 through MG24, MG26 through MG28, MG51, and MG113)."

[23] Units CO07-CO09 are located at the Cosmopolitan property, which was a minor source until March 25, 2024, when MGMRI acquired the property and incorporated these units into their OP.

MGMRI did not address other control options, such as those in EPA's 1978 ACT guidance document for $NO_x$ emissions (EPA 1978b).

### 8.6.2.2 DAQ RACT Analysis

DAQ reviewed the MGMRI RACT analyses (Attachment 4) and revised them as necessary, including conducting RACT analyses for control technologies not included in the MGMRI analysis (Table 6). Since all the emergency engines have similar limitations, DAQ performed two CE calculations using the highest and lowest PTE emissions listed in the OP (Attachment 9).

**Table 6. MGMRI RACT Analyses for Emergency Engines**

| CT # | Control Tech | RACT? | Discussion |
|---|---|---|---|
| 1 | DLN and SLN | No | These technologies appear to be primarily for turbines, since no articles, documents, or websites indicated use of DLN or SLN on diesel engines. Therefore, DAQ concludes these are not a available control technology for these emergency engines. |
| 2 | GCP and GMP | Yes | These practices are the most common RACT determinations in the RBLC and are already required by the = OP.[24] DAQ concludes these are technically feasible and cost-effective control technologies. |
| 3 | Pre-stratified charge | No | EPA documents indicate that this technique is for spark ignition engines, not CI engines (EPA 1993a) (p. 5-14). DAQ concludes that this control technology is not available for these CI emergency engines. |
| 4 | ITR | No | If the engine already has an automated electronic control system for injection, ITR is desirable because it only requires field adjustments to the unit. The MGMRI analysis does not mention the type of control system. The literature states that ITR degrades performance and longevity and increases CO, PM, and VOC emissions. EPA literature supports these concerns, including a 5 - 8% fuel penalty (EPA 1996). The HA 212 area is sensitive to both $NO_x$ and VOC (Warneke et al. 2025); therefore, the benefit of decreased $NO_x$ emissions is outweighed by the corresponding increase in VOC emissions. For these reasons, DAQ concludes that ITR is not RACT because the emergency and collateral pollutant disbenefits outweigh the benefits of the potential emissions reduction. |
| 5 | AFR adjustments | No | AFR adjustments increase brake specific fuel consumption and HC and increase CO emissions (EPA 1978b, p. 4-63). Therefore, DAQ finds this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the potential emissions reductions. |
| 6 | Derating/ increasing speed | No | Derating increases brake specific fuel consumption and HC and increase CO emissions (EPA 1978b, p. 4-63). Therefore, DAQ finds this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the potential emissions reductions. |
| 7 | Inlet MAT adjustment/aftercooler | Yes, if on already.<br><br>No, if not. | DAQ estimates that the CE for retrofitting a cooler is about $8,415/ton. DAQ concludes this control technology is technically feasible but not cost-effective and, therefore, does not qualify as RACT unless already required. Units MG17 through MG23, MC019 and MC020, TBA15 and TBB15, MB061, MB062, MB063, MB066, MB067, and MB093, LX009 – LX011, LX024, and LX025, BE80 through BE88, CC009 through CC015 are required to have aftercoolers according to the OP. |
| 8 | Water/fuel | No | DAQ concludes that emulsified diesel is technically feasible and DAQ estimated this CE at |

[24] For example, Condition 1.1.2.2 from the OP: "The permittee shall operate and maintain all diesel generators and fire pumps in accordance with the manufacturer's O&M manual for emissions-related components."

| CT # | Control Tech | RACT? | Discussion |
|---|---|---|---|
| | emulsions | | $1,649/ton with 10% water emulsion. However, there are environmental and operational concerns with this control option. Because emulsified fuel has lower heating value than conventional diesel, additional fuel is required to generate the same power output compared to pure diesel and the water content can promote corrosion of engine components (Issa et al., 2019). Further, EPA ACT states there is no documentation of this control technique in stationary internal combustion engines and engine manufacturers contacted stated that water/fuel emulsions are not an option for their engines (EPA 1993b). Some studies show that water-emulsified diesel as fuel led to a significant increase of CO and VOC emissions (Syu et al. 2014)., DAQ concludes that emulsified diesel fuel is cost effective, but the energy and collateral pollutant disbenefits outweigh the potential benefits from the emissions reduction; therefore, this control technology is not RACT for these engines. |
| 9 | EPMS | No | DAQ finds this control technology does not qualify as RACT because the amount of additional $NO_x$ emissions reductions is likely negligible. |
| 10 | High-pressure fuel injection | No | The effect on reducing $NO_x$ emissions, and the ability to retrofit existing emission units are undemonstrated; therefore, DAQ concludes that this control technology is not RACT because it is not available. |
| 11 | Conversion to dual fuel (diesel/natural gas) | No | Dual fuel conversions are not considered RACT for emergency engines, as these units are typically required to rely on diesel fuel for reliability and fuel stability. Emergency engines should be regularly tested on diesel to ensure proper operation during an outage. Federal requirements under NSPS and NESHAP limit non-emergency operation to 50 hours per year.[25] Given the federally established limits, converting to dual fuel offers little benefit and is not appropriate for RACT compliance in this context. |
| 12 | Alternative fuels (other than natural gas) | No | The literature indicates that other fuels are not available for these engines. Methanol and LNG are the main alternatives other than emulsions. Methanol has serious corrosive and toxic problems, is costly, and can be readily contaminated with water, even though NOx reductions can reach 60%. LNG requires huge investments for storage and installation and has high CO emissions (Issa et al., 2019). DAQ finds that alternative fuels are not RACT for these emergency engines because the potential collateral pollutant disbenefits outweigh the benefits of potential emissions reductions. |

The current status of the emergency engines is:

- All must follow GCP and GMP.
- All have and use turbochargers and aftercoolers, except for the seven units (EX007–EX010 and NY27–NY29) that are not required to have aftercoolers and the four units (TM01, CO07–CO09) that are not required to have turbochargers or aftercoolers because they are Tier Certified.
- TM01, LX024, LX025, and CO07–CO09 are Tier Certified and meet the appropriate limit in 40 CFR Part 60, Subpart IIII.

DAQ has determined that the existing control techniques (GCP/GMP, turbochargers, and aftercoolers, except as noted above) constitute RACT for all emergency engines except TM01 and CO07–CO09, for which Tier Certification emissions limits apply.

[25] The 50-hour nonemergency limit is established under the NESHAP RICE rule at 40 CFR Part 63.6640(f) and under the NSPS requirements for stationary engines at 40 CFR Part 60.4243(d) for spark ignition engines and 40 CFR Part 60.4211(f) for compression ignition engines.

# 9.0 STORAGE TANKS AND OTHER VOC RACT

## 9.1 CALNEV PIPE LINE—LAS VEGAS TERMINAL

This section explains DAQ's case-by-case VOC RACT determinations for storage tanks and other VOC affected units at Calnev Pipe Line's Las Vegas Terminal (LVT, Source ID: 13). DAQ relied on information from the RACT demonstration for the LVT, supplementing the source's analysis when appropriate. This section does not repeat all the information from Calnev's RACT demonstration, only highlights key information critical to DAQ's decision-making process.

LVT is a bulk petroleum distribution terminal (SIC: 4226, NAICS: 424710) that receives petroleum fuel products via pipeline or truck and transfers gasoline, diesel, and biodiesel from storage tanks into trucks via loading racks. Denatured ethanol stored and distributed at LVT is received via railcar. The terminal also has the capability to unload ethanol via tank trucks.

The current OP has a VOC PTE of 188.01 tpy and a $NO_x$ PTE of 3.26 tpy. Since the $NO_x$ PTE is below the major source applicability threshold, LVT is an affected source for VOC RACT but not $NO_x$ RACT. In its RACT demonstration (Attachment 5A), LVT listed all the emission units potentially subject to VOC RACT. Individual emission units were grouped such that group PTE exceeded 5 tpy, then LVT conducted RACT analyses on these groups: (1) storage tanks with a total PTE of 61.3 tpy VOC;[26] (2) a vapor recovery unit with a total PTE of 14.5 tpy VOC;[27] (3) loading racks with a total PTE of 65.7 tpy VOC;[28] (4) a remediation system with a total PTE of 37.75 tpy VOC;[29] and (5) fugitive components (e.g., valves, flanges, fittings, pump seals) with a total PTE of 6.6 tpy VOC. LVT also listed all emission units not evaluated for VOC RACT (Attachment 5A).

### 9.1.1 Storage Tanks

In its RACT analysis, LVT delineated three vertical fixed roof tanks (VFRT); four FRT; 21 internal floating roof tanks (IFR); 12 external floating roof tanks (EFR); and three domed external floating roof tanks (DEFR).

According to LVT, all the FRT except 501 (A27) and 522 (A18), which are authorized to store only denatured ethanol, are designed and permitted to store multiple liquids; however, several of the tanks are authorized for only a few liquids.[30] LVT assumed that gasoline with a Reid vapor pressure (RVP) of 11 pounds per square inch (psi) represents the average annual vapor pressure of the gasoline stored and loaded at LVT, and DAQ agreed with this approach.

[26] Attachment 5A, Table 3-1: "LVT RACT Analysis." No tank has a PTE of 5 tpy or more.
[27] The vapor recovery unit is itself a control device that LVT says is considered BACT.
[28] There are 15 loading racks. Most of the 65.7 tpy PTE is from gasoline dispensing. Assuming each rack has the same PTE, 65.7/15 = 4.38 tpy per rack, less than the 5 tpy PTE threshold for RACT review.
[29] This system is also considered BACT, per LVT.
[30] Diesel/Biodiesel only: A14-15: Jet Fuel, and Diesel/Biodiesel: A23-24.

Two main losses (i.e., VOC emissions) are associated with storage tanks: working losses that take place during transfers of stored liquid and standing losses due to evaporation resulting from temperature swings, seal leaks, etc.

The 1978 CTG for EFR tanks recommends applying RACT control measures to tanks larger than 150,000 L (approximately 943 bbl)[31] storing petroleum liquids (EPA 1978a). The CTG does not apply to FRT, IFR, or small production tanks. In general, the 1978 CTG for EFR tanks defines RACT as (EPA 1978a):

- A welded EFR tank equipped with primary metallic shoe or liquid-mounted seals is required to retrofit with a rim-mounted secondary seal if the true vapor pressure (TVP) of the stored liquid exceeds 27.6 kPa (4 psi).[32]
- A welded or riveted EFR tank equipped with primary vapor-mounted seals is required to retrofit with a rim-mounted secondary seal if the TVP of the stored liquid exceeds 10.5 kPa (1.5 psi).
- A riveted EFR tank equipped with primary metallic shoe or liquid-mounted seals is required to retrofit with a rim-mounted secondary seal if the TVP of the stored liquid exceeds 10.5 kPa (1.5 psi).

Information on the controls that are already on the tanks is included in the LVT analysis (Attachment 5A) and summarized in LVT's OP, as shown in Table 7.

**Table 7. CalNev Tank Control Requirements**

| EU | Facility ID | Control Requirements |
|---|---|---|
| A01 | 530 | External floating roof with primary and secondary seals |
| A02 | 531 | External floating roof with primary and secondary seals |
| A03 | 532 | External floating roof with primary and secondary seals |
| A04 | 533 | External floating roof with primary and secondary seals |
| A05 | 534 | External floating roof with primary and secondary seals |
| A06 | 535 | External floating roof with primary and secondary seals |
| A07 | 536 | External floating roof with primary and secondary seals |
| A08 | 537 | External floating roof with primary and secondary seals |
| A09 | 538 | External floating roof with primary and secondary seals |
| A10 | 539 | External floating roof with primary and secondary seals |
| A11 | 540 | Internal floating roof with primary and secondary seals |
| A12 | 541 | Domed external floating roof with primary and secondary seals |
| A13 | 524 | Internal floating roof with primary and secondary seals |
| A14 | 542 | Internal floating roof with primary seal |
| A15 | 543 | Internal floating roof with primary seal |

[31] All of the tanks in Table 7 have a capacity greater than 950 bbl (approximately 39,900 gal).

[32] For an RVP of 11 psi, the TVP of 4 psi would be exceeded any time the stock temperature was higher than about 45°F. See AP-42, Chapter 7, Figure 7.1-14a (https://www.epa.gov/sites/default/files/2020- 10/documents/ch07s01.pdf) for the conversion, assuming S=3.0.

| EU | Facility ID | Control Requirements |
|---|---|---|
| A16 | 545 | Internal floating roof with primary and secondary seals |
| A17 | 546 | Internal floating roof with primary and secondary seals |
| A18 | 522 | Internal floating roof with primary and secondary seals |
| A19 | 525 | Fixed roof |
| A20 | 526 | Fixed roof |
| A21 | 547 | Internal floating roof with primary and secondary seals |
| A22 | 512 | Fixed roof |
| A23 | 510 | External floating roof with primary seal |
| A24 | 511 | External floating roof with primary seal |
| A25 | ASA Conductivity Improver | Fixed roof |
| A26 | 500 AIA | Fixed roof |
| A27 | 501 | Internal floating roof with primary and secondary seals |
| A28 | 523 | Internal floating roof with primary and secondary seals |
| A29 | 544 | Internal floating roof with primary and secondary seals |
| A30 | 533 A | Fixed roof |
| A31 | 537 A | Fixed roof |
| A32 | 541 A | Fixed roof |
| A33 | 541 B | Fixed roof |
| A34 | 542D | Fixed roof |
| A35 | 542A | Fixed roof |
| A36 | 531A | Fixed roof |
| A37 | 542C | Fixed roof |
| A38 | 537 B | Fixed roof |
| A39 | 531B | Fixed roof |
| A45 | 548 | Domed external floating roof with primary and secondary seals |
| A46 | 549 | Domed external floating roof with primary and secondary seals |
| A47 | 550 | Internal floating roof with primary and secondary seals |
| A48 | 551 | Internal floating roof with primary and secondary seals |
| A53 | 548B | Fixed roof |
| A54 | 548A | Fixed roof |
| A56 | 513 | Internal floating roof with primary and secondary seals |

EPA's control technology documents indicate that for IFR and EFR tanks, the use of primary and secondary seals is the best control (EPA 1978a; 40 CFR Part 60, Subpart Kc). Furthermore, 40 CFR Part 60, Subpart Kc, finalized in 2023, requires IFR and EFR tanks to have both primary and rim-mounted secondary seals, recognizing this configuration as the Best System of Emission Reduction (BSER). All but four of LVT's tanks are already equipped with primary and rim-mounted secondary seals, so RACT is the current technology. Two out of the four floating roof tanks are IFR tanks with only primary seals (A14–15) that are used only for diesel and biodiesel, which has a TVP at 60°F of only 0.006 pounds per square inch absolute (psia) (EPA 2025a, Table 7.1-2). The diesel-only tanks are not subject to CTG requirements and the current primary seals constitute RACT.

The other two floating roof tanks are EFR tanks with primary seals (A23-24) that store jet fuel, diesel, and biodiesel. Jet fuel is assumed to be Jet A, which has a TVP at 60°F of 0.008 psia (EPA 2025a, Table 7.1-2).[33] The CTG for external EFR tanks requires secondary seals if the TVP of the stored liquid exceeds 1.5 psi, thus diesel and jet fuel are not subject to the CTG requirements (EPA 1978a).

The fixed roof tanks are the most likely candidates for finding cost-effective add-on emissions controls, since they emit more than IFR and EFR tanks. EPA's CTG document for storage tanks states:

> "Existing fixed roof tanks with greater than 150,000-liter capacity containing petroleum liquids with true vapor pressure greater than 10.5 kilopascals should be controlled by retrofitting with internal floating roofs or equivalent external floating roofs, vapor recovery, vapor disposal systems, or other equivalent control technology. Bolted tanks generally cannot be retrofitted with internal floating roofs, and thus will require alternative equivalent control technology" (EPA 1977b).

Only low-volatility liquids are stored in these tanks, with the most volatile being jet fuel in Tank A22. Jet fuel is assumed to be Jet A, which has a TVP at 60°F of 0.008 psia (EPA 2025a, Table 7.1-2)[34]—below the TVP threshold in the EPA CTG.[35] Due to the low volatility of the liquids stored in the tanks, DAQ concludes that RACT for the fixed roof tanks is current controls.

### 9.1.2 Vapor Recovery Unit and Loading Racks

LVT's 15 loading racks have a total permitted throughput of 35,379,927 bbl/yr. Gasoline and diesel are loaded directly into trucks; biodiesel, ethanol, and additives are blended during loading. Emissions are controlled by a collection system that captures vapor (98.7% capture efficiency) from the empty trucks as they are loaded; approximately 65 tpy of VOC are fugitive emissions because they are not captured by the collection system. The captured emissions are routed to a high-efficiency adsorption-absorption John Zink Vapor Recovery Unit (VRU) with an estimated 99.7% control efficiency. The approximately 4,893 tpy treated by the VRU is reduced to about 14 tpy of VOC emissions. LVT operates a flare as a backup if the VRU cannot operate.

LVT's analysis did not mention any RBLC searches for VOC controls for loading racks, so DAQ conducted an independent search to identify potentially available control technologies. A review of the 1977 CTG and update (EPA 1977a, 1992a) for loading terminals indicates that a vapor control system with a flare as backup is considered RACT. The CTG mentions three systems—compression-refrigeration-absorption, refrigeration, and thermal oxidation—but the adsorption-absorption system appears to be different. However, DAQ did find a 1976 patent on such system.

[33] AP 42, Fifth Edition, Volume I Chapter 7: Liquid Storage Tanks notes that jet naphtha (JP-4) is no longer produced or procured (EPA 2025a, Table 7.1-2).
[34] AP 42, Fifth Edition, Volume I Chapter 7: Liquid Storage Tanks notes that jet naphtha (JP-4) is no longer produced or procured (EPA 2025a, Table 7.1-2).
[35] Even if the fixed roof tanks were subject to CTG, the highest PTE, for Tank A19, is 1.84 tpy, which would make it unlikely to be cost-effective.

The CTG also identified thermal oxidation (99+% efficiency) as an available control technology, but its control efficiency is equivalent to the current VRU. Therefore, DAQ finds the John Zinc VRU at LVT, with at least 99.7% control efficiency on captured VOC and with the backup flare, is the most effective control technology available, so qualifies as RACT for this major source.[36]

The bulk of emissions from the loading rack are fugitive (65.7048 tpy, of which 64.37 tpy is from gasoline loading). The CTG indicates that fugitive emissions occur during truck filling as a result of faulty seals, overfilling, and other leakage (vapor capture efficiency is 98.70%), but does not address additional control measures for fugitive emissions from loading. For some sources, VOC fugitive emissions reductions from improving O&M practices may be feasible, but LVT's system is already subject to the NSPS requirements in 40 CFR Part 60, Subpart XX (OP Condition 2.2.1). This includes using the John Zinc VRU during loading, maintaining the gauge pressure to the delivery tank at no more than 4,500 pa during loading, and operating so the pressure vacuum vents do not open if the system pressure is less than 4,500 pa. Conditions 2.2.3.a–d of the OP specify tanker loading requirements and measures to minimize vapor releases: minimizing gasoline spills, cleaning up spills as expeditiously as possible, covering all open gasoline containers with a gasketed seal when not in use, and minimizing gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices. DAQ identified no additional measures after conducting a literature search, so finds that RACT for the fugitive emissions from the loading racks consists of the requirements already in place.

### 9.1.3 Remediation Systems

LVT has two soil vapor extraction (SVE) systems to treat historical contamination of soil, both permitted by DAQ. The first, termed a "combustion system" in the analysis, has a 98.5% VOC destruction efficiency, but is not currently being used. The second, consisting of carbon beds and a fluidized bed reactor (FBR) for 95+% VOC control, is being used. LVT used a control efficiency of 98.5% for CE calculations regardless of the system in use.

LVT did not conduct a search of the RBLC or the literature to identify potential available control technologies, so DAQ conducted an independent search and identified the following:

- Thermal destruction (e.g., direct flame thermal oxidation, catalytic oxidizers)
- Adsorption (e.g., granular activated carbon, zeolites, polymers)
- Biofiltration
- Nonthermal plasma destruction
- Photolytic/photocatalytic destruction
- Membrane separation
- Gas absorption
- Vapor condensation.

[36] The OP specifies that the control system be maintained and operated per the manufacturer's specifications.

The estimated control efficiencies for these control technologies ranges from 50–99% (EPA 2006; Federal Remediation Technologies Roundtable). Both SVE and FBR are highly efficient combustion devices that burn most of the VOC in the extracted gas. LVT currently operates its FBR system in a manner that achieves the same level of emission reductions allowable for the SVE combustion system. Accordingly, DAQ concludes that these technologies, as applied based on contaminant treatment conditions, are equally effective, and a higher rate of control efficiency is unlikely with a different control. Moreover, replacing these systems with a different control technology, even if one of the other technologies had a control efficiency slightly higher than the current system efficiency of 98.5%, would yield few additional emissions reductions from the estimated 37.57 tpy, and would not be economically reasonable for RACT; therefore, the existing control system is RACT.

### 9.1.4 Fugitive Emissions

LVT is also subject to the leak monitoring requirements in 40 CFR Part 63, Subpart BBBBBB. The requirements in this recently promulgated standard represent the most effective control technology for leak detection. Among the many leak monitoring requirements in Subpart BBBBBB (40 CFR Part 63.11092(a)(1)(i)) is one for the source to conduct vapor collection leak monitoring during a performance test on the vapor recovery system using Method 21, with a 500 ppm threshold for doing maintenance and repair. Although the standard regulates HAPs, those are generally also VOC emissions, so DAQ expects a similar level of emissions reduction from LVT compliance with the standard.

LVT states that it inspects fugitive components for leaks on a consistent basis and repairs any leaks in the system, and that "these leak monitoring protocols are considered to meet the requirements of RACT." DAQ supplemented LVT's analysis by first checking the RBLC, then documents such as "Control Techniques for Volatile Organic Emissions from Stationary Sources" (EPA 1978c). This document discusses leaks found at petroleum refineries, but the information pertains to all pumps, valves, flanges, and other fugitive emissions at a variety of sources (see page 144). EPA notes that flanges produce the least fugitive emissions, and that there are some pump and valve options when switching out old ones, but for existing equipment, proper maintenance is the key to reducing leaks around packing and seals.

DAQ finds that the extensive leak monitoring requirements already in LVT's OP for tanks and other equipment are sufficient to ensure compliance, and therefore constitute RACT.

# 10.0 GYPSUM MANUFACTURING RACT

## 10.1 CERTAINTEED GYPSUM MANUFACTURING

This section explains DAQ's case-by-case RACT determinations for $NO_x$ and VOC for the only affected source in gypsum manufacturing, CertainTeed Gypsum Manufacturing. CertainTeed operates a gypsum wallboard manufacturing facility at 13500 Blue Diamond Road in Las Vegas, NV. The facility's SIC code is 3275, "Gypsum Products," and its NAICS code is 327420, "Gypsum Product Manufacturing." Operations include gypsum rock transport, milling, calcining, plaster production, wallboard manufacturing, and recycling.

CertainTeed is a $NO_x$ major source, based on a PTE of 84.86 tpy, and a VOC minor source with 27.16 tpy of emissions. CertainTeed has three affected units with a $NO_x$ PTE above 5 tpy (Table 8). The CP mill is routed through a baghouse.

DAQ relied on information provided in the RACT demonstration provided by CertainTeed, its current OP, and its own RACT analysis through review of the RBLC.

**Table 8. CertainTeed RACT-Affected Units**

| Emission Unit | Description | Control(s) | $NO_x$ Emission Limit |
|---|---|---|---|
| E.11 | CP Mill, natural gas | LNB | 7.88 tpy<br>0.049 lb/MMBtu<br>40 ppm @ 3% $O_2$ |
| J.3 | AKI Board Dryer, natural gas | LNB | 28.41 tpy<br>38 ppm @ 3% $O_2$ |
| Engine | Portable diesel engine, Caterpillar model C-18 | Tier 3, turbocharger and after-cooler, GCP | 5.73 tpy |

### 10.1.1 $NO_x$ RACT Analysis

#### 10.1.1.1 CP Mill

The CP mill system (EU: E.11) grinds, dries, and calcines raw gypsum to produce stucco using a 37 MMBtu/hr low-$NO_x$ natural gas burner. Exhaust gases and cooler air are recirculated to improve energy efficiency, with a portion vented through a stack. $NO_x$ emissions are limited to 40 ppm at 3% $O_2$ (0.049 lb/MMBtu), resulting in a $NO_x$ PTE of 7.88 tpy.

The CP Mill system is specially designed for gypsum calcination. Due to its unique design and operating conditions (exhaust temperatures below 300°F), conventional post-combustion $NO_x$ controls such as SCR or SNCR are not technically feasible. CertainTeed stated that the CP mill is not capable of being configured to reroute flue gas to the burners, so FGR is not feasible. The only technically feasible option for the CP mill is identified as LNB and ULNB. The CP mill currently has LNB.

CertainTeed provided CE for ULNB on the CP mill based on an estimated 20-yr equipment life expectancy, stating that is a conservative estimate since the current CP mill is more than 25 years old. DAQ updated the CE, using a 30-yr analysis in accordance with AQR 120, and determined

that use of a longer life expectancy did not alter the conclusion that the technology is not cost-effective (Table 9).

**Table 9. CertainTeed CP Mill Potential Control Technologies**

| Control Technology | CP Mill | Achievable Emissions (ppm @ 3% $O_2$) | Cost Effectiveness |
|---|---|---|---|
| SCR | Not technically feasible | NA | NA |
| FGR | Not technically feasible | NA | NA |
| Low NOx Burner | Already equipped | 40 | NA |
| Ultra Low NOx Burner | Yes | 18[1] | $6,043 |
| GCP | Yes | NA | $0 |

[1] Manufacturer literature states NOx emissions can be reduced to 45% of a conventional burner. (Note from CertainTeed RACT analysis, Attachment 6A)

Because no further technically feasible or cost-effective controls were identified and the unit already meets stringent $NO_x$ emission limits with an LNB, DAQ concludes that current controls constitute RACT for the CP mill system.

10.1.1.2 AKI Board Dryer

The board dryer (EU J.3) uses four natural gas-fired LNBs with a total capacity of 141 MMBtu/hr to remove excess moisture from gypsum boards after forming. Boards pass through multiple heated zones in layers to maximize space and efficiency, and emissions are vented through a single stack. During stack testing, the dryer emitted $NO_x$ at 0.046 lb/MMBtu (approximately 38 ppm), resulting in a $NO_x$ PTE of 28.41 tons per year (Attachment 6A).

Similar to the CP mill, the board dryer is customized to the manufacturing plant and is not compatible with general controls for $NO_x$. The dry exhaust gas temperature is less than 300°F, making it unsuitable for SCR and SNCR. CertainTeed stated that FGR is not feasible. Therefore, the only technically feasible options are LNB and ULNB, and CertainTeed states that the board dryer is already equipped with LNB.

CertainTeed provided CE for ULNB on the board dryer based on an estimated 20-yr equipment life expectancy, stating that is a conservative estimate since the current board dryer is more than 25 years old. DAQ updated the CE and determined that using a longer life expectancy does not alter the conclusion that the technology is not cost-effective (Table 10).

**Table 10. CertainTeed Board Dryer Potential Control Technologies**

| Control Technology | CP Mill | Achievable Emissions (ppm @ 3% $O_2$) | Cost Effectiveness |
|---|---|---|---|
| SCR | Not technically feasible | NA | NA |
| FGR | Not technically feasible | NA | NA |
| Low NOx Burner | Already equipped | 38 | $0 |
| Ultra Low $NO_x$ Burner | Yes | 10[1] | $6,718 |
| GCP | Yes | NA | $0 |

[1] Based on CertainTeed discussions with burner suppliers, the actual manufacturer guarantees were obtained for the board dryer (note from CertainTeed RACT analysis, Attachment 6A).

DAQ concludes that use of LNBs on the board dryer represents the only technically feasible and cost-effective control for $NO_x$ emissions for this source, and the existing controls meet RACT requirements.

#### 10.1.1.3 Diesel Engine

CertainTeed has one diesel engine that is subject to RACT requirements. It is a 575-hp Caterpillar C-18, certified to EPA Tier 3 standards, that powers a portable wallboard grinding machine (Crambo). The engine is equipped with a turbocharger and aftercooler, and operated and maintained in accordance with the manufacturer's O&M manual. It is limited to 2,400 hours of operation per year and a $NO_x$ PTE of 5.73 tpy. CertainTeed notes that this engine is designed to move routinely to different locations, therefore certain add-on controls are not feasible.

CertainTeed performed a RACT analysis and identified replacement of the engine with one certified to Tier 4 standards as the only feasible option. However, DAQ does not consider engine replacement an available control technology because RACT is defined relative to the affected unit under review, and replacement does not result in emissions control for an existing unit.[37]

DAQ identified and reviewed other potential controls, as listed in Table 11.

**Table 11. CertainTeed RACT Determinations for Diesel Engine**

| CT # | Control Technology | RACT? | Discussion |
|---|---|---|---|
| 1 | SCR | No | SCR is not portable, and, therefore, is not an appropriate technology for this engine because the engine is moved throughout the major source. DAQ concludes that this control technology is not available for this engine. |
| 2 | SNCR | No | Although having a lower capital and operating cost, SNCR is not considered available for diesel engines because it operates best at temperatures of 1,600°F – 2,000°F, and diesel engine exhaust gas ranges from 800°F –1,200°F (Pronobis 2020). SNCR also needs fuel-rich engine operation or the use of reducing agents, so its use is limited to rich-burn engines; CI diesel engines are generally lean-burning. In addition, the exhaust gas temperature makes SNCR unsuitable (Figure 3) (EPA 1993d) (p. 2-18). DAQ concludes this control technology is not available for this engine. |
| 3 | DLN and SLN | No | These technologies appear to be primarily for turbines, since no articles, documents, or websites indicated use of DLN or SLN on diesel engines. DAQ concludes this control technology is not yet demonstrated as technically feasible for this engine, and therefore, is not an available control technology.. |
| 4 | GCP and GMP | Yes | These practices are the most common RACT determinations in the RBLC . DAQ concludes that these control technologies are technically feasible and cost-effective. |
| 5 | Pre-stratified charge | No | EPA documents indicate that this technique is for spark ignition engines, not CI engines (EPA 1993b) (p. 5-14). DAQ concludes this control technology is not available for this engine. |

[37] Although DAQ finds that replacing an existing emission unit and reducing hours of operation are not control technology options for RACT, a major source could opt to use these strategies to meet certain emissions limitations established based on RACT or to avoid applicability by reducing PTE.

| CT # | Control Technology | RACT? | Discussion |
|---|---|---|---|
| 6 | EGR | No | EGR can reduce $NO_x$ by 40% on low-load mobile diesels, but EPA notes it requires external hardware retrofits, some additional controls, and possibly cooling/cleaning of exhaust. Downsides include substantial fouling of heat exchanger and flow passages, increased maintenance, substantial increases in CO and smoke, and increased wear. As of 1993, EGR was not being offered for production CI engines (EPA 1993b) (p. 5-85). In addition, a study by NRDC on cleaning up diesel engine emissions found that EGR resulted in fuel penalties of 0–5%, was one of the most costly control options available, and increased PM emissions (Kassel and Bailey 2004). A web search found only a few companies offering EGR, and those often paired EGR with other controls (such as PM), mainly on propulsion engines. DAQ concludes this control technology does not qualify as RACT because energy and collateral pollutant disbenefits outweigh potential emissions reductions. |
| 7 | ITR | No | If the engine already has an automated electronic control system for injection, ITR is desirable because it only requires field adjustments to the unit. The literature states that ITR degrades performance and longevity and increases CO, PM, and VOC emissions. EPA literature backs up these concerns, including a 3% fuel penalty. Further, ITR may make starting the engine at cold temperatures more difficult.[38] CertainTeed states the engine manufacturer restricts use of ITR to avoid impacts on engine durability. DAQ concludes that this control technology is not technically feasible for this engine. |
| 8 | AFR adjustments | No | AFR adjustments increase brake specific fuel consumption and HC and increase CO emissions (EPA 1978b, p. 4-63). Therefore, DAQ finds AFR adjustments do not qualify as RACT because the energy and collateral pollutant disbenefits outweigh potential emissions reductions. |
| 9 | Derating/increasing speed | No | Derating increases brake specific fuel consumption and HC and increase CO emissions (EPA 1978b, p. 4-63). Therefore, DAQ finds this control technology does not qualify as RACT because energy and collateral pollutant disbenefits outweigh potential emissions reductions. |
| 10 | MAT adjustment/aftercooler | Yes | This engine is already equipped with an aftercooler. DAQ finds that this control technology is technically feasible and cost effective. |
| 11 | DWI | No | Similar to emergency engines, DWI would not be practical for use on a portable engine with intermittent-use. DAQ concludes that this control technology is not technically feasible for this engine. |
| 12 | Water/fuel emulsions | No | DAQ concludes that emulsified diesel is technically feasible and DAQ estimated CE at $3,505/ton assuming 50% control with 10% water emulsion. However, there are environmental and operational concerns with this control option. Because emulsified fuel has lower heating value than conventional diesel, additional fuel is required to generate the same power output compared to pure diesel and the water content can promote corrosion of engine components (Issa et al., 2019). Further, EPA ACT states there is no documentation of this control technique in stationary internal combustion engines and engine manufacturers contacted stated that water/fuel emulsions are not an option for their engines (EPA 1993b). Some studies show that water-emulsified diesel as fuel led to a significant increase of CO and VOC emissions (Syu et al. 2014). DAQ concludes that emulsified diesel fuel is not RACT for these engines because the energy and collateral pollutant disbenefits outweigh potential emissions reduction benefits. |
| 13 | EPMS | No | DAQ finds this control technology does not qualify as RACT because the amount of additional $NO_x$ emissions reductions through use of an EPMS system is likely negligible. |

[38] Based on data from EPA's ACT for $NO_x$ emissions from ICE engines, p. 2-42, Table 2-14.

| CT # | Control Technology | RACT? | Discussion |
|---|---|---|---|
| 14 | High-pressure fuel injection | No | DAQ concludes this control technology does not qualify as RACT because the effect on reducing $NO_x$ emissions and ability to retrofit the technology for existing emission units is highly uncertain. |
| 15 | Conversion to natural gas | No | Conversion to natural gas usually requires the engine to be stationary to have reliable source of natural gas. Therefore that is not practical for a portable engine. DAQ does not find this to be technically feasible. |
| 16 | Conversion to dual fuel (diesel/natural gas) | No | Similarly to above, conversion to natural gas is not practical. Therefore, DAQ does not find this to be technically feasible. |

### 10.1.2 RACT Determination

Based on the limited hours of use, DAQ concludes that RACT is the use of existing controls. CertainTeed proposed a RACT emissions limitation of 38 ppm @ 3% $O_2$ for the AKI Board Dryer, based on a performance test, but DAQ's RACT includes a 20% safety margin above testing values when establishing enforceable emissions limitations. Therefore, DAQ is establishing a RACT emission limitation of 46 ppm @ 3% $O_2$ for the AKI Board Dryer. DAQ concludes that the diesel engine meet the applicable emission limits under 40 CFR Part 60, Subpart IIII, and thus satisfies RACT.

**Table 12. CertainTeed RACT Limitations**

| Emission Unit | $NO_X$ RACT-based Emission Limitation |
|---|---|
| CP Mill | 40 ppm @ 3% $O_2$, Operate and maintain CP mill in accordance with manufacturer's O&M. |
| AKI Board Dryer | 46 ppm @ 3% $O_2$, Operate and maintain dryer in accordance with manufacturer's O&M. |
| Diesel Engine | Tier 3, with GCP and GMP. |

# 11.0 ELECTRIC UTILITY NOX AND VOC RACT

## 11.1 INTRODUCTION

This section explains DAQ's case-by-case RACT determinations for $NO_x$ and VOC for the four affected sources in the electric utility sector. Common emission units in electric utilities include combustion turbines (CTs), combined cycle units (CCUs), and boilers. DAQ relied on information provided in the RACT demonstrations supplied by NV Energy (Attachments 7A–7D) and Saguaro Power Company (Attachments 8A–8B), supplementing these analyses when appropriate. When the analyses provided cost estimates, DAQ adjusted calculation methodologies as needed, including equipment life and cost components, to ensure a consistent approach.

This section does not repeat all the information from each source's proposed RACT analysis, but highlights key information critical to DAQ's decision-making process.

## 11.2 POTENTIALLY AVAILABLE CONTROL TECHNOLOGIES

Emission units at the affected electric utility sources include simple cycle CTs, CCUs, package boilers, cooling towers, emergency engines, and storage tanks; however, the only emission units that meet the VOC or $NO_x$ affected unit applicability thresholds are CTs, CCUs, and boilers. This section discusses $NO_x$ and VOC control options for CTs and CCUs.

RACT should be determined based on the actual or potential operations of the affected unit. Therefore, DAQ did not consider emissions management a viable control technology for RACT unless the affected source identified the approach in its own RACT demonstration.

### 11.2.1 $NO_x$ Control Technologies

#### 11.2.1.1 Selective Non-Catalytic Reduction

In an SNCR control system, urea or ammonia is injected into boilers where the flue gas temperature is approximately 1,600°F–2,100°F. At these temperatures, urea or ammonia reacts with $NO_x$, forming elemental nitrogen and water without the need for a catalyst. Overall $NO_x$ reduction reactions are similar to those for SCR. Multiple injection points are required to thoroughly mix the reagent into the boiler furnace. The limiting factor for an SNCR system is the ability to contact the $NO_x$ with the reagent as the concentration decreases without in excessive ammonia slip and excessive ammonia decomposition before $NO_x$ emissions can be reduced. SNCR is widely used in various types of boilers; however, the required residence time and temperature range is incompatible with gas turbines. DAQ is not aware of SNCR application to any gas turbine in the U.S. or worldwide; therefore, it is not an available control technology for the affected units.

#### 11.2.1.2 Selective Catalytic Reduction

SCR is a post-combustion treatment of the flue gas that involves the injection of a reagent (typically ammonia or urea) into the system in the presence of a catalyst to convert $NO_x$ emissions to nitrogen and water. SCR on boilers and CTs/CCUs works in essentially the same manner. The

effectiveness of SCR depends on several factors, including exhaust gas temperature (typically optimal between 480°F–800°F), the amount and distribution of reagent, injection grid design, and catalyst activity. SCR can result in $NO_x$ reductions as high as 70–90%, and is a widely used technology for large gas turbines (EPA 2020). DAQ concludes this is an available control technology for the affected units.

#### 11.2.1.3 Non-Selective Catalytic Reduction

Non-selective catalytic reduction (NSCR) is a post-combustion treatment of the flue gas that uses a catalyst (typically platinum) to convert $NO_x$, CO, and HC to water, $CO_2$, and nitrogen. Unlike SCR, which requires ammonia, NSCR utilizes unburnt hydrocarbons as a reducing agent. For $NO_x$ removal, oxygen concentration is limited to less than 0.5% because the oxidation reactions tend to favor CO and HC. Since the oxygen concentration in turbine exhaust is significantly higher (12–18% vol) (Pavri and Moore 2001), DAQ concludes NSCR is not an available control technology for the affected units.

#### 11.2.1.4 Catalytic Combustion

Catalytic combustion uses a specially designed combustor equipped with a catalyst to increase fuel oxidation rates, which enables lower combustion temperatures and reduced thermal $NO_x$ formation. Two vendors have produced catalytic combustor products designed for turbine applications:

- Rich Catalytic Lean (RCL) catalytic combustor (Precision Combustion, Inc.).
- Xonon Cool Combustion (SCR-Tech, LLC).

The catalytic combustion technology owned by SCR-Tech is not currently being marketed or produced. While Precision Combustion actively markets the RCL combustor, DAQ could find no gas-fired CTs or CCUs (> 50 MW) installed with this control technology. Therefore, DAQ concludes this technology is not yet demonstrated as available for the affected units.

#### 11.2.1.5 Catalytic Absorption/Oxidation

EMx™ Catalytic Absorption/Oxidation (the second generation of the SCONO$_x$™ $NO_x$ Absorber technology), owned by Miratech Corporation, is based on a proprietary catalytic oxidation and absorption technology. EMx™ uses a potassium carbonate ($K_2CO_3$)-coated catalyst to reduce $NO_x$ and CO emissions from natural gas-fired gas turbines. The catalyst oxidizes CO to $CO_2$ and NO to $NO_2$. The $NO_2$ absorbs onto the catalyst to form potassium nitrite ($KNO_2$) and potassium nitrate ($KNO_3$). Dilute hydrogen gas is periodically passed across the surface of the catalyst to regenerate the $K_2CO_3$ coating. The regeneration cycle converts $KNO_2$ and $KNO_3$ to $K_2CO_3$, water, and elemental nitrogen. This makes the $K_2CO_3$ available for further absorption.

EMx™ technology is no longer being installed on new units; Miratech indicated it is strictly servicing units already equipped with this technology.[39] DAQ concludes EMx™ is no longer commercially available.

#### 11.2.1.6 Water/Steam Injection

The mechanism of using water or steam injection for $NO_x$ reduction in turbines is similar to that of boilers. Water or steam injection into the combustion zone lowers the flame temperature, which reduces thermal $NO_x$ formation. However, because steam is not as effective as water in reducing thermal $NO_x$, DAQ eliminated steam injection from this evaluation.

Water injection can achieve a 70–80% reduction from uncontrolled levels for utility and large turbines. The typical range in the water-to-fuel ratio (WFR) is 0.33–2.48, although the optimal WFR for a gas-fired turbine is 1.0 (EPA 1998a). Actual reduction depends on combustor geometry, injection nozzle design, and fuel-bound nitrogen content.

Water injection can be retrofitted onto many existing turbines, depending on combustor design and the availability of high-purity filtered water. Compared with other $NO_x$ control technologies, capital costs are generally lower and operating costs higher due to the need for a water treatment system (Sargent & Lundy 2022).

Units with WSI may sometimes be able to further reduce $NO_x$ emissions by increasing rates of steam or water injection, depending on combustor design. Increasing the injection rate reduces thermodynamic efficiency, which generally results in an increase in CO and VOC emissions, although this effect depends on turbine inlet temperature: the higher the inlet temperature, the greater the tolerance for increased injection without substantial increases in CO. Certain combustor designs may allow up to 1.4% compressor inlet water concentration at 1,900°F before CO increases (Pavri and Moore 2001). For any given unit, the practical injection limit is set by combustor design, available water quality, acceptable efficiency loss, and emissions compliance for other pollutants (e.g., CO and VOCs). DAQ concludes that water injection is available, but only technically feasible as a retrofit on turbines specifically designed to accommodate it; therefore, the achievable $NO_x$ reduction, as well as secondary pollutant impacts, must be determined on a case-by-case basis.

#### 11.2.1.7 Dry Low $NO_x$ Combustion

DLNC, also referred to as "Dry Low Emissions" (DLE) systems and LNB, generally refers to a turbine combustor design in which thermal $NO_x$ is reduced by a combination of premixing air and fuel prior to combustion and then staging combustion to achieve optimal air/fuel mixing at all operating loads. Many existing CTs and CCUs can be retrofitted with DLNC, although the combustors take up more space than conventional annular combustors and may not be feasible on all turbines. DLNC retrofits can achieve $NO_x$ emissions of 9–25 ppm, depending on existing combustor design, although newer designs with additional staging (i.e., ULNB) can achieve even lower levels of emissions. DAQ concludes that this is an available control technology for the affected units.

[39] Appendix 8.

#### 11.2.1.8 Good Combustion and Maintenance Practices

Good combustion and maintenance practices involve operating the turbine to maximize energy output or thermal efficiency while maintaining optimized oxygen levels to ensure complete combustion. GCP can also involve running equipment in accordance with the manufacturer's recommended settings and preventative maintenance schedules. DAQ concludes that this is an available control technology for the affected units.

#### 11.2.1.9 Emissions Management through Operating Restrictions

RACT should be determined based on the actual or potential operations of the affected unit. Therefore, DAQ did not consider emissions management a viable control technology for RACT unless the affected source identified the approach in its own RACT demonstration.

### 11.2.2 Potentially Available VOC Control Technologies

#### 11.2.2.1 Oxidation Catalysts

For natural gas turbine applications, the lowest CO and VOC emission levels are achieved using oxidation catalysts (OC) installed as post-combustion control systems. The typical OC is a rhodium or platinum (i.e., noble metal) catalyst on an alumina support material that is typically installed in a reactor with a flue gas inlet and outlet distribution plates. CO and VOC react with $O_2$ in the presence of the catalyst to form $CO_2$ and water according to the following equations:

**Eq. 11-1.** $$2CO + O_2 \rightarrow 2CO_2$$

**Eq. 11-2.** $$2C_nH_{2n+2} + (3n + 1)O_2 \rightarrow 2nCO_2 + (2n+2)$$

Acceptable catalyst operating temperatures range from 400°F–1,250°F, with an optimum temperature range of 850°F–1,100°F. Below approximately 400°F, catalyst activity (and oxidation potential) is negligible. This temperature range is generally achievable with simple cycle GTs except at low-load startup and shutdown conditions. Oxidation catalysts have the potential to achieve approximately 90% reductions in "uncontrolled" emissions at steady-state operation. DAQ concludes this is an available control technology for the affected units.

#### 11.2.2.2 Dry Low $NO_x$ Combustion

The installation of DLNC is not generally considered an effective VOC control option, since the reduction in combustion temperature typically increases both CO and VOC emissions. However, a DLNC retrofit may reduce $NO_x$, CO, and VOC on some older turbines due to increased combustion efficiency. DAQ concludes this is an available control technology for the affected units.

#### 11.2.2.3 Good Combustion Practices/Good Maintenance Practices

GCP and GMP involve operating the turbine to maximize energy output or thermal efficiency while maintaining optimized oxygen levels to ensure complete combustion. GCP can also involve running equipment in accordance with the manufacturer's recommended settings and

preventative maintenance schedules. DAQ concludes this is an available control technology for the affected units.

#### 11.2.2.4 Emissions Management through Operating Restrictions

RACT should be determined based on the actual or potential operations of the affected unit. Therefore, DAQ did not consider emissions management a viable control technology for RACT unless the affected source identified the approach in its own RACT demonstration.

## 11.3 LAS VEGAS GENERATING STATION

### 11.3.1 Background

NV Energy owns and operates the Las Vegas Generating Station (LVGS, Source ID: 329), located in North Las Vegas, Nevada. LVGS is an electric power generating facility (SIC: 4911, NAICS: 221112) that operates five turbine generator packages with stationary combustion turbines, one with a heat recovery steam generator (HRSG) and four with once-through steam generators (OTSG). In addition, LVGS operates three steam turbines, two cooling towers, and one diesel fire pump. The current Part 70 OP has a source-wide PTE for $NO_x$ of 94.66 tpy and for VOCs of 35.56 tpy, making LVGS a major source only for $NO_x$. Table 13 shows the emission units with $NO_x$ above 5 tpy and therefore subject to RACT analysis.

NV Energy identified emissions management through an emission cap as part of their RACT demonstration. Because the source proposed the emissions management, the following analysis incorporates NV Energy's proposed emission caps on Unit 1 as a viable control option.

**Table 13. LVGS RACT-Affected Units**

| EU | Description | # Units | Control(s) | $NO_x$ PTE (tpy)[1] | $NO_x$ Emission Limits |
|---|---|---|---|---|---|
| Unit 1 (A01) | Turbine Generator Package, Natural Gas-fired (44 MW) | 1 | SCR, water injection | 48[2] | 10 ppmv @ 15% $O_2$ |
| Units 2–5 (A03-A06)[2] | Turbine Generator Package, Natural Gas-fired (44 MW) | 4 | SCR, water injection | 45.72[3] | 2 ppmv @ 15% $O_2$ |

[1] Emission unit PTE, including startup, shutdown, and testing/tuning.
[2] NV Energy requested an emission cap of 43 tpy of $NO_x$.
[3] Annual PTE permitted together for Unit 2–Unit 5 (A03–A06).

### 11.3.2 $NO_x$ RACT Analysis

DAQ conducted the following analysis using data and information in the RACT analysis provided by NV Energy as noted and where applicable.

#### 11.3.2.1 Potential Control Technologies

Unit 1 was reviewed as a separate unit, since the OP has its own emission limit and PTE. Units 2–5 were reviewed together, since the OP has a combined emission limit and PTE for them. Table 14 lists the potential control technologies considered for each unit. These are consistent with the potential retrofit options identified in EPA guidance for combustion turbines. Certain technologies were not considered technically feasible, so were eliminated from consideration.

**Table 14. LVGS Technical Feasibility of Additional $NO_x$ Control Technologies**

| Control Technology | Unit 1 | Units 2–5 |
|---|---|---|
| Emissions management | Yes | No, affected source did not propose |
| SCR | Already equipped | Already equipped |
| DLNC (with existing SCR) | Yes | Yes |
| SCR catalyst replacement | Yes | Yes |
| Water Injection | Already equipped | Already equipped |
| GCP | Yes | Yes |

All units are equipped with SCR and water injection. NV Energy reviewed SCR either alone or in combination with DLNC or DLNC with steam injection. NV Energy stated that reducing the emissions limit on Unit 1 would require an upgrade to the existing SCR system, including replacing the existing ammonia injection grid (AIG) and performing AIG tuning, and recommended an emissions management strategy as an alternative control option. DAQ accepted the emissions management strategy as viable control technology for the RACT analysis.

NV Energy noted that DLNC was not further reviewed because DLNC alone would not provide additional emission benefits, stating that when these specific CTs are equipped with DLNC, combustor systems are typically capable of meeting a $NO_x$ concentration of 15 ppm. Table 14 lists possible control technologies for Unit 1 and Units 2–5. Table 14 shows possible control technologies for Unit 1 and Units 2–5.

#### 11.3.2.2 Control Equipment Costs

Units 2–5 are already subject to the lowest achievable emission limit. DAQ determined it was not possible to further reduce $NO_x$ with any additional controls; therefore, DAQ concluded that the current Unit 2–5 controls of SCR and water injection are RACT.

For Unit 1, DAQ considered SCR catalyst replacement and SCR with DLNC as available control options, using vendor estimates provided by NV Energy for SCR catalyst replacement at LVGS. NV Energy did not provide a cost estimate for SCR with DLNC, so DAQ estimated the cost using a vendor estimate provided by Saguaro Power Company for a similar turbine. Costs for Unit 1 were reviewed with NV Energy's requested emission cap.

DAQ assumed an interest rate of 7.14% based on the justification provided by NV Energy.[40]

#### 11.3.2.3 Control Equipment Performance

For Unit 1, the achievable emission level for the SCR replacement was assumed to be the same limit as for Units 2–5 (2 ppm @ 15% $O_2$). The achievable emissions level for the SCR with DLNC retrofit was based on the lowest RBLC determination for a similarly equipped unit (2 ppm @ 15% $O_2$) (Attachment 10).

No further controls were reviewed for Units 2–5.

[40] Attachments 7A & 7D.

#### 11.3.2.4 Energy and Environmental Impacts

**SCR catalyst replacement.** Unit 1 is already equipped with an SCR system and catalyst that is functioning to meet the current permitted $NO_x$ limits. Typically a stationary source does not replace a catalyst until it reaches end-of-life and can no longer reliably meet permitted $NO_x$ limits due to deactivation from poisoning, masking by particulates, or thermal and mechanical stress.

The SCR catalyst replacement control technology analyzed here is not routine end-of-life replacement, but rather premature replacement of the existing functional catalyst with a more efficient catalyst to achieve lower $NO_x$ emissions. While upgrading to a higher-performance catalyst could reduce $NO_x$ emissions below current levels, doing so would require disposing of a catalyst that is still performing its intended function and has not yet reached the end of its useful life.

Premature catalyst replacement presents several environmental concerns. First, it generates significant solid waste by discarding a functional catalyst before it reaches the end of its service life. Spent catalyst disposal poses environmental challenges, as vanadium and titanium compounds may require special handling and disposal or recycling. Second, manufacturing replacement catalysts are resource- and energy-intensive, incurring additional environmental impacts and high life cycle costs. The production of new catalyst material, transportation, installation, and disposal of the functional but prematurely replaced catalyst all contribute to the overall negative environmental footprint of this control option.

DAQ prioritizes using an existing functional SCR catalyst to its full service life before replacement. This aligns with sustainable resource management principles and prevents needless environmental burdens from premature disposal. DAQ concludes that the energy and environmental disbenefits of prematurely replacing the SCR catalyst may outweigh the minimal additional emissions reductions achievable with SCR catalyst replacement.

**Emissions Management**. This strategy has no known energy or other environmental disbenefits.

Based on this analysis, DAQ concludes that consideration of energy and environmental impacts weighs in favor of finding emissions management a more reasonably available control option than catalyst replacement, if $NO_x$ emissions are properly managed to a sufficient level compared to the emissions reductions achievable through SCR catalyst replacement.

#### 11.3.2.5 RACT Determination

Table 15 provides a summary of the incremental control efficiency, achievable level of emissions, and cost-effectiveness of each control option used in the RACT determination for Unit 1. The cost effectiveness is calculated with NV Energy's requested emission cap.

**Table 15. LVGS $NO_x$ RACT Cost-Effectiveness for Unit 1**

| Unit | PTE Baseline Emission (tpy) | Control Equipment | Incremental Control (%) | Achievable Emissions (ppm @ 15% $O_2$) | Cost Effectiveness |
|---|---|---|---|---|---|
| 1 | 48 | Emissions Management | 10% | 10 | $0.00 |
| | 43 (emission cap suggested by NV Energy) | SCR | Already equipped | 10 | N/A |
| | | DLNC (with existing SCR) | 80% | 2 | $9,011 |
| | | SCR catalyst replacement | 80% | 2 | $5,528 |
| | | Water Injection (existing controls) | Already equipped | NA | N/A |

**Unit 1:** NV Energy's RACT submittal incorporated an emissions management control option with a 43-tpy emission cap on Unit 1. This control option reduces potential emissions with minimal to no associated control costs, but with the RACT proposed by NV Energy in its demonstration, catalyst replacement was only marginally above DAQ's CE guideline, making it more difficult to clearly weigh the benefits and disbenefits of the two control options to identify RACT. DAQ determined that an emissions limitation of 42 tpy represented RACT, slightly below the level proposed by NV Energy for emissions management, and increased the control efficiency to 13%. Under DAQ's cap, the CE of SCR catalyst replacement is $5,660 per ton of $NO_x$ reduced (at least 2.5% above the CE threshold), which clearly separates the emissions management option from the SCR catalyst replacement option to satisfy RACT.

**Units 2–5:** Units 2–5 are already equipped with SCR and water injection, and currently achieve an emission limit of 2 ppm @ 15% $O_2$. No further controls would provide additional $NO_x$ reductions beyond the current emission level. DAQ determines that the existing emission limitations (based on SCR and water injection) represent RACT for Units 2–5.

## 11.4 CLARK GENERATING STATION

### 11.4.1 Background

NV Energy also owns and operates the Clark Generating Station (CGS, Source ID: 7), located in Whitney, Nevada. CGS is an electric power generating facility (SIC: 4911, NAICS: 221112) consisting of four natural gas-fired CCCTs (no supplemental firing)[41] and 13 natural-gas fired simple cycle CTs. Other emissions sources include two cooling towers, one diesel-powered emergency engine, one diesel-powered emergency fire pump, and gasoline dispensing operations.

CGS currently operates as a major source under the conditions in its OP (Source ID: 7). According to the source PTE summary in its OP, the facility's $NO_x$ PTE is 2,467 tpy and its VOC PTE is 217 tpy. The only emission units with a VOC PTE greater than 5 tpy are Unit 4 and Units 5–8; the only emission units with a $NO_x$ PTE greater than 5 tpy are Units 4, 5–8, and 11–22 (all CTs/CCUs). PTEs for both $NO_x$ and VOC for all other emission units are below 5 tpy. CGS is therefore subject to $NO_x$ RACT for all turbines and VOC RACT for Units 4 and 5–8. Table 16 summarizes affected units, current control equipment, and $NO_x$ and VOC emission limits.

[41] Turbine vintage is approximately 1980.

**Table 16. CGS RACT-Affected Units**

| Emission unit | Description | Date of Commercial Operation | # of Units | Control(s) | $NO_x$ PTE (tpy) | $NO_x$ Emission Limits | VOC PTE (tpy) |
|---|---|---|---|---|---|---|---|
| Unit 4 (A00704D) | Natural gas-fired CT (60 MW) | 1973 | 1 | None | 1732.6[1] | 1732.6 tpy | 94.5 |
| Units 5–8 (A00701A, A00702B, A00705, A00708) | Natural gas-fired CCR (85 MW) | ~1980 | 4 | LNB | 360 (total)[2] | 360 tpy 5 ppm @ 15% $O_2$ (1-hr) 19.11 lb/hr | 87.6[3] |
| Units 11-22 (A27-A38) | Natural gas-fired CTs (57.9 MW) | 2008 | 12 | SCR/water injection Oxidation cat-alyst | 371.5[3] | 360 tpy 5 ppm @ 15% $O_2$ (1-hr) 19.11 lb/hr | Each unit is less than 5 tpy[3] |

[1] NV Energy requested a 292 tpy $NO_x$ emission cap.
[2] $NO_x$ PTE for Units 5–8 is capped at 360 tpy per calendar year pursuant to the Consent Decree (Condition IV-C-38-b), which applies to combined emissions from these four units.
[3] $NO_x$ and VOC totals for Units 5–8 and 11–22 are based on summing each individual unit's PTE values from the Part 70 Operating Permit (Table II-C-1). VOC is not applicable to Units 11–22 because each unit's VOC PTE is less than 5 tpy.

As part of the RACT submittal, NV Energy requested that Unit 4 incorporate an emissions cap on the $NO_x$ PTE. The following analysis includes emissions management through this emissions cap, as requested by NV Energy, as a viable control option. Additionally, Units 5–8, as written in the current OP, have a combined total $NO_x$ PTE, but for its RACT analysis, NV Energy split the combined PTE equally among the four units, assigning each unit one-fourth of the total PTE. DAQ reviewed this approach and determined that since the units share a combined emission threshold, all four units would require additional controls to effectively implement RACT. Therefore, DAQ updated the cost analysis to reflect the cost of installing controls on all four units. DAQ also evaluated an alternative scenario where only one unit receives controls and is assigned the full $NO_x$ PTE.

### 11.4.2 RACT Analysis

DAQ conducted the following RACT analysis for $NO_x$ and VOC using data and information provided by NV Energy as noted and where applicable.

#### 11.4.2.1 $NO_x$ RACT Analysis

##### *11.4.2.1.1 Potential Control Technologies*

Table 17 lists the potential control technologies considered for each unit. These technologies are consistent with the potential retrofit options in EPA guidance for combustion turbines (EPA 1993c). Certain technologies were not considered technically feasible so eliminated from consideration, as discussed below.

**Table 17. CGS Technical Feasibility of $NO_x$ Control Technologies**

| Control Technology | Unit 4 | Units 5–8 | Units 11–22 |
|---|---|---|---|
| Emissions management | Yes | No: not proposed by affected source | No: not proposed by affected source |
| SCR | Yes | Yes | Already equipped; increased ammonia injection is not technically feasible |
| DLNC | No | Already equipped | Yes |
| Water Injection | Uncertain whether technical feasibility is demonstrated in practice. | No | Already equipped; increased water injection is not technically feasible |
| GCP | Yes | Yes | Yes |

For Unit 4, DLNC was eliminated from consideration because the vendor indicated[42] the only retrofit option for this unit (GE 7B DLN1+) had not been demonstrated as technically feasible on this turbine frame. The addition of water injection was considered technically feasible for this evaluation, although further investigation would be required to confirm whether the retrofit has been demonstrated in practice on similar turbines.[43]

For Units 5–8, DAQ determined that the existing combustors were not designed for water injection and would have to be replaced. Since RACT does not require replacement of an affected unit, DAQ concluded that this technology was not technically feasible.

For Units 11–22, DAQ concluded use of increased ammonia injection rates with the existing SCR configuration was not technically feasible because adding ammonia beyond current design specifications would flood the catalyst with ammonia and reduce $NO_x$ removal.[44] Retrofitting DLNC without WSI, however, is a technically feasible retrofit option.

*11.4.2.1.2 Control Equipment Costs*

NV Energy resubmitted its previous RACT submittal from the Moderate SIP to represent its 2025 RACT demonstration. However, AQR 120 requires the use of PTE and a 30-year life expectancy to calculate the CE of control technologies. Since its previous RACT submittal included calculations based on actual emissions, not PTE, DAQ requested that NV Energy update its calculations to reflect PTE. NV Energy provided revised calculations using PTE based on the methodology from its previous RACT demonstration.

For units with a combined annual tpy limit across multiple turbines, NV Energy provided calculations that split the combined limit equally among all four turbines to determine CE. Upon further review, DAQ determined that NV Energy's approach was not satisfactory given that one turbine is permitted to operate more than one-fourth of the operational limit, in fact up to the entire operational limit. Therefore, DAQ performed additional calculations using two alternative approaches: (1) DAQ applied the full combined tpy limit to a single unit to evaluate the CE of

[42] Moderate SIP, Attachment D, Appendix 7b.
[43] GE provides a water injection kit for MS7001B (Frame 7B) turbines, but more information is needed to determine whether it has been successfully installed and operated on other turbines.
[44] Moderate SIP, Attachment D, Appendix 7b.

upgrading only one unit with the control technology; (2) DAQ evaluated the CE of upgrading all units simultaneously while maintaining the combined tpy limit.

All control equipment costs are based on vendor estimates provided by NV Energy in its previous RACT submittal, its 2025 RACT supplemental submittal, or through EPA's Cost Strategy Tool (CoST) as calculated in its previous submittal.[45] Calculations performed from the previous submittal included only total capital investment (TCI), which consists of initial capital investment and direct costs. This is a conservative approach because it does not include indirect costs of installation, such as engineering time, potential energy impacts for certain upgrade options, and other cost components described in the *EPA Air Pollution Control Cost Manual* (EPA 2002). If a control technology was cost-effective based solely on initial capital investment and direct costs, DAQ reviewed NV Energy's calculations to include sales tax (Nevada sales tax 4.6%) and indirect installation costs (estimated at 35% of capital equipment cost). DAQ assumed an interest rate of 7.14% based on a justification provided by NV Energy and approved by the public utility commission.[46] Attachment 9 provides detailed CE calculations.

For Unit 4, SCR equipment, installation, and catalyst costs were based on a vendor estimate provided by NV Energy in its previous RACT submittal. Estimated costs for a water injection retrofit were based on CoST, adjusted for inflation. No additional costs are associated with the implementation of GCP.

For Units 5–8, SCR equipment, installation, and catalyst costs were based on the Unit 4 SCR cost estimate, scaled according to the "six-tenths factor" methodology. The "rule of six-tenths" refers to a cost scaling method that can be used to estimate the cost of a similar item of different size or capacity, based on the equation: $Cost_1/Cost_2 = (MW_1/MW_2)^{0.6}$.

For Units 11–22, total installed LNB costs were estimated based on a vendor cost estimate for Unit 4 provided by NV Energy.

#### *11.4.2.1.3 Control Equipment Performance*

For Unit 4, the achievable emissions level for the SCR retrofit option (4 ppm @ 15% $O_2$) was based on vendor data provided by NV Energy. The achievable emissions level for installation of water injection was based on the lowest RBLC determination for a similarly equipped unit (25 ppm @ 15% $O_2$).[47] The achievable emissions level for GCP assumed the current level of emissions would be maintained (~120 ppm @ 15% $O_2$), and for the emissions management control, NV Energy proposed a 292 tpy $NO_x$ emissions cap, which represents an 83% reduction in potential emissions.

[47] The lowest RBLC determination for the period 2015–2025 for CTs equipped with water injection is 25 ppm @ 15% $O_2$ (Attachment 10). Further investigation would be required to determine if this level of performance has been achieved on a similar turbine retrofit.

For Units 5–8, the achievable emissions level for the addition of SCR with the existing DLNC (DLNC/SCR) was based on the lowest RBLC determination (2 ppm at 15% $O_2$) for a similarly equipped unit.[48]

For Units 11–22, the achievable emissions level for the installation of DLNC with the existing SCR system (DLNC/SCR) was based on the lowest RBLC determination (2 ppm at 15% $O_2$) for a similarly equipped unit.

*11.4.2.1.4 Energy and Environmental Impacts*

**SCR.** SCR converts $NO_x$ (NO and $NO_2$) to NO and O by reacting the $NO_x$ compounds with ammonia in the presence of a catalyst. However, excess ammonia is required to account for nonuniform distribution of gases across the catalyst bed. The amount of slip required to maintain $NO_x$ removal efficiency also increases over time due to catalyst deactivation. Because ammonia is a contributor to atmospheric $PM_{2.5}$ formation, excess ammonia presents an adverse environmental impact. Other environmental concerns include the accidental release of stored ammonia and the disposal of spent catalyst, which contains vanadium and/or titanium. SCR also presents an adverse energy impact because the increased pressure drop across the catalyst bed reduces turbine efficiency.

**DLNC.** Maximum reduction in $NO_x$ is typically achievable only at higher load conditions with premixed operation (< 75% load). A significant lack of turn-down capability may be an issue for peaking units or units with variable demand. In addition, decreasing the firing temperature may increase CO and VOC emissions.

DLNCs have a lower combustion efficiency than conventional combustors, which adversely affects fuel efficiency for these units. The source would have to purchase additional generating capacity elsewhere to maintain total system generating capacity. Units equipped with water injection would incur an energy penalty due to the loss of power augmentation.

**Water Injection.** Water injection increases power output due to the increased mass flow needed to maintain the turbine inlet temperature. However, it also reduces combustion efficiency: some energy from combustion gases is needed to overcome the latent heat of water vaporization, which can result in higher emissions of CO and VOC. It also causes nonuniform heat release within the combustor, which can create pressure oscillations that induce turbine vibration. Although combustor modifications can reduce the effects of these oscillations, they are not completely eliminated, which may affect equipment life.

*11.4.2.1.5 RACT Determination*

Table 18 provides a summary of the incremental control efficiency, achievable level of emissions, and CE of each control option used in the RACT determination for each unit. Attachment 9 provides additional supporting calculations.

[48] RBLC determinations for the period 2015–2025 for CCUs equipped with SCR/DLN range from 2–3 ppm @ 15% $O_2$ (see Attachment 10).

**Table 18. CGS $NO_x$ Cost-Effectiveness**

| Unit | PTE Baseline Emission (tpy) | Control Equipment | Incremental Control Efficiency (%) | Achievable Emissions (ppm @ 15% $O_2$) | CE ($/ton) |
|---|---|---|---|---|---|
| 4 | 1732.6 | Emissions management | 83% | N/A | $0.00 |
| | 292.0[1] | SCR | 97% | 4 | $6,707[2] |
| | | Water injection | 79% | 25 | $13,735 |
| | | GCP | N/A | ~120 | N/A |
| 5–8 | 360[3] | SCR/LNB on one unit | 60% | 2 | $8,862[4] |
| | | SCR/LNB on all units | 60% | 2 | $35,448[5] |
| | | LNB (existing controls) | N/A | 5 | N/A |
| 11–22 | 30.96[6] | SCR/LNB | 60% | 2 | $83,565 |
| | | SCR with WSI (existing controls) | N/A | 5 | N/A |

[1] Emission cap suggested by NV Energy.
[2] Nevada sales tax and indirect installation cost included.
[3] Combined PTE limit for all four units.
[4] Cost based on total PTE with only one unit upgraded with control technology.
[5] Cost based on total PTE with all four units upgraded with control technology.
[6] PTE is per unit.

Table 18 shows the CE of each control option for each unit. As part of its RACT submittal, NV Energy requested an emission cap for Unit 4 at 292 tpy. DAQ concludes this is a cost-effective control option. DAQ then updated CE values for the other control options to include Nevada sales tax and indirect installation cost, and used the emissions management option as the baseline for evaluating the other control options. After these adjustments, DAQ determined that no additional control option is cost-effective and NV Energy's suggested 292 tpy is the achievable emissions limitation for RACT.

For Units 5–8 and 11–22, DAQ rejected all technically feasible upgrade options due to excessive cost. For Units 5–8, even when applying the full combined PTE to a single unit and upgrading only that unit with control technology, CE exceeded $7,000/ton, demonstrating that additional controls were not economically feasible under any scenario evaluated.

Therefore, DAQ determines that a $NO_x$ limit of 5 ppm @ 15% $O_2$ based on existing LNB (Units 5–8) and SCR (Units 11–22) represents RACT for these units, excluding startup, shutdown, and non-normal operations. During startup and shutdown, DAQ determines that $NO_x$ limits of 360 tpy on LNB (Units 5–8) and 96 ppm @ 15% $O_2$ on SCR (Units 11–22) represent RACT for these units. Further, all units will use GCP during startup, shutdown, and other non-normal operations. Compliance will be demonstrated using the existing continuous emission monitoring system (CEMS) on each unit based on a 1-hr average.

#### 11.4.2.2 VOC RACT Analysis

The VOC RACT analysis included Units 4–8, which are not currently equipped with any VOC controls. Units 11–22 are already equipped with an oxidation catalyst limiting VOC PTE to less than 5 tpy, so were excluded from the analysis.

#### *11.4.2.2.1 Potential Control Technologies*

Table 19 lists the potential control technologies considered for each unit. These technologies are consistent with the potential retrofit options identified in EPA guidance for combustion turbines (EPA 2002). As discussed below, certain technologies were not considered technically feasible and were eliminated from consideration.

**Table 19. CGS Technical Feasibility of VOC Control Technologies for Turbines**

| Control Technology | Unit 4 | Units 5-8 |
|---|---|---|
| DLNC | No | Already equipped |
| OC | Yes | Yes |
| GCP | Yes | Yes |

The only option considered technically infeasible is a DLNC upgrade for Unit 4. Improved combustion efficiency may reduce VOC emissions, although a DLNC retrofit for this turbine frame has not been demonstrated in practice (see Section 11.4.2.1.1).

#### *11.4.2.2.2 Control Equipment Costs*

DAQ applied the same methodology for estimating costs as in the $NO_x$ RACT analysis. As described in Section 11.4.2.1.2, energy impacts and certain cost components described in the *EPA Air Pollution Control Cost Manual* (EPA 2002) were not included to simplify the analysis, which may understate actual costs associated with each control option.

For Units 5–8, equipment, installation, and catalyst costs were based on a vendor estimate provided by NV Energy. For Unit 4, OC costs were based on the Unit 4 vendor estimate and scaled using the "six-tenths factor" methodology. No additional costs are associated with the implementation of GCP.

#### *11.4.2.2.3 Control Equipment Performance*

For Unit 4, OC control effectiveness was based on a vendor estimate of 80% removal efficiency provided by NV Energy in its previous RACT demonstration. For Units 5–8, OC control effectiveness was based on a vendor estimate of 2 ppm @ 15% $O_2$ provided by NV Energy in its previous RACT demonstration. Control effectiveness resulting from implementation of GCP is based on maintaining the current level of VOC emissions.

#### *11.4.2.2.4 Energy and Environmental Impacts*

**Oxidation Catalysts.** The environmental impact of OC use includes potential increases of $NO_x$ from oxidation of NO and sulfur trioxide ($SO_3$) formation resulting from the oxidation of $SO_2$, both of which are precursors to formation of acid rain. Energy impacts include a reduction in turbine efficiency caused by an increase in exhaust back pressure across the catalyst bed.

### *11.4.2.2.5 RACT Determination*

Table 20 summarizes the RACT determination for each unit. For Unit 4, DAQ determines that the existing requirement to use GCP represents RACT for VOC because oxidation catalyst is not cost-effective. The VOC limit of 94.5 tpy, including startup, shutdown, and testing/tuning operations, does not require any specific control, so by itself does not establish RACT.

**Table 20. CGS VOC RACT Cost-Effectiveness**

| Unit | Control Equipment | VOC PTE Baseline Emission (tpy) | Incremental Control Efficiency (%) | Achievable Emissions from PTE | CE ($/ton) |
|---|---|---|---|---|---|
| Unit 4 | Oxidation Catalyst | 94.5 | 97% | 21.9 | $5,536[1] |
| | GCP | 94.5 | N/A | 94.5 | N/A |
| Units 5–8 | Oxidation Catalyst | 21.9 | 88% | 2.63 | $23,848 |
| | GCP | 21.9 | N/A | 4.57 | N/A |

[1] When adjusted for compliance with $NO_x$ RACT (allowing approximately 1,480 hours/year operation and resulting in a maximum of 16 tpy VOC), CE exceeds $32,000/ton, far above the RACT threshold.

Initially, NV Energy's CE analysis for an oxidation catalyst on Unit 4 showed a cost of $5,536 per ton of VOC removed, just marginally above the CE threshold. However, this analysis was based on continuous annual operation (8,760 hours/year). NV Energy's demonstration did not account for the operational effects of complying with $NO_x$ RACT on Unit 4. When the analysis was adjusted to reflect an estimated reduction in hours of operation to 1,480 annually to meet $NO_x$ RACT, the unit's potential VOC emissions declined to 16 tpy. Using this annual emissions value as baseline emissions for the oxidation catalyst increases the CE of that control option to greater than $32,000 per ton, a cost that clearly exceeds DAQ's RACT CE threshold. DAQ concludes that the oxidation catalyst does not qualify as VOC RACT. Instead, based on compliance with the $NO_x$ RACT limit, the reasonably available VOC control is GCP and GMP, with no additional add-on control. Accordingly, DAQ establishes a short-term emissions limit of 21.6 lb/hr[49] during normal operation as VOC RACT unless the affected source opts for an add-on oxidation catalyst. RACT during startup, shutdown, and other non-normal operations is adherence to GCP; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT.

For Units 5–8, DAQ determines that the existing VOC limit of 5.01 lb/hr (excluding startup, shutdown, and testing/tuning operation) represents RACT based on the application of GCP. DAQ eliminated OC use due to excessive cost (> $23,848/ton for all units). RACT during startup, shutdown, and other non-normal operation is adherence to GCP; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. NV Energy will follow the compliance requirements during startup, shutdown, and non-normal operations for each unit as outlined in the source's current OP.

[49] Based on prorating 16-tpy annual operation over 1,480 hours of operation.

## 11.5 SUN PEAK GENERATING STATION

### 11.5.1 Background

NV Energy owns and operates SPGS (Source ID: 423). SPGS is an electric power generating facility (SIC code 4911, NAICS code 221112) consisting of three natural gas-fired simple cycle CTs and one 81-hp diesel power emergency engine with a diesel storage tank. SPGS is a major source of $NO_x$. Table 21 provides a summary of the affected units, current control equipment, and $NO_x$ and VOC emission limits.

**Table 21. SPGS RACT-Affected Units**

| EU | Description | Date of Commercial Operation | Controls | $NO_x$ Emission Limits | VOC Emission Limits |
|---|---|---|---|---|---|
| A01 (Unit 3) | Natural gas / oil-fired CT (84.5 MW) | 1991 | Water injection | Natural Gas:<br>249.11 tpy<br>143.00 lb/hr<br>42 ppmvd@15% O2<br>#2 Oil:<br>249.02 tpy<br>227.00 lb/hr<br>65 ppmvd @ 15% $O_2$ | Natural Gas:<br>3.59 tpy<br>2.06 lb/hr<br>#2 Oil:<br>4.94 tpy<br>54.50 lb/hr |
| A02 (Unit 4) | Natural gas / oil-fired CT (84.5 MW) | 1991 | Water injection | | |
| A03 (Unit 5) | Natural gas / oil-fired CT (84.5 MW) | 1991 | Water injection | | |

Units 3–5, as written in the current OP, have a combined total $NO_x$ PTE. NV Energy's RACT analysis split the combined PTE equally among the three units, assigning each unit one-third of the total PTE. DAQ reviewed this approach and determined that since the units share a combined emission threshold, all three units would require additional controls to meet RACT because each turbine is permitted to operate more than one-third of the total operational limit. Therefore, DAQ updated the cost analysis to reflect the cost of installing controls on all three units. DAQ also evaluated an alternative scenario where only one unit receives controls and is assigned the full $NO_x$ PTE.

### 11.5.2 $NO_x$ RACT Analysis

DAQ conducted the following analysis, using data and information in the RACT demonstration provided by NV Energy as noted and where applicable.

#### 11.5.2.1 Potential Control Technologies

Table 22 lists the potential control technologies considered for each unit. These are consistent with the potential retrofit options identified in EPA guidance for combustion turbines (EPA 1993c). DAQ determined that certain technologies are not technically feasible and eliminated them from consideration.

**Table 22. SPGS Technical Feasibility of $NO_x$ Control Technologies**

| Control Technology | Units 3-5 |
|---|---|
| SCR | Yes |
| DLNC | Yes |
| SCR + DLNC | Yes |
| Increase water injection | No |
| GCP | Yes |

Installation of DLNC is a technically feasible option, but water injection would become infeasible because the new burners would not support it. DAQ also considered the use of increased water injection as a relatively inexpensive method of further $NO_x$ reductions, with the possibility of achieving a RACT level of 25 ppmv 15% $O_2$. DAQ eliminated this option from further consideration after vendor information demonstrated these units are not capable of meeting this level of emissions with the current combustors.[50] The combination of DLNC and SCR is technically feasible but only achieves reductions comparable to the performance of SCR alone, based on the lowest RBLC determinations for similarly equipped units, and SCR alone is not cost-effective.

#### 11.5.2.2 Control Equipment Costs

NV Energy resubmitted its RACT analysis for the Moderate SIP as its 2025 RACT demonstration. However, AQR 120 requires the use of PTE and a 30-year life expectancy to calculate the CE of control technologies. Since NV Energy's previous RACT submittal included calculations based on actual emissions, not PTE, DAQ requested that NV Energy update its calculations to reflect PTE. NV Energy provided revised calculations using PTE based on the methodology from its previous RACT demonstration.

For units with a combined annual tpy limit across multiple turbines, NV Energy provided calculations that split the combined limit equally among all units to determine CE. Upon further review, DAQ performed additional calculations using two alternative approaches: (1) DAQ applied the full combined tpy limit to a single unit to evaluate the CE of upgrading only one unit with the control technology; (2) DAQ evaluated the CE of upgrading all units simultaneously while maintaining the combined tpy limit.

All control equipment costs are based on vendor estimates provided by NV Energy in its previous RACT submittal, 2025 RACT supplemental submittal, or through CoST calculations in the previous submittal.[51] Calculations performed from the 2024 submittal included only TCI, which consists of initial capital investment and direct costs. This is a conservative approach because it does not include indirect costs of installation, such as engineering time, potential energy impacts for certain upgrade options, and other cost components described in the *EPA Air Pollution Control Cost Manual* (EPA 2002). If a control technology was cost-effective based solely on initial capital investment and direct costs, DAQ reviewed NV Energy's calculations to include sales tax (Nevada sales tax 4.6%) and indirect installation costs (estimated at 35% of capital equipment

[50] Moderate SIP, Attachment D, Appendix 7b.
[51] Moderate SIP, Attachment D, Appendix 7, and Attachment 7D of this document.

cost). DAQ assumed an interest rate of 7.14% based on a justification from NV Energy approved by the public utility commission.[52] Attachment 9 provides detailed CE calculations.

Total installed SCR costs were based on a vendor estimate provided by NV Energy. SCR catalyst replacement cost was based on estimated catalyst costs for CGS Unit 4. LNB total installed cost was based on a vendor estimate for CGS Unit 4 and scaled using the "six-tenths factor" method.

#### 11.5.2.3 Control Equipment Performance

The achievable emissions level for the SCR (2 ppm @ 15% $O_2$) and DLNC (9 ppm @ 15% $O_2$) options were based on vendor data provided by NV Energy.[53] The achievable emissions level for the combination of SCR and DLNC was comparable to performance with SCR only, based on vendor data. The lowest RBLC determination for a gas-fired simple cycle CT with SCR and DLNC is 2 ppm @ 15% $O_2$.[54]

#### 11.5.2.4 Energy and Environmental Impacts

**SCR.** SCR converts $NO_x$ to NO and O by reacting the $NO_x$ compounds with ammonia in the presence of a catalyst. However, ammonia slip is required to account for nonuniform distribution of gases across the catalyst bed. The amount of slip required to maintain $NO_x$ removal efficiency also increases over time due to catalyst deactivation. Because ammonia is a contributor to atmospheric $PM_{2.5}$ formation, excess ammonia presents an adverse environmental impact. Other environmental concerns included the accidental release of stored ammonia and the disposal of spent catalyst, which may contain vanadium and/or titanium. SCR also presents an adverse energy impact, since the increased pressure drop across the catalyst bed reduces turbine efficiency.

**DLNC.** Maximum reduction in $NO_x$ is typically achievable only at higher load conditions with premixed operation (< 75% load). A significant lack of turn-down capability may be an issue for peaking units or units with variable demand. In addition, decreasing the firing temperature may increase CO and VOC emissions.

DLNC have lower combustion efficiency than conventional combustors, which adversely affects fuel efficiency for these units. The source would have to purchase additional generating capacity elsewhere to maintain total system generating capacity. Units equipped with water injection would incur an energy penalty due to the loss of power augmentation.

#### 11.5.2.5 RACT Determination

Table 23 lists the incremental control efficiency, achievable level of emissions, and CE of each control option used in the RACT determination for each unit. Attachment 9 provides additional supporting calculations.

[57] Attachment 7D.
[53] Attachment 7D.
[54] RBLC determinations for the period 2015–2025 for CTs equipped with SCR/DLNC range from 2-3 ppm @ 15% $O_2$ (see Attachment 10).

**Table 23. SPGS NOx RACT Summary**

| Unit | Control Equipment | Incremental Control (%) | Achievable Emissions (ppm @ 15% $O_2$) | CE |
|---|---|---|---|---|
| Units 3–5 | SCR on one unit | 95% | 2 | $9,750[1] |
| | SCR on all units | 95% | 2 | $29,249[2] |
| | LNB on one unit | 86% | 9 | $5,872[3] |
| | LNB on all units | 86% | 9 | $17,616[4] |
| | Water Injection (existing controls) | N/A | 42 | NA |

[1] Nevada sales tax and indirect installation cost included. Cost based on total PTE with only one unit upgraded with control technology.
[2] Nevada sales tax and indirect installation cost included. Cost based on total PTE with all four units upgraded with control technology.
[3] Nevada sales tax and indirect installation cost included. Cost based on total PTE with only one unit upgraded with control technology.
[4] Nevada sales tax and indirect installation cost included. Cost based on total PTE with all four units upgraded with control technology.

Units 3–5 have a combined PTE limit. As Section 11.5.2.1 discussed, DAQ evaluated two scenarios: upgrading only one unit with the full combined PTE applied to that unit, and upgrading all three units while maintaining the combined PTE limit. As Table 23 shows, all upgrade options were determined not to be cost-effective under both scenarios.

DAQ has determined that the existing $NO_x$ limit of 42 ppmvd @ 15% $O_2$ (3-hour average) while firing natural gas (excluding startup, shutdown, and testing/tuning operations) represents RACT based on the use of existing $NO_x$ controls. All upgrade options have been eliminated due to excessive cost. Further, DAQ decided to carry forward the $NO_x$ limit of 65 ppmvd at 15% $O_2$ while burning #2 diesel fuel (excluding startup, shutdown, and testing/tuning operations) from AQR 121. Compliance shall be demonstrated using CEMS, according to the monitoring and reporting procedures in the source's current OP.

For startup and shutdown, DAQ determined that that the existing $NO_x$ limit of 94 ppmvd @ 15% $O_2$ (4-hour rolling average) represents RACT. NV Energy shall follow the compliance requirements during startup and shutdown operations for each unit as outlined in the source's OP.

## 11.6 SAGUARO POWER COMPANY

### 11.6.1 Background

Saguaro Power Company (SPC) (Source ID: 393) is an electric power generating facility (SIC code 4931, NAICS code 221112) that consists of two natural gas-/oil-fired CCTs (GE PG6541), each equipped with two 25 MMBtu/hr duct burners, two diesel starter engines, and one cooling tower.

SPC is a major stationary source for $NO_x$ and a minor source for all other pollutants, and operates according to the conditions in its OP issued by DAQ. According to the PTE summary in the affected source's current OP, the facility's $NO_x$ PTE is 135.18 tpy and its VOC PTE is 8.22 tpy. For each turbine, the $NO_x$ PTE is 66.58 tpy and the VOC PTE is 4.03 tpy.

Based on DAQ's RACT applicability guidelines, SPC is subject to $NO_x$ RACT for both turbines. Table 24 provides a summary of the affected units, current control equipment, and $NO_x$ and VOC emission limits.

**Table 24. SPC RACT-Affect Units**

| EU | Description | Date of Commercial Operation | Control(s) | $NO_x$ Emission Limit | $NO_x$ PTE (tpy) |
|---|---|---|---|---|---|
| A01 (Unit 1) | Combustion Turbine Generator #1 (35 MW) with two fired HRSG (F05/05a) | 1991 | SCR/Steam Injection | Natural Gas: 15.20 lb/hr 10 ppm @ 15% $O_2$ (includes duct burners) | 66.58 |
| F05 | Supplemental Duct Burner (25 MMBtu/hr), Skid #1 | 1991 | | | |
| F05a | Supplemental Duct Burner (25 MMBtu/hr), Skid #1 | 1991 | | | |
| A02 (Unit 2) | Combustion Turbine Generator #2 (35 MW) with two fired HRSG (F06/06a) | 1991 | SCR/Steam Injection | Natural Gas: 15.20 lb/hr 10 ppm @ 15% $O_2$ (includes duct burners) | 66.58 |
| F06 | Supplemental Duct Burner (25 MMBtu/hr), Skid #2 | 1991 | | | |
| F06a | Supplemental Duct Burner (25 MMBtu/hr), Skid #2 | 1991 | | | |

## 11.6.2 $NO_x$ RACT Analysis

DAQ conducted the following RACT analysis for $NO_x$ using data and information in the RACT demonstration provided by SPC[55] as noted and where applicable.

### 11.6.2.1 Combined Cycle Units (Units 1 and 2)

The analysis for the CCUs is based on natural gas combustion only. Both units were previously permitted to burn #2 oil in the event of natural gas curtailment. However, the plant does not currently have the capability to burn oil in either unit because the fuel oil storage tanks have been repurposed. DAQ revised the operating permit on September 18, 2023, to remove the option of #2 oil as a fuel. If SPC elects to burn oil in the future, the facility must submit a revised RACT evaluation.

#### *11.6.2.1.1 Potential Control Technologies*

Table 25 shows the potential control technologies for each affected unit. These technologies are consistent with the potential retrofit options identified in EPA guidance for combustion turbines (EPA 1993c). DAQ concluded that certain technologies were not technically feasible and eliminated them from consideration.

**Table 25. SPC Technical Feasibility of $NO_x$ Control Technologies**

| Control Technology | Units 1 and 2 |
|---|---|
| DLNC (with existing SCR) | Yes |
| SCR | Already equipped |
| SCR catalyst replacement | Yes |
| Steam injection | Already equipped |
| GCP | Yes |

[55] Attachments 8A–8B.

The installation of DLNC is a technically feasible option for both units, but steam injection would become infeasible because this technology cannot be used simultaneously with DNLC. SPC included an SCR catalyst replacement option in its analysis. Details on the scope of this option are limited; the ability to meet the proposed emission limit (6 ppm @ 15% $O_2$ or lower) cannot be determined without further investigation. SPC included an additional ammonia cost component in its annual operating cost evaluation, which suggests the replacement may include a new catalyst or catalyst bed design that allows higher levels of ammonia injection. DAQ considers this option technically feasible based on this assumption. DAQ used the cost and performance estimates provided by SPC, updated to reflect AQR 120 requirements.

*11.6.2.1.2 Control Equipment Costs*

All control equipment costs are based on vendor estimates provided by SPC except as noted below. DAQ modified the estimates as follows to provide consistency between RACT determination for the various units:

- TCI includes initial capital investment (equipment cost only) and direct costs (direct installation cost only).
- Annualized TCI for the catalyst replacement assumes a 10-yr catalyst replacement cycle.

Potential energy impacts for certain upgrade options and several of the cost components described in the *EPA Air Pollution Control Cost Manual* were not included to simplify the analysis.[56] Estimated costs likely underestimate actual costs associated with each control option (see Attachment 9).

*11.6.2.1.3 Control Equipment Performance*

The achievable emissions level for the DLNC retrofit is based on the lowest RBLC determination for a similarly equipped unit (2 ppm @ 15% $O_2$).[57] The achievable emissions level for the SCR catalyst replacement is based on the highest RBLC determination for a similarly equipped unit (2 ppm @ 15% $O_2$).[58] DAQ assumed the highest level of emissions in this case to account for the uncertainty in the scope and performance of the catalyst replacement project.

*11.6.2.1.4 Energy and Environmental Impacts*

**SCR.** SCR converts $NO_x$ to NO and O by reacting the $NO_x$ compounds with ammonia in the presence of a catalyst. However, ammonia slip is required to account for nonuniform distribution of gases across the catalyst bed. The amount of slip required to maintain $NO_x$ removal efficiency also increases over time due to catalyst deactivation. Because ammonia is a contributor to

[56] SPC also included annual remote tuning costs in their DLNC evaluation. DAQ excluded this cost from the evaluation for consistency with other DLNC evaluations.
[57] RBLC determinations for $NO_x$ for the period 2015–2025 for CCUs equipped with SCR/LNB range from 2–3 ppm @ 15% $O_2$ (see Appendix 13). This is lower than the estimated level of performance (4 ppm @ 15% $O_2$) provided in the SPC RACT analysis. Further investigation would be required to determine if this level of performance can be achieved as a retrofit on these units.
[58] RBLC determinations for $NO_x$ for the period 2015–2025 for CCUs equipped with SCR (with and without water/steam injection) range from 2–3 ppm @ 15% $O_2$ (see Attachment10).

atmospheric $PM_{2.5}$ formation, excess ammonia presents an adverse environmental impact. Other environmental concerns include accidental release of stored ammonia and disposal of spent catalyst, which may contain vanadium and/or titanium. SCR also presents an adverse energy impact, since the increased pressure drop across the catalyst bed reduces turbine efficiency.

**DLNC.** Maximum reduction in $NO_x$ is typically achievable only at higher load conditions with premixed operation (< 75% load). A significant lack of turn-down capability may be an issue for peaking units or units with variable demand. In addition, decreasing the firing temperature may increase CO and VOC emissions.

DLNC have lower combustion efficiency than conventional combustors, which adversely affects fuel efficiency for these units. The source would have to purchase additional generating capacity elsewhere to maintain total system generating capacity. Units equipped with water or steam injection would incur an energy penalty due to the loss of power augmentation.

*11.6.2.1.5 RACT Determination*

Table 26 lists the incremental control efficiency, achievable level of emissions, and CE of each control option used in the RACT determination for each unit. Attachment 9 provides additional supporting calculations. Table 27 summarizes the RACT determination for each unit and the achievable emission limitations for all the units.

**Table 26. $NO_x$ RACT Summary (SPC CCUs)**

| EU | Control Equipment | Incremental Control Efficiency (%) | Achievable Emissions (ppm @ 15% $O_2$) | Cost Effectiveness ($/ton) |
|---|---|---|---|---|
| Units 1 & 2 | DLNC with existing SCR | 80% | 2 | $9,069 |
| | SCR catalyst replacement | 70% | 3 | $6,223 |
| | SCR/steam injection (existing controls) | N/A | 10 | N/A |

**Table 27. Proposed RACT-Based $NO_x$ Emission Limitations (SPC CCUs)**

| EU | Emission Limitation/Work Practice | | Monitoring Req'ts |
|---|---|---|---|
| | Normal Operation | Startup/Shutdown | |
| Units 1 & 2 | 10 ppm @ 15% $O_2$ (4-hr average) | Follow good combustion practices | CEMS (follow existing permit requirements) |

DAQ determines that the existing $NO_x$ limit of 10 ppmvd @ 15% $O_2$ (4-hr average) while firing natural gas (excluding startup, shutdown, and malfunction) represents RACT based on the use of existing $NO_x$ controls. All other technically feasible control options were eliminated as not cost-effective. Compliance will be demonstrated using CEMS. RACT during startup, shutdown, and other non-normal operation is GCP during each of those modes of operation. Emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT.

# 12.0 REFERENCES

42 U.S.C. 7401 et seq. Clean Air Act.

40 CFR Part 51.1300, Subpart CC. Provisions for Implementation of the 2015 Ozone National Ambient Air Quality Standards.

40 CFR Part 51.1312(a). Requirements for reasonably available control technology (RACT) and reasonably available control measures (RACM).

40 CFR Part 60, Subpart IIII. Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

40 CFR Part 60, Subpart K. Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978.

40 CFR Part 60, Subpart Kc. Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After October 4, 2023.

40 CFR Part 60, Subpart XX. Standards of Performance for Bulk Gasoline Terminals That Commenced Construction, Modification, or Reconstruction After December 17, 1980.

40 CFR Part 60, Subparts XX and XXa. Standards of Performance for Bulk Gasoline Terminals That Commenced Construction, Modification, or Reconstruction After December 17, 1980, and On or Before June 10, 2022; and Standards of Performance for Bulk Gasoline Terminals that Commenced Construction, Modification, or Reconstruction After June 10, 2022.

40 CFR Part 63, Subpart BBBBBB. National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities.

40 CFR Part 1039. Control of Emissions From New and In-Use Nonroad Compression-Ignition Engines.

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# ATTACHMENT 1: Major Source RACT Notice

**From:** Ted Lendis
**To:** Ted Lendis; AQPlanning
**Subject:** REGULATORY NOTIFICATION - Major Source RACT Requirements
**Date:** Thursday, April 3, 2025 2:09:38 PM
**Attachments:** image001.png
image002.png
image003.png
image004.png

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Clark County Environment & Sustainability

April 3, 2025

**Re: Regulatory Notification – Major Stationary Source RACT Requirements**

Dear Stakeholder,

The Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) is establishing emissions control requirements in its State Implementation Plan (SIP), including Reasonably Available Control Technology (RACT) for major sources, as mandated by Section 182(b)(2) of the Clean Air Act (42 U.S.C. § 7511a).

DAQ is notifying owners and operators of major stationary sources of nitrogen oxides (NOx) and/or volatile organic compounds (VOC) located within the ozone nonattainment area of Clark County, NV (Las Vegas Valley), of their obligation to comply with Section 120 of the Clark County Air Quality Regulations (AQRs). **Compliance with the application requirements of Section 120 is due on or before August 1, 2025, which is within 120 days after the Control Officer issues this written notice.** Based on DAQ's assessment, you have been identified as an owner or operator of an affected source under Section 120.2(a).

**Major Source RACT Demonstration**
Owners and operators must submit a major source RACT demonstration for all affected units by applying for a new stationary source permit or a significant permit revision. In addition to the definition in Section 120.3, and unless notified otherwise by the Control Officer, **affected units are emissions units located at your major stationary source with a potential to emit NOx or VOC that is equal to, or greater than five tons per year**. This application must comply with the submittal requirements outlined in AQR Sections 12.4 and/or 12.5. Even if the demonstration does not result in additional control requirements, you still must submit a complete application to the Control Officer.

**Previous RACT Determinations**
If you have been subject to a major source RACT determination within the past 36 months that meets the requirements of Section 120 and the basis of that determination is still valid, you may

submit a copy of the prior determination, along with a sworn certification. The certification must confirm that the determination continues to represent RACT, because there have been no changes to available control technologies, technical feasibility, control effectiveness, cost-effectiveness, or environmental, energy, and other impacts since the original determination.

**Avoiding RACT Requirements**
You may avoid SIP-related RACT requirements by accepting synthetic minor limits in your permit to reduce allowable NOx and/or VOC emissions below the major source thresholds. To explore this option, contact DAQ's Permitting Section to discuss potential permit revisions.

For more information, please refer to the resources included below. Contact DAQ at 702-455-5942 if you have any questions or would like further clarification.

PLEASE RESPOND TO ACKNOWLEDGE RECEIPT OF THIS NOTIFICATION

Sincerely,



Theodore A. Lendis
Planning Manger

**Resources**

Small Business Assistance Program's Section 120 FAQs:
https://webfiles.clarkcountynv.gov//FAQ%20AQR%20120%20HA212.pdf

Clark County Air Quality Regulations:
https://www.clarkcountynv.gov/government/departments/environment_and_sustainability/division_of_air_quality/rules___regulations/current_aq_rules.php

EPA Control Technology Guidelines (CTG): https://www.epa.gov/ground-level-ozone-pollution/control-techniques-guidelines-and-alternative-control-techniques

EPA Cost Control Manual: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Federal Register notice of Clark County's nonattainment designation:
https://www.federalregister.gov/documents/2018/06/04/2018-11838/additional-air-quality-designations-for-the-2015-ozone-national-ambient-air-quality-standards

# ATTACHMENT 2A: NAFB RACT

DES
DEPARTMENT OF ENVIRONMENT AND SUSTAINABILITY
air quality desert conservation sustainability
4701 W. Russell Road 2nd Floor
Las Vegas, NV 89118-2231
Phone: (702) 455-5942 Fax: (702) 383-9994
Marci Henson, Director

**For DAQ Use Only**

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2025 JUL 30 AM8:45

## Certification Statement

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the attached document(s) are true, accurate, and complete for the submittal of a RACT analysis for a new generator. This certification applies to the following stationary source:

| Source ID: | Source Name: |
|---|---|
| 114 | Nellis AFB |

## Certification

| Name of Responsible Official: | Responsible Official's Title: | Company/Organization: |
|---|---|---|
| Colonel Jason J. Glynn | Commander, 99th Air Base Wing | United States Air Force, Nellis Air Force Base |

| Jason J. Glynn | 27 July 2025 |
|---|---|
| **Responsible Official's Signature** | **Certification Date** |

# Authority to Construct Permit Application for a 40 CFR Part 70 Source

## Clark County Department of Environment & Sustainability Division of Air Quality

**Submit Application and Payment to:**
**Division of Air Quality**
**4701 W. Russell Road, Suite 200**
**Las Vegas NV 89118**

**For DAQ Use Only**

**Invoice No.:** 076941

**Date:**

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## Section A: Permit Application Type (check one):

- ☐ ATC with PSD Review (AQR 12.2)
- ☐ ATC with Nonattainment Review (AQR 12.3)
- ☐ ATC (AQR 12.4; not subject to AQR 12.2 or 12.3)
- ☐ ATC as part of a Part 70 OP Significant Revision (AQR 12.4.3.2(d))
- ☒ ATC as part of a Part 70 OP Minor Revision (AQR 12.4.3.2(e))
- ☐ Administrative Revision of Existing ATC (AQR 12.4.4.1(b))
- ☐ Significant Revision of Existing ATC (AQR 12.4.4.1(c))

***Application Description:*** Describe the action being proposed, e.g., new process, change to equipment, change to permit conditions, Voluntarily Accepted Emission Limit (VAEL), etc.

ATC Application to submit a major source RACT demonstration for G194.

**Applications for a Part 70 source ATC shall include the information requested in Sections B–F.**

***Complete the fields in Sections B–F even if there is no change from the previous application.***

## Section B: Source Information

Source ID No (existing permits only): 114

Source Name (as listed on Clark County/State of Nevada business license):
Nellis Air Force Base

City/County Business License #: Not Applicable

**Source Location Information**

| Number: | Direction: | Street Name: | Cross Streets: |
|---|---|---|---|
| 4430 | Not Applicable | Grissom Avenue | Ellsworth Avenue |

City: Nellis AFB | State: NV | ZIP: 89191-6520

**Phone Numbers**

Office: (702) 652-2882 | Fax: Not Applicable

**North American Industry Classification System (NAICS) / Source Industry Classification Code**

Primary NAICS: 928110 | Additional NAICS: Not Applicable

***Source Description:*** Describe the nature of your business, including processes and products.

National Security

## Section C: Company Information (AS LISTED ON THE SECRETARY OF STATE'S BUSINESS CERTIFICATE/FILING)

Has any of this information changed since the previous application? ☐ YES ☒ NO **(Existing Permit Holders Only)**
If YES, submit the Transfer of Ownership/Change of Name form and fee (SS-PER-020-01).

Company Name: United States Air Force, Nellis Air Force Base

Nevada Secretary of State Business Certificate/Filing No.: Not Applicable

## Section G: Application Instructions

1. An owner or operator of an existing or new Part 70 source shall obtain an Authority to Construct (ATC) Permit from the Control Officer before beginning actual construction or continuing with any of the following:
   a. Operating a new Part 70 source;
   b. "Major modification," as defined in AQR 12.2 or 12.3;
   c. Modification that increases the Part 70 source's potential to emit (PTE) by an amount equal to or greater than the minor New Source Review (NSR) significant level in AQR 12.4.2.1;
   d. Construction, modification, or reconstruction of an affected facility that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 60;
   e. Construction or reconstruction of a new source or of an affected source that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 63, including, but not limited to, construction or modification that requires preconstruction review under 40 CFR Part 63.5; or
   f. Modification to a solid waste incinerator unit, as defined by an applicable standard under 40 CFR Part 60.
2. When the owner or operator of a Part 70 source must revise the existing Part 70 Operating Permit before construction, modification, or reconstruction, as specified in AQR 12.4.1.1(c), the Control Officer shall follow AQR 12.5.2.13 or 12.5.2.14, as applicable, to process the ATC Permit application and revise the Part 70 Operating Permit.
3. For construction, modification, or reconstruction that meets the AQR 12.5.14(c)(1) criteria for a significant permit revision, the owner or operator may submit an ATC Permit application that fulfills both AQR 12.4.3.1(a) requirements and the requirements for an application for a significant revision to an existing Part 70 Operating Permit in AQR 12.5.2.14(c)(2). The owner or operator and the Control Officer may then follow the AQR 12.5.2.14(c) process for significant permit revisions to obtain authorization to construct and operate under a revised Part 70 Operating Permit and/or an ATC Permit.
4. For modifications that increase the Part 70 source's PTE by an amount less than the minor NSR significance level defined in AQR 12.4.2.1 and meet the AQR 12.5.2.14(a)(1) criteria for a minor permit revision:
   a. The owner or operator may submit an application for an ATC Permit that fulfills both the AQR 12.4.3.1(a) requirements and the requirements for an application for a minor permit revision in AQR 12.5.2.14(a)(3). The owner or operator may then begin actual construction and operate under the authority provided by AQR 12.5.2.14(a)(6), and the Control Officer may follow the AQR 12.5.2.14 minor permit revision process to issue an authorization to construct and operate under a revised Part 70 Operating Permit and/or an ATC Permit.
   b. An authorization to construct and operate per AQR 12.5.2.14(a)(6) remains in effect until the Control Officer takes final action on the minor permit revision application under AQR 12.5.2.14(a)(5)(A), (B), or (C), or issues a separate ATC Permit.
   c. The Control Officer may modify the AQR 12.5.2.14(a)(6) authorization to construct and operate before taking final action on the minor permit revision application by revising the draft minor permit revision under AQR 12.5.2.14(a)(5)(D).
5. When an owner or operator and the Control Officer follow the procedures in G.2, G.3, or G.4 then, in accordance with AQR 12.4.5.2(b), the revised Part 70 Operating Permit serves as both the Operating Permit and the ATC Permit for the affected and constructed emission units at the source when the Control Officer does not issue a separate ATC Permit.

## Section H: Application Supplemental Documents

*Information worksheets for common source types and emission units are posted on the DES website under **Applications/Forms → Stationary Source Permitting Forms → Emission Unit/Control Device Worksheets & Tools**. Applicants can use these documents to provide some of the technical information requested below.*

1. To complete this application, provide the following information related to the construction or project, as set forth in AQR 12.4.3.1:
   a. Description of all emissions of regulated air pollutants from all affected and construction emission units, and a projected operating schedule for each unit;

AQR 12.3, the application shall also contain the following:

a. The statewide compliance demonstration required by AQR 12.3.3;

b. The alternatives analysis required by AQR 12.3.4;

c. The LAER demonstration and draft permit conditions required by AQR 12.3.5.2;

d. An air impact analysis, including dispersion modeling;

e. The information necessary to demonstrate that the applicant has satisfied or will satisfy the emissions offset requirements in AQR 12.3.6; and

f. Any other information that the Control Officer determines is necessary to process the application in accordance with AQR 12.2 or 12.3.

4. A justification for any exemption sought from any otherwise applicable requirement.

5. In addition to any other application requirements, if the construction of a new Part 70 source—or the construction or reconstruction of an existing Part 70 source—creates a "new affected source" or "reconstructed affected source" that is a major source under 40 CFR Part 63, the owner or operator shall comply with the application requirements under 40 CFR Part 63.5 and Section G.1. The ATC Permit for the source shall comply with 40 CFR Part 63.5(e) requirements.

## Section I: Fees and Payments

Air Quality Program Fees: AQR 18, "Permit and Technical Service Fees," describes all fees related to this application and the resulting permit: https://www.clarkcountynv.gov/government/departments/environment_and_sustainability/division_of_air_quality/fees_and_payments/fees_page.php.

Application Filing Fee: The application fee invoice must be paid in full before the application will be processed.

Permit Issuance: All outstanding invoices for the source and associated with the parent company of the source must be paid in full; otherwise, DAQ cannot issue the source any permits. This includes the invoice for the permit fees resulting from this application.

Payment: Invoices must be paid by check, money order, or credit card. Make checks and money orders payable to **Division of Air Quality** or **DAQ**. Credit card payments may be made in person at DAQ's main office or online at https://www.clarkcountynv.gov/government/departments/environment_and_sustainability/division_of_air_quality/ fees_and_payments/page_payments.php.

## Section J: Grant of Authority

I authorize DAQ to transmit all communications, permits, and billing invoices by the primary communication method selected in Section D of this application. I acknowledge that if I select "Email," DAQ will transmit all listed items electronically. I further acknowledge that if I select "U.S. Postal Service," I may incur applicable postage fees.

## Section K: Certification of Truth, Accuracy, and Completeness

As the Responsible Official, I declare, under penalty of perjury under the laws of the state of Nevada, that the statements and information in this application and the attached supplemental documents and worksheets are true, accurate, and complete. My signature acknowledges that I am subject to liability for perjury under NRS Chapter 199.145.

Jason J. Glynn — 27 July 2025

Responsible Official Certification (original "wet" signature) — Date

Colonel Jason J. Glynn

Printed Name of Responsible Official

**If this application is being submitted for an existing permit holder, it must be signed by an RO on file for this source.**

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2025 JUL 30 AM8:46

# NELLIS AIR FORCE BASE, NEVADA
# SOURCE 114




# REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT) ANALYSIS

**July 2025**

OPR: 99 CES/CEIE

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Appendix A RBLC Data Review

Appendix B Air Force Directive Prohibiting the Use of Natural Gas

**Acronyms and Abbreviations**

| | |
|---|---|
| < | less than |
| ≤ | less than or equal to |
| AFB | Air Force Base |
| application | Authority to Construct Permit Application |
| BACT | Best Available Control Technology |
| DAQ | Division of Air Quality |
| DES | Clark County Department of Environment and Sustainability |
| DLN | Dry Low NOx |
| EGR | Exhaust Gas Recirculation |
| EPA | U.S. Environmental Protection Agency |
| EU | emission unit |
| g | gram(s) |
| gal | gallon(s) |
| HA | hydrographic area |
| hp | horsepower |
| hr | hour(s) |
| hr/yr | hour(s) per year |
| ITR | Injection Timing Retard |
| kW | kilowatt(s) |
| LAER | Lowest Achievable Emission Rate |
| lb | pound(s) |
| N/A | not applicable |
| NAAQS | National Ambient Air Quality Standards |
| Nellis | Nellis Air Force Base |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NOx | nitrogen oxide |
| NSPS | New Source Performance Standards |
| NV | Nevada |
| permit | Source 114 Part 70 Operating Permit |
| PTE | potential to emit |
| RACT | Reasonably Available Control Technology |
| RBLC | RACT/BACT/LAER Clearinghouse |
| RICE | Reciprocating Internal Combustion Engine |
| SCR | Selective Catalytic Reduction |
| SIP | State Implementation Plan |
| SLN | SoLoNOx |
| SNCR | Selective Non-Catalytic Reduction |
| TBD | to be determined |
| tpy | ton(s) per year |
| VOC | volatile organic compounds |
| yr | year |

# I. Introduction

## A. Purpose

In 2018, the U.S. Environmental Protection Agency (EPA) designated hydrographic area (HA) 212 in Clark County, Nevada (NV), as nonattainment for the 2015 ozone National Ambient Air Quality Standards (NAAQS) and assigned a classification of "marginal" to the area. Under the marginal classification, HA 212 was required to reach attainment of the 2015 ozone NAAQS by 03 August 2021. In 2021, the Clark County Department of Environment and Sustainability (DES), Division of Air Quality (DAQ), submitted data requesting exclusion of certain monitored data from calculation of HA 212's design value based on exceptional events (wildfires and stratospheric intrusions). In July 2022, the U. S. Environmental Protection Agency (EPA) proposed not to approve those demonstrations and to find that HA 212 failed to meet its attainment date based on a 2018-2020 design value of 0.074 parts per million. As a result, EPA also proposed to reclassify (bump-up) HA 212's classification to "moderate." The new classification would require HA 212 to achieve attainment by 03 August 2024 and require DAQ to establish emissions control requirements in its State Implementation Plan (SIP), including Reasonably Available Control Technology (RACT).

DAQ is establishing emissions control requirements in its SIP, including RACT for major sources, as mandated by Section 182(b)(2) of the Clean Air Act (42 United States Code [U.S.C.] § 7511a). On 03 April 2025, DAQ notified major stationary sources of nitrogen oxides (NOx) and/or volatile organic compounds (VOCs) located within the ozone nonattainment area of Clark County, NV (Las Vegas Valley), of their obligation to comply with Section 120 of the Clark County Air Quality Regulations (AQRs). Compliance with the application requirements of Section 120 is due on or before 01 August 2025. Since Nellis Air Force Base (Nellis) submitted an initial RACT analysis in 2023 for all NOx sources above 5 tons per year (tpy), there is only one additional unit which require analysis under this cover.

The RACT-specific information requested includes:

- Information sources relied on to identify available control options;
- Ranking of available control options based on control effectiveness;
- Evaluation of technical feasibility;
- Annual and incremental cost effectiveness (in dollars per ton);
- Baseline and controlled tpy emissions estimates (and their basis);
- Environmental, energy, and other impacts (benefits and disbenefits); greenhouse gases, hazardous air pollutants, or other pollutants;
- Proposed RACT emissions limitation or averaging approach;
- Schedule for installing and operating the emissions controls; and
- Proposed testing, monitoring, recordkeeping, and reporting to meet periodic monitoring requirements.

### B. Resources Consulted

Nellis resources used to develop this document include the Nellis Title V Operating Permit issued 15 June 2021 and revised 01 May 2025 and potential to emit (PTE) calculations. Many additional resources and references were consulted; see appendices for additional details.

### C. Emission Unit Evaluated

The emission units that met the evaluation criteria of having a NOx PTE greater than 5 tpy were evaluated. A RACT analysis was submitted in 2023. This report addresses the additional units which were not included in the 2023 report. There is one new emergency engine. This unit is included in the Nellis Part 70 Operating Permit. **Table 1-1** provides permitted maximum-potential operations and VOC/NOx emissions.

In accordance with 102.7(a)(3), an owner or operator of a GDF "that is an existing source with a combined throughput of gasoline greater than 1,200,000 gallons in any consecutive 12-month period shall commence compliance with Sections 102.7(c)(1-4) by April 2, 2024". The gasoline dispensing operations that have a 3,000,000 throughput each for the 20,000-gallon AST and 25,000-gallon underground storage tank currently have these conditions in their OP and have been operating in compliance with these conditions along with 40 CFR 63.11118 of the EPA standard for gasoline dispensing which currently has Phase II Enhanced Vapor Recovery. This GDF satisfies the requirements of Section 102.

Therefore, if there is a modification, replacement, or newly installed equipment, Nellis would have to commence compliance with Section 102.7(c)(5) after 180 days from the Control Officer providing written notice satisfying the requirement of Section 102.4(d). On January 21, 2025, Nellis received notification due to the ozone status change from moderate to serious the GDF has triggered the requirement for EVR. Nellis will commence compliance by 20 July 2025, and has until 21 January 2027 to have EVR fully installed on the affected facility. This RACT analysis does not include the GDF source.

**Table 1-1 Nellis Air Force Base (AFB), VOC/NOx from RACT Analysis Sources**

| Source | Building Number | EU | EPA Engine Tier Rating | HP Rating | Fuel Type | Potential Annual Operation | NOx Potential to Emit (PTE) (tons/yr) | VOC Potential to Emit (PTE) (tons/yr) |
|---|---|---|---|---|---|---|---|---|
| Emergency Engine | 21 | G194 | Tier 2 | 2,220 | Diesel | 500 (hr/yr) | 5.90 | 0.11 |

The remainder of this document is organized as follows:

- Section II, Emergency Engines, presents the RACT analysis for the one emergency engine.

## II. Emergency-Use Stationary Engines

### A. Background Information on Source and Emission Point

Nellis plans to operate one new emergency generator that exceeds the 5 tons per year NOx threshold for RACT analysis. The generator supports building 21 on Nellis. The engine specifications for this unit is listed below in **Table 2-1**.

Limited data is available for EU G194, as it has not been installed, and this analysis is based on the assumptions of the engine proposed to be installed.

**Table 2-1 Emergency Generator Engine Data**

| Building Number | EU | Engine Data | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Manufacturer | Model Number | Serial Number | Capacity (hp) | Date of Manufacture | | Fuel Type |
| | | | | | | Month | Year | |
| 21 | G194 | Cummins | DQGAA | TBD | 2,220 | TBD | TBD | Diesel |

As G194 has not been installed, there is no actual emergency and maintenance and testing hourly usage or actual NOx emissions data for the last five years.

Anticipated controls are:

- Turbocharger;
- Aftercooler;
- Good combustion practices based on manufacturer specifications; and
- Good maintenance practices.

### B. Review of Available Control Technologies

Potential Control Technologies

Potential NOx control retrofit technologies to consider are as follows:

- Selective Catalytic Reduction (SCR)
- Pre-stratified charge
- Exhaust Gas Recirculation (EGR)
- Injection Timing Retard (ITR)
- Air-to-Fuel Ratio adjustments
- Reduction in potential maximum allowable hours of operation
- Conversion to natural gas
- Conversion to dual fuel (diesel/natural gas)
- Derating
- Replacement with Tier 4 diesel engines
- Replacement with Tier 3 diesel engines
- Replacement with natural gas engines
- Replacement with battery backup power
- Removal
- Selective Non-Catalytic Reduction (SNCR)
- Intake air cooling adjustment/aftercooler
- Water injection

- Water/fuel emulsions
- Alternative fuels
- Dry Low NOx (DLN) and SoLoNOx (SLN)
- Engine performance management system
- High-pressure fuel injection

An EPA RACT/Best Available Control Technology [BACT]/ Lowest Achievable Emission Rate [LAER] Clearinghouse (RBLC) search was conducted on 06 June 2025, for similar engines – both emergency and non-emergency units burning diesel fuel. Database review line items are provided in Appendix A.

Potential Control Technologies Removed from Further Evaluation – Not Available/Practical

From the lists above, some items were removed from consideration. Controls removed from consideration are listed below:

- The Air Force confirmed that the engines need to remain in place for mission requirements, so removal is not an option.
- Air-to-fuel ratio adjustments were removed because manufacturer guidance indicated this adjustment is not available for this engine.
- Engine derating was removed because it was determined by the manufacturer to not be technically beneficial in terms of grams of NOx per hp-hr output for these particular engines.
- For the purpose of the mission, it was confirmed that the currently permitted maximum potential hours of operation cannot be reduced, so a reduction in potential operating hours was removed from consideration.
- The mission and purpose of these units precludes any reliance on natural gas. An excerpt from the Air Force directive prohibiting use of natural gas for standby generation is provided in Appendix B.
- Likewise, the mission does not allow the utilization of battery backup power.
- Engine performance management systems were not found to substantially reduce NOx, and the operators utilize good maintenance and operations practices as established by the manufacturers. Intake air cooling could be adjusted (by way of an after-cooler), along with other parameters, which may improve engine performance; but no quantifiable benefit to NOx was found for intake air cooling alone.
- Water injection, which could theoretically reduce the peak combustion temperatures, adversely impacts the oil film protecting the walls of the cylinders. Water/fuel emulsions, as with water injection, attack the cylinders and also the fuel system, and therefore were not considered viable by any engine manufacturers in the literature review conducted. High-pressure fuel injection was not found in any related examples to have a quantifiable impact on potential NOx emissions.

The following controls and processes were removed from consideration and further analysis due to non-availability:

- SNCR applies to external combustion and was noted in EPA literature as being possibly feasible for compression ignition engines, but this could not be quantified with any examples, nor was it found to be implemented with any available results, during the research for this report. Therefore, SNCR was removed.
- Alternative fuels including methanol were not identified as demonstrated or available for these engines.
- DLN and SLN combustors apply primarily to turbines and utilize multistage premix combustors where the air and fuel are mixed at a lean fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture, both resulting in greatly reduced NOx formation rates. However, no examples could be found of applying this technology to this type of diesel unit.
- Generally, retrofits with EGR on low-load mobile diesels have been shown in research to reduce NOx by up to 40% (MECA, 2009). No application of EGR to units similar to the proposed installation at Nellis were found. The conclusion was that EGR is not readily available, and it was removed from consideration.
- Pre-stratified charge is not applicable to or available for these units, according to the manufacturer.
- Typically, ignition timing retard carries penalties of increased particulates, carbon monoxide, hydrocarbons, and fuel consumption, and degrades engine performance and longevity if not incorporated with electronic engine control. However, ITR was also removed from consideration because it determined by the manufacturer to not be applicable to or available for these engines, and no vendor offerings were found.

SCR Concerns

SCR as a control technology and Tier 4 manufacturer-certified engines are not recommended by the California Air Resources Board for emergency generators. As all generators in this section are true emergency generators, Nellis feels that SCR retrofit and Tier 4 replacement be removed from further analysis because it is not an appropriate control technology.

Potential Control Technologies for Further Review and Evaluation

Based on the above analysis, there is one possible control option.

- Replacement with Tier 3 diesel engines

Tier 3 standards are only required for non-emergency units, per Reciprocating Internal Combustion Engine (RICE) National Emission Standards for Hazardous Air Pollutants (NESHAP) and related New Source Performance Standards (NSPS). Tier 3, generally, is achieved by more advanced engine design, such as water induction at some point in the combustion process, and may in some cases use limited after-treatment on the exhaust to achieve the lower NOx standard.

The Tier 3 standard applicable to non-emergency, stationary diesel generators sized 500 kW or less, is 4.0 grams per kilowatt hour (g/kW-hr). So, if there were a corresponding Tier 3 standard for emergency use engines (despite Tier 3 not applicable at this capacity).

Since Tier 3 doesn't specifically apply to emergency generators, it appears reasonable that Tier 3 has not been required by the EPA in permitting (based on RBLC search) or rules (NSPS/NESHAP) for emergency engines.

### C. Elimination of Technically Infeasible Options

Replacing the existing engines with new models which meet EPA Tier 3 standards would not be practical due to the required capacity for this engine.

### D. Calculation of Control Technology Cost

No estimating of costs was necessary.

### E. RACT Recommendation

Because of economic unreasonableness, Nellis does not propose to install NOx controls on these units.

Therefore, the proposed RACT requires no additional controls or practices, emergency generators do not traditionally required any modifications or add-on controls to comply with RACT.

The results of the RBLC database search support that adherence to manufacturer guidelines and good combustion practices are RACT for similar, limited-use engines. Tabulated RBLC results for engines burning similar fuels are shown in **Appendix A**. There were many similar emergency and intermittent-use diesel engines that were considered RACT with no additional controls or practices, other than the limited use (emergency) and preventive requirement of good combustion practices. RBLC listed many Tier 2 emergency engines, as required by NSPS. Injection timing retard was mentioned in several RBLC records, but only for engines Tier 1 or higher on which ignition timing that is optimized for NOx is part of the engine control system design.

Immediate implementation is assumed. There are no proposed changes to RACT for emergency generators.

Appendix A RBLC Data Review

File is too big to print. PDF will be emailed to the permitting staff after submittal of the analysis.

Appendix B Air Force Directive Prohibiting the Use of Natural Gas

DEPARTMENT OF THE AIR FORCE
AIR FORCE CIVIL ENGINEER CENTER
TYNDALL AIR FORCE BASE FLORIDA

15 May 2014

FROM: AFCEC/DD
139 Barnes Drive Suite 1
Tyndall AFB, FL 32403-5319

SUBJECT: **Engineering Technical Letter (ETL) 13-4 (Change 1): Standby Generator Design, Maintenance, and Testing Criteria**

**1. Purpose.** This ETL provides criteria for design, maintenance, and testing of Air Force emergency and standby generator systems. It supersedes ETL 11-21, *Emergency and Standby Generator Design, Maintenance, and Testing Criteria* (Change 2), dated 16 March 2012. Requirements in this ETL modify or replace guidance within Air Force instruction (AFI) 32-1062, *Electrical Power Plants and Generators*, and AFI 32-1063, *Electric Power Systems*, as detailed in paragraphs 1.1, 1.2, and 6. **Use the *Inspection Checklist for the Generator Operating Log* (see paragraph 3.8) for all requirements of this ETL in lieu of AF IMT 487 (revision pending) until further notice.**

**1.1.** Criteria replaced by this ETL include:

**1.1.1.** AFI 32-1062:
- paragraph 9
- paragraph 10 and subparagraphs
- A2.3

**1.1.2.** AFI 32-1063:
- paragraph 1.8.8
- paragraph 4
- paragraphs 5.1 and 5.2
- paragraphs 7.1, 7.2, and 7.3, and their subparagraphs

**1.2.** Use this ETL with AFI 32-1062; AFI 32-1063; Title 40 Code of Federal Regulations (CFR) Part 60 Subparts IIII and JJJJ; 40 CFR Part 63 Subpart ZZZZ; 40 CFR Part 89.

**Note:** Use of the name or mark of a specific manufacturer, commercial product, commodity, or service in this ETL does not imply endorsement by the Air Force.

**Summary of Revisions:** Expanded guidance for semiannual RPIE generator testing (paragraph 15.3.1) to recommend testing with loss of power to the entire facility when verifying connectivity and proper operation of all mission loads.

**APPROVED FOR PUBLIC RELEASE: DISTRIBUTION UNLIMITED**

**21.2.** Oil Change Intervals. An oil change may be deferred for a maximum of 12 months, provided:

**21.2.1.** Total operating hours are less than 150 within the last 12 months. Oil change interval may not exceed 24 months or manufacturer's recommended engine hours.

**21.2.2.** The oil analysis meets requirements for fuel dilution, viscosity, and total base (acid) content. Sample in accordance with manufacturers' recommendations and field test using oil analysis kit NSN 6630-01-096-4792, *Test Kit, Oil Condition*, or an independent oil analysis company test kit (e.g., Cummins Filtration #CC2543; Caterpillar S•O•S$^{SM}$; Wix Filters). Record results on *Inspection Checklist for the Generator Operating Log* and AF IMT 719. If an approved field test kit is not available or the above tests are not performed, the oil must be changed.

**22. Fuels.**

**22.1.** Fuel oils used for standby generators must meet Federal Specification A-A-52557, *Fuel Oil, Diesel; For Posts, Camps, and Stations*. Follow the specific temperature and applicable service conditions and ensure sulfur content does not exceed environmental restrictions. Do not mix different grades of fuel. Consult T.O. 42B-1-1, *Quality Control of Fuels and Lubricants*, and MIL-STD-3004, *Quality Assurance/Surveillance for Fuels, Lubricants and Related Products*, for additional information.

**22.2.** Jet fuel potentially may be used with required additives when diesel is not available. Consult the AFCEC/CZTQ for local and Environmental Protection Agency (EPA) emission restrictions. (Consult the manufacturer for kW de-rating when using JP-8 or Jet A(m).)

**22.3.** Use of natural gas (NG), liquid petroleum gas (LPG), or bio-diesel fuels is not permitted for mission-essential standby generation. NG, LPG, or alternate fuels may be authorized for prime power generation or co-generation. BCEs must either program existing mission-essential generators that use NG, LPG, or bio-diesel for replacement within five years or request a waiver from the MAJCOM/A7 for continued operation. BCEs will ensure refueling plans address backup fuel support for existing mission-essential, non-diesel generators in the event of fuel supply disruption.

**22.4.** Personnel must be trained to manage fuel storage tanks in accordance with AFI 23-204, *Organizational Fuel Tanks*. Ensure storage tanks are marked according to fuel type and warning signs are appropriately located. If an external fuel tank is installed, post a one-line diagram of the fuel system indicating tank size and valve locations.

**24.2.** AFCEC/COSM must be notified through the MAJCOM when a generator authorization is no longer required.

**24.3.** The BCE will prepare a plan for all generators that do not have an AFCEC authorization and are available for relocation or disposition. The plan will be included as a part of the revalidation process.

**25. Point of Contact.** Generator requests and recommendations for improvements to this ETL are encouraged and should be furnished to the Electrical subject matter expert, AFCEC/COSM, 139 Barnes Drive, Suite 1, Tyndall AFB, FL 32403-5319, DSN 523-6813, commercial (850) 283-6813, email: AFCEC.RBC@us.af.mil

ANTHONY A. HIGDON, Colonel, USAF
Deputy Director

5 Atchs
1. New and Replacement Authorization Template
2. Generator Design Evidence Template
3. Existing Generator Authorization and Design Sizing Template
4. AF/A7C Memorandum for Authorization and Size Validation of Emergency and Standby Generators
5. Distribution List

# ATTACHMENT 2B: NAFB RACT Supplemental

**From:** EVANS, CHERYL E CIV USAF ACC 99 CES/CEIE
**To:** Michael Rael
**Cc:** Santosh Mathew; Scott Jelinek; KENNEDY, STEPHANIE M CIV USAF ACC 99 CES/CEIE
**Subject:** Supplemental Information
**Date:** Wednesday, September 10, 2025 9:23:39 AM

Good morning

In response to the correspondence from the County 09 September 2025, this email serves as supplemental information the RACT determination application submitted 30 July 2025 to address the following RACT determinations for:

a. One Clayton mobile paint booth (D034);

b. One emergency engine (EU: G188); and

c. Miscellaneous Chemical Usage (EU: O001).

## One Clayton mobile paint booth (D034)

Nellis Air Force Base (Nellis AFB) is currently preparing their Title V Operating Permit renewal application for submittal no later than December 14, 2025. In this permitting action, Nellis AFB will propose an operational limit that will lower the Clayton mobile paint booth below the 5 tons per year of VOC emissions.

## One emergency engine (EU: G188)

The submittal of 30 July 2025 is applicable to this emergency generator. The following will address the emissions in Table 1-1, background, and details of this generator.

Table 1-1 Nellis AFB, VOC/NOx from RACT Analysis Sources

| Source | Building Number | EU | EPA Engine Tier Rating | HP Rating | Fuel Type | Potential Annual Operation | NOx Potential to Emit (PTE) (tons/yr) | VOC Potential to Emit (PTE) (tons/yr) |
|---|---|---|---|---|---|---|---|---|
| Emergency Engine | 1771 | G188 | Tier 2 | 2,922 | Diesel | 500 (hr/yr) | 8.54 | 0.18 |

Background Information on Source and Emission Point

Nellis AFB plans to operate the new emergency generator that exceeds the 5 tons per year NOx threshold for RACT analysis. The generator supports building 1771 on Nellis AFB. The engine specifications for this unit is listed below in Table 2-1.

Limited data is available for EU G188, as it is being constructed and turned over to Nellis AFB to be operated, and this analysis is based on the assumptions of the engine proposed to be installed.

**Table 2-1 Emergency Generator Engine Data**

| Building Number | EU | Engine Data | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Manufacturer | Model Number | Serial Number | Capacity (hp) | Date of Manufacture | | Fuel Type |
| | | | | | | Month | Year | |
| 1771 | G188 | Cummins | DQKAB | TBD | 2,922 | TBD | TBD | Diesel |

As G188 has not been installed, there is no actual emergency and maintenance and testing hourly usage or actual NOx emissions data for the last five years.

Anticipated controls are:

- Turbocharger;
- Aftercooler;
- Good combustion practices based on manufacturer specifications; and
- Good maintenance practices.

**Miscellaneous Chemical Usage (EU: O001)**

Regarding the miscellaneous chemical usage above the 5 tons per year of VOC, the emissions are an aggregation of the all the miscellaneous chemicals for the entire base. These emissions are not from a single source, nor is there an operation in this category that is over the 5-ton threshold, therefore a RACT determination is not required.

Please acknowledge receipt of this supplemental information. Thanks.

v/r

Cheryl Evans, GS-12, USAF
Air Quality Program Manager
99 CES/CEIEC
6020 Beale Ave, Building 812, Room 122
Nellis AFB, NV 89191
(702) 652-2882

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**From:** Silvia Gonzalez <SXG@ClarkCountyNV.gov>
**Sent:** Tuesday, September 9, 2025 10:56 AM
**To:** Nellis Air Quality <Nellis.Air.Quality@us.af.mil>
**Cc:** Nellis Air Quality <Nellis.Air.Quality@us.af.mil>; EVANS, CHERYL E CIV USAF ACC 99 CES/CEIE <cheryl.evans.3@us.af.mil>; Santosh Mathew <MATHEW@ClarkCountyNV.gov>; Scott Jelinek <JELINEK@ClarkCountyNV.gov>
**Subject:** [Non-DoD Source] DAQ Letter for Source ID: 00114 - NELLIS AIR FORCE BASE
**Importance:** High

Good morning,

Attached is a letter regarding your application for Source ID: 00114, Nellis Air Force Base.

If you have any questions, please contact Mike Rael at 702-455-5942.

***Please confirm receipt of this email.***

Thank you,

Silvia Gonzalez
Administrative Secretary
Clark County Department of Environment & Sustainability
Divison of Air Quality
4701 W. Russell Road, Suite 200
Las Vegas, NV 89118
Phone: 702-455-8007
sxg@clarkcountynv.gov

DES office hours are M-TH, 7:30 a.m. – 5:30 p.m.
Our offices are closed on Fridays.

# ATTACHMENT 3A: Caesars RACT

BROADBENT
8 West Pacific Ave., Henderson, NV 89015
[T] 702-563-0600 [F] 702-563-0610
broadbentinc.com

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July 23, 2025

Project No. 13-01-207

Clark County Department of Environment and Sustainability
Division of Air Quality
Attn: Permitting Manager
4701 West Russell Road, Suite 200
Las Vegas, Nevada 89118

**RE: Caesars Entertainment, Inc. – Source 257**
**Part 70 Operating Permit Significant Revision Application**

On behalf of Caesars Entertainment, Inc. (Caesars), Broadbent & Associates, Inc. (Broadbent) is pleased to present the attached Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) Part 70 Operating Permit Significant Revision Application. Caesars is currently permitted with DAQ as Source 257, a Title V source. This application is being submitted under Air Quality Regulation (AQR) Section 120 as this source is applicable to the requirements of Section 120.2(a).

The following changes are requested as part of this revision application:

**Reduction in Operating Hours for Various Emergency Generators**
Caesars proposes to reduce the operating hours for diesel emergency generators that currently have emissions above five tons per year. A historical analysis of power outages at multiple properties shows that a reduction in hours will not affect facility operations, including during power outages. Please refer to the potential to emit (PTE) calculations for further details.

**RACT Determination for Boilers CP01-CP05**
A Reasonably Available Control Technology (RACT) analysis was conducted for five boilers located at Caesars Palace, emission units (EUs) CP01-CP05, within the past 36 months. That RACT analysis was based on actual emissions for these emission units. However, since Section 120 requires RACT to be based on PTE, a revised RACT analysis has been prepared for these boilers as part of this application package.

It is requested that a draft copy of the permit and technical support document be provided to both the source and the consultant for review prior to permit issuance. Should you have any questions or concerns regarding this submittal, please feel free to contact me at (702) 917-6468 or sorlov@broadbentinc.com.

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Sincerely,
BROADBENT & ASSOCIATES, INC.

Carol Adams
Senior Engineer

Reviewed and approved by:

Sergy Orlov
Associate Environmental Scientist

Attachment: Part 70 Operating Permit Significant Revision Application

EC: Jeri Ruskowitz, jruskowitz1@caesars.com
Gina Wilder, gwilder1@caesars.com

Attachment: Part 70 Operating Permit
Significant Revision Application

# Title V (Part 70) Permit Application

**Clark County Department of Environment & Sustainability**
**Division of Air Quality**

**Submit Application to:**
**Division of Air Quality**
**4701 W. Russell Road, Suite 200**
**Las Vegas NV 89118**

**For DAQ Use Only**

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## Section A: Permit Application Basis (check all that apply):

- ☐ Initial Permit
- ☐ Renewal Permit
- ☐ Administrative Revision
- ☐ Minor Revision*
- ■ Significant Revision*

*For all AQR 12.4.3.2 modifications, including Title V permit revisions based on AQR 12.4.3.2(d) and (e), use the Title V ATC application form (see Section G, "Application Instructions").

If applying for a revision: Has an NSR Authority to Construct already been issued? ☐ Yes ■ No

***Application Description:*** Describe the Title V permitting action being proposed, e.g., new process, change to equipment, change to permit conditions, Voluntarily Accepted Emission Limit (VAEL), incorporating ATC, etc.

As part of this significant revision application, Caesars proposes to reduce the operating hours for diesel emergency generators that currently have emissions above five tons per year and provide a revised RACT determination for EUs CP01-CP05.

**Applications for a Part 70 permit shall include the information requested in Sections B–F.**

***Complete the fields in Sections B–F even if there is no change from the previous application.***

## Section B: Source Information

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**

Source ID No: 257

Source Name (as listed on Clark County/State of Nevada business license): Caesars Entertainment, Inc., Caesars Consolidated Properties

Permit Expiration Date (existing permits only): September 22, 2026

City/County Business License #:

**Source Location Information**

| Number: | Direction (E., W.): | Street Name: | Cross Streets: |
|---|---|---|---|
| One | | Caesars Palace Drive | |

| City: Las Vegas | State: NV | Zip: 89109 |
|---|---|---|

**Phone Numbers**

| Office: 702-343-9501 | Fax: |
|---|---|

**North American Industry Classification System (NAICS) / Source Industry Classification Code**

| Primary NAICS: 721120 | Additional NAICS (optional): |
|---|---|

***Source Description:*** Describe the nature of your business, including processes and products.

Caesars owns and operates several adjacent and contiguous hotels and casinos and a convention center grouped under SIC code 7011, "Hotels and Motels" (NAICS code 721120, "Casino Hotels"). The source operates ten facilities: Harrah's Las Vegas, Flamingo Las Vegas, Horseshoe Las Vegas, The Cromwell Las Vegas, Caesars Palace, Paris Las Vegas, The LINQ Hotel & Casino, Planet Hollywood, LINQ Complex – High Roller, and the Forum Meeting Center.

## Section C: Company Information (AS LISTED ON THE SECRETARY OF STATE'S BUSINESS CERTIFICATE/FILING)

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**
If company ownership and/or name has changed, separately submit a Transfer of Ownership / Change of Name form+ fee (SS-PER-020-01).

Company Name: Caesars Entertainment, Inc.

**Location Information**

| Number: | Direction (W., E.): | Street Name: | Street Type (Rd., Ave.): | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| One | | Caesars Palace | Drive | | |
| City: Las Vegas | | | State: NV | ZIP: 89109 | |

***Proof of Company Name:*** Have you selected "New Permit" for the action type above? ☐ YES ■ NO

If YES, attach a printout of your company's business listing on the Nevada Secretary of State website, or other formal documentation that includes your company's full legal name.

**Phone Numbers**

| Office: | Fax: |
|---|---|

**Type of Organization**

■ Corporation ☐ Individual Owner ☐ Partnership ☐ Government Entity ☐ Other

## Section D: Responsible Official (RO) Information

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**
If the RO has changed, separately submit a Declaration of Responsible Official form (RO-PER-003).

| Name: Jeri Ruskowitz | Title: Director Environmental Compliance |
|---|---|

**Location Information**

| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| One | | Caesars Palace | Drive | | |
| City: Las Vegas | | | State: NV | Zip: 89109 | |
| Email: jruskowitz1@caesars.com | | | Primary Communication Method: ■ Email ☐ U.S. Postal | | |

**Phone Numbers**

| Office: 702-755-3579 | Extension: | Cell: | Fax: |
|---|---|---|---|

## Section E: Plant Manager/Environmental Representative Contact Information

| Name: | Title: |
|---|---|

**Location Information**

| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| | | | | | |
| City: | | | State: | Zip: | |
| Email: | | | Primary Communication Method: ☐ Email ☐ U.S. Postal | | |

**Phone Numbers**

| Office: | Extension: | Cell: | Fax: |
|---|---|---|---|

## Section F: Billing Contact (Accounts Payable) Information (Optional)

| Name: | Title: |
|---|---|
| Email: | Primary Communication Method: ☐ Email ☐ U.S. Postal |

**Phone Numbers**

| Office: | Extension: | Cell: | Fax: |
|---|---|---|---|

## Section G: Application Instructions

1. For all construction, modification, or reconstruction, the owner or operator shall use the Title V ATC Application Form instead of this Title V Application Form.
2. An owner or operator of an existing or new Part 70 source shall obtain an Authority to Construct (ATC) Permit from the Control Officer before beginning actual construction or continuing with any of the following:
   a. Operating a new Part 70 source;
   b. "Major modification," as defined in AQR 12.2 or 12.3;
   c. Modification that increases the Part 70 source's potential to emit (PTE) by an amount equal to or greater than the minor New Source Review (NSR) significant level in AQR 12.4.2.1;
   d. Construction, modification, or reconstruction of an affected facility that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 60;
   e. Construction or reconstruction of a new source or of an affected source that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 63, including, but not limited to, construction or modification that requires preconstruction review under 40 CFR Part 63.5; or
   f. Modification to a solid waste incinerator unit, as defined by an applicable standard under 40 CFR Part 60.
3. For each Part 70 source, the owner or operator shall submit a timely and complete permit application in accordance with AQR 12.5.2.1.
4. Claims of confidentiality as to information submitted to EPA shall be made pursuant to applicable federal requirements in 40 CFR Part 2. Claims of confidentiality as to information submitted to the department shall be made pursuant to AQR 12.6.

## Section H: Application Supplemental Documents

*Information worksheets for common source types and emission units are posted on the DES website under **Applications/Forms → Stationary Source Permitting Forms → Emission Unit/Control Device Worksheets & Tools**. Applicants can use these documents to provide some of the technical information requested below.*

1. To comply with the requirements of AQR 12.5, the applicant shall submit all of the following information for initial and renewal Title V permit applications. For all other applications, the applicant may omit information that is not related to the proposed changes.
   A. Process description, including any alternative operating scenarios or federally enforceable emissions caps. Emission unit descriptions, including material/fuel usage and/or operating schedules.
   B. Emissions information with supporting calculations for all regulated air pollutants and HAPs, including fugitive emission rates, which shall include calculations of emission rates, short-term limits, hourly rates and tons per year emissions of each emission unit..
   C. Emission information in tons per year for each emission unit and the entire source.
   D. Description of all applicable requirements and/or exemptions, including Voluntarily Accepted Emission Limits (VAEL) and/or Plant-wide Applicability Limits (PAL).
   E. Air pollution control information with associated monitoring and testing requirements (example: for a baghouse, opacity test, pressure drop range and periodic inspections).
   F. Information related to stack height limitations and stack parameters.
   G. An explanation of any proposed exemptions from otherwise applicable requirements.
   H. Any alternative operating scenarios that are proposed in the application pursuant to paragraph (j) of Section 12.5.2.6, such information as is necessary for the Control Officer to define those scenarios and determine the applicable requirements for each proposed scenario.
   I. Compliance plan for all applicable requirements, as set forth in AQR 12.5.2.3(j).
   J. Compliance certification, as set forth in AQR 12.5.2.3(k).
   K. Compliance Assurance Monitoring plan, if determined to be applicable.
   L. Acid rain application, if applicable.

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M. Permit shield (optional).

N. Other information that may be necessary to implement and enforce other requirements of the Clean Air Act or determine the applicability of such requirements.

2. In addition to the requirements above, an application for a minor revision shall include the following:

   A. A description of the change, the emissions estimated to result from the change, and any new applicable requirements that will apply if the change occurs.

   B. Suggested draft permit conditions from the source, including a markup of the operating permit with the changes.

   C. Justification that the proposed modifications meet the criteria for use of minor revision procedures.

   D. All relevant forms, completed, for the Control Officer to submit to EPA and affected states or tribes.

## Section I: Application Advisories

**Permit Applications: Duty to Supplement or Correct (AQR 12.5.2.2).** When an applicant learns of missing or incorrect information in its permit application, it must provide or correct the information as soon as practicable. If additional requirements are deemed to apply after an applicant files a complete application but before the draft permit is released, the applicant must furnish all information needed to address them. The applicant's Responsible Official shall certify the additional information consistent with the requirements of Section 12.5.2.4.

1. **Small Business Assistance.** A DAQ program that offers free assistance on permitting and compliance matters to small businesses (100 employees or fewer). Please ask for an SBA representative at our front counter or call (702) 455-5942 to schedule an appointment.

2. **Fees and Payments.**

   A. Application Filing Fee: There is no application filing fee for Title V permits.

   B. Permit Issuance: All outstanding invoices for the source and associated with the parent company of the source must be paid in full; otherwise, DAQ cannot issue the source any permits. This includes the invoice for the permit fees resulting from this application.

   C. Payment: Invoices must be paid by check, money order, or credit card. Make checks and money orders payable to Division of Air Quality or DAQ. Credit card payments must be made in person at DAQ's main office.

## Section J: Grant of Authority

I authorize DAQ to transmit all communications, permits, and billing invoices by the primary communication method selected in Section D of this application. I acknowledge that if I select "Email," DAQ will transmit all listed items electronically. I further acknowledge that if I select "U.S. Postal Service," I may incur applicable postage fees.

## Section K: Certification of Truth, Accuracy, and Completeness

As the Responsible Official, I declare, under penalty of perjury under the laws of the state of Nevada, that the statements and information in this application and the attached supplemental documents and worksheets are true and correct. My signature acknowledges that I am subject to liability for perjury under NRS Chapter 199.145.

Jeri L Rusk — 7/31/2025

Responsible Official Certification (original "wet" signature) — Date

Jeri Ruskowitz

Printed Name of Responsible Official

**If this application is being submitted for an existing permit holder, it must be signed by an RO on file for this source.**

# PROCESS DESCRIPTION

**Process Description**

Caesars proposes to reduce the operating hours for diesel emergency generators that currently have emissions above five tons per year.

# EMISSION UNIT DESCRIPTIONS

**Emission Unit Descriptions**

The diesel emergency generator information is briefly summarized below for the affected emission units.

**EU HA13 – Harrah's Las Vegas**
Generator Make: Marathon Electric
Generator Model No.: 573RSL2056AP266W
Generator Serial No.: VE3575357
Generator Rating: 800 kW
Engine Make: Detroit Diesel
Engine Model No.: 81637416
Engine Serial No.: 16VF007962
Engine Rating: 1,232 hp
Operation Schedule: 300 hours/year

**EU HA14 – Harrah's Las Vegas**
Generator Make: Caterpillar
Generator Model No.: SR4
Generator Serial No.: 6FA06166
Generator Rating: 600 kW
Engine Make: Caterpillar
Engine Model No.: 3412
Engine Serial No.: 81Z09924
Engine Rating: 890 hp
Operation Schedule: 400 hours/year

**EU HA18 – Harrah's Las Vegas**
Generator Make: Caterpillar
Generator Model No.: SR-4B
Generator Serial No.: 7AJ00864
Generator Rating: 800 kW
Engine Make: Caterpillar
Engine Model No.: 3412
Engine Serial No.: 2WJ00740
Engine Rating: 1,180 hp
Operation Schedule: 300 hours/year

**EUs FL09/FL10 – Flamingo Las Vegas**
Generator Make: Caterpillar
Generator Model No.: SR4B
Generator Serial No.: 6EJ01215 (FL09), 6EJ01238 (FL10)
Generator Rating: 750 kW
Engine Make: Caterpillar
Engine Model No.: 3412
Engine Serial No.: 2WJ02515 (FL09), 2WJ02570 (FL10)

Engine Rating: 1,109 hp
Operation Schedule: 325 hours/year

**EUs B04/B05 – Horseshoe Las Vegas**
Generator Make: Magna One
Generator Model No.: 682FDR8080ABP667W
Generator Serial No.: LD95982-1 (B04), LD95982-2 (B05)
Generator Rating: 1,000 kW
Engine Make: Detroit Diesel
Engine Model No.: 91637305
Engine Serial No.: 16E0006591 (B04), 16E0006592 (B05)
Engine Rating: 1,340 hp
Operation Schedule: 275 hours/year

**EUs B11/B12 – Horseshoe Las Vegas**
Generator Make: Detroit Diesel
Generator Model No.: 1000DS
Generator Serial No.: 600214 (B11), 600215 (B12)
Generator Rating: 1,000 kW
Engine Make: Detroit Diesel
Engine Model No.: 72437406
Engine Serial No.: 24VA001710 (B11), 24VA001728 (B12)
Engine Rating: 1,340 hp
Operation Schedule: 275 hours/year

**EU CR07 – Cromwell Las Vegas**
Generator Make: Caterpillar
Generator Model No.: SR4B-GD
Generator Serial No.: G4W01097
Generator Rating: 1,500 kW
Engine Make: Caterpillar
Engine Model No.: 3512C
Engine Serial No.: EBG01274
Engine Rating: 2,206 hp
Operation Schedule: 275 hours/year

**EUs CP13/CP14/CP17 – Caesars Palace**
Generator Make: Caterpillar
Generator Model No.: SR-4B
Generator Serial No.: 8DM00558 (CP13), 8DM00557 (CP14), 8DM00625 (CP17)
Generator Rating: 2,000 kW
Engine Make: Caterpillar
Engine Model No.: 3516
Engine Serial No.: 6HN00155 (CP13), 6HN00154 (CP14), 6HN00199 (CP17)
Engine Rating: 2,876 hp
Operation Schedule: 125 hours/year

**EU CP15 – Caesars Palace**

Generator Make: Caterpillar
Generator Model No.: SR-4B
Generator Serial No.: 7GM00534
Generator Rating: 1,750 kW
Engine Make: Caterpillar
Engine Model No.: 3516
Engine Serial No.: 25Z05223
Engine Rating: 2,520 hp
Operation Schedule: 145 hours/year

**EU CP16 – Caesars Palace**

Generator Make: Caterpillar
Generator Model No.: SR4
Generator Serial No.: 4DM00503
Generator Rating: 1,250 kW
Engine Make: Caterpillar
Engine Model No.: 3512
Engine Serial No.: 24Z06413
Engine Rating: 1,818 hp
Operation Schedule: 200 hours/year

**EUs CP28/CP29 – Caesars Palace**

Generator Make: Caterpillar
Generator Model No.: SR-4BHV
Generator Serial No.: G3X00133 (CP28), G3X00229 (CP29)
Generator Rating: 2,000 kW
Engine Make: Caterpillar
Engine Model No.: 3516CDITA
Engine Serial No.: SBJ00672 (CP28), SBJ00673 (CP29)
Engine Rating: 2,937 hp
Operation Schedule: 200 hours/year

**EUs PA17/PA18 – Paris Las Vegas**

Generator Make: Cummins
Generator Model No.: QSW73
Generator Serial No.: 79652 (PA17), 79651 (PA18)
Generator Rating: 2,100 kW
Engine Make: Cummins
Engine Model No.: CW73-G
Engine Serial No.: 66300058 (PA17), 66300040 (PA18)
Engine Rating: 2,816 hp
Operation Schedule: 130 hours/year

**EU IP07 – The LINQ Hotel & Casino**

Generator Make: Caterpillar
Generator Model No.: SR4
Generator Serial No.: 5NA05002
Generator Rating: 500 kW
Engine Make: Caterpillar
Engine Model No.: 3412
Engine Serial No.: 81Z04033
Engine Rating: 755 hp
Operation Schedule: 475 hours/year

**EUs IP08/IP09 – The LINQ Hotel & Casino**

Generator Make: Caterpillar
Generator Model No.: SR4
Generator Serial No.: 6FA04856 (IP08), 6FA05404 (IP09)
Generator Rating: 600 kW
Engine Make: Caterpillar
Engine Model No.: 3412
Engine Serial No.: 81Z07511 (IP08), 81Z08595 (IP09)
Engine Rating: 890 hp
Operation Schedule: 400 hours/year

**EUs PH10/PH11/PH12 – Planet Hollywood**

Generator Make: Spectrum
Generator Model No.: 1750DS4
Generator Serial No.: 0628031 (PH10), 0628032 (PH11), 0628033 (PH12)
Generator Rating: 1,750 kW
Engine Make: MTU/Detroit Diesel
Engine Model No.: T1637K16
Engine Serial No.: 5272000427 (PH10), 5272000397 (PH11), 5272000421 (PH12)
Engine Rating: 2,550 hp
Operation Schedule: 145 hours/year

**EU PH13 – Planet Hollywood**

Generator Make: MTU
Generator Model No.: 1750RXC6DT2
Generator Serial No.: 301122111208
Generator Rating: 1,750 kW
Engine Make: MTU/Detroit Diesel
Engine Model No.: T1238A36
Engine Serial No.: 5262003725
Engine Rating: 2,560 hp
Operation Schedule: 350 hours/year

**EUs LI06/LI07 – LINQ Complex – High Roller**

| | |
|---|---|
| Generator Make: | Caterpillar |
| Generator Model No.: | SR4B-GD |
| Generator Serial No.: | G4Z00115 (LI06), G4Z00116 (LI07) |
| Generator Rating: | 2,000 kW |
| Engine Make: | Caterpillar |
| Engine Model No.: | 3516C |
| Engine Serial No.: | SBJ01461 (LI06), SBJ01460 (LI07) |
| Engine Rating: | 2,937 hp |
| Operation Schedule: | 200 hours/year |

| Harrah's Las Vegas | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| HA06 | Natural Gas Boiler | 10300603 | 4.50 MMBtu/hr | Bryan | RV450-S-150-FDG | 66726 (#5) |
| HA07 | Natural Gas Boiler | 10300603 | 9.00 MMBtu/hr | Bryan | LM900-S-15-FDG | 66665 (#4) |
| HA08 | Natural Gas Boiler | 10300603 | 8.369 MMBtu/hr | Cleaver Brooks | CB.200-200 | L-70272 (#1) |
| HA09 | Natural Gas Boiler | 10300603 | 8.369 MMBtu/hr | Cleaver Brooks | CB.200-200 | L-70271 (#2) |
| HA10 | Natural Gas Boiler | 10300603 | 8.369 MMBtu/hr | Cleaver Brooks | CB.200-200 | L-70270 (#3) |
| HA11 | Natural Gas Boiler | 10300603 | 4.80 MMBtu/hr | Universal Energy | BF108C | 10341-1 (#6) |
| HA12 | Emergency Fire Pump<br>Diesel Engine; DOM: Pre-2006 | 20300101 | 276 kW<br>370 hp | Fairbanks Morse Pump<br>Caterpillar | 5922F<br>3406BD1 | 3T1-020216<br>6TB06046 |
| HA13 | Emergency Generator<br>Diesel Engine; DOM:Pre-2006 | 20300101 | 800 kW<br>1,232 hp | Marathon Electric Generator<br>Detroit Diesel | 573RSL2056AP266W<br>81637416 | VE3575357<br>16VF007962 |
| HA14 | Emergency Generator<br>Diesel Engine; DOM:Pre-2006 | 20300101 | 600 kW<br>890 hp | Caterpillar | SR4<br>3412 | 6FA06166<br>81Z09924 |
| HA15 | Emergency Generator<br>Diesel Engine; DOM:Pre-2006 | 20300101 | 400 kW<br>536 hp | Magna One<br>Detroit Diesel | 502FDR8056ABL000W<br>71237305 | KK-95206-3<br>12VA069124 |
| HA16 | Emergency Generator<br>Diesel Engine; DOM:Pre-2006 | 20300101 | 400 kW<br>536 hp | Magna One<br>Detroit Diesel | 502FDR8056ABL000W<br>71237305 | KK-95206-1<br>12VA069593 |
| HA17 | Emergency Generator<br>Diesel Engine; DOM:Pre-2006 | 20300101 | 400 kW<br>536 hp | Magna One<br>Detroit Diesel | 502FDR8056ABL000W<br>71237305 | KK-95206-2<br>12VA066655 |
| HA18 | Emergency Generator<br>Diesel Engine; DOM:Pre-2006 | 20300101 | 800 kW<br>1,180 hp | Caterpillar | SR-4B<br>3412 | 7AJ00864<br>2WJ00740 |
| HA26 | Cooling Tower (2 cell) | 38500101 | 5,200 gpm | Evapco | USS 224-3O18 | 17-830216 |
| HA27 | Cooling Tower (2 cell) | 38500101 | 5,200 gpm | Evapco | USS 224-3O18 | 17-830217 |
| HA28 | Cooling Tower (2 cell) | 38500101 | 5,200 gpm | Evapco | USS 224-3O18 | 17-830218 |

| Flamingo Las Vegas | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| FL01 | Natural Gas Boiler | 10300602 | 14.343 MMBtu/hr | Johnston | 8786 | 9180-01 |
| FL02 | Natural Gas Boiler | 10300602 | 14.645 MMBtu/hr | Kewanee | H3S-350-G | 10016 |
| FL03 | Natural Gas Boiler | 10300602 | 14.645 MMBtu/hr | Kewanee | H3S-350-G | 10017 |
| FL04 | Natural Gas Boiler | 10300602 | 14.645 MMBtu/hr | Kewanee | H3S-350-G | 10476 |
| FL05 | Natural Gas Boiler | 10300603 | 8.165 MMBtu/hr | Cleaver Brooks | CBI 700-200-150 | 0L104650 |
| FL06 | Emergency Fire Pump<br>Diesel Engine; DOM: Pre-2006 | 20300101 | 313 kW<br>420 hp | Fairbanks Morse<br>Caterpillar | 5922<br>3406 | K3P1017265<br>6TB02994 |
| FL09 | Emergency Generator<br>Diesel Engine; DOM:1999 | 20300101 | 750 kW<br>1,109 hp | Caterpillar | SR4B<br>3412 | 6EJ01215<br>2WJ02515 |
| FL10 | Emergency Generator<br>Diesel Engine; DOM:1999 | 20300101 | 750 kW<br>1,109 hp | Caterpillar | SR4<br>3412 | 6EJ01238<br>2WJ02570 |
| FL11 | Emergency Generator<br>Diesel Engine; DOM:Pre-2006 | 20300101 | 475 kW<br>724 hp | Caterpillar | SR4<br>3412 | 6EA01398<br>81Z08892 |
| FL26 | Emergency Generator<br>Diesel Engine; DOM:Pre-2010 | 20300101 | 600 kW<br>923 hp | Caterpillar | LC7<br>C18 | G7A03394<br>EST01182 |
| FL28 | Cooling Tower (4 cell) | 38500101 | 9,600 gpm | Marley | NC8411TAN4BGF | 10050562-(A1-A4) |
| FL29 | Cooling Tower (2 cell) | 38500101 | 3,800 gpm | Evapco | USS 224-3N18 | 17-833834 |
| FL30 | Cooling Tower (2 cell) | 38500101 | 3,800 gpm | Evapco | USS 224-3N18 | 17-833835 |
| FL31 | Cooling Tower (2 cell) | 38500101 | 3,800 gpm | Evapco | USS 224-3N18 | 17-833836 |

| Horseshoe Las Vegas | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| BA01 | Natural Gas Boiler | 10300602 | 16.80 MMBtu/hr | Kewanee | H3S-750-G02 | NB-24935 |
| BA02 | Natural Gas Boiler | 10300602 | 16.80 MMBtu/hr | Kewanee | H3S-750-G02 | NB-25232 |
| BA03 | Natural Gas Boiler | 10300602 | 25.106 MMBtu/hr | Kewanee | H3S-750-G02 | NB-24875 |
| BA04 | Emergency Generator (#1)<br>Diesel Engine; DOM: Pre-2006 | 20300101 | 1,000 kW<br>1,340 hp | Magna One<br>Detroit Diesel | 682FDR8080AB-P667W<br>9163-7305 | LD-95982-1<br>16E0006591 |
| BA05 | Emergency Generator (#2)<br>Diesel Engine; DOM: Pre-2006 | 20300101 | 1,000 kW<br>1,340 hp | Magna One<br>Detroit Diesel | 682FDR8080AB-P667W<br>9163-7305 | LD-95982-2<br>16E0006592 |
| BA06 | Emergency Generator<br>Diesel Engine; DOM: Pre-2006 | 20300101 | 500 kW<br>670 hp | Magna One<br>Detroit Diesel | 500SR9E<br>7163-7305 | 66111<br>16VA7496 |
| BA07 | Emergency Generator<br>Diesel Engine; DOM: Pre-2006 | 20300101 | 155 kW<br>200 hp | Magna One<br>Detroit Diesel | 440FDR8024GG-H000W<br>N/A | LD-94032<br>N/A |
| BA11 | Emergency Generator (#3)<br>Diesel Engine; DOM: Pre-2006 | 20300101 | 1,000 kW<br>1,340 hp | Detroit Diesel | 1000 DS<br>7243-7406 | 600214<br>24VA001710 |
| BA12 | Emergency Generator (#4)<br>Diesel Engine; DOM: Pre-2006 | 20300101 | 1,000 kW<br>1,340 hp | Detroit Diesel | 1000 DS<br>7243-7406 | 600215<br>24VA001728 |
| BA17 | Emergency Fire Pump<br>Diesel Engine; DOM: 06/2011 | 20300101 | 526 hp | Clarke<br>John Deere | JX6H-UFADK0-D<br>6135HFC48A | RG6135L023246 |
| BA18 | Emergency Fire Pump<br>Diesel Engine; DOM: 04/2011 | 20300101 | 526 hp | Clarke<br>John Deere | JX6H-UFADK0-D<br>6135HFC48A | RG6135L022100 |
| BA19 | Cooling Tower (3 cell) | 38500101 | 18,000 gpm | Evapco | USS 314-4O72 | 16-804451 |
| BA20 | Cooling Tower (3 cell) | 38500101 | 18,000 gpm | Evapco | USS 314-4O72 | 16-804450 |
| BA21 | Emergency Fire Pump | 20300101 | 260 hp | Aurora<br>Cummins | 10-481-18<br>QSB6.7 | 15-2460314<br>73884312 |

| The Cromwell Las Vegas | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| CR01 | Natural Gas Boiler | 10300603 | 3.00 MMBtu/hr | Lochinvar | FBN3000 | G13H00252062 |
| CR02 | Natural Gas Boiler | 10300603 | 3.00 MMBtu/hr | Lochinvar | FBN3000 | G13H00252063 |
| CR03 | Natural Gas Boiler | 10300603 | 3.00 MMBtu/hr | Lochinvar | FBN3000 | G13H00252141 |
| CR04 | Natural Gas Boiler | 10300603 | 3.00 MMBtu/hr | Lochinvar | FBN3000 | G13H00252065 |
| CR05 | Natural Gas Boiler | 10300603 | 3.00 MMBtu/hr | Lochinvar | FBN3000 | G13H00251706 |
| CR06 | Natural Gas Boiler | 10300603 | 3.00 MMBtu/hr | Lochinvar | FBN3000 | G13H00252064 |
| CR07 | Emergency Generator<br>Diesel Engine; DOM: 2013 | 20300101 | 1,500 kW<br>2,206 hp | Caterpillar | SR4B-GD<br>3512C | G4W01097<br>EBG01274 |
| CR08 | Emergency Generator<br>Diesel Engine; DOM: 2013 | 20300101 | 150 kW<br>275 hp | Caterpillar | D150-8<br>C6.6 | CAT00C66ALC600121<br>E6L00768 |
| CR09 | Cooling Tower (3 cell) | 38500101 | 5,850 gpm | Evapco | USS 312-936 | 13-541894 |

| Caesars Palace | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| CP01 | Natural Gas Boiler | 10300602 | 35.40 MMBtu/hr | Hurst | S4-G-800-150 | S4000-150-18 |
| CP02 | Natural Gas Boiler | 10300602 | 35.40 MMBtu/hr | Hurst | S4-G-800-150 | S4000-150-19 |
| CP03 | Natural Gas Boiler | 10300602 | 33.475 MMBtu/hr | Burnham | 3P80050GBNM | 12524 |
| CP04 | Natural Gas Boiler | 10300602 | 33.475 MMBtu/hr | Burnham | 3P80050GBNM | 12164 |
| CP05 | Natural Gas Boiler | 10300602 | 33.475 MMBtu/hr | Burnham | 3P80050GBNM | 12238 |
| CP13 | Emergency Generator<br>Diesel Engine; DOM: 3/5/1997 | 20300101 | 2,000 kW<br>2,876 hp | Caterpillar | SR-4B<br>3516 | 8DM00558<br>6HN00155 |
| CP14 | Emergency Generator<br>Diesel Engine; DOM: 3/3/1997 | 20300101 | 2,000 kW<br>2,876 hp | Caterpillar | SR-4B<br>3516 | 8DM00557<br>6HN00154 |
| CP15 | Emergency Generator<br>Diesel Engine; DOM: 8/14/1996 | 20300101 | 1,750 kW<br>2,520 hp | Caterpillar | SR-4B<br>3516 | 7GM00534<br>25Z05223 |
| CP16 | Emergency Generator<br>Diesel Engine; DOM: 4/18/1995 | 20300101 | 1,250 kW<br>1,818 hp | Caterpillar | SR4<br>3512 | 4DM00503<br>24Z06413 |
| CP17 | Emergency Generator<br>Diesel Engine; DOM: 12/10/1997 | 20300101 | 2,000 kW<br>2,876 hp | Caterpillar | SR-4B<br>3516 | 8DM00625<br>6HN00199 |
| CP19 | Cooling Tower (3 cell) | 38500101 | 31,950 gpm | Baltimore Aircoil | 4469-20-3W | 92-4G-6184-P4 |
| CP20 | Cooling Tower (3 cell) | 38500101 | 5,750 gpm | Baltimore Aircoil | 3725A-3 | U040665201MAD |
| CP21 | Cooling Tower (3 cell) | 38500101 | 5,750 gpm | Baltimore Aircoil | 3725A-3 | U040665202MAD |
| CP22 | Cooling Tower (3 cell) | 38500101 | 5,750 gpm | Baltimore Aircoil | 3725A-3 | U040665203MAD |
| CP24 | Natural Gas Boiler | 10300603 | 1.50 MMBtu/hr | RBI Futera | FW1500 | 120644885 |
| CP25 | Natural Gas Boiler | 10300603 | 1.50 MMBtu/hr | RBI Futera | FW1500 | 042393736 |
| CP26 | Natural Gas Boiler | 10300602 | 24.00 MMBtu/hr | Unilux | ZF2500W-1-300/400 | A1683 |
| CP27 | Natural Gas Boiler | 10300602 | 24.00 MMBtu/hr | Unilux | ZF2500W-1-300/400 | A1684 |
| CP28 | Emergency Generator<br>Diesel Engine; DOM: 2008 | 20300101 | 2,000 kW<br>2,937 hp | Caterpillar | SR4B HV<br>3516CDITA | G3X00133<br>SBJ00672 |
| CP29 | Emergency Generator<br>Diesel Engine; DOM: 2008 | 20300101 | 2,000 kW<br>2,937 hp | Caterpillar | SR4B HV<br>3516CDITA | G3X00229<br>SBJ00673 |
| CP30 | Cooling Tower (2 cell) | 38500101 | 11,200 gpm | Composite Cooling Solutions | FT-2828-75-P6IL | CT-7 |
| CP32 | GDO with an AST and nozzles | 40600401 | 1,000-gallon | Fireguard | MWCFG | N/A |
| CP34 | Emergency Fire Pump<br>Diesel Engine; DOM: Post - 2006 | 20300101 | 525 hp | Clarke<br>John Deere | JX6H-UF60<br>6125HF070 | FPVT-C084983-002<br>RG6125H063341 |
| CP35 | Emergency Fire Pump<br>Diesel Engine; DOM: Post - 2006 | 20300101 | 525 hp | Clarke<br>John Deere | JX6H-UF60<br>6125HF070 | FPVT-C084983-001<br>RG6125H063339 |
| CP37 | Natural Gas Boiler | 10300603 | 1.50 MMBtu/hr | RBI Futera | FW1500 | 101984123 |

| Paris Las Vegas | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| PA12 | Natural Gas Boiler #4 | 10300603 | 3.50 MMBtu/hr | Bryan | RV350-S-150-FDG-LX | 81362 |
| PA13 | Natural Gas Boiler #5 | 10300603 | 3.50 MMBtu/hr | Bryan | RV350-S-150-FDG-LX | 81349 |
| PA14 | Natural Gas Boiler #3 | 10300602 | 17.00 MMBtu/hr | Bryan | RW1700-W-FDG-LX | 81458 |
| PA15 | Natural Gas Boiler #1 | 10300602 | 21.00 MMBtu/hr | Bryan | RW2100-W-FDG-LX | 81444 |
| PA16 | Natural Gas Boiler #2 | 10300602 | 21.00 MMBtu/hr | Bryan | RW2100-W-FDG-LX | 81457 |
| PA17 | Emergency Generator Diesel Engine; DOM: 03/25/1998 | 20300101 | 2,100 kW 2,816 hp | Cummins | QSW73 CW-73-G | 79652 66300058 |
| PA18 | Emergency Generator Diesel Engine; DOM: 02/26/1998 | 20300101 | 2,100 kW 2,816 hp | Cummins | QSW73 CW-73-G | 79651 66300040 |
| PA19 | Cooling Tower #1 (2 Cell) | 38500101 | 4,725 gpm | Baltimore Aircoil | 33758-2W | 97221981 & 97222002 |
| PA20 | Cooling Tower #2 (2 Cell) | 38500101 | 4,725 gpm | Baltimore Aircoil | 33758-2W | 97222011 & 97222001 |
| PA21 | Cooling Tower #3 (2 Cell) | 38500101 | 4,725 gpm | Baltimore Aircoil | 33758-2W | 97222021 & 97221992 |
| PA22 | Cooling Tower #4 (2 Cell) | 38500101 | 4,725 gpm | Baltimore Aircoil | 33758-2W | 97221991 & 97222012 |
| PA23 | Cooling Tower #5 (2 Cell) | 38500101 | 4,725 gpm | Baltimore Aircoil | 33758-2W | 97222022 & 97221982 |
| PA28 | Natural Gas Boiler | 10300603 | 1.95 MMBtu/hr | RBI Futera II | FW1950 | 040952881 |
| PA29 | Natural Gas Boiler | 10300603 | 1.95 MMBtu/hr | RBI Futera II | FW1950 | 092086486 |
| PA30 | Natural Gas Boiler | 10300603 | 1.95 MMBtu/hr | RBI Futera II | FW1950 | 092086497 |
| PA31 | Natural Gas Boiler | 10300603 | 1.95 MMBtu/hr | RBI Futera II | FW1950 | 071983421 |
| PA32 | Natural Gas Boiler | 10300603 | 1.95 MMBtu/hr | RBI Futera II | FW1950 | 021261112 |
| PA33 | Natural Gas Boiler | 10300603 | 1.95 MMBtu/hr | RBI Futera II | FW1950 | 121160719 |
| PA34 | Natural Gas Boiler | 10300603 | 1.95 MMBtu/hr | RBI Futera II | FW1950 | 011260847 |
| PA35 | Natural Gas Boiler | 10300603 | 1.95 MMBtu/hr | RBI Futera II | FW1950 | 021982198 |
| PA36 | Natural Gas Boiler | 10300603 | 1.95 MMBtu/hr | RBI Futera II | FW1950 | 051570836 |

| The LINQ Hotel & Casino | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| IP01 | Natural Gas Boiler | 10300603 | 1.25 MMBtu/hr | Ajax | WG-1250 D | 82-34510 |
| IP02 | Natural Gas Boiler | 10300603 | 1.25 MMBtu/hr | Ajax | WG-1250 D | 82-34507 |
| IP03 | Natural Gas Boiler | 10300603 | 1.25 MMBtu/hr | Ajax | WG-1250 D | 82-34502 |
| IP04 | Natural Gas Boiler | 10300602 | 16.738 MMBtu/hr | Kewanee | H3S 400HP | R8190 |
| IP05 | Natural Gas Boiler | 10300602 | 16.738 MMBtu/hr | Kewanee | H3S 400GO | R8191 |
| IP06 | Emergency Generator Diesel Engine; DOM: Pre-2006 | 20300101 | 470 kW 680 hp | Caterpillar | SR4 3412 | 6EA00547 81Z01351 |
| IP07 | Emergency Generator Diesel Engine; DOM: Pre-2006 | 20300101 | 500 kW 755 hp | Caterpillar | SR4 3412 | 5NA05002 81Z04033 |
| IP08 | Emergency Generator Diesel Engine; DOM: Pre-2006 | 20300101 | 600 kW 890 hp | Caterpillar | SR4 3412 | 6FA04856 81Z07511 |
| IP09 | Emergency Generator Diesel Engine; DOM: Pre-2006 | 20300101 | 600 kW 890 hp | Caterpillar | SR4 3412 | 6FA05404 81Z08595 |
| IP10 | Emergency Generator Diesel Engine; DOM: Pre-2006 | 20300101 | 280 kW 375 hp | Marathon Electric Detroit Diesel | 7083-7305 N/A | 263120414 N/A |
| IP11 | Emergency Generator Diesel Engine; DOM: Pre-2006 | 20300101 | 500 kW 670 hp | Marathon Electric Detroit Diesel | 580FDF4036FF PD1 W 71637305 | JB-95613 16VA015737 |
| IP38 | Emergency Generator Diesel Engine; DOM: 2019 | 20300101 | 500 kW 762 hp | Caterpillar | LC6 C15 | G6B25666 FTE04081 |

| Planet Hollywood | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| PH03 | Natural Gas Boiler | 10300603 | 1.75 MMBtu/hr | RBI | FW1750 | 080850764 |
| PH04 | Natural Gas Boiler | 10300603 | 1.75 MMBtu/hr | RBI | FW1750 | 050849828 |
| PH07 | Natural Gas Boiler | 10300602 | 23.60 MMBtu/hr | Unilux | ZF2000W | 2339 |
| PH08 | Natural Gas Boiler | 10300602 | 23.60 MMBtu/hr | Unilux | ZF2000W | 2340 |
| PH09 | Natural Gas Boiler | 10300602 | 23.60 MMBtu/hr | Unilux | ZF2000W | 2341 |
| PH10 | Emergency Generator<br>Diesel Engine; DOM: 1999 | 20300101 | 1,750 kW<br>2,550 hp | Spectrum<br>MTU/Detroit | 1750DS4<br>T1637K16 | 0628031<br>5272000427 |
| PH11 | Emergency Generator<br>Diesel Engine; DOM: 1999 | 20300101 | 1,750 kW<br>2,550 hp | Spectrum<br>MTU/Detroit | 1750DS4<br>T1637K16 | 0628032<br>5272000397 |
| PH12 | Emergency Generator<br>Diesel Engine; DOM: 1999 | 20300101 | 1,750 kW<br>2,550 hp | Spectrum<br>MTU/Detroit | 1750DS4<br>T1637K16 | 0628033<br>5272000421 |
| PH13 | Emergency Generator<br>Diesel Engine; DOM: 2008 | 20300101 | 1,750 kW<br>2,560 hp | Spectrum<br>MTU/Detroit | 1750RXC6DT2<br>T1238A36 | 301122-1-1-1208<br>5262003725 |
| PH14 | Cooling Tower (6 cell) | 38500101 | 33,360 gpm | Baltimore Aircoil | PCS50-2424-10 | PC2429 |

| LINQ Complex - High Roller | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| LI01 | Natural Gas Boiler | 10300603 | 5.00 MMBtu/hr | CAMUS | DNRH-5000-MSI | 041215509 |
| LI02 | Natural Gas Boiler | 10300603 | 5.00 MMBtu/hr | CAMUS | DNRH-5000-MSI | 041215507 |
| LI03 | Natural Gas Boiler | 10300603 | 5.00 MMBtu/hr | CAMUS | DNRH-5000-MSI | 041215508 |
| LI04 | Natural Gas Boiler | 10300603 | 5.00 MMBtu/hr | CAMUS | DNRH-5000-MSI | 041215506 |
| LI05 | Natural Gas Boiler | 10300603 | 5.00 MMBtu/hr | CAMUS | DNRH-5000-MSI | 041215505 |
| LI06 | Emergency Generator<br>Diesel Engine; DOM: 2012 | 20300101 | 2,000 kW<br>2,937 hp | Caterpillar | SR4B-GD<br>3516C | G4Z00115<br>SBJ01461 |
| LI07 | Emergency Generator<br>Diesel Engine; DOM: 2012 | 20300101 | 2,000 kW<br>2,937 hp | Caterpillar | SR4B-GD<br>3516C | G4Z00116<br>SBJ01460 |
| LI08 | Cooling Tower (2 cell) | 38500101 | 6,000 gpm | Marley | NC8413VAN2BGF | NC-10054867-B1&B2 |
| LI09 | Cooling Tower (2 cell) | 38500101 | 6,000 gpm | Marley | NC8413VAN2BGF | NC-10054867-C1&C2 |
| LI10 | Cooling Tower (2 cell) | 38500101 | 6,000 gpm | Marley | NC8413VAN2BGF | NC-10054867-A1&A2 |
| LI12 | Emergency Engine<br>Diesel Engine; DOM: 11/2012 | 20300101 | 180kw<br>241 hp | Deutz | TCD 6.1 L6 | 11360110 |
| LI13 | Emergency Engine<br>Diesel Engine; DOM: 11/2012 | 20300101 | 180kw<br>241 hp | Deutz | TCD 6.1 L6 | 11353814 |

| Forum Meeting Center | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| FMC01 | Natural Gas Boiler | 10300603 | 6.00 MMBtu/hr | Lochinvar | FBN6001 | 1847112615298 |
| FMC02 | Natural Gas Boiler | 10300603 | 6.00 MMBtu/hr | Lochinvar | FBN6001 | 1847112615299 |
| FMC03 | Natural Gas Boiler | 10300603 | 6.00 MMBtu/hr | Lochinvar | FBN6001 | 1847112615300 |
| FMC04 | Natural Gas Boiler | 10300603 | 6.00 MMBtu/hr | Lochinvar | FBN6001 | 1847112615301 |
| FMC05 | Emergency Generator<br>Diesel Engine; DOM: 1/21/2019 | 20300101 | 1,000 kW<br>1,490 hp | Cummins | DQFAD-A061Y200<br>QST30 | B190508151<br>37277632 |
| FMC06 | Cooling Tower (2 cell) | 38500101 | 4,800 gpm | Evapco | USS224-4P20 | 18-849683 |
| FMC07 | Cooling Tower (2 cell) | 38500101 | 4,800 gpm | Evapco | USS224-4P20 | 18-849684 |

| Harrah's Las Vegas | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating/Capacity** | **Make** | **Model No.** | **Serial No.** |
| IA | Natural Gas Pool Heater | 10300603 | 0.726 MMBtu/hr | Raypak | P-724 | 1404376451 |
| IA | Spray Paint Booth | 40201101 | NA | Global Finishing Solutions | FP10812.100 | NA |
| IA | Dust Collector | 30703001 | 4,550 cfm | Murphy-Rodgers | MRM-12-4D(42B) | 1839 |
| IA | Diesel AST | 39090003 | 3,000 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 1,000 gal | NA | NA | NA |
| IA | Diesel AST (2) | 39090003 | 550 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 100 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 50 gal | NA | NA | NA |

| Flamingo Las Vegas | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating/Capacity** | **Make** | **Model No.** | **Serial No.** |
| IA | Dust Collector | 30703001 | 2,600 cfm | Murphy-Rodgers | MRM-10-2D | 1181 |
| IA | Abrasive Blast Cabinet | 30900204 | NA | Badboy Blasters, Inc. | BB-3000-XLD | NA |
| IA | Diesel UST | 40400413 | 8,000 gal | NA | NA | NA |
| IA | Diesel UST | 40400413 | 1,000 gal | NA | NA | NA |
| IA | Diesel AST (3) | 39090003 | NA | NA | NA | NA |

| Horseshoe Las Vegas | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating/Capacity** | **Make** | **Model No.** | **Serial No.** |
| IA | Spray Paint Booth | 40201101 | NA | Spray King | 200FAFC | 659-1 |
| IA | Abrasive Blast Cabinet w/Dust Collector | 30900204 | NA | Econoline Syphon; Dayton | 36-1; 2Z982H | NA |
| IA | Dust Collector | 30703001 | NA | Cincinnati Fan and Ventilator Company | 100S | G006678 |
| IA | Dust Collector | 30703001 | NA | Cincinnati Fan and Ventilator Company | 100S | G006766 |
| IA | Dust Collector | 30703001 | NA | Cincinnati Fan and Ventilator Company | 100S | G006769 |
| IA | Dust Collector | 30703001 | NA | Cincinnati Fan and Ventilator Company | 100S | G006768 |
| IA | Dust Collector | 30703001 | NA | Cincinnati Fan and Ventilator Company | 100S | G006677 |
| IA | Diesel AST | 39090003 | 12,150 gal | NA | NA | NA |
| IA | Diesel UST | 40400413 | 2,500 gal | NA | NA | NA |
| IA | Diesel AST (3) | 39090003 | 300 gal | NA | NA | NA |
| IA | Diesel AST (2) | 39090003 | 480 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 270 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 200 gal | NA | NA | NA |
| IA | Diesel AST (2) | 39090003 | 150 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 100 gal | NA | NA | NA |

| The Cromwell Las Vegas | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| IA | Dust Collector | 30703001 | 3,000 cfm | NA | NA | NA |

| Caesars Palace | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating/Capacity** | **Make** | **Model No.** | **Serial No.** |
| IA | Spray Paint Booth | 40201101 | NA | Spray King | 200-P | NA |
| IA | Dust Collector | 30703001 | 3,000 cfm | Pollution International | 33N375 | NA |
| IA | Natural Gas Water Heater | 10300603 | 0.199 MMBtu/hr | Lochinvar | SNR201-100 | 1916114475102 |
| IA | Natural Gas Water Heater | 10300603 | 0.199 MMBtu/hr | Lochinvar | SNR201-100 | 149112752853 |
| IA | Natural Gas Water Heater | 10300603 | 0.999 MMBtu/hr | Lochinvar | PBN1002 | A15H00273568 |
| IA | Natural Gas Water Heater | 10300603 | 0.250 MMBtu/hr | A.O. Smith | BTH250A200 | 1615M000633 |
| IA | Natural Gas Water Heater | 10300603 | 0.250 MMBtu/hr | A.O. Smith | BTH250A100 | 0826M001486 |
| IA | Diesel AST (2) | 39090003 | 575 gal | NA | NA | NA |
| IA | Diesel AST (2) | 39090003 | 1,500 gal | NA | NA | NA |
| IA | Diesel AST (4) | 39090003 | 1,000 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 750 gal | NA | NA | NA |
| IA | Diesel AST (2) | 39090003 | 650 gal | NA | NA | NA |

| Paris Las Vegas | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating/Capacity** | **Make** | **Model No.** | **Serial No.** |
| IA | Spray Paint Booth | 40201101 | NA | Spray Systems | I-887 | NA |
| IA | Dust Collector | 30703001 | NA | Donaldson Torit | UMA358K11AD | 97-1572 |
| IA | Natural Gas Water Heater | 10300603 | 0.500 MMBtu/hr | A.O. Smith | BTR-500A-120 | 1718106055440 |
| IA | Natural Gas Water Heater | 10300603 | 0.390 MMBtu/hr | A.O. Smith | BTR-400A-118 | 1427M000763 |
| IA | Natural Gas Water Heater | 10300603 | 0.199 MMBtu/hr | Bradford White | D100L1993N | SD41254652 |
| IA | Natural Gas Water Heater | 10300603 | 0.199 MMBtu/hr | Bradford White | D100L1993N | YA49261313 |
| IA | Sandblasting Cabinet | 30900204 | NA | NA | NA | NA |
| IA | Diesel UST | 40400413 | 8,000 gal | NA | NA | NA |
| IA | Diesel AST (2) | 39090003 | 100 gal | NA | NA | NA |

| The LINQ Hotel & Casino | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| IA | Dust Collector | 30703001 | NA | Air Sentry, Inc. | 205D550F | 1216 |
| IA | Diesel AST (2) | 39090003 | 650 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 300 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 275 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 250 gal | NA | NA | NA |

| Planet Hollywood | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating/Capacity** | **Make** | **Model No.** | **Serial No.** |
| IA | Natural Gas Boiler | 10300603 | 0.650 MMBtu/hr | Lochinvar | CB0645 | L008207 |
| IA | Natural Gas Boiler | 10300603 | 0.650 MMBtu/hr | Lochinvar | CB0645 | L008208 |
| IA | Spray Paint Booth | 40201101 | NA | NA | NA | NA |
| IA | Dust Collector | 30703001 | 1,500 cfm | Torit | RVS15 | I6600032-001 |
| IA | Cooking Oil AST | 39090003 | 488 gal | NA | NA | NA |
| IA | Diesel UST | 40400413 | 2,500 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 2,000 gal | NA | NA | NA |
| IA | Diesel AST | 39090003 | 250 gal | NA | NA | NA |

| LINQ Complex - High Roller | | | | | | |
|---|---|---|---|---|---|---|
| **EU** | **Description** | **SCC** | **Rating** | **Make** | **Model No.** | **Serial No.** |
| IA | Natural Gas Water Heater | 10300603 | 0.150 MMBtu/hr | A.O. Smith | BTH-150-300 | 2102122746244 |

# POTENTIAL TO EMIT CALCULATIONS

Source ID: 257

**Facility-Wide Potential to Emit (PTE)**

Caesars Entertainment Inc.

**Facility-Wide PTE**

| Pollutant (Tons per Year) | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|
| Harrah's Las Vegas | 3.67 | 3.67 | 32.32 | 13.34 | 0.17 | 2.66 | 0.43 |
| Flamingo Las Vegas | 5.90 | 5.90 | 32.22 | 19.36 | 0.23 | 2.27 | 0.60 |
| Horseshoe Las Vegas | 4.57 | 4.57 | 32.92 | 10.07 | 0.24 | 2.23 | 0.58 |
| The Cromwell Las Vegas | 0.95 | 0.95 | 5.65 | 3.59 | 0.08 | 0.70 | 0.14 |
| Caesars Palace | 21.35 | 21.35 | 62.38 | 19.87 | 0.69 | 6.37 | 1.95 |
| Paris Las Vegas | 9.06 | 9.06 | 20.82 | 29.96 | 0.29 | 2.27 | 0.74 |
| The LINQ Hotel & Casino | 2.06 | 2.06 | 35.48 | 18.14 | 0.18 | 1.78 | 0.38 |
| Planet Hollywood | 11.60 | 11.60 | 29.27 | 29.15 | 0.24 | 2.39 | 0.66 |
| LINQ Complex - High Roller | 5.53 | 5.53 | 10.10 | 5.45 | 0.09 | 0.82 | 0.24 |
| Forum Meeting Center | 1.38 | 1.38 | 6.17 | 4.29 | 0.09 | 0.82 | 0.21 |

| Pollutant | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|
| **Revision Totals (TPY)** | **66.07** | **66.07** | **267.33** | **153.22** | **2.30** | **22.31** | **5.93** |
| Current Permit (TPY)* | 70.38 | 70.38 | 440.30 | 187.12 | 2.30 | 27.24 | 5.93 |
| Net Emission Increase (NEI) | -4.31 | -4.31 | -172.97 | -33.90 | 0.00 | -4.93 | 0.00 |
| Minor NSR Significance Levels (§12.5.1(d)) | 7.5 | 5 | 20 | 50 | 20 | 20 | NA |

*Current permit totals are from the permit issued on 03/06/2025.

# EMISSIONS INFORMATION AND SUPPORTING CALCULATIONS

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| HA06 | 4.50 MMBtu/hr | 8,760 hours/yr | 0.15 | 0.15 | 0.21 | 0.73 | 0.01 | 0.11 | 0.04 |
| HA07 | 9.00 MMBtu/hr | 8,760 hours/yr | 0.30 | 0.30 | 1.44 | 1.46 | 0.02 | 0.21 | 0.07 |
| HA08 | 8.369 MMBtu/hr | 8,760 hours/yr | 0.27 | 0.27 | 0.54 | 1.36 | 0.02 | 0.20 | 0.07 |
| HA09 | 8.369 MMBtu/hr | 8,760 hours/yr | 0.27 | 0.27 | 0.54 | 1.36 | 0.02 | 0.20 | 0.07 |
| HA10 | 8.369 MMBtu/hr | 8,760 hours/yr | 0.27 | 0.27 | 0.54 | 1.36 | 0.02 | 0.20 | 0.07 |
| HA11 | 4.80 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.77 | 0.78 | 0.01 | 0.11 | 0.04 |
| HA12 | 370 hp | 500 hours/yr | 0.20 | 0.20 | 2.87 | 0.62 | 0.01 | 0.23 | 0.01 |
| HA13 | 1,232 hp | 500 hours/yr | 0.22 | 0.22 | 7.39 | 1.69 | 0.01 | 0.22 | 0.01 |
| HA14 | 890 hp | 500 hours/yr | 0.16 | 0.16 | 5.34 | 1.22 | 0.01 | 0.16 | 0.01 |
| HA15 | 536 hp | 500 hours/yr | 0.29 | 0.29 | 4.15 | 0.90 | 0.01 | 0.34 | 0.01 |
| HA16 | 536 hp | 500 hours/yr | 0.29 | 0.29 | 4.15 | 0.90 | 0.01 | 0.34 | 0.01 |
| HA17 | 536 hp | 500 hours/yr | 0.29 | 0.29 | 4.15 | 0.90 | 0.01 | 0.34 | 0.01 |
| HA18 | 1,180 hp | 500 hours/yr | 0.21 | 0.21 | 7.08 | 1.62 | 0.01 | 0.21 | 0.01 |
| HA26 | 5,200 gpm | 8,760 hours/yr | 0.27 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| HA27 | 5,200 gpm | 8,760 hours/yr | 0.27 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| HA28 | 5,200 gpm | 8,760 hours/yr | 0.27 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Totals (tons/yr)** | | | **3.89** | **3.89** | **39.17** | **14.90** | **0.17** | **2.87** | **0.43** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$.

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| HA06 | 4.50 MMBtu/hr | 8,760 hours/yr | 0.15 | 0.15 | 0.21 | 0.73 | 0.01 | 0.11 | 0.04 |
| HA07 | 9.00 MMBtu/hr | 8,760 hours/yr | 0.30 | 0.30 | 1.44 | 1.46 | 0.02 | 0.21 | 0.07 |
| HA08 | 8.369 MMBtu/hr | 8,760 hours/yr | 0.27 | 0.27 | 0.54 | 1.36 | 0.02 | 0.20 | 0.07 |
| HA09 | 8.369 MMBtu/hr | 8,760 hours/yr | 0.27 | 0.27 | 0.54 | 1.36 | 0.02 | 0.20 | 0.07 |
| HA10 | 8.369 MMBtu/hr | 8,760 hours/yr | 0.27 | 0.27 | 0.54 | 1.36 | 0.02 | 0.20 | 0.07 |
| HA11 | 4.80 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.77 | 0.78 | 0.01 | 0.11 | 0.04 |
| HA12 | 370 hp | 500 hours/yr | 0.20 | 0.20 | 2.87 | 0.62 | 0.01 | 0.23 | 0.01 |
| HA13 | 1,232 hp | 300 hours/yr | 0.13 | 0.13 | 4.44 | 1.02 | 0.01 | 0.13 | 0.01 |
| HA14 | 890 hp | 400 hours/yr | 0.12 | 0.12 | 4.27 | 0.98 | 0.01 | 0.13 | 0.01 |
| HA15 | 536 hp | 500 hours/yr | 0.29 | 0.29 | 4.15 | 0.90 | 0.01 | 0.34 | 0.01 |
| HA16 | 536 hp | 500 hours/yr | 0.29 | 0.29 | 4.15 | 0.90 | 0.01 | 0.34 | 0.01 |
| HA17 | 536 hp | 500 hours/yr | 0.29 | 0.29 | 4.15 | 0.90 | 0.01 | 0.34 | 0.01 |
| HA18 | 1,180 hp | 300 hours/yr | 0.12 | 0.12 | 4.25 | 0.97 | 0.01 | 0.12 | 0.01 |
| HA26 | 5,200 gpm | 8,760 hours/yr | 0.27 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| HA27 | 5,200 gpm | 8,760 hours/yr | 0.27 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| HA28 | 5,200 gpm | 8,760 hours/yr | 0.27 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Totals (tons/yr)** | | | **3.67** | **3.67** | **32.32** | **13.34** | **0.17** | **2.66** | **0.43** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$.

Source ID: 257

**Harrah's Las Vegas**
**Emergency Generator Calculations**

Caesars Entertainment Inc.

| | |
|---|---|
| **EU#** | HA13 |
| **Make:** | Detroit Diesel |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 1,232 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.86 | 20.70 | 0.22 |
| **NOx** | 2.40E-02 | 29.57 | 709.63 | 7.39 |
| **CO** | 5.50E-03 | 6.78 | 162.62 | 1.69 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.36 | 0.01 |
| **VOC** | 7.05E-04 | 0.87 | 20.85 | 0.22 |
| **HAP** | 1.10E-05 | 0.01 | 0.33 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | HA13 |
| **Make:** | Detroit Diesel |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 1,232 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 300 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.86 | 20.70 | 0.13 |
| **NOx** | 2.40E-02 | 29.57 | 709.63 | 4.44 |
| **CO** | 5.50E-03 | 6.78 | 162.62 | 1.02 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.36 | 0.01 |
| **VOC** | 7.05E-04 | 0.87 | 20.85 | 0.13 |
| **HAP** | 1.10E-05 | 0.01 | 0.33 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

Source ID: 257

**Harrah's Las Vegas**
**Emergency Generator Calculations**

Caesars Entertainment Inc.

| | |
|---|---|
| **EU#** | HA14 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 890 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.62 | 14.95 | 0.16 |
| **NOx** | 2.40E-02 | 21.36 | 512.64 | 5.34 |
| **CO** | 5.50E-03 | 4.90 | 117.48 | 1.22 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.26 | 0.01 |
| **VOC** | 7.05E-04 | 0.63 | 15.06 | 0.16 |
| **HAP** | 1.10E-05 | 0.01 | 0.24 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | HA14 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 890 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 400 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.62 | 14.95 | 0.12 |
| **NOx** | 2.40E-02 | 21.36 | 512.64 | 4.27 |
| **CO** | 5.50E-03 | 4.90 | 117.48 | 0.98 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.26 | 0.01 |
| **VOC** | 7.05E-04 | 0.63 | 15.06 | 0.13 |
| **HAP** | 1.10E-05 | 0.01 | 0.24 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

Source ID: 257

**Harrah's Las Vegas**
**Emergency Generator Calculations**

Caesars Entertainment Inc.

| | |
|---|---|
| **EU#** | HA18 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 1,180 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.83 | 19.82 | 0.21 |
| **NOx** | 2.40E-02 | 28.32 | 679.68 | 7.08 |
| **CO** | 5.50E-03 | 6.49 | 155.76 | 1.62 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.34 | 0.01 |
| **VOC** | 7.05E-04 | 0.83 | 19.97 | 0.21 |
| **HAP** | 1.10E-05 | 0.01 | 0.31 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | HA18 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 1,180 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 300 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.83 | 19.82 | 0.12 |
| **NOx** | 2.40E-02 | 28.32 | 679.68 | 4.25 |
| **CO** | 5.50E-03 | 6.49 | 155.76 | 0.97 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.34 | 0.01 |
| **VOC** | 7.05E-04 | 0.83 | 19.97 | 0.12 |
| **HAP** | 1.10E-05 | 0.01 | 0.31 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| FL01 | 14.343 MMBtu/hr | 8,760 hours/yr | 0.47 | 0.47 | 2.21 | 4.42 | 0.04 | 0.34 | 0.12 |
| FL02 | 14.645 MMBtu/hr | 8,760 hours/yr | 0.48 | 0.48 | 3.12 | 2.37 | 0.04 | 0.35 | 0.12 |
| FL03 | 14.645 MMBtu/hr | 8,760 hours/yr | 0.48 | 0.48 | 3.12 | 2.37 | 0.04 | 0.35 | 0.12 |
| FL04 | 14.645 MMBtu/hr | 8,760 hours/yr | 0.48 | 0.48 | 3.12 | 2.37 | 0.04 | 0.35 | 0.12 |
| FL05 | 8.165 MMBtu/hr | 8,760 hours/yr | 0.27 | 0.27 | 1.26 | 1.46 | 0.02 | 0.19 | 0.07 |
| FL06 | 420 hp | 500 hours/yr | 0.23 | 0.23 | 3.26 | 0.70 | 0.01 | 0.26 | 0.01 |
| FL09 | 1,109 hp | 500 hours/yr | 0.19 | 0.19 | 6.65 | 1.52 | 0.01 | 0.20 | 0.01 |
| FL10 | 1,109 hp | 500 hours/yr | 0.19 | 0.19 | 6.65 | 1.52 | 0.01 | 0.20 | 0.01 |
| FL11 | 724 hp | 500 hours/yr | 0.13 | 0.13 | 4.34 | 1.00 | 0.01 | 0.13 | 0.01 |
| FL26 | 923 hp | 500 hours/yr | 0.03 | 0.03 | 3.13 | 0.44 | 0.01 | 0.04 | 0.01 |
| FL28 | 9,600 gpm | 8,760 hours/yr | 2.47 | 2.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| FL29 | 3,800 gpm | 8,760 hours/yr | 0.20 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| FL30 | 3,800 gpm | 8,760 hours/yr | 0.20 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| FL31 | 3,800 gpm | 8,760 hours/yr | 0.20 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Totals (tons/yr)** | | | **6.02** | **6.02** | **36.86** | **18.17** | **0.23** | **2.41** | **0.60** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| FL01 | 14.343 MMBtu/hr | 8,760 hours/yr | 0.47 | 0.47 | 2.21 | 4.42 | 0.04 | 0.34 | 0.12 |
| FL02 | 14.645 MMBtu/hr | 8,760 hours/yr | 0.48 | 0.48 | 3.12 | 3.12 | 0.04 | 0.35 | 0.12 |
| FL03 | 14.645 MMBtu/hr | 8,760 hours/yr | 0.48 | 0.48 | 3.12 | 3.12 | 0.04 | 0.35 | 0.12 |
| FL04 | 14.645 MMBtu/hr | 8,760 hours/yr | 0.48 | 0.48 | 3.12 | 3.12 | 0.04 | 0.35 | 0.12 |
| FL05 | 8.165 MMBtu/hr | 8,760 hours/yr | 0.27 | 0.27 | 1.26 | 1.46 | 0.02 | 0.19 | 0.07 |
| FL06 | 420 hp | 500 hours/yr | 0.23 | 0.23 | 3.26 | 0.70 | 0.01 | 0.26 | 0.01 |
| FL09 | 1,109 hp | 325 hours/yr | 0.13 | 0.13 | 4.33 | 0.99 | 0.01 | 0.13 | 0.01 |
| FL10 | 1,109 hp | 325 hours/yr | 0.13 | 0.13 | 4.33 | 0.99 | 0.01 | 0.13 | 0.01 |
| FL11 | 724 hp | 500 hours/yr | 0.13 | 0.13 | 4.34 | 1.00 | 0.01 | 0.13 | 0.01 |
| FL26 | 923 hp | 500 hours/yr | 0.03 | 0.03 | 3.13 | 0.44 | 0.01 | 0.04 | 0.01 |
| FL28 | 9,600 gpm | 8,760 hours/yr | 2.47 | 2.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| FL29 | 3,800 gpm | 8,760 hours/yr | 0.20 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| FL30 | 3,800 gpm | 8,760 hours/yr | 0.20 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| FL31 | 3,800 gpm | 8,760 hours/yr | 0.20 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Totals (tons/yr)** | | | **5.90** | **5.90** | **32.22** | **19.36** | **0.23** | **2.27** | **0.60** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$.

| | |
|---|---|
| **EU#** | FL09 - FL10 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 1,109 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.78 | 18.63 | 0.19 |
| **NOx** | 2.40E-02 | 26.62 | 638.78 | 6.65 |
| **CO** | 5.50E-03 | 6.10 | 146.39 | 1.52 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.32 | 0.01 |
| **VOC** | 7.05E-04 | 0.78 | 18.76 | 0.20 |
| **HAP** | 1.10E-05 | 0.01 | 0.29 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | FL09 - FL10 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 1,109 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 325 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.78 | 18.63 | 0.13 |
| **NOx** | 2.40E-02 | 26.62 | 638.78 | 4.33 |
| **CO** | 5.50E-03 | 6.10 | 146.39 | 0.99 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.32 | 0.01 |
| **VOC** | 7.05E-04 | 0.78 | 18.76 | 0.13 |
| **HAP** | 1.10E-05 | 0.01 | 0.29 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| BA01 | 16.80 MMBtu/hr | 8,760 hours/yr | 0.55 | 0.55 | 2.24 | 1.25 | 0.04 | 0.40 | 0.14 |
| BA02 | 16.80 MMBtu/hr | 8,760 hours/yr | 0.55 | 0.55 | 2.24 | 1.25 | 0.04 | 0.40 | 0.14 |
| BA03 | 25.106 MMBtu/hr | 8,760 hours/yr | 0.82 | 0.82 | 3.34 | 1.87 | 0.07 | 0.59 | 0.21 |
| BA04 | 1,340 hp | 500 hours/yr | 0.23 | 0.23 | 8.04 | 1.84 | 0.01 | 0.24 | 0.01 |
| BA05 | 1,340 hp | 500 hours/yr | 0.23 | 0.23 | 8.04 | 1.84 | 0.01 | 0.24 | 0.01 |
| BA06 | 670 hp | 500 hours/yr | 0.12 | 0.12 | 4.02 | 0.92 | 0.01 | 0.12 | 0.01 |
| BA07 | 200 hp | 500 hours/yr | 0.11 | 0.11 | 1.55 | 0.33 | 0.01 | 0.13 | 0.01 |
| BA11 | 1,340 hp | 500 hours/yr | 0.23 | 0.23 | 8.04 | 1.84 | 0.01 | 0.24 | 0.01 |
| BA12 | 1,340 hp | 500 hours/yr | 0.23 | 0.23 | 8.04 | 1.84 | 0.01 | 0.24 | 0.01 |
| BA17 | 526 hp | 500 hours/yr | 0.01 | 0.01 | 0.75 | 0.12 | 0.01 | 0.03 | 0.01 |
| BA18 | 526 hp | 500 hours/yr | 0.01 | 0.01 | 0.75 | 0.12 | 0.01 | 0.03 | 0.01 |
| BA19 | 18,000 gpm | 8,760 hours/yr | 0.93 | 0.93 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| BA20 | 18,000 gpm | 8,760 hours/yr | 0.93 | 0.93 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| BA21 | 260 hp | 500 hours/yr | 0.02 | 0.02 | 0.35 | 0.17 | 0.01 | 0.01 | 0.01 |
| **Totals (tons/yr)** | | | **4.97** | **4.97** | **47.40** | **13.39** | **0.24** | **2.67** | **0.58** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$.

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| BA01 | 16.80 MMBtu/hr | 8,760 hours/yr | 0.55 | 0.55 | 2.24 | 1.25 | 0.04 | 0.40 | 0.14 |
| BA02 | 16.80 MMBtu/hr | 8,760 hours/yr | 0.55 | 0.55 | 2.24 | 1.25 | 0.04 | 0.40 | 0.14 |
| BA03 | 25.106 MMBtu/hr | 8,760 hours/yr | 0.82 | 0.82 | 3.34 | 1.87 | 0.07 | 0.59 | 0.21 |
| BA04 | 1,340 hp | 275 hours/yr | 0.13 | 0.13 | 4.42 | 1.01 | 0.01 | 0.13 | 0.01 |
| BA05 | 1,340 hp | 275 hours/yr | 0.13 | 0.13 | 4.42 | 1.01 | 0.01 | 0.13 | 0.01 |
| BA06 | 670 hp | 500 hours/yr | 0.12 | 0.12 | 4.02 | 0.92 | 0.01 | 0.12 | 0.01 |
| BA07 | 200 hp | 500 hours/yr | 0.11 | 0.11 | 1.55 | 0.33 | 0.01 | 0.13 | 0.01 |
| BA11 | 1,340 hp | 275 hours/yr | 0.13 | 0.13 | 4.42 | 1.01 | 0.01 | 0.13 | 0.01 |
| BA12 | 1,340 hp | 275 hours/yr | 0.13 | 0.13 | 4.42 | 1.01 | 0.01 | 0.13 | 0.01 |
| BA17 | 526 hp | 500 hours/yr | 0.01 | 0.01 | 0.75 | 0.12 | 0.01 | 0.03 | 0.01 |
| BA18 | 526 hp | 500 hours/yr | 0.01 | 0.01 | 0.75 | 0.12 | 0.01 | 0.03 | 0.01 |
| BA19 | 18,000 gpm | 8,760 hours/yr | 0.93 | 0.93 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| BA20 | 18,000 gpm | 8,760 hours/yr | 0.93 | 0.93 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| BA21 | 260 hp | 500 hours/yr | 0.02 | 0.02 | 0.35 | 0.17 | 0.01 | 0.01 | 0.01 |
| **Totals (tons/yr)** | | | **4.57** | **4.57** | **32.92** | **10.07** | **0.24** | **2.23** | **0.58** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$.

| | | | |
|---|---|---|---|
| **EU#** | BA04 - BA05 | **Horsepower:** | 1,340 |
| **Make:** | Detroit Diesel | **Hours/Day:** | 24.0 |
| **Model:** | | **Hours/Year** | 500 |
| **S/N:** | | | |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.94 | 22.51 | 0.23 |
| **NOx** | 2.40E-02 | 32.16 | 771.84 | 8.04 |
| **CO** | 5.50E-03 | 7.37 | 176.88 | 1.84 |
| **$SO_2$** | 1.21E-05 | 0.02 | 0.39 | 0.01 |
| **VOC** | 7.05E-04 | 0.94 | 22.67 | 0.24 |
| **HAP** | 1.10E-05 | 0.01 | 0.35 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | | | |
|---|---|---|---|
| **EU#** | BA04 - BA05 | **Horsepower:** | 1,340 |
| **Make:** | Detroit Diesel | **Hours/Day:** | 24.0 |
| **Model:** | | **Hours/Year** | 275 |
| **S/N:** | | | |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.94 | 22.51 | 0.13 |
| **NOx** | 2.40E-02 | 32.16 | 771.84 | 4.42 |
| **CO** | 5.50E-03 | 7.37 | 176.88 | 1.01 |
| **$SO_2$** | 1.21E-05 | 0.02 | 0.39 | 0.01 |
| **VOC** | 7.05E-04 | 0.94 | 22.67 | 0.13 |
| **HAP** | 1.10E-05 | 0.01 | 0.35 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | | | |
|---|---|---|---|
| **EU#** | BA11 - BA12 | **Horsepower:** | 1,340 |
| **Make:** | Detroit Diesel | **Hours/Day:** | 24.0 |
| **Model:** | | **Hours/Year** | 500 |
| **S/N:** | | | |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions lb/hr | lb/day | ton/yr |
|---|---|---|---|---|
| **PM10** | 7.00E-04 | 0.94 | 22.51 | 0.23 |
| **NOx** | 2.40E-02 | 32.16 | 771.84 | 8.04 |
| **CO** | 5.50E-03 | 7.37 | 176.88 | 1.84 |
| **$SO_2$** | 1.21E-05 | 0.02 | 0.39 | 0.01 |
| **VOC** | 7.05E-04 | 0.94 | 22.67 | 0.24 |
| **HAP** | 1.10E-05 | 0.01 | 0.35 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | | | |
|---|---|---|---|
| **EU#** | BA11 - BA12 | **Horsepower:** | 1,340 |
| **Make:** | Detroit Diesel | **Hours/Day:** | 24.0 |
| **Model:** | | **Hours/Year** | 275 |
| **S/N:** | | | |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions lb/hr | lb/day | ton/yr |
|---|---|---|---|---|
| **PM10** | 7.00E-04 | 0.94 | 22.51 | 0.13 |
| **NOx** | 2.40E-02 | 32.16 | 771.84 | 4.42 |
| **CO** | 5.50E-03 | 7.37 | 176.88 | 1.01 |
| **$SO_2$** | 1.21E-05 | 0.02 | 0.39 | 0.01 |
| **VOC** | 7.05E-04 | 0.94 | 22.67 | 0.13 |
| **HAP** | 1.10E-05 | 0.01 | 0.35 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| CR01 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR02 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR03 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR04 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR05 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR06 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR07 | 2,206 hp | 500 hours/yr | 0.05 | 0.05 | 7.76 | 1.02 | 0.01 | 0.19 | 0.01 |
| CR08 | 275 hp | 500 hours/yr | 0.02 | 0.02 | 0.42 | 0.09 | 0.01 | 0.17 | 0.01 |
| CR09 | 5,850 gpm | 8,760 hours/yr | 0.30 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Totals (tons/yr)** | | | **0.97** | **0.97** | **9.14** | **4.05** | **0.08** | **0.78** | **0.14** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$.

**Allowable Emissions**

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| CR01 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR02 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR03 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR04 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR05 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR06 | 3.00 MMBtu/hr | 8,760 hours/yr | 0.10 | 0.10 | 0.16 | 0.49 | 0.01 | 0.07 | 0.02 |
| CR07 | 2,206 hp | 275 hours/yr | 0.03 | 0.03 | 4.27 | 0.56 | 0.01 | 0.11 | 0.01 |
| CR08 | 275 hp | 500 hours/yr | 0.02 | 0.02 | 0.42 | 0.09 | 0.01 | 0.17 | 0.01 |
| CR09 | 5,850 gpm | 8,760 hours/yr | 0.30 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Totals (tons/yr)** | | | **0.95** | **0.95** | **5.65** | **3.59** | **0.08** | **0.70** | **0.14** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$.

Source ID: 257

**The Cromwell Las Vegas**
**Emergency Generator Calculations**

Caesars Entertainment Inc.

| | |
|---|---|
| **EU#** | CR07 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,206 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | 0.04 | g/hp-hr |
| **NOx** | 6.38 | g/hp-hr |
| **CO** | 0.84 | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | 0.16 | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 8.82E-05 | 0.19 | 4.67 | 0.05 |
| **NOx** | 1.41E-02 | 31.03 | 744.69 | 7.76 |
| **CO** | 1.85E-03 | 4.09 | 98.05 | 1.02 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.64 | 0.01 |
| **VOC** | 3.53E-04 | 0.78 | 18.68 | 0.19 |
| **HAP** | 1.10E-05 | 0.02 | 0.58 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | CR07 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,206 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 275 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | 0.04 | g/hp-hr |
| **NOx** | 6.38 | g/hp-hr |
| **CO** | 0.84 | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | 0.16 | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 8.82E-05 | 0.19 | 4.67 | 0.03 |
| **NOx** | 1.41E-02 | 31.03 | 744.69 | 4.27 |
| **CO** | 1.85E-03 | 4.09 | 98.05 | 0.56 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.64 | 0.01 |
| **VOC** | 3.53E-04 | 0.78 | 18.68 | 0.11 |
| **HAP** | 1.10E-05 | 0.02 | 0.58 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| CP01 | 35.40 MMBtu/hr | 8,760 hours/yr | 1.16 | 1.16 | 5.46 | 1.15 | 0.09 | 0.84 | 0.29 |
| CP02 | 35.40 MMBtu/hr | 8,760 hours/yr | 1.16 | 1.16 | 5.46 | 1.15 | 0.09 | 0.84 | 0.29 |
| CP03 | 33.475 MMBtu/hr | 8,760 hours/yr | 1.10 | 1.10 | 5.35 | 1.08 | 0.09 | 0.79 | 0.28 |
| CP04 | 33.475 MMBtu/hr | 8,760 hours/yr | 1.10 | 1.10 | 5.35 | 1.08 | 0.09 | 0.79 | 0.28 |
| CP05 | 33.475 MMBtu/hr | 8,760 hours/yr | 1.10 | 1.10 | 5.35 | 1.08 | 0.09 | 0.79 | 0.28 |
| CP13 | 2,876 hp | 500 hours/yr | 0.50 | 0.50 | 17.26 | 3.95 | 0.01 | 0.51 | 0.01 |
| CP14 | 2,876 hp | 500 hours/yr | 0.50 | 0.50 | 17.26 | 3.95 | 0.01 | 0.51 | 0.01 |
| CP15 | 2,520 hp | 500 hours/yr | 0.44 | 0.44 | 15.12 | 3.47 | 0.01 | 0.44 | 0.01 |
| CP16 | 1,818 hp | 500 hours/yr | 0.32 | 0.32 | 10.91 | 2.50 | 0.01 | 0.32 | 0.01 |
| CP17 | 2,876 hp | 500 hours/yr | 0.50 | 0.50 | 17.26 | 3.95 | 0.01 | 0.51 | 0.01 |
| CP19 | 31,950 gpm | 8,760 hours/yr | 8.23 | 8.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| CP20 | 5,750 gpm | 8,760 hours/yr | 1.48 | 1.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| CP21 | 5,750 gpm | 8,760 hours/yr | 1.48 | 1.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| CP22 | 5,750 gpm | 8,760 hours/yr | 1.48 | 1.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| CP24 | 1.50 MMBtu/hr | 8,760 hours/yr | 0.05 | 0.05 | 0.08 | 0.24 | 0.01 | 0.04 | 0.01 |
| CP25 | 1.50 MMBtu/hr | 8,760 hours/yr | 0.05 | 0.05 | 0.08 | 0.24 | 0.01 | 0.04 | 0.01 |
| CP26 | 24.00 MMBtu/hr | 8,760 hours/yr | 0.79 | 0.79 | 1.15 | 3.89 | 0.06 | 0.57 | 0.20 |
| CP27 | 24.00 MMBtu/hr | 8,760 hours/yr | 0.79 | 0.79 | 1.15 | 3.89 | 0.06 | 0.57 | 0.20 |
| CP28 | 2,937 hp | 500 hours/yr | 0.06 | 0.06 | 10.62 | 0.87 | 0.01 | 0.23 | 0.01 |
| CP29 | 2,937 hp | 500 hours/yr | 0.06 | 0.06 | 10.62 | 0.87 | 0.01 | 0.23 | 0.01 |
| CP30 | 11,200 gpm | 8,760 hours/yr | 0.58 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| CP32 | 1,000 gallon | 18,000 gal/yr | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.15 | 0.01 |
| CP34 | 525 hp | 500 hours/yr | 0.02 | 0.02 | 1.35 | 0.08 | 0.01 | 0.04 | 0.01 |
| CP35 | 525 hp | 500 hours/yr | 0.02 | 0.02 | 1.35 | 0.08 | 0.01 | 0.04 | 0.01 |
| CP37 | 1.50 MMBtu/hr | 8,760 hours/yr | 0.05 | 0.05 | 0.08 | 0.24 | 0.01 | 0.04 | 0.01 |
| **Totals (tons/yr)** | | | **23.02** | **23.02** | **131.26** | **33.76** | **0.69** | **8.29** | **1.95** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$.

**Allowable Emissions**

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| CP01 | 35.40 MMBtu/hr | 8,760 hours/yr | 1.16 | 1.16 | 5.46 | 1.15 | 0.09 | 0.84 | 0.29 |
| CP02 | 35.40 MMBtu/hr | 8,760 hours/yr | 1.16 | 1.16 | 5.46 | 1.15 | 0.09 | 0.84 | 0.29 |
| CP03 | 33.475 MMBtu/hr | 8,760 hours/yr | 1.10 | 1.10 | 5.35 | 1.08 | 0.09 | 0.79 | 0.28 |
| CP04 | 33.475 MMBtu/hr | 8,760 hours/yr | 1.10 | 1.10 | 5.35 | 1.08 | 0.09 | 0.79 | 0.28 |
| CP05 | 33.475 MMBtu/hr | 8,760 hours/yr | 1.10 | 1.10 | 5.35 | 1.08 | 0.09 | 0.79 | 0.28 |
| CP13 | 2,876 hp | 125 hours/yr | 0.13 | 0.13 | 4.31 | 0.99 | 0.01 | 0.13 | 0.01 |
| CP14 | 2,876 hp | 125 hours/yr | 0.13 | 0.13 | 4.31 | 0.99 | 0.01 | 0.13 | 0.01 |
| CP15 | 2,520 hp | 145 hours/yr | 0.13 | 0.13 | 4.38 | 1.00 | 0.01 | 0.13 | 0.01 |
| CP16 | 1,818 hp | 200 hours/yr | 0.13 | 0.13 | 4.36 | 1.00 | 0.01 | 0.13 | 0.01 |
| CP17 | 2,876 hp | 125 hours/yr | 0.13 | 0.13 | 4.31 | 0.99 | 0.01 | 0.13 | 0.01 |
| CP19 | 31,950 gpm | 8,760 hours/yr | 8.23 | 8.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| CP20 | 5,750 gpm | 8,760 hours/yr | 1.48 | 1.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| CP21 | 5,750 gpm | 8,760 hours/yr | 1.48 | 1.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| CP22 | 5,750 gpm | 8,760 hours/yr | 1.48 | 1.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| CP24 | 1.50 MMBtu/hr | 8,760 hours/yr | 0.05 | 0.05 | 0.08 | 0.24 | 0.01 | 0.04 | 0.01 |
| CP25 | 1.50 MMBtu/hr | 8,760 hours/yr | 0.05 | 0.05 | 0.08 | 0.24 | 0.01 | 0.04 | 0.01 |
| CP26 | 24.00 MMBtu/hr | 8,760 hours/yr | 0.79 | 0.79 | 1.15 | 3.89 | 0.06 | 0.57 | 0.20 |
| CP27 | 24.00 MMBtu/hr | 8,760 hours/yr | 0.79 | 0.79 | 1.15 | 3.89 | 0.06 | 0.57 | 0.20 |
| CP28 | 2,937 hp | 200 hours/yr | 0.03 | 0.03 | 4.25 | 0.35 | 0.01 | 0.09 | 0.01 |
| CP29 | 2,937 hp | 200 hours/yr | 0.03 | 0.03 | 4.25 | 0.35 | 0.01 | 0.09 | 0.01 |
| CP30 | 11,200 gpm | 8,760 hours/yr | 0.58 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| CP32 | 1,000 gallon | 18,000 gal/yr | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.15 | 0.01 |
| CP34 | 525 hp | 500 hours/yr | 0.02 | 0.02 | 1.35 | 0.08 | 0.01 | 0.04 | 0.01 |
| CP35 | 525 hp | 500 hours/yr | 0.02 | 0.02 | 1.35 | 0.08 | 0.01 | 0.04 | 0.01 |
| CP37 | 1.50 MMBtu/hr | 8,760 hours/yr | 0.05 | 0.05 | 0.08 | 0.24 | 0.01 | 0.04 | 0.01 |
| **Totals (tons/yr)** | | | **21.35** | **21.35** | **62.38** | **19.87** | **0.69** | **6.37** | **1.95** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$.

| | | | |
|---|---|---|---|
| **EU#** | CP13 - CP14, CP17 | **Horsepower:** | 2,876 |
| **Make:** | Caterpillar | **Hours/Day:** | 24.0 |
| **Model:** | | **Hours/Year** | 500 |
| **S/N:** | | | |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 2.01 | 48.32 | 0.50 |
| **NOx** | 2.40E-02 | 69.02 | 1656.58 | 17.26 |
| **CO** | 5.50E-03 | 15.82 | 379.63 | 3.95 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.84 | 0.01 |
| **VOC** | 7.05E-04 | 2.03 | 48.66 | 0.51 |
| **HAP** | 1.10E-05 | 0.03 | 0.76 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | | | |
|---|---|---|---|
| **EU#** | CP13 - CP14, CP17 | **Horsepower:** | 2,876 |
| **Make:** | Caterpillar | **Hours/Day:** | 24.0 |
| **Model:** | | **Hours/Year** | 125 |
| **S/N:** | | | |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 2.01 | 48.32 | 0.13 |
| **NOx** | 2.40E-02 | 69.02 | 1656.58 | 4.31 |
| **CO** | 5.50E-03 | 15.82 | 379.63 | 0.99 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.84 | 0.01 |
| **VOC** | 7.05E-04 | 2.03 | 48.66 | 0.13 |
| **HAP** | 1.10E-05 | 0.03 | 0.76 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | CP15 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,520 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 1.76 | 42.34 | 0.44 |
| **NOx** | 2.40E-02 | 60.48 | 1451.52 | 15.12 |
| **CO** | 5.50E-03 | 13.86 | 332.64 | 3.47 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.73 | 0.01 |
| **VOC** | 7.05E-04 | 1.78 | 42.64 | 0.44 |
| **HAP** | 1.10E-05 | 0.03 | 0.67 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | CP15 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,520 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 145 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 1.76 | 42.34 | 0.13 |
| **NOx** | 2.40E-02 | 60.48 | 1451.52 | 4.38 |
| **CO** | 5.50E-03 | 13.86 | 332.64 | 1.00 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.73 | 0.01 |
| **VOC** | 7.05E-04 | 1.78 | 42.64 | 0.13 |
| **HAP** | 1.10E-05 | 0.03 | 0.67 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

**Emergency Generators Calculations**

| | | | |
|---|---|---|---|
| **EU#** | CP16 | **Horsepower:** | 1,818 |
| **Make:** | Caterpillar | **Hours/Day:** | 24.0 |
| **Model:** | | **Hours/Year** | 500 |
| **S/N:** | | | |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor | Potential Emissions | | |
|---|---|---|---|---|
| | (lb/hp-hr) | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 1.27 | 30.54 | 0.32 |
| **NOx** | 2.40E-02 | 43.63 | 1047.17 | 10.91 |
| **CO** | 5.50E-03 | 10.00 | 239.98 | 2.50 |
| **$SO_2$** | 1.21E-05 | 0.02 | 0.53 | 0.01 |
| **VOC** | 7.05E-04 | 1.28 | 30.76 | 0.32 |
| **HAP** | 1.10E-05 | 0.02 | 0.48 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | | | |
|---|---|---|---|
| **EU#** | CP16 | **Horsepower:** | 1,818 |
| **Make:** | Caterpillar | **Hours/Day:** | 24.0 |
| **Model:** | | **Hours/Year** | 200 |
| **S/N:** | | | |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor | Potential Emissions | | |
|---|---|---|---|---|
| | (lb/hp-hr) | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 1.27 | 30.54 | 0.13 |
| **NOx** | 2.40E-02 | 43.63 | 1047.17 | 4.36 |
| **CO** | 5.50E-03 | 10.00 | 239.98 | 1.00 |
| **$SO_2$** | 1.21E-05 | 0.02 | 0.53 | 0.01 |
| **VOC** | 7.05E-04 | 1.28 | 30.76 | 0.13 |
| **HAP** | 1.10E-05 | 0.02 | 0.48 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

Source ID: 257

**Caesars Palace**
**Emergency Generators Calculations**

Caesars Entertainment Inc.

| | |
|---|---|
| **EU#** | CP28 - CP29 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,937 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | 0.04 | g/hp-hr |
| **NOx** | 6.56 | g/hp-hr |
| **CO** | 0.54 | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | 0.14 | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions lb/hr | Potential Emissions lb/day | Potential Emissions ton/yr |
|---|---|---|---|---|
| **PM10** | 8.82E-05 | 0.26 | 6.22 | 0.06 |
| **NOx** | 1.45E-02 | 42.48 | 1019.43 | 10.62 |
| **CO** | 1.19E-03 | 3.50 | 83.92 | 0.87 |
| **$SO_2$** | 1.21E-05 | 0.04 | 0.86 | 0.01 |
| **VOC** | 3.09E-04 | 0.91 | 21.76 | 0.23 |
| **HAP** | 1.10E-05 | 0.03 | 0.78 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | CP28 - CP29 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,937 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 200 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | 0.04 | g/hp-hr |
| **NOx** | 6.56 | g/hp-hr |
| **CO** | 0.54 | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | 0.14 | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions lb/hr | Potential Emissions lb/day | Potential Emissions ton/yr |
|---|---|---|---|---|
| **PM10** | 8.82E-05 | 0.26 | 6.22 | 0.03 |
| **NOx** | 1.45E-02 | 42.48 | 1019.43 | 4.25 |
| **CO** | 1.19E-03 | 3.50 | 83.92 | 0.35 |
| **$SO_2$** | 1.21E-05 | 0.04 | 0.86 | 0.01 |
| **VOC** | 3.09E-04 | 0.91 | 21.76 | 0.09 |
| **HAP** | 1.10E-05 | 0.03 | 0.78 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| PA12 | 3.50 MMBtu/hr | 8,760 hours/yr | 0.11 | 0.11 | 0.48 | 1.26 | 0.01 | 0.08 | 0.03 |
| PA13 | 3.50 MMBtu/hr | 8,760 hours/yr | 0.11 | 0.11 | 0.48 | 1.26 | 0.01 | 0.08 | 0.03 |
| PA14 | 17.00 MMBtu/hr | 8,760 hours/yr | 0.56 | 0.56 | 2.72 | 6.28 | 0.04 | 0.40 | 0.14 |
| PA15 | 21.00 MMBtu/hr | 8,760 hours/yr | 0.69 | 0.69 | 3.36 | 7.75 | 0.06 | 0.50 | 0.17 |
| PA16 | 21.00 MMBtu/hr | 8,760 hours/yr | 0.69 | 0.69 | 3.36 | 7.75 | 0.06 | 0.50 | 0.17 |
| PA17 | 2,816 hp | 500 hours/yr | 0.49 | 0.49 | 16.90 | 3.87 | 0.01 | 0.50 | 0.01 |
| PA18 | 2,816 hp | 500 hours/yr | 0.49 | 0.49 | 16.90 | 3.87 | 0.01 | 0.50 | 0.01 |
| PA19 | 4,725 gpm | 8,760 hours/yr | 1.22 | 1.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PA20 | 4,725 gpm | 8,760 hours/yr | 1.22 | 1.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PA21 | 4,725 gpm | 8,760 hours/yr | 1.22 | 1.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PA22 | 4,725 gpm | 8,760 hours/yr | 1.22 | 1.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PA23 | 4,725 gpm | 8,760 hours/yr | 1.22 | 1.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PA28 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA29 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA30 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA31 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA32 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA33 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA34 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA35 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.70 | 0.01 | 0.05 | 0.02 |
| PA36 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.84 | 0.70 | 0.01 | 0.05 | 0.02 |
| **Totals (tons/yr)** | | | **9.78** | **9.78** | **45.84** | **35.68** | **0.29** | **3.01** | **0.74** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4 and 3.4) and 100% of cooling tower $PM_{10}$.

**Allowable Emissions**

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| PA12 | 3.50 MMBtu/hr | 8,760 hours/yr | 0.11 | 0.11 | 0.48 | 1.26 | 0.01 | 0.08 | 0.03 |
| PA13 | 3.50 MMBtu/hr | 8,760 hours/yr | 0.11 | 0.11 | 0.48 | 1.26 | 0.01 | 0.08 | 0.03 |
| PA14 | 17.00 MMBtu/hr | 8,760 hours/yr | 0.56 | 0.56 | 2.72 | 6.28 | 0.04 | 0.40 | 0.14 |
| PA15 | 21.00 MMBtu/hr | 8,760 hours/yr | 0.69 | 0.69 | 3.36 | 7.75 | 0.06 | 0.50 | 0.17 |
| PA16 | 21.00 MMBtu/hr | 8,760 hours/yr | 0.69 | 0.69 | 3.36 | 7.75 | 0.06 | 0.50 | 0.17 |
| PA17 | 2,816 hp | 130 hours/yr | 0.13 | 0.13 | 4.39 | 1.01 | 0.01 | 0.13 | 0.01 |
| PA18 | 2,816 hp | 130 hours/yr | 0.13 | 0.13 | 4.39 | 1.01 | 0.01 | 0.13 | 0.01 |
| PA19 | 4,725 gpm | 8,760 hours/yr | 1.22 | 1.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PA20 | 4,725 gpm | 8,760 hours/yr | 1.22 | 1.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PA21 | 4,725 gpm | 8,760 hours/yr | 1.22 | 1.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PA22 | 4,725 gpm | 8,760 hours/yr | 1.22 | 1.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PA23 | 4,725 gpm | 8,760 hours/yr | 1.22 | 1.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PA28 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA29 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA30 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA31 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA32 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA33 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA34 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.32 | 0.01 | 0.05 | 0.02 |
| PA35 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.10 | 0.70 | 0.01 | 0.05 | 0.02 |
| PA36 | 1.95 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.84 | 0.70 | 0.01 | 0.05 | 0.02 |
| **Totals (tons/yr)** | | | **9.06** | **9.06** | **20.82** | **29.96** | **0.29** | **2.27** | **0.74** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4 and 3.4) and 100% of cooling tower $PM_{10}$.

**Emergency Generators Calculations**

| | | | |
|---|---|---|---|
| **EU#** | PA17 - PA18 | **Horsepower:** | 2,816 |
| **Make:** | Cummins | **Hours/Day:** | 24.0 |
| **Model:** | | **Hours/Year** | 500 |
| **S/N:** | | | |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 1.97 | 47.31 | 0.49 |
| **NOx** | 2.40E-02 | 67.58 | 1622.02 | 16.90 |
| **CO** | 5.50E-03 | 15.49 | 371.71 | 3.87 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.82 | 0.01 |
| **VOC** | 7.05E-04 | 1.99 | 47.65 | 0.50 |
| **HAP** | 1.10E-05 | 0.03 | 0.74 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | | | |
|---|---|---|---|
| **EU#** | PA17 - PA18 | **Horsepower:** | 2,816 |
| **Make:** | Cummins | **Hours/Day:** | 24.0 |
| **Model:** | | **Hours/Year** | 130 |
| **S/N:** | | | |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 1.97 | 47.31 | 0.13 |
| **NOx** | 2.40E-02 | 67.58 | 1622.02 | 4.39 |
| **CO** | 5.50E-03 | 15.49 | 371.71 | 1.01 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.82 | 0.01 |
| **VOC** | 7.05E-04 | 1.99 | 47.65 | 0.13 |
| **HAP** | 1.10E-05 | 0.03 | 0.74 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| IP01 | 1.25 MMBtu/hr | 8,760 hours/yr | 0.04 | 0.04 | 0.80 | 0.45 | 0.01 | 0.03 | 0.01 |
| IP02 | 1.25 MMBtu/hr | 8,760 hours/yr | 0.04 | 0.04 | 0.80 | 0.45 | 0.01 | 0.03 | 0.01 |
| IP03 | 1.25 MMBtu/hr | 8,760 hours/yr | 0.04 | 0.04 | 0.80 | 0.45 | 0.01 | 0.03 | 0.01 |
| IP04 | 16.738 MMBtu/hr | 8,760 hours/yr | 0.55 | 0.55 | 3.58 | 5.43 | 0.04 | 0.40 | 0.14 |
| IP05 | 16.738 MMBtu/hr | 8,760 hours/yr | 0.55 | 0.55 | 3.58 | 5.43 | 0.04 | 0.40 | 0.14 |
| IP06 | 680 hp | 500 hours/yr | 0.12 | 0.12 | 4.08 | 0.94 | 0.01 | 0.12 | 0.01 |
| IP07 | 755 hp | 500 hours/yr | 0.13 | 0.13 | 4.53 | 1.04 | 0.01 | 0.13 | 0.01 |
| IP08 | 890 hp | 500 hours/yr | 0.16 | 0.16 | 5.34 | 1.22 | 0.01 | 0.16 | 0.01 |
| IP09 | 890 hp | 500 hours/yr | 0.16 | 0.16 | 5.34 | 1.22 | 0.01 | 0.16 | 0.01 |
| IP10 | 375 hp | 500 hours/yr | 0.21 | 0.21 | 2.91 | 0.63 | 0.01 | 0.24 | 0.01 |
| IP11 | 670 hp | 500 hours/yr | 0.12 | 0.12 | 4.02 | 0.92 | 0.01 | 0.12 | 0.01 |
| IP38 | 762 hp | 500 hours/yr | 0.02 | 0.02 | 2.07 | 0.49 | 0.01 | 0.02 | 0.01 |
| **Totals (tons/yr)** | | | **2.14** | **2.14** | **37.85** | **18.67** | **0.18** | **1.84** | **0.38** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4).

**Allowable Emissions**

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| IP01 | 1.25 MMBtu/hr | 8,760 hours/yr | 0.04 | 0.04 | 0.80 | 0.45 | 0.01 | 0.03 | 0.01 |
| IP02 | 1.25 MMBtu/hr | 8,760 hours/yr | 0.04 | 0.04 | 0.80 | 0.45 | 0.01 | 0.03 | 0.01 |
| IP03 | 1.25 MMBtu/hr | 8,760 hours/yr | 0.04 | 0.04 | 0.80 | 0.45 | 0.01 | 0.03 | 0.01 |
| IP04 | 16.738 MMBtu/hr | 8,760 hours/yr | 0.55 | 0.55 | 3.58 | 5.43 | 0.04 | 0.40 | 0.14 |
| IP05 | 16.738 MMBtu/hr | 8,760 hours/yr | 0.55 | 0.55 | 3.58 | 5.43 | 0.04 | 0.40 | 0.14 |
| IP06 | 680 hp | 500 hours/yr | 0.12 | 0.12 | 4.08 | 0.94 | 0.01 | 0.12 | 0.01 |
| IP07 | 755 hp | 475 hours/yr | 0.13 | 0.13 | 4.30 | 0.99 | 0.01 | 0.13 | 0.01 |
| IP08 | 890 hp | 400 hours/yr | 0.12 | 0.12 | 4.27 | 0.98 | 0.01 | 0.13 | 0.01 |
| IP09 | 890 hp | 400 hours/yr | 0.12 | 0.12 | 4.27 | 0.98 | 0.01 | 0.13 | 0.01 |
| IP10 | 375 hp | 500 hours/yr | 0.21 | 0.21 | 2.91 | 0.63 | 0.01 | 0.24 | 0.01 |
| IP11 | 670 hp | 500 hours/yr | 0.12 | 0.12 | 4.02 | 0.92 | 0.01 | 0.12 | 0.01 |
| IP38 | 762 hp | 500 hours/yr | 0.02 | 0.02 | 2.07 | 0.49 | 0.01 | 0.02 | 0.01 |
| **Totals (tons/yr)** | | | **2.06** | **2.06** | **35.48** | **18.14** | **0.18** | **1.78** | **0.38** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4).

Source ID: 257

**The LINQ Hotel Casino**
**Emergency Generator Calculations**

Caesars Entertainment Inc.

| | |
|---|---|
| **EU#** | IP07 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 755 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.53 | 12.68 | 0.13 |
| **NOx** | 2.40E-02 | 18.12 | 434.88 | 4.53 |
| **CO** | 5.50E-03 | 4.15 | 99.66 | 1.04 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.22 | 0.01 |
| **VOC** | 7.05E-04 | 0.53 | 12.77 | 0.13 |
| **HAP** | 1.10E-05 | 0.01 | 0.20 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | IP07 |
| **Make:** | Detroit |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 755 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 475 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.53 | 12.68 | 0.13 |
| **NOx** | 2.40E-02 | 18.12 | 434.88 | 4.30 |
| **CO** | 5.50E-03 | 4.15 | 99.66 | 0.99 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.22 | 0.01 |
| **VOC** | 7.05E-04 | 0.53 | 12.77 | 0.13 |
| **HAP** | 1.10E-05 | 0.01 | 0.20 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | IP08 - IP09 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 890 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.62 | 14.95 | 0.16 |
| **NOx** | 2.40E-02 | 21.36 | 512.64 | 5.34 |
| **CO** | 5.50E-03 | 4.90 | 117.48 | 1.22 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.26 | 0.01 |
| **VOC** | 7.05E-04 | 0.63 | 15.06 | 0.16 |
| **HAP** | 1.10E-05 | 0.01 | 0.24 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | IP08 - IP09 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 890 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 400 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 0.62 | 14.95 | 0.12 |
| **NOx** | 2.40E-02 | 21.36 | 512.64 | 4.27 |
| **CO** | 5.50E-03 | 4.90 | 117.48 | 0.98 |
| **$SO_2$** | 1.21E-05 | 0.01 | 0.26 | 0.01 |
| **VOC** | 7.05E-04 | 0.63 | 15.06 | 0.13 |
| **HAP** | 1.10E-05 | 0.01 | 0.24 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| PH03 | 1.75 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.08 | 0.28 | 0.01 | 0.04 | 0.01 |
| PH04 | 1.75 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.08 | 0.28 | 0.01 | 0.04 | 0.01 |
| PH07 | 23.60 MMBtu/hr | 8,760 hours/yr | 0.78 | 0.78 | 3.77 | 7.65 | 0.06 | 0.56 | 0.20 |
| PH08 | 23.60 MMBtu/hr | 8,760 hours/yr | 0.78 | 0.78 | 3.77 | 7.65 | 0.06 | 0.56 | 0.20 |
| PH09 | 23.60 MMBtu/hr | 8,760 hours/yr | 0.78 | 0.78 | 3.77 | 7.65 | 0.06 | 0.56 | 0.20 |
| PH10 | 2,550 hp | 500 hours/yr | 0.45 | 0.45 | 15.30 | 3.51 | 0.01 | 0.45 | 0.01 |
| PH11 | 2,550 hp | 500 hours/yr | 0.45 | 0.45 | 15.30 | 3.51 | 0.01 | 0.45 | 0.01 |
| PH12 | 2,550 hp | 500 hours/yr | 0.45 | 0.45 | 15.30 | 3.51 | 0.01 | 0.45 | 0.01 |
| PH13 | 2,560 hp | 500 hours/yr | 0.21 | 0.21 | 6.40 | 3.68 | 0.01 | 0.34 | 0.01 |
| PH14 | 33,360 gpm | 8,760 hours/yr | 8.60 | 8.60 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Totals (tons/yr)** | | | **12.62** | **12.62** | **63.77** | **37.72** | **0.24** | **3.45** | **0.66** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4 and 3.4) and 100% of cooling tower $PM_{10}$.

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| PH03 | 1.75 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.08 | 0.28 | 0.01 | 0.04 | 0.01 |
| PH04 | 1.75 MMBtu/hr | 8,760 hours/yr | 0.06 | 0.06 | 0.08 | 0.28 | 0.01 | 0.04 | 0.01 |
| PH07 | 23.60 MMBtu/hr | 8,760 hours/yr | 0.78 | 0.78 | 3.77 | 7.65 | 0.06 | 0.56 | 0.20 |
| PH08 | 23.60 MMBtu/hr | 8,760 hours/yr | 0.78 | 0.78 | 3.77 | 7.65 | 0.06 | 0.56 | 0.20 |
| PH09 | 23.60 MMBtu/hr | 8,760 hours/yr | 0.78 | 0.78 | 3.77 | 7.65 | 0.06 | 0.56 | 0.20 |
| PH10 | 2,550 hp | 145 hours/yr | 0.13 | 0.13 | 4.44 | 1.02 | 0.01 | 0.13 | 0.01 |
| PH11 | 2,550 hp | 145 hours/yr | 0.13 | 0.13 | 4.44 | 1.02 | 0.01 | 0.13 | 0.01 |
| PH12 | 2,550 hp | 145 hours/yr | 0.13 | 0.13 | 4.44 | 1.02 | 0.01 | 0.13 | 0.01 |
| PH13 | 2,560 hp | 350 hours/yr | 0.15 | 0.15 | 4.48 | 2.58 | 0.01 | 0.24 | 0.01 |
| PH14 | 33,360 gpm | 8,760 hours/yr | 8.60 | 8.60 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Totals (tons/yr)** | | | **11.60** | **11.60** | **29.27** | **29.15** | **0.24** | **2.39** | **0.66** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4 and 3.4) and 100% of cooling tower $PM_{10}$.

Source ID: 257

**Planet Hollywood**
**Emergency Generators Calculations**

Caesars Entertainment Inc.

| | |
|---|---|
| **EU#** | PH10 - PH12 |
| **Make:** | MTU/Detroit Diesel |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,550 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 1.79 | 42.84 | 0.45 |
| **NOx** | 2.40E-02 | 61.20 | 1468.80 | 15.30 |
| **CO** | 5.50E-03 | 14.03 | 336.60 | 3.51 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.74 | 0.01 |
| **VOC** | 7.05E-04 | 1.80 | 43.15 | 0.45 |
| **HAP** | 1.10E-05 | 0.03 | 0.67 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | PH10 - PH12 |
| **Make:** | MTU/Detroit Diesel |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,550 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 145 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | | g/hp-hr |
| **NOx** | | g/hp-hr |
| **CO** | | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 7.00E-04 | 1.79 | 42.84 | 0.13 |
| **NOx** | 2.40E-02 | 61.20 | 1468.80 | 4.44 |
| **CO** | 5.50E-03 | 14.03 | 336.60 | 1.02 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.74 | 0.01 |
| **VOC** | 7.05E-04 | 1.80 | 43.15 | 0.13 |
| **HAP** | 1.10E-05 | 0.03 | 0.67 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

Source ID: 257

**Planet Hollywood**
**Emergency Generator Calculations**

Caesars Entertainment Inc.

| | |
|---|---|
| **EU#** | PH13 |
| **Make:** | MTU/Detroit Diesel |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,560 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | 0.2 | g/kW-hr |
| **NOx** | 6.08 | g/kW-hr |
| **CO** | 3.5 | g/kW-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | 0.32 | g/kW-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 3.29E-04 | 0.84 | 20.20 | 0.21 |
| **NOx** | 1.00E-02 | 25.59 | 614.12 | 6.40 |
| **CO** | 5.75E-03 | 14.73 | 353.52 | 3.68 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.75 | 0.01 |
| **VOC** | 5.26E-04 | 1.35 | 32.32 | 0.34 |
| **HAP** | 1.10E-05 | 0.03 | 0.68 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | PH13 |
| **Make:** | MTU/Detroit Diesel |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,560 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 350 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | 0.2 | g/kW-hr |
| **NOx** | 6.08 | g/kW-hr |
| **CO** | 3.5 | g/kW-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | 0.32 | g/kW-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 3.29E-04 | 0.84 | 20.20 | 0.15 |
| **NOx** | 1.00E-02 | 25.59 | 614.12 | 4.48 |
| **CO** | 5.75E-03 | 14.73 | 353.52 | 2.58 |
| **$SO_2$** | 1.21E-05 | 0.03 | 0.75 | 0.01 |
| **VOC** | 5.26E-04 | 1.35 | 32.32 | 0.24 |
| **HAP** | 1.10E-05 | 0.03 | 0.68 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| LI01 | 5.00 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.24 | 0.81 | 0.01 | 0.12 | 0.04 |
| LI02 | 5.00 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.24 | 0.81 | 0.01 | 0.12 | 0.04 |
| LI03 | 5.00 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.24 | 0.81 | 0.01 | 0.12 | 0.04 |
| LI04 | 5.00 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.24 | 0.81 | 0.01 | 0.12 | 0.04 |
| LI05 | 5.00 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.24 | 0.81 | 0.01 | 0.12 | 0.04 |
| LI06 | 2,937 hp | 500 hours/yr | 0.06 | 0.06 | 10.62 | 0.87 | 0.01 | 0.23 | 0.01 |
| LI07 | 2,937 hp | 500 hours/yr | 0.06 | 0.06 | 10.62 | 0.87 | 0.01 | 0.23 | 0.01 |
| LI08 | 6,000 gpm | 8,760 hours/yr | 1.55 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| LI09 | 6,000 gpm | 8,760 hours/yr | 1.55 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| LI10 | 6,000 gpm | 8,760 hours/yr | 1.55 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| LI12 | 241 hp | 500 hours/yr | 0.01 | 0.01 | 0.20 | 0.35 | 0.01 | 0.02 | 0.01 |
| LI13 | 241 hp | 500 hours/yr | 0.01 | 0.01 | 0.20 | 0.35 | 0.01 | 0.02 | 0.01 |
| **Totals (tons/yr)** | | | **5.59** | **5.59** | **22.84** | **6.49** | **0.09** | **1.10** | **0.24** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$.

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| LI01 | 5.00 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.24 | 0.81 | 0.01 | 0.12 | 0.04 |
| LI02 | 5.00 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.24 | 0.81 | 0.01 | 0.12 | 0.04 |
| LI03 | 5.00 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.24 | 0.81 | 0.01 | 0.12 | 0.04 |
| LI04 | 5.00 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.24 | 0.81 | 0.01 | 0.12 | 0.04 |
| LI05 | 5.00 MMBtu/hr | 8,760 hours/yr | 0.16 | 0.16 | 0.24 | 0.81 | 0.01 | 0.12 | 0.04 |
| LI06 | 2,937 hp | 200 hours/yr | 0.03 | 0.03 | 4.25 | 0.35 | 0.01 | 0.09 | 0.01 |
| LI07 | 2,937 hp | 200 hours/yr | 0.03 | 0.03 | 4.25 | 0.35 | 0.01 | 0.09 | 0.01 |
| LI08 | 6,000 gpm | 8,760 hours/yr | 1.55 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| LI09 | 6,000 gpm | 8,760 hours/yr | 1.55 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| LI10 | 6,000 gpm | 8,760 hours/yr | 1.55 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| LI12 | 241 hp | 500 hours/yr | 0.01 | 0.01 | 0.20 | 0.35 | 0.01 | 0.02 | 0.01 |
| LI13 | 241 hp | 500 hours/yr | 0.01 | 0.01 | 0.20 | 0.35 | 0.01 | 0.02 | 0.01 |
| **Totals (tons/yr)** | | | **5.53** | **5.53** | **10.10** | **5.45** | **0.09** | **0.82** | **0.24** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4, 3.3, and 3.4) and 100% of cooling tower $PM_{10}$.

| | |
|---|---|
| **EU#** | LI06 - LI07 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,937 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 500 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | 0.04 | g/hp-hr |
| **NOx** | 6.56 | g/hp-hr |
| **CO** | 0.54 | g/hp-hr |
| **$SO_2$** | | lb/hp-hr |
| **VOC** | 0.14 | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 8.82E-05 | 0.26 | 6.22 | 0.06 |
| **NOx** | 1.45E-02 | 42.48 | 1019.43 | 10.62 |
| **CO** | 1.19E-03 | 3.50 | 83.92 | 0.87 |
| **$SO_2$** | 1.21E-05 | 0.04 | 0.86 | 0.01 |
| **VOC** | 3.09E-04 | 0.91 | 21.76 | 0.23 |
| **HAP** | 1.10E-05 | 0.03 | 0.78 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| | |
|---|---|
| **EU#** | LI06 - LI07 |
| **Make:** | Caterpillar |
| **Model:** | |
| **S/N:** | |
| **Horsepower:** | 2,937 |
| **Hours/Day:** | 24.0 |
| **Hours/Year** | 200 |

**Manufacturer Guarantees**

| | | |
|---|---|---|
| **PM10** | 0.04 | g/hp-hr |
| **NOx** | 6.56 | g/hp-hr |
| **CO** | 0.54 | g/hp-hr |
| **$SO_2$** | | g/hp-hr |
| **VOC** | 0.14 | g/hp-hr |

**Engine Type:** Diesel

| | Emission Factor (lb/hp-hr) | Potential Emissions | | |
|---|---|---|---|---|
| | | lb/hr | lb/day | ton/yr |
| **PM10** | 8.82E-05 | 0.26 | 6.22 | 0.03 |
| **NOx** | 1.45E-02 | 42.48 | 1019.43 | 4.25 |
| **CO** | 1.19E-03 | 3.50 | 83.92 | 0.35 |
| **$SO_2$** | 1.21E-05 | 0.04 | 0.86 | 0.01 |
| **VOC** | 3.09E-04 | 0.91 | 21.76 | 0.09 |
| **HAP** | 1.10E-05 | 0.03 | 0.78 | 0.01 |

Diesel Fuel Sulfur Content is 15 ppm (0.0015%)

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| FMC01 | 6.00 MMBtu/hr | 8,760 hours/yr | 0.20 | 0.20 | 0.64 | 0.97 | 0.02 | 0.14 | 0.05 |
| FMC02 | 6.00 MMBtu/hr | 8,760 hours/yr | 0.20 | 0.20 | 0.64 | 0.97 | 0.02 | 0.14 | 0.05 |
| FMC03 | 6.00 MMBtu/hr | 8,760 hours/yr | 0.20 | 0.20 | 0.64 | 0.97 | 0.02 | 0.14 | 0.05 |
| FMC04 | 6.00 MMBtu/hr | 8,760 hours/yr | 0.20 | 0.20 | 0.64 | 0.97 | 0.02 | 0.14 | 0.05 |
| FMC05 | 1,490 hp | 500 hours/yr | 0.08 | 0.08 | 3.61 | 0.41 | 0.01 | 0.26 | 0.01 |
| FMC06 | 4,800 gpm | 8,760 hours/yr | 0.25 | 0.25 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| FMC07 | 4,800 gpm | 8,760 hours/yr | 0.25 | 0.25 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Totals (tons/yr)** | | | **1.38** | **1.38** | **6.17** | **4.29** | **0.09** | **0.82** | **0.21** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4 and 3.4) and 100% of cooling tower $PM_{10}$.

| EU | Rating | Conditions | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
|---|---|---|---|---|---|---|---|---|---|
| FMC01 | 6.00 MMBtu/hr | 8,760 hours/yr | 0.20 | 0.20 | 0.64 | 0.97 | 0.02 | 0.14 | 0.05 |
| FMC02 | 6.00 MMBtu/hr | 8,760 hours/yr | 0.20 | 0.20 | 0.64 | 0.97 | 0.02 | 0.14 | 0.05 |
| FMC03 | 6.00 MMBtu/hr | 8,760 hours/yr | 0.20 | 0.20 | 0.64 | 0.97 | 0.02 | 0.14 | 0.05 |
| FMC04 | 6.00 MMBtu/hr | 8,760 hours/yr | 0.20 | 0.20 | 0.64 | 0.97 | 0.02 | 0.14 | 0.05 |
| FMC05 | 1,490 hp | 500 hours/yr | 0.08 | 0.08 | 3.61 | 0.41 | 0.01 | 0.26 | 0.01 |
| FMC06 | 4,800 gpm | 8,760 hours/yr | 0.25 | 0.25 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| FMC07 | 4,800 gpm | 8,760 hours/yr | 0.25 | 0.25 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Totals (tons/yr)** | | | **1.38** | **1.38** | **6.17** | **4.29** | **0.09** | **0.82** | **0.21** |

NOTE: $PM_{2.5}$ is assumed to be 100% of $PM_{10}$ for all combustion sources (AP-42 Chapters 1.4 and 3.4) and 100% of cooling tower $PM_{10}$.

Source ID: 257

**Combustion Insignigicant Activities Calculations**

Caesars Entertainment Inc.

| Harrah's Las Vegas | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating (MMBtu/hr) | Operations (hours/year) | $PM_{10}$ PTE, tons/yr | $PM_{2.5}$ PTE, tons/yr | $NO_X$ PTE, tons/yr | CO PTE, tons/yr | $SO_X$ PTE, tons/yr | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | Raypak Natural Gas Pool Heater | 0.726 | 8,760 | 0.02 | 0.02 | 0.31 | 0.26 | 0.01 | 0.02 | 0.01 |
| **Caesars Palace** | | | | | | | | | | |
| EU | Description | Rating (MMBtu/hr) | Operations (hours/year) | $PM_{10}$ PTE, tons/yr | $PM_{2.5}$ PTE, tons/yr | $NO_X$ PTE, tons/yr | CO PTE, tons/yr | $SO_X$ PTE, tons/yr | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | Various Natural Gas Water Heaters (5) | 1.897 | 8,760 | 0.06 | 0.06 | 0.81 | 0.68 | 0.01 | 0.04 | 0.02 |
| **Paris Las Vegas** | | | | | | | | | | |
| EU | Description | Rating (MMBtu/hr) | Operations (hours/year) | $PM_{10}$ PTE, tons/yr | $PM_{2.5}$ PTE, tons/yr | $NO_X$ PTE, tons/yr | CO PTE, tons/yr | $SO_X$ PTE, tons/yr | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | Various Natural Gas Water Heaters (4) | 1.288 | 8,760 | 0.04 | 0.55 | 0.55 | 0.46 | 0.01 | 0.03 | 0.01 |
| **Planet Hollywood** | | | | | | | | | | |
| EU | Description | Rating (MMBtu/hr) | Operations (hours/year) | $PM_{10}$ PTE, tons/yr | $PM_{2.5}$ PTE, tons/yr | $NO_X$ PTE, tons/yr | CO PTE, tons/yr | $SO_X$ PTE, tons/yr | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | Lochinvar Natural Gas Water Heaters (2) | 1.300 | 8,760 | 0.04 | 0.04 | 0.56 | 0.47 | 0.01 | 0.03 | 0.01 |
| **LINQ Complex - High Roller** | | | | | | | | | | |
| EU | Description | Rating (MMBtu/hr) | Operations (hours/year) | $PM_{10}$ PTE, tons/yr | $PM_{2.5}$ PTE, tons/yr | $NO_X$ PTE, tons/yr | CO PTE, tons/yr | $SO_X$ PTE, tons/yr | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | A.O. Smith Natural Gas Water Heater | 0.150 | 8,760 | 0.01 | 0.01 | 0.06 | 0.03 | 0.01 | 0.01 | 0.01 |
| **Facility-Wide Totals** | | | | | | | | | | |
| Pollutant | | | | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_X$ | VOC | HAP |
| Tons per year | | | | 0.17 | 0.68 | 2.29 | 1.90 | 0.05 | 0.13 | 0.06 |
| | | | | 4.24 | 2.42 | 0.00 | 0.00 | 0.00 | 3.69 | 0.48 |
| | | | | 4.41 | 3.10 | 2.29 | 1.90 | 0.05 | 3.82 | 0.54 |

| Harrah's Las Vegas | | | | | |
|---|---|---|---|---|---|
| **Spray Paint Booth** | | | | | |
| **EU** | **Description** | **VOC EF (lb/gal)** | **Rate (gal/year)** | **VOC PTE, tons/year** | **HAP PTE, tons/year** |
| IA | Global Finishing Solutions Spray Paint Booth | 7.25 | 200 | 0.73 | 0.01 |
| **Woodworking Operations Dust Collector** | | | | | |
| **EU** | **Description** | **Flow Rate (cfm)** | **Loading Rate ($gr/ft^3$)** | **$PM_{10}$ PTE, tons/yr** | **$PM_{2.5}$ PTE, tons/yr** |
| IA | Murphy-Rogers Dust Collector | 4,550 | 0.01 | 0.90 | 0.50 |
| **Diesel Tanks** | | | | | |
| **EU** | **Description** | **VOC EF (lb/gal)** | **Rate (gal/year)** | **VOC PTE, tons/year** | **HAP PTE, tons/year** |
| IA | 3,000 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 1,000 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 550 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 100 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 50 Gal Tank | NA | NA | 0.01 | 0.01 |
| **Flamingo Las Vegas** | | | | | |
| **Woodworking Operations Dust Collector** | | | | | |
| **EU** | **Description** | **Flow Rate (cfm)** | **Loading Rate ($gr/ft^3$)** | **$PM_{10}$ PTE, tons/yr** | **$PM_{2.5}$ PTE, tons/yr** |
| IA | Murphy-Rogers Dust Collector | 2,600 | 0.01 | 0.52 | 0.29 |
| **EU** | **Description** | **Flow Rate (tons/yr)** | **EF (lb/1000 lb abrasive)** | **$PM_{10}$ PTE, tons/yr** | **$PM_{2.5}$ PTE, tons/yr** |
| IA | Abrasive Blast Cabinet | 55.93 | 0.69 | 0.04 | 0.04 |
| **Diesel Tanks** | | | | | |
| **EU** | **Description** | **VOC EF (lb/gal)** | **Rate (gal/year)** | **VOC PTE, tons/year** | **HAP PTE, tons/year** |
| IA | 8,000 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 1,000 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 3 AST Tanks | NA | NA | 0.03 | 0.03 |
| **Horseshoe Las Vegas** | | | | | |
| **Spray Paint Booth** | | | | | |
| **EU** | **Description** | **VOC EF (lb/gal)** | **Rate (gal/year)** | **VOC PTE, tons/year** | **HAP PTE, tons/year** |
| IA | Spray King Paint Booth | 7.25 | 200 | 0.73 | 0.01 |
| **Woodworking Operations Dust Collector** | | | | | |
| **EU** | **Description** | **Flow Rate (tons/yr)** | **EF (lb/1000 lb abrasive)** | **$PM_{10}$ PTE, tons/yr** | **$PM_{2.5}$ PTE, tons/yr** |
| IA | Abrasive Blast Cabinet | 55.93 | 0.69 | 0.04 | 0.04 |

Source ID: 257

**Non-Combustion**
**Insignigicant Activities**
**Calculations**

Caesars Entertainment Inc.

| EU | Description | Flow Rate (cfm) | Loading Rate ($gr/ft^3$) | $PM_{10}$ PTE, tons/yr | $PM_{2.5}$ PTE, tons/yr |
|---|---|---|---|---|---|
| IA | Cincinnati Dust Collector | 700 | 0.01 | 0.14 | 0.08 |
| IA | Cincinnati Dust Collector | 700 | 0.01 | 0.14 | 0.08 |
| IA | Cincinnati Dust Collector | 700 | 0.01 | 0.14 | 0.08 |
| IA | Cincinnati Dust Collector | 700 | 0.01 | 0.14 | 0.08 |
| IA | Cincinnati Dust Collector | 700 | 0.01 | 0.14 | 0.08 |
| **Diesel Tanks** | | | | | |
| EU | Description | VOC EF (lb/gal) | Rate (gal/year) | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | 12,150 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 2,500 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 300 Gal Tanks (3) | NA | NA | 0.03 | 0.03 |
| IA | 480 Gal Tanks (2) | NA | NA | 0.02 | 0.02 |
| IA | 270 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 200 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 150 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 100 Gal Tank | NA | NA | 0.01 | 0.01 |
| **The Cromwell Las Vegas** | | | | | |
| **Woodworking Operations Dust Collector** | | | | | |
| EU | Description | Flow Rate (cfm) | Loading Rate ($gr/ft^3$) | $PM_{10}$ PTE, tons/yr | $PM_{2.5}$ PTE, tons/yr |
| IA | NA | 3,000 | 0.01 | 0.60 | 0.33 |
| **Caesars Palace** | | | | | |
| **Spray Paint Booth** | | | | | |
| EU | Description | VOC EF (lb/gal) | Rate (gal/year) | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | Spray King Paint Booth | 7.25 | 200 | 0.73 | 0.01 |
| **Woodworking Operations Dust Collector** | | | | | |
| EU | Description | Flow Rate (cfm) | Loading Rate ($gr/ft^3$) | $PM_{10}$ PTE, tons/yr | $PM_{2.5}$ PTE, tons/yr |
| IA | Pollution International Dust Collector | 3,000 | 0.01 | 0.60 | 0.33 |
| **Diesel Tanks** | | | | | |
| EU | Description | VOC EF (lb/gal) | Rate (gal/year) | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | 575 Gal Tanks (2) | NA | NA | 0.01 | 0.01 |
| IA | 1,500 Gal Tanks (2) | NA | NA | 0.02 | 0.02 |
| IA | 1,000 Gal Tanks (4) | NA | NA | 0.04 | 0.04 |
| IA | 750 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 650 Gal Tanks (2) | NA | NA | 0.02 | 0.02 |
| **Paris Las Vegas** | | | | | |
| **Spray Paint Booth** | | | | | |
| EU | Description | VOC EF (lb/gal) | Rate (gal/year) | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | Spray Systems Paint Booth | 7.25 | 200 | 0.73 | 0.01 |

| Woodworking Operations Dust Collector | | | | | |
|---|---|---|---|---|---|
| EU | Description | Flow Rate (cfm) | Loading Rate ($gr/ft^3$) | $PM_{10}$ PTE, tons/yr | $PM_{2.5}$ PTE, tons/yr |
| IA | Donaldson Torit Dust Collector | 3,000 | 0.01 | 0.60 | 0.33 |
| IA | Abrasive Blast Cabinet | NA | NA | 0.04 | 0.04 |
| **Diesel Tanks** | | | | | |
| EU | Description | VOC EF (lb/gal) | Rate (gal/year) | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | 8,000 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 100 Gal Tanks (2) | NA | NA | 0.02 | 0.02 |
| **LINQ Hotel** | | | | | |
| **Woodworking Operations Dust Collector** | | | | | |
| EU | Description | Flow Rate (cfm) | Loading Rate ($gr/ft^3$) | $PM_{10}$ PTE, tons/yr | $PM_{2.5}$ PTE, tons/yr |
| IA | Air Sentry Dust Collector | 2,600 | 0.01 | 0.52 | 0.29 |
| **Diesel Tanks** | | | | | |
| EU | Description | VOC EF (lb/gal) | Rate (gal/year) | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | 650 Gal Tanks (2) | NA | NA | 0.02 | 0.02 |
| IA | 300 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 275 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 250 Gal Tank | NA | NA | 0.01 | 0.01 |
| **Planet Hollywood** | | | | | |
| **Spray Paint Booth** | | | | | |
| EU | Description | VOC EF (lb/gal) | Rate (gal/year) | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | Spray Paint Booth | 7.25 | 100 | 0.36 | 0.01 |
| **Woodworking Operations Dust Collector** | | | | | |
| EU | Description | Flow Rate (cfm) | Loading Rate ($gr/ft^3$) | $PM_{10}$ PTE, tons/yr | $PM_{2.5}$ PTE, tons/yr |
| IA | Donaldson Torit Dust Collector | 1,500 | 0.01 | 0.30 | 0.17 |
| **Diesel Tanks** | | | | | |
| EU | Description | VOC EF (lb/gal) | Rate (gal/year) | VOC PTE, tons/year | HAP PTE, tons/year |
| IA | 488 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 2,500 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 2,000 Gal Tank | NA | NA | 0.01 | 0.01 |
| IA | 250 Gal Tank | NA | NA | 0.01 | 0.01 |
| **Facility-Wide Totals** | | | | | |
| Pollutant | | $PM_{10}$ | $PM_{2.5}$ | VOC | HAP |
| Tons per year | | 4.24 | 2.42 | 3.69 | 0.48 |

Source ID: 257

**Greenhouse Gas**
**Potential to Emit Calculations**

Caesars Entertainment Inc.

**Source-Wide Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Harrah's Las Vegas | 23,407.70 | 0.47 | 0.05 | 23,408.22 | 23,434.67 |
| Flamingo Las Vegas | 35,035.65 | 0.68 | 0.07 | 35,036.40 | 35,074.19 |
| Horseshoe Las Vegas | 31,526.93 | 0.63 | 0.07 | 31,527.63 | 31,562.96 |
| The Cromwell Las Vegas | 9,642.75 | 0.19 | 0.02 | 9,642.96 | 9,653.71 |
| Caesars Palace | 116,620.79 | 2.24 | 0.23 | 116,623.26 | 116,745.97 |
| Paris Las Vegas | 43,226.98 | 0.82 | 0.08 | 43,227.89 | 43,272.61 |
| The LINQ Hotel & Casino | 20,378.40 | 0.41 | 0.05 | 20,378.86 | 20,402.57 |
| Planet Hollywood | 39,203.12 | 0.76 | 0.08 | 39,203.96 | 39,246.31 |
| LINQ Complex - High Roller | 13,607.78 | 0.27 | 0.03 | 13,608.08 | 13,623.74 |
| Forum Meeting Center | 12,717.92 | 0.25 | 0.03 | 12,718.19 | 12,732.06 |
| **Revised Title V Totals (TPY)** | **345,368.01** | **6.73** | **0.71** | **345,375.45** | **345,748.79** |
| Current Title V Totals (TPY)* | 357,253.67 | 7.15 | 0.79 | 357,261.61 | 357,668.64 |
| Net Emissions Increase (TPY) | -11,885.66 | -0.42 | -0.08 | -11,886.16 | -11,919.85 |

*Current permit totals are from the draft permit issued on 03/06/2025.

Source ID: 257

**Greenhouse Gas**
**Applicability and Source Determination**
**Calculations**

Caesars Entertainment Inc.

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Harrah's Las Vegas | 24,101.22 | 0.49 | 0.05 | 24,101.77 | 24,129.68 |
| Flamingo Las Vegas | 35,254.03 | 0.69 | 0.07 | 35,254.80 | 35,293.33 |
| Horseshoe Las Vegas | 32,205.47 | 0.65 | 0.07 | 32,206.20 | 32,243.82 |
| The Cromwell Las Vegas | 9,922.01 | 0.20 | 0.02 | 9,922.24 | 9,933.93 |
| Caesars Palace | 121,214.96 | 2.41 | 0.26 | 121,217.63 | 121,353.57 |
| Paris Las Vegas | 45,059.45 | 0.88 | 0.09 | 45,060.43 | 45,109.79 |
| The LINQ Hotel & Casino | 20,489.17 | 0.42 | 0.05 | 20,489.63 | 20,513.72 |
| Planet Hollywood | 41,613.32 | 0.85 | 0.10 | 41,614.26 | 41,663.19 |
| LINQ Complex - High Roller | 14,676.12 | 0.32 | 0.04 | 14,676.47 | 14,695.56 |
| Forum Meeting Center | 12,717.92 | 0.25 | 0.03 | 12,718.19 | 12,732.06 |
| **Totals (tons/yr)** | **357,253.67** | **7.15** | **0.79** | **357,261.61** | **357,668.64** |

Source ID: 257

**Greenhouse Gas**
**Allowable Calculations**

Caesars Entertainment Inc.

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Harrah's Las Vegas | 23,407.70 | 0.47 | 0.05 | 23,408.22 | 23,434.67 |
| Flamingo Las Vegas | 35,035.65 | 0.68 | 0.07 | 35,036.40 | 35,074.19 |
| Horseshoe Las Vegas | 31,526.93 | 0.63 | 0.07 | 31,527.63 | 31,562.96 |
| The Cromwell Las Vegas | 9,642.75 | 0.19 | 0.02 | 9,642.96 | 9,653.71 |
| Caesars Palace | 116,620.79 | 2.24 | 0.23 | 116,623.26 | 116,745.97 |
| Paris Las Vegas | 43,226.98 | 0.82 | 0.08 | 43,227.89 | 43,272.61 |
| The LINQ Hotel & Casino | 20,378.40 | 0.41 | 0.05 | 20,378.86 | 20,402.57 |
| Planet Hollywood | 39,203.12 | 0.76 | 0.08 | 39,203.96 | 39,246.31 |
| LINQ Complex - High Roller | 13,607.78 | 0.27 | 0.03 | 13,608.08 | 13,623.74 |
| Forum Meeting Center | 12,717.92 | 0.25 | 0.03 | 12,718.19 | 12,732.06 |
| **Totals (tons/yr)** | **345,368.01** | **6.73** | **0.71** | **345,375.45** | **345,748.79** |

Source ID: 257

# Harrah's Las Vegas
# Greenhouse Gas
# Applicability and Source Determination
# Calculations

Caesars Entertainment Inc.

**Harrah's Las Vegas**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| HA06 | Boiler | 4.50 | 8,760 | 1.026E-03 | 38,421,053 | $CO_2$ | 53.06 | 2,306.02 | 1 | 2,306.02 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.04 | 25 | 1.09 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.004 | 298 | 1.30 |
| HA07 | Boiler | 9.00 | 8,760 | 1.026E-03 | 76,842,105 | $CO_2$ | 53.06 | 4,612.03 | 1 | 4,612.03 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.09 | 25 | 2.17 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 2.59 |
| HA08 | Boiler | 8.369 | 8,760 | 1.026E-03 | 71,454,620 | $CO_2$ | 53.06 | 4,288.68 | 1 | 4,288.68 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.08 | 25 | 2.02 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 2.41 |
| HA09 | Boiler | 8.369 | 8,760 | 1.026E-03 | 71,454,620 | $CO_2$ | 53.06 | 4,288.68 | 1 | 4,288.68 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.08 | 25 | 2.02 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 2.41 |
| HA10 | Boiler | 8.369 | 8,760 | 1.026E-03 | 71,454,620 | $CO_2$ | 53.06 | 4,288.68 | 1 | 4,288.68 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.08 | 25 | 2.02 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 2.41 |
| HA11 | Boiler | 4.80 | 8,760 | 1.026E-03 | 40,982,456 | $CO_2$ | 53.06 | 2,459.75 | 1 | 2,459.75 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.16 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.38 |
| IA | Boiler | 0.73 | 8,760 | 1.026E-03 | 6,198,596 | $CO_2$ | 53.06 | 372.037 | 1 | 372.04 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.007 | 25 | 0.18 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.21 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

Source ID: 257

# Harrah's Las Vegas
## Greenhouse Gas
## Applicability and Source Determination
## Calculations

Caesars Entertainment Inc.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| HA12 | Engine | 370 | 500 | 0.138 | 9,250 | $CO_2$ | 73.96 | 104.09 | 1 | 104.09 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.004 | 25 | 0.11 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.25 |
| HA13 | Engine | 1,232 | 500 | 0.138 | 30,800 | $CO_2$ | 73.96 | 346.58 | 1 | 346.58 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.35 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.003 | 298 | 0.84 |
| HA14 | Engine | 890 | 500 | 0.138 | 22,250 | $CO_2$ | 73.96 | 250.37 | 1 | 250.37 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.25 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.61 |
| HA15 | Engine | 536 | 500 | 0.138 | 13,400 | $CO_2$ | 73.96 | 150.79 | 1 | 150.79 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| HA16 | Engine | 536 | 500 | 0.138 | 13,400 | $CO_2$ | 73.96 | 150.79 | 1 | 150.79 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| HA17 | Engine | 536 | 500 | 0.138 | 13,400 | $CO_2$ | 73.96 | 150.79 | 1 | 150.79 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| HA18 | Engine | 1,180 | 500 | 0.138 | 29,500 | $CO_2$ | 73.96 | 331.95 | 1 | 331.95 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.34 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.003 | 298 | 0.80 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x 500 hr/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**Harrah's Las Vegas Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 24,101.22 | 0.49 | 0.05 | 24,101.77 | 24,129.68 |

Source ID: 257

# Harrah's Las Vegas
# Greenhouse Gas
# Allowable Calculations

Caesars Entertainment Inc.

**Harrah's Las Vegas**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| HA06 | Boiler | 4.50 | 8,760 | 1.026E-03 | 38,421,053 | $CO_2$ | 53.06 | 2,306.02 | 1 | 2,306.02 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.04 | 25 | 1.09 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.004 | 298 | 1.30 |
| HA07 | Boiler | 9.00 | 8,760 | 1.026E-03 | 76,842,105 | $CO_2$ | 53.06 | 4,612.03 | 1 | 4,612.03 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.09 | 25 | 2.17 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 2.59 |
| HA08 | Boiler | 8.369 | 8,760 | 1.026E-03 | 71,454,620 | $CO_2$ | 53.06 | 4,288.68 | 1 | 4,288.68 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.08 | 25 | 2.02 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 2.41 |
| HA09 | Boiler | 8.369 | 8,760 | 1.026E-03 | 71,454,620 | $CO_2$ | 53.06 | 4,288.68 | 1 | 4,288.68 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.08 | 25 | 2.02 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 2.41 |
| HA10 | Boiler | 8.369 | 8,760 | 1.026E-03 | 71,454,620 | $CO_2$ | 53.06 | 4,288.68 | 1 | 4,288.68 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.08 | 25 | 2.02 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 2.41 |
| HA11 | Boiler | 4.80 | 8,760 | 1.026E-03 | 40,982,456 | $CO_2$ | 53.06 | 2,459.75 | 1 | 2,459.75 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.16 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.38 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

Source ID: 257

**Harrah's Las Vegas**
**Greenhouse Gas**
**Allowable Calculations**

Caesars Entertainment Inc.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| HA12 | Engine | 370 | 500 | 0.138 | 9,250 | $CO_2$ | 73.96 | 104.09 | 1 | 104.09 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.004 | 25 | 0.11 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.25 |
| HA13 | Engine | 1,232 | 300 | 0.138 | 18,480 | $CO_2$ | 73.96 | 207.95 | 1 | 207.95 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.50 |
| HA14 | Engine | 890 | 400 | 0.138 | 17,800 | $CO_2$ | 73.96 | 200.30 | 1 | 200.30 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.20 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.48 |
| HA15 | Engine | 536 | 500 | 0.138 | 13,400 | $CO_2$ | 73.96 | 150.79 | 1 | 150.79 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| HA16 | Engine | 536 | 500 | 0.138 | 13,400 | $CO_2$ | 73.96 | 150.79 | 1 | 150.79 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| HA17 | Engine | 536 | 500 | 0.138 | 13,400 | $CO_2$ | 73.96 | 150.79 | 1 | 150.79 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| HA18 | Engine | 1,180 | 300 | 0.138 | 17,700 | $CO_2$ | 73.96 | 199.17 | 1 | 199.17 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.20 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.48 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x hrs/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**Harrah's Las Vegas Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 23,407.70 | 0.47 | 0.05 | 23,408.22 | 23,434.67 |

Source ID: 257

# Flamingo Las Vegas
# Greenhouse Gas
# Applicability and Source Determination
# Calculations

Caesars Entertainment Inc.

**Flamingo Las Vegas**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| FL01 | Boiler | 14.343 | 8,760 | 1.026E-03 | 122,460,702 | $CO_2$ | 53.06 | 7,350.04 | 1 | 7,350.04 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.14 | 25 | 3.46 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 4.12 |
| FL02 | Boiler | 14.645 | 8,760 | 1.026E-03 | 125,039,181 | $CO_2$ | 53.06 | 7,504.80 | 1 | 7,504.80 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.14 | 25 | 3.54 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 4.21 |
| FL03 | Boiler | 14.645 | 8,760 | 1.026E-03 | 125,039,181 | $CO_2$ | 53.06 | 7,504.80 | 1 | 7,504.80 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.14 | 25 | 3.54 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 4.21 |
| FL04 | Boiler | 14.645 | 8,760 | 1.026E-03 | 125,039,181 | $CO_2$ | 53.06 | 7,504.80 | 1 | 7,504.80 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.14 | 25 | 3.54 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 4.21 |
| FL05 | Boiler | 8.165 | 8,760 | 1.026E-03 | 69,712,865 | $CO_2$ | 53.06 | 4,184.14 | 1 | 4,184.14 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.08 | 25 | 1.97 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 2.35 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| FL06 | Engine | 420 | 500 | 0.138 | 10,500 | $CO_2$ | 73.96 | 118.15 | 1 | 118.15 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.005 | 25 | 0.12 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.29 |
| FL09 | Engine | 1,109 | 500 | 0.138 | 27,725 | $CO_2$ | 73.96 | 311.98 | 1 | 311.98 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.32 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.003 | 298 | 0.75 |
| FL10 | Engine | 1,109 | 500 | 0.138 | 27,725 | $CO_2$ | 73.96 | 311.98 | 1 | 311.98 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.32 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.003 | 298 | 0.75 |
| FL11 | Engine | 724 | 500 | 0.138 | 18,100 | $CO_2$ | 73.96 | 203.67 | 1 | 203.67 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.49 |
| FL26 | Engine | 923 | 500 | 0.138 | 23,075 | $CO_2$ | 73.96 | 259.65 | 1 | 259.65 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.26 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.63 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x 500 hr/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**Flamingo Las Vegas Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 35,254.03 | 0.69 | 0.07 | 35,254.80 | 35,293.33 |

Source ID: 257

# Flamingo Las Vegas
# Greenhouse Gas
# Allowable Calculations

Caesars Entertainment Inc.

**Flamingo Las Vegas**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| FL01 | Boiler | 14.343 | 8,760 | 1.026E-03 | 122,460,702 | $CO_2$ | 53.06 | 7,350.04 | 1 | 7,350.04 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.14 | 25 | 3.46 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 4.12 |
| FL02 | Boiler | 14.645 | 8,760 | 1.026E-03 | 125,039,181 | $CO_2$ | 53.06 | 7,504.80 | 1 | 7,504.80 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.14 | 25 | 3.54 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 4.21 |
| FL03 | Boiler | 14.645 | 8,760 | 1.026E-03 | 125,039,181 | $CO_2$ | 53.06 | 7,504.80 | 1 | 7,504.80 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.14 | 25 | 3.54 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 4.21 |
| FL04 | Boiler | 14.645 | 8,760 | 1.026E-03 | 125,039,181 | $CO_2$ | 53.06 | 7,504.80 | 1 | 7,504.80 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.14 | 25 | 3.54 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 4.21 |
| FL05 | Boiler | 8.165 | 8,760 | 1.026E-03 | 69,712,865 | $CO_2$ | 53.06 | 4,184.14 | 1 | 4,184.14 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.08 | 25 | 1.97 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 2.35 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| FL06 | Engine | 420 | 500 | 0.138 | 10,500 | $CO_2$ | 73.96 | 118.15 | 1 | 118.15 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.005 | 25 | 0.12 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.29 |
| FL09 | Engine | 1,109 | 325 | 0.138 | 18,021 | $CO_2$ | 73.96 | 202.79 | 1 | 202.79 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.49 |
| FL10 | Engine | 1,109 | 325 | 0.138 | 18,021 | $CO_2$ | 73.96 | 202.79 | 1 | 202.79 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.49 |
| FL11 | Engine | 724 | 500 | 0.138 | 18,100 | $CO_2$ | 73.96 | 203.67 | 1 | 203.67 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.49 |
| FL26 | Engine | 923 | 500 | 0.138 | 23,075 | $CO_2$ | 73.96 | 259.65 | 1 | 259.65 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.26 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.63 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x hrs/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**Flamingo Las Vegas Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 35,035.65 | 0.68 | 0.07 | 35,036.40 | 35,074.19 |

Source ID: 257

# Horseshoe Las Vegas
# Greenhouse Gas
# Applicability and Source Determination
# Calculations

Caesars Entertainment Inc.

**Horseshoe Las Vegas**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| BA01 | Boiler | 16.80 | 8,760 | 1.026E-03 | 143,438,596 | $CO_2$ | 53.06 | 8,609.13 | 1 | 8,609.13 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.16 | 25 | 4.06 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 4.84 |
| BA02 | Boiler | 16.80 | 8,760 | 1.026E-03 | 143,438,596 | $CO_2$ | 53.06 | 8,609.13 | 1 | 8,609.13 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.16 | 25 | 4.06 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 4.84 |
| BA03 | Boiler | 25.106 | 8,760 | 1.026E-03 | 214,355,322 | $CO_2$ | 53.06 | 12,865.52 | 1 | 12,865.52 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.24 | 25 | 6.06 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 7.23 |

[1] Fuel usage calculation: (hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| BA04 | Engine | 1,340 | 500 | 0.138 | 33,500 | $CO_2$ | 73.96 | 376.96 | 1 | 376.96 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.02 | 25 | 0.38 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.003 | 298 | 0.91 |
| BA05 | Engine | 1,340 | 500 | 0.138 | 33,500 | $CO_2$ | 73.96 | 376.96 | 1 | 376.96 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.02 | 25 | 0.38 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.003 | 298 | 0.91 |
| BA06 | Engine | 670 | 500 | 0.138 | 16,750 | $CO_2$ | 73.96 | 188.48 | 1 | 188.48 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.19 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.46 |
| BA07 | Engine | 200 | 500 | 0.138 | 5,000 | $CO_2$ | 73.96 | 56.26 | 1 | 56.26 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.002 | 25 | 0.06 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.0005 | 298 | 0.14 |
| BA11 | Engine | 1,340 | 500 | 0.138 | 33,500 | $CO_2$ | 73.96 | 376.96 | 1 | 376.96 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.02 | 25 | 0.38 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.003 | 298 | 0.91 |
| BA12 | Engine | 1,340 | 500 | 0.138 | 33,500 | $CO_2$ | 73.96 | 376.96 | 1 | 376.96 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.02 | 25 | 0.38 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.003 | 298 | 0.91 |
| BA17 | Engine | 526 | 500 | 0.138 | 13,150 | $CO_2$ | 73.96 | 147.97 | 1 | 147.97 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| BA18 | Engine | 526 | 500 | 0.138 | 13,150 | $CO_2$ | 73.96 | 147.97 | 1 | 147.97 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| BA21 | Engine | 260 | 500 | 0.138 | 6,500 | $CO_3$ | 73.96 | 73.14 | 1 | 73.14 |
| | | | | | | $CH_5$ | 3.0E-03 | 0.003 | 25 | 0.07 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.18 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x 500 hr/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**Horseshoe Las Vegas Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 32,205.47 | 0.65 | 0.07 | 32,206.20 | 32,243.82 |

Source ID: 257

# Horseshoe Las Vegas
# Greenhouse Gas
# Allowable Calculations

Caesars Entertainment Inc.

**Horseshoe Las Vegas**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| BA01 | Boiler | 16.80 | 8,760 | 1.026E-03 | 143,438,596 | $CO_2$ | 53.06 | 8,609.13 | 1 | 8,609.13 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.16 | 25 | 4.06 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 4.84 |
| BA02 | Boiler | 16.80 | 8,760 | 1.026E-03 | 143,438,596 | $CO_2$ | 53.06 | 8,609.13 | 1 | 8,609.13 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.16 | 25 | 4.06 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 4.84 |
| BA03 | Boiler | 25.106 | 8,760 | 1.026E-03 | 214,355,322 | $CO_2$ | 53.06 | 12,865.52 | 1 | 12,865.52 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.24 | 25 | 6.06 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 7.23 |

[1] Fuel usage calculation: (hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| BA04 | Engine | 1,340 | 275 | 0.138 | 18,425 | $CO_2$ | 73.96 | 207.33 | 1 | 207.33 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.50 |
| BA05 | Engine | 1,340 | 275 | 0.138 | 18,425 | $CO_2$ | 73.96 | 207.33 | 1 | 207.33 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.50 |
| BA06 | Engine | 670 | 500 | 0.138 | 16,750 | $CO_2$ | 73.96 | 188.48 | 1 | 188.48 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.19 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.46 |
| BA07 | Engine | 200 | 500 | 0.138 | 5,000 | $CO_2$ | 73.96 | 56.26 | 1 | 56.26 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.002 | 25 | 0.06 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.0005 | 298 | 0.14 |
| BA11 | Engine | 1,340 | 275 | 0.138 | 18,425 | $CO_2$ | 73.96 | 207.33 | 1 | 207.33 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.50 |
| BA12 | Engine | 1,340 | 275 | 0.138 | 18,425 | $CO_2$ | 73.96 | 207.33 | 1 | 207.33 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.50 |
| BA17 | Engine | 526 | 500 | 0.138 | 13,150 | $CO_2$ | 73.96 | 147.97 | 1 | 147.97 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| BA18 | Engine | 526 | 500 | 0.138 | 13,150 | $CO_2$ | 73.96 | 147.97 | 1 | 147.97 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| BA21 | Engine | 260 | 500 | 0.138 | 6,500 | $CO_3$ | 73.96 | 73.14 | 1 | 73.14 |
| | | | | | | $CH_5$ | 3.0E-03 | 0.003 | 25 | 0.07 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.18 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x hrs/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**Horseshoe Las Vegas Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 31,526.93 | 0.63 | 0.07 | 31,527.63 | 31,562.96 |

Source ID: 257

# The Cromwell Las Vegas
# Greenhouse Gas
# Applicability and Source Determination
# Calculations

Caesars Entertainment Inc.

**The Cromwell Las Vegas**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| CR01 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |
| CR02 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |
| CR03 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |
| CR04 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |
| CR05 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |
| CR06 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| CR07 | Engine | 2,206 | 500 | 0.138 | 55,150 | $CO_2$ | 73.96 | 620.58 | 1 | 620.58 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.63 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 1.50 |
| CR08 | Engine | 275 | 500 | 0.138 | 6,875 | $CO_2$ | 73.96 | 77.36 | 1 | 77.36 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.00 | 25 | 0.08 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.19 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x 500 hr/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**The Cromwell Las Vegas Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 9,922.01 | 0.20 | 0.02 | 9,922.24 | 9,933.93 |

Source ID: 257

# The Cromwell Las Vegas
# Greenhouse Gas
# Allowable Calculations

Caesars Entertainment Inc.

**The Cromwell Las Vegas**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| CR01 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |
| CR02 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |
| CR03 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |
| CR04 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |
| CR05 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |
| CR06 | Boiler | 3.00 | 8,760 | 1.026E-03 | 25,614,035 | $CO_2$ | 53.06 | 1,537.34 | 1 | 1,537.34 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 0.86 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| CR07 | Engine | 2,206 | 275 | 0.138 | 30,333 | $CO_2$ | 73.96 | 341.32 | 1 | 341.32 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.35 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.83 |
| CR08 | Engine | 275 | 500 | 0.138 | 6,875 | $CO_2$ | 73.96 | 77.36 | 1 | 77.36 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.00 | 25 | 0.08 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.19 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x hrs/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**The Cromwell Las Vegas Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 9,642.75 | 0.19 | 0.02 | 9,642.96 | 9,653.71 |

Source ID: 257

# Caesars Palace
# Greenhouse Gas
# Applicability and Source Determination
# Calculations

Caesars Entertainment Inc.

**Caesars Palace**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| CP01 | Boiler | 35.40 | 8,760 | 1.026E-03 | 302,245,614 | $CO_2$ | 53.06 | 18,140.67 | 1 | 18,140.67 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.34 | 25 | 8.55 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.03 | 298 | 10.19 |
| CP02 | Boiler | 35.40 | 8,760 | 1.026E-03 | 302,245,614 | $CO_2$ | 53.06 | 18,140.67 | 1 | 18,140.67 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.34 | 25 | 8.55 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.03 | 298 | 10.19 |
| CP03 | Boiler | 33.475 | 8,760 | 1.026E-03 | 285,809,942 | $CO_2$ | 53.06 | 17,154.20 | 1 | 17,154.20 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.32 | 25 | 8.08 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.03 | 298 | 9.63 |
| CP04 | Boiler | 33.475 | 8,760 | 1.026E-03 | 285,809,942 | $CO_2$ | 53.06 | 17,154.20 | 1 | 17,154.20 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.32 | 25 | 8.08 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.03 | 298 | 9.63 |
| CP05 | Boiler | 33.475 | 8,760 | 1.026E-03 | 285,809,942 | $CO_2$ | 53.06 | 17,154.20 | 1 | 17,154.20 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.32 | 25 | 8.08 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.03 | 298 | 9.63 |
| CP24 | Boiler | 1.50 | 8,760 | 1.026E-03 | 12,807,018 | $CO_2$ | 53.06 | 768.67 | 1 | 768.67 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.36 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.43 |
| CP25 | Boiler | 1.50 | 8,760 | 1.026E-03 | 12,807,018 | $CO_2$ | 53.06 | 768.67 | 1 | 768.67 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.36 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.43 |
| CP26 | Boiler | 24.00 | 8,760 | 1.026E-03 | 204,912,281 | $CO_2$ | 53.06 | 12,298.76 | 1 | 12,298.76 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.23 | 25 | 5.79 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.91 |
| CP27 | Boiler | 24.00 | 8,760 | 1.026E-03 | 204,912,281 | $CO_2$ | 53.06 | 12,298.76 | 1 | 12,298.76 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.23 | 25 | 5.79 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.91 |
| CP37 | Boiler | 1.50 | 8,760 | 1.026E-03 | 12,807,018 | $CO_2$ | 53.06 | 768.67 | 1 | 768.67 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.36 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.43 |
| IA | Water Heaters (5) | 1.90 | 8,760 | 1.026E-03 | 16,196,608 | $CO_2$ | 53.06 | 972.114 | 1 | 972.11 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.018 | 25 | 0.46 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.55 |

[1] Fuel usage calculation: (hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

Source ID: 257

# Caesars Palace
# Greenhouse Gas
# Applicability and Source Determination
# Calculations

Caesars Entertainment Inc.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| CP13 | Engine | 2,876 | 500 | 0.138 | 71,900 | $CO_2$ | 73.96 | 809.07 | 1 | 809.07 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.82 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 1.96 |
| CP14 | Engine | 2,876 | 500 | 0.138 | 71,900 | $CO_2$ | 73.96 | 809.07 | 1 | 809.07 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.82 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 1.96 |
| CP15 | Engine | 2,520 | 500 | 0.138 | 63,000 | $CO_2$ | 73.96 | 708.92 | 1 | 708.92 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.72 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 1.71 |
| CP16 | Engine | 1,818 | 500 | 0.138 | 45,450 | $CO_2$ | 73.96 | 511.43 | 1 | 511.43 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.02 | 25 | 0.52 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.004 | 298 | 1.24 |
| CP17 | Engine | 2,876 | 500 | 0.138 | 71,900 | $CO_2$ | 73.96 | 809.07 | 1 | 809.07 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.82 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 1.96 |
| CP28 | Engine | 2,937 | 500 | 0.138 | 73,425 | $CO_2$ | 73.96 | 826.23 | 1 | 826.23 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.84 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 2.00 |
| CP29 | Engine | 2,937 | 500 | 0.138 | 73,425 | $CO_2$ | 73.96 | 826.23 | 1 | 826.23 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.84 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 2.00 |
| CP34 | Engine | 525 | 500 | 0.138 | 13,125 | $CO_2$ | 73.96 | 147.69 | 1 | 147.69 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| CP35 | Engine | 525 | 500 | 0.138 | 13,125 | $CO_2$ | 73.96 | 147.69 | 1 | 147.69 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x 500 hr/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**Caesars Palace Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 121,214.96 | 2.41 | 0.26 | 121,217.63 | 121,353.57 |

Source ID: 257

# Caesars Palace
# Greenhouse Gas
# Allowable Calculations

Caesars Entertainment Inc.

**Caesars Palace**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| CP01 | Boiler | 35.40 | 8,760 | 1.026E-03 | 302,245,614 | $CO_2$ | 53.06 | 18,140.67 | 1 | 18,140.67 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.34 | 25 | 8.55 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.03 | 298 | 10.19 |
| CP02 | Boiler | 35.40 | 8,760 | 1.026E-03 | 302,245,614 | $CO_2$ | 53.06 | 18,140.67 | 1 | 18,140.67 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.34 | 25 | 8.55 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.03 | 298 | 10.19 |
| CP03 | Boiler | 33.475 | 8,760 | 1.026E-03 | 285,809,942 | $CO_2$ | 53.06 | 17,154.20 | 1 | 17,154.20 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.32 | 25 | 8.08 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.03 | 298 | 9.63 |
| CP04 | Boiler | 33.475 | 8,760 | 1.026E-03 | 285,809,942 | $CO_2$ | 53.06 | 17,154.20 | 1 | 17,154.20 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.32 | 25 | 8.08 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.03 | 298 | 9.63 |
| CP05 | Boiler | 33.475 | 8,760 | 1.026E-03 | 285,809,942 | $CO_2$ | 53.06 | 17,154.20 | 1 | 17,154.20 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.32 | 25 | 8.08 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.03 | 298 | 9.63 |
| CP24 | Boiler | 1.50 | 8,760 | 1.026E-03 | 12,807,018 | $CO_2$ | 53.06 | 768.67 | 1 | 768.67 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.36 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.43 |
| CP25 | Boiler | 1.50 | 8,760 | 1.026E-03 | 12,807,018 | $CO_2$ | 53.06 | 768.67 | 1 | 768.67 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.36 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.43 |
| CP26 | Boiler | 24.00 | 8,760 | 1.026E-03 | 204,912,281 | $CO_2$ | 53.06 | 12,298.76 | 1 | 12,298.76 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.23 | 25 | 5.79 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.91 |
| CP27 | Boiler | 24.00 | 8,760 | 1.026E-03 | 204,912,281 | $CO_2$ | 53.06 | 12,298.76 | 1 | 12,298.76 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.23 | 25 | 5.79 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.91 |
| CP37 | Boiler | 1.50 | 8,760 | 1.026E-03 | 12,807,018 | $CO_2$ | 53.06 | 768.67 | 1 | 768.67 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.36 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.43 |

[1] Fuel usage calculation: (hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

Source ID: 257

# Caesars Palace
# Greenhouse Gas
# Allowable Calculations

Caesars Entertainment Inc.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| CP13 | Engine | 2,876 | 125 | 0.138 | 17,975 | $CO_2$ | 73.96 | 202.27 | 1 | 202.27 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.49 |
| CP14 | Engine | 2,876 | 125 | 0.138 | 17,975 | $CO_2$ | 73.96 | 202.27 | 1 | 202.27 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.49 |
| CP15 | Engine | 2,520 | 145 | 0.138 | 18,270 | $CO_2$ | 73.96 | 205.59 | 1 | 205.59 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.50 |
| CP16 | Engine | 1,818 | 200 | 0.138 | 18,180 | $CO_2$ | 73.96 | 204.57 | 1 | 204.57 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.49 |
| CP17 | Engine | 2,876 | 125 | 0.138 | 17,975 | $CO_2$ | 73.96 | 202.27 | 1 | 202.27 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.49 |
| CP28 | Engine | 2,937 | 200 | 0.138 | 29,370 | $CO_2$ | 73.96 | 330.49 | 1 | 330.49 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.34 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.80 |
| CP29 | Engine | 2,937 | 200 | 0.138 | 29,370 | $CO_2$ | 73.96 | 330.49 | 1 | 330.49 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.34 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.80 |
| CP34 | Engine | 525 | 500 | 0.138 | 13,125 | $CO_2$ | 73.96 | 147.69 | 1 | 147.69 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |
| CP35 | Engine | 525 | 500 | 0.138 | 13,125 | $CO_2$ | 73.96 | 147.69 | 1 | 147.69 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.15 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.36 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x hrs/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**Caesars Palace Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 116,620.79 | 2.24 | 0.23 | 116,623.26 | 116,745.97 |

Source ID: 257

# Paris Las Vegas
# Greenhouse Gas
# Applicability and Source Determination
# Calculations

Caesars Entertainment Inc.

**Paris Las Vegas**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| PA12 | Boiler | 3.50 | 8,760 | 1.026E-03 | 29,883,041 | $CO_2$ | 53.06 | 1,793.57 | 1 | 1,793.57 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.85 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 1.01 |
| PA13 | Boiler | 3.50 | 8,760 | 1.026E-03 | 29,883,041 | $CO_2$ | 53.06 | 1,793.57 | 1 | 1,793.57 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.85 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 1.01 |
| PA14 | Boiler | 17.00 | 8,760 | 1.026E-03 | 145,146,199 | $CO_2$ | 53.06 | 8,711.62 | 1 | 8,711.62 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.16 | 25 | 4.10 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 4.89 |
| PA15 | Boiler | 21.00 | 8,760 | 1.026E-03 | 179,298,246 | $CO_2$ | 53.06 | 10,761.41 | 1 | 10,761.41 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.20 | 25 | 5.07 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.04 |
| PA16 | Boiler | 21.00 | 8,760 | 1.026E-03 | 179,298,246 | $CO_2$ | 53.06 | 10,761.41 | 1 | 10,761.41 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.20 | 25 | 5.07 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.04 |
| PA28 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA29 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA30 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA31 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_3$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_5$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA32 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA33 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA34 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA35 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA36 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| 1A | Water Heater (4) | 1.29 | 8,760 | 1.026E-03 | 10,996,959 | $CO_2$ | 53.06 | 660.033 | 1 | 660.03 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.012 | 25 | 0.31 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.37 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide (CO2). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the CO2e value.

Source ID: 257

# Paris Las Vegas
# Greenhouse Gas
# Applicability and Source Determination
# Calculations

Caesars Entertainment Inc.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| PA17 | Engine | 2,816 | 500 | 0.138 | 70,400 | $CO_2$ | 73.96 | 792.19 | 1 | 792.19 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.80 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 1.92 |
| PA18 | Engine | 2,816 | 500 | 0.138 | 70,400 | $CO_2$ | 73.96 | 792.19 | 1 | 792.19 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.80 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 1.92 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x 500 hr/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide (CO2). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the CO2e value.

**Paris Las Vegas Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 45,059.45 | 0.88 | 0.09 | 45,060.43 | 45,109.79 |

Source ID: 257

# Paris Las Vegas
# Greenhouse Gas
# Allowable Calculations

Caesars Entertainment Inc.

**Paris Las Vegas**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| PA12 | Boiler | 3.50 | 8,760 | 1.026E-03 | 29,883,041 | $CO_2$ | 53.06 | 1,793.57 | 1 | 1,793.57 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.85 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 1.01 |
| PA13 | Boiler | 3.50 | 8,760 | 1.026E-03 | 29,883,041 | $CO_2$ | 53.06 | 1,793.57 | 1 | 1,793.57 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.03 | 25 | 0.85 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.003 | 298 | 1.01 |
| PA14 | Boiler | 17.00 | 8,760 | 1.026E-03 | 145,146,199 | $CO_2$ | 53.06 | 8,711.62 | 1 | 8,711.62 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.16 | 25 | 4.10 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 4.89 |
| PA15 | Boiler | 21.00 | 8,760 | 1.026E-03 | 179,298,246 | $CO_2$ | 53.06 | 10,761.41 | 1 | 10,761.41 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.20 | 25 | 5.07 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.04 |
| PA16 | Boiler | 21.00 | 8,760 | 1.026E-03 | 179,298,246 | $CO_2$ | 53.06 | 10,761.41 | 1 | 10,761.41 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.20 | 25 | 5.07 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.04 |
| PA28 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA29 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA30 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA31 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_3$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_5$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA32 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA33 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA34 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA35 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |
| PA36 | Boiler | 1.95 | 8,760 | 1.026E-03 | 16,649,123 | $CO_2$ | 53.06 | 999.27 | 1 | 999.27 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.02 | 25 | 0.47 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.56 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide (CO2). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the CO2e value.

Source ID: 257

# Paris Las Vegas
# Greenhouse Gas
# Allowable Calculations

Caesars Entertainment Inc.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| PA17 | Engine | 2,816 | 130 | 0.138 | 18,304 | $CO_2$ | 73.96 | 205.97 | 1 | 205.97 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.50 |
| PA18 | Engine | 2,816 | 130 | 0.138 | 18,304 | $CO_2$ | 73.96 | 205.97 | 1 | 205.97 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.50 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x hrs/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide (CO2). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the CO2e value.

**Paris Las Vegas Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 43,226.98 | 0.82 | 0.08 | 43,227.89 | 43,272.61 |

Source ID: 257

# The LINQ Hotel & Casino
# Greenhouse Gas
# Applicability and Source Determination
# Calculations

Caesars Entertainment Inc.

**The LINQ Hotel & Casino**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| IP01 | Boiler | 1.25 | 8,760 | 1.026E-03 | 10,672,515 | $CO_2$ | 53.06 | 640.56 | 1 | 640.56 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.30 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.36 |
| IP02 | Boiler | 1.25 | 8,760 | 1.026E-03 | 10,672,515 | $CO_2$ | 53.06 | 640.56 | 1 | 640.56 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.30 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.36 |
| IP03 | Boiler | 1.25 | 8,760 | 1.026E-03 | 10,672,515 | $CO_2$ | 53.06 | 640.56 | 1 | 640.56 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.30 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.36 |
| IP04 | Boiler | 16.738 | 8,760 | 1.026E-03 | 142,909,240 | $CO_2$ | 53.06 | 8,577.36 | 1 | 8,577.36 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.16 | 25 | 4.04 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 4.82 |
| IP05 | Boiler | 16.738 | 8,760 | 1.026E-03 | 142,909,240 | $CO_2$ | 53.06 | 8,577.36 | 1 | 8,577.36 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.16 | 25 | 4.04 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 4.82 |

[1] Fuel usage calculation: (hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| IP06 | Engine | 680 | 500 | 0.138 | 17,000 | $CO_2$ | 73.96 | 191.29 | 1 | 191.29 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.19 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.46 |
| IP07 | Engine | 755 | 500 | 0.138 | 18,875 | $CO_2$ | 73.96 | 212.39 | 1 | 212.39 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.22 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.51 |
| IP08 | Engine | 890 | 500 | 0.138 | 22,250 | $CO_2$ | 73.96 | 250.37 | 1 | 250.37 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.25 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.61 |
| IP09 | Engine | 890 | 500 | 0.138 | 22,250 | $CO_2$ | 73.96 | 250.37 | 1 | 250.37 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.25 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.61 |
| IP10 | Engine | 375 | 500 | 0.138 | 9,375 | $CO_2$ | 73.96 | 105.49 | 1 | 105.49 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.004 | 25 | 0.11 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.26 |
| IP11 | Engine | 670 | 500 | 0.138 | 16,750 | $CO_2$ | 73.96 | 188.48 | 1 | 188.48 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.19 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.46 |
| IP38 | Engine | 762 | 500 | 0.138 | 19,050 | $CO_2$ | 73.96 | 214.36 | 1 | 214.36 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.22 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.52 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x 500 hr/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**The LINQ Hotel & Casino Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 20,489.17 | 0.42 | 0.05 | 20,489.63 | 20,513.72 |

Source ID: 257

# The LINQ Hotel & Casino
## Greenhouse Gas
## Allowable Calculations

Caesars Entertainment Inc.

**The LINQ Hotel & Casino**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| IP01 | Boiler | 1.25 | 8,760 | 1.026E-03 | 10,672,515 | $CO_2$ | 53.06 | 640.56 | 1 | 640.56 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.30 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.36 |
| IP02 | Boiler | 1.25 | 8,760 | 1.026E-03 | 10,672,515 | $CO_2$ | 53.06 | 640.56 | 1 | 640.56 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.30 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.36 |
| IP03 | Boiler | 1.25 | 8,760 | 1.026E-03 | 10,672,515 | $CO_2$ | 53.06 | 640.56 | 1 | 640.56 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.30 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.001 | 298 | 0.36 |
| IP04 | Boiler | 16.738 | 8,760 | 1.026E-03 | 142,909,240 | $CO_2$ | 53.06 | 8,577.36 | 1 | 8,577.36 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.16 | 25 | 4.04 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 4.82 |
| IP05 | Boiler | 16.738 | 8,760 | 1.026E-03 | 142,909,240 | $CO_2$ | 53.06 | 8,577.36 | 1 | 8,577.36 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.16 | 25 | 4.04 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 4.82 |

[1] Fuel usage calculation: (hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| IP06 | Engine | 680 | 500 | 0.138 | 17,000 | $CO_2$ | 73.96 | 191.29 | 1 | 191.29 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.19 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.46 |
| IP07 | Engine | 755 | 475 | 0.138 | 17,931 | $CO_2$ | 73.96 | 201.77 | 1 | 201.77 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.20 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.49 |
| IP08 | Engine | 890 | 400 | 0.138 | 17,800 | $CO_2$ | 73.96 | 200.30 | 1 | 200.30 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.20 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.48 |
| IP09 | Engine | 890 | 400 | 0.138 | 17,800 | $CO_2$ | 73.96 | 200.30 | 1 | 200.30 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.20 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.48 |
| IP10 | Engine | 375 | 500 | 0.138 | 9,375 | $CO_2$ | 73.96 | 105.49 | 1 | 105.49 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.004 | 25 | 0.11 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.26 |
| IP11 | Engine | 670 | 500 | 0.138 | 16,750 | $CO_2$ | 73.96 | 188.48 | 1 | 188.48 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.19 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.46 |
| IP38 | Engine | 762 | 500 | 0.138 | 19,050 | $CO_2$ | 73.96 | 214.36 | 1 | 214.36 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.22 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.002 | 298 | 0.52 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x hrs/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**The LINQ Hotel & Casino Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 20,378.40 | 0.41 | 0.05 | 20,378.86 | 20,402.57 |

Source ID: 257

# Planet Hollywood
# Greenhouse Gas
# Applicability and Source Determination
# Calculations

Caesars Entertainment Inc.

**Planet Hollywood**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| PH03 | Boiler | 1.75 | 8,760 | 1.026E-03 | 14,941,520 | $CO_1$ | 53.06 | 896.78 | 1 | 896.78 |
| | | | | | | $CH_3$ | 1.0E-03 | 0.02 | 25 | 0.42 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.50 |
| PH04 | Boiler | 1.75 | 8,760 | 1.026E-03 | 14,941,520 | $CO_1$ | 53.06 | 896.78 | 1 | 896.78 |
| | | | | | | $CH_3$ | 1.0E-03 | 0.02 | 25 | 0.42 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.50 |
| PH07 | Boiler | 23.60 | 8,760 | 1.026E-03 | 201,497,076 | $CO_2$ | 53.06 | 12,093.78 | 1 | 12,093.78 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.23 | 25 | 5.70 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.79 |
| PH08 | Boiler | 23.60 | 8,760 | 1.026E-03 | 201,497,076 | $CO_2$ | 53.06 | 12,093.78 | 1 | 12,093.78 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.23 | 25 | 5.70 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.79 |
| PH09 | Boiler | 23.60 | 8,760 | 1.026E-03 | 201,497,076 | $CO_2$ | 53.06 | 12,093.78 | 1 | 12,093.78 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.23 | 25 | 5.70 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.79 |
| IA | Water Heater (2) | 1.30 | 8,760 | 1.026E-03 | 11,099,415 | $CO_2$ | 53.06 | 666.18 | 1 | 666.18 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.01 | 25 | 0.31 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.00 | 298 | 0.37 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| PH10 | Engine | 2,550 | 500 | 0.138 | 63,750 | $CO_2$ | 73.96 | 717.36 | 1 | 717.36 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.73 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 1.73 |
| PH11 | Engine | 2,550 | 500 | 0.138 | 63,750 | $CO_2$ | 73.96 | 717.36 | 1 | 717.36 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.73 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 1.73 |
| PH12 | Engine | 2,550 | 500 | 0.138 | 63,750 | $CO_2$ | 73.96 | 717.36 | 1 | 717.36 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.73 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 1.73 |
| PH13 | Engine | 2,560 | 500 | 0.138 | 64,000 | $CO_2$ | 73.96 | 720.17 | 1 | 720.17 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.73 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 1.74 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x 500 hr/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**Planet Hollywood Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 41,613.32 | 0.85 | 0.10 | 41,614.26 | 41,663.19 |

Source ID: 257

# Planet Hollywood
# Greenhouse Gas
# Allowable Calculations

Caesars Entertainment Inc.

**Planet Hollywood**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| PH03 | Boiler | 1.75 | 8,760 | 1.026E-03 | 14,941,520 | $CO_1$ | 53.06 | 896.78 | 1 | 896.78 |
| | | | | | | $CH_3$ | 1.0E-03 | 0.02 | 25 | 0.42 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.50 |
| PH04 | Boiler | 1.75 | 8,760 | 1.026E-03 | 14,941,520 | $CO_1$ | 53.06 | 896.78 | 1 | 896.78 |
| | | | | | | $CH_3$ | 1.0E-03 | 0.02 | 25 | 0.42 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.002 | 298 | 0.50 |
| PH07 | Boiler | 23.60 | 8,760 | 1.026E-03 | 201,497,076 | $CO_2$ | 53.06 | 12,093.78 | 1 | 12,093.78 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.23 | 25 | 5.70 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.79 |
| PH08 | Boiler | 23.60 | 8,760 | 1.026E-03 | 201,497,076 | $CO_2$ | 53.06 | 12,093.78 | 1 | 12,093.78 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.23 | 25 | 5.70 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.79 |
| PH09 | Boiler | 23.60 | 8,760 | 1.026E-03 | 201,497,076 | $CO_2$ | 53.06 | 12,093.78 | 1 | 12,093.78 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.23 | 25 | 5.70 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.02 | 298 | 6.79 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| PH10 | Engine | 2,550 | 145 | 0.138 | 18,488 | $CO_2$ | 73.96 | 208.03 | 1 | 208.03 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.50 |
| PH11 | Engine | 2,550 | 145 | 0.138 | 18,488 | $CO_2$ | 73.96 | 208.03 | 1 | 208.03 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.50 |
| PH12 | Engine | 2,550 | 145 | 0.138 | 18,488 | $CO_2$ | 73.96 | 208.03 | 1 | 208.03 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.21 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.50 |
| PH13 | Engine | 2,560 | 350 | 0.138 | 44,800 | $CO_2$ | 73.96 | 504.12 | 1 | 504.12 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.02 | 25 | 0.51 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 1.22 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x hrs/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**Planet Hollywood Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 39,203.12 | 0.76 | 0.08 | 39,203.96 | 39,246.31 |

Source ID: 257

# LINQ Complex - High Roller
# Greenhouse Gas
# Applicability and Source Determination
# Calculations

Caesars Entertainment Inc.

**LINQ Complex - High Roller**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| LI01 | Boiler | 5.00 | 8,760 | 1.026E-03 | 42,690,058 | $CO_2$ | 53.06 | 2,562.24 | 1 | 2,562.24 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.21 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.44 |
| LI02 | Boiler | 5.00 | 8,760 | 1.026E-03 | 42,690,058 | $CO_2$ | 53.06 | 2,562.24 | 1 | 2,562.24 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.21 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.44 |
| LI03 | Boiler | 5.00 | 8,760 | 1.026E-03 | 42,690,058 | $CO_2$ | 53.06 | 2,562.24 | 1 | 2,562.24 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.21 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.44 |
| LI04 | Boiler | 5.00 | 8,760 | 1.026E-03 | 42,690,058 | $CO_2$ | 53.06 | 2,562.24 | 1 | 2,562.24 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.21 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.44 |
| LI05 | Boiler | 5.00 | 8,760 | 1.026E-03 | 42,690,058 | $CO_2$ | 53.06 | 2,562.24 | 1 | 2,562.24 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.21 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.44 |
| IA | Water Heater | 0.15 | 8,760 | 1.026E-03 | 1,280,702 | $CO_2$ | 53.06 | 76.867 | 1 | 76.87 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.001 | 25 | 0.04 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.000 | 298 | 0.04 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| LI06 | Engine | 2,937 | 500 | 0.138 | 73,425 | $CO_2$ | 73.96 | 826.23 | 1 | 826.23 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.84 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 2.00 |
| LI07 | Engine | 2,937 | 500 | 0.138 | 73,425 | $CO_2$ | 73.96 | 826.23 | 1 | 826.23 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.03 | 25 | 0.84 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.01 | 298 | 2.00 |
| LI12 | Engine | 241 | 500 | 0.138 | 6,025 | $CO_2$ | 73.96 | 67.80 | 1 | 67.80 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.003 | 25 | 0.07 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.16 |
| LI13 | Engine | 241 | 500 | 0.138 | 6,025 | $CO_2$ | 73.96 | 67.80 | 1 | 67.80 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.003 | 25 | 0.07 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.16 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x 500 hr/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**LINQ Complex - High Roller Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 14,676.12 | 0.32 | 0.039 | 14,676.47 | 14,695.56 |

Source ID: 257

# LINQ Complex - High Roller
# Greenhouse Gas
# Allowable Calculations

Caesars Entertainment Inc.

**LINQ Complex - High Roller**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| LI01 | Boiler | 5.00 | 8,760 | 1.026E-03 | 42,690,058 | $CO_2$ | 53.06 | 2,562.24 | 1 | 2,562.24 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.21 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.44 |
| LI02 | Boiler | 5.00 | 8,760 | 1.026E-03 | 42,690,058 | $CO_2$ | 53.06 | 2,562.24 | 1 | 2,562.24 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.21 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.44 |
| LI03 | Boiler | 5.00 | 8,760 | 1.026E-03 | 42,690,058 | $CO_2$ | 53.06 | 2,562.24 | 1 | 2,562.24 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.21 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.44 |
| LI04 | Boiler | 5.00 | 8,760 | 1.026E-03 | 42,690,058 | $CO_2$ | 53.06 | 2,562.24 | 1 | 2,562.24 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.21 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.44 |
| LI05 | Boiler | 5.00 | 8,760 | 1.026E-03 | 42,690,058 | $CO_2$ | 53.06 | 2,562.24 | 1 | 2,562.24 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.05 | 25 | 1.21 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.005 | 298 | 1.44 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engines | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year* [1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP* [2] | *$CO_2e$ tons/year* |
| LI06 | Engine | 2,937 | 200 | 0.138 | 29,370 | $CO_2$ | 73.96 | 330.49 | 1 | 330.49 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.34 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.80 |
| LI07 | Engine | 2,937 | 200 | 0.138 | 29,370 | $CO_2$ | 73.96 | 330.49 | 1 | 330.49 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.01 | 25 | 0.34 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.00 | 298 | 0.80 |
| LI12 | Engine | 241 | 500 | 0.138 | 6,025 | $CO_2$ | 73.96 | 67.80 | 1 | 67.80 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.003 | 25 | 0.07 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.16 |
| LI13 | Engine | 241 | 500 | 0.138 | 6,025 | $CO_2$ | 73.96 | 67.80 | 1 | 67.80 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.003 | 25 | 0.07 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.001 | 298 | 0.16 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x hrs/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**LINQ Complex - High Roller Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 13,607.78 | 0.27 | 0.031 | 13,608.08 | 13,623.74 |

Source ID: 257

# Forum Meeting Center
# Greenhouse Gas
# Applicability and Allowable
# Calculations

Caesars Entertainment Inc.

**Forum Meeting Center**

| Natural Gas Boilers | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *MMBtu/hr* | *hrs/year* | *MMBtu/scf* | *scf/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| FMC01 | Boiler | 6.00 | 8,760 | 1.026E-03 | 51,228,070 | $CO_2$ | 53.06 | 3,074.69 | 1 | 3,074.69 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.06 | 25 | 1.45 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 1.73 |
| FMC02 | Boiler | 6.00 | 8,760 | 1.026E-03 | 51,228,070 | $CO_2$ | 53.06 | 3,074.69 | 1 | 3,074.69 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.06 | 25 | 1.45 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 1.73 |
| FMC03 | Boiler | 6.00 | 8,760 | 1.026E-03 | 51,228,070 | $CO_2$ | 53.06 | 3,074.69 | 1 | 3,074.69 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.06 | 25 | 1.45 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 1.73 |
| FMC04 | Boiler | 6.00 | 8,760 | 1.026E-03 | 51,228,070 | $CO_2$ | 53.06 | 3,074.69 | 1 | 3,074.69 |
| | | | | | | $CH_4$ | 1.0E-03 | 0.06 | 25 | 1.45 |
| | | | | | | $N_2O$ | 1.0E-04 | 0.01 | 298 | 1.73 |

[1] Fuel usage calculation: (8,760 hours/year * MMBtu/hr) / 1.026E-03 MMBtu/scf = scf/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

| Emergency Engine | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| EU | Description | Rating | Operation | HHV | Fuel Usage | Pollutant | EF | GHG Emissions | | |
| | | *hp* | *hrs/year* | *MMBtu/gal* | *gal/year*[1] | | *kg/ MMBtu* | *GHG tons/year* | *GWP*[2] | *$CO_2e$ tons/year* |
| FMC05 | Engine | 1,490 | 500 | 0.138 | 37,250 | $CO_2$ | 73.96 | 419.16 | 1 | 419.16 |
| | | | | | | $CH_4$ | 3.0E-03 | 0.02 | 25 | 0.43 |
| | | | | | | $N_2O$ | 6.0E-04 | 0.003 | 298 | 1.01 |

[1] Fuel usage calculation: (0.35 lb/hp-hr x hp x 500 hr/year) / 7 lb/gal = gal/year.

[2] Global Warming Potential (GWP) is used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWP is based on the heat-absorbing ability of each gas relative to that of carbon dioxide ($CO_2$). Once the individual GHG emissions are calculated, they have to be multiplied by the GWP to obtain the $CO_2e$ value.

**Forum Meeting Center Greenhouse Gas PTE**

| Pollutant | $CO_2$ | $CH_4$ | $N_2O$ | GHG | $CO_2e$ |
|---|---|---|---|---|---|
| Potential to Emit (tpy) | 12,717.92 | 0.25 | 0.03 | 12,718.19 | 12,732.06 |

# RACT Analysis

# AQR Section 120 Reasonably Available Control Technology Analysis

**Clark County Department of Environment and Sustainability**
**Division of Air Quality**

Caesars Entertainment, Inc.
Caesars Consolidated Properties
One Caesars Palace Drive
Las Vegas, Nevada 89109

Source ID 257

July 23, 2025

Prepared by:

Broadbent & Associates, Inc.
8 West Pacific Avenue
Henderson, Nevada 89015

Project No. 13-01-207

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**Attachments**

Attachment A – Cost Effectiveness Calculations

## 1.0 Background

On December 19, 2024, the Environmental Protection Agency (EPA) advanced the Clark County Hydrographic Area (HA) 212 (Las Vegas Valley) to the serious nonattainment category under the 2015 ozone National Ambient Air Quality Standards (NAAQS) for failing to comply with the standard by August 2024. This reclassification became effective on January 21, 2025, and brought the following changes to permit requirements for existing, new, and modified sources of ozone precursors, including volatile organic compounds (VOCs) and nitrogen oxides ($NO_X$) [40 CFR Part 51, Appendix S]:

- The major source threshold for VOC and $NO_X$ emissions, previously a potential to emit (PTE) of 100 tons per year (tpy) under the "moderate" classification, is lowered to 50 tpy.
- The significant emissions increase threshold, which determines whether a modification is subject to Nonattainment New Source Review (NNSR), is lowered from 40 to 25 tpy of VOC and/or $NO_X$.
- The NNNSR emissions offset ratio, which was 1.15:1 under moderate nonattainment, is raised to 1.2:1 under serious nonattainment and will apply to all NNSR for new major sources and major modifications to existing major sources.

In an anticipatory response to this EPA action, the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) adopted Air Quality Regulation (AQR) Section 120 – Reasonably Available Control Technology (RACT) Demonstration and Determination Requirements for Major Stationary Sources in Ozone Nonattainment Areas effective on December 3, 2024. AQR Section 120 establishes and implements RACT requirements for major stationary sources of $NO_X$ and/or VOCs in areas of serious nonattainment for ozone, including HA 212. According to the regulation, owners and operators of existing stationary sources affected by the regulation must submit a major source RACT demonstration for all affected units by applying for a new stationary source permit or a significant permit revision. In addition to the definition in Section 120.3, DAQ has specified that affected units are individual emissions units located at the major stationary source with a PTE for $NO_X$ or VOC that is equal to, or greater than five tons per year. This application must comply with the submittal requirements outlined in AQR Sections 12.4 and/or 12.5. Even if the demonstration does not result in additional control requirements, sources still must submit a complete application to the Control Officer. Compliance with the application requirements of AQR Section 120 is due on or before August 1, 2025, which is within 120 days after the Control Officer issued a written notice dated April 3, 2025. In lieu of submitting a major source RACT analysis, owners and operators of existing stationary sources affected by the regulation may request voluntary emission limitations that reduce the source's or individual emission unit's $NO_X$ and/or VOC PTE below the major source or affected units' thresholds.

According to AQR Section 120.5(c) sources that were subject to a major source RACT determination that meets the requirements of AQR Section 120 within the past 36 months and the basis of that determination is still relevant, the owner or operator may provide a copy of that prior determination along with a sworn certification that it continues to be RACT because there are no changes to the available control technologies, technical feasibility, control effectiveness, cost-effectiveness, or environmental, energy, and other impacts since that determination was initially performed. Caesars Entertainment, Inc. (Caesars) submitted a major source RACT determination analysis in October 2022 in response to the anticipated January 5, 2023, EPA rulemaking determining that the Las Vegas Valley failed to attain the 2015 $O_3$ NAAQS by the applicable marginal nonattainment deadline and reclassifying the area as a moderate nonattainment area. The RACT analysis submitted at that time was approved and subsequently

incorporated as part of AQR Section 121. AQR Section 121 was adopted February 4, 2025. AQR Section 121.9 contains the RACT Control Requirements, RACT Monitoring Requirements, RACT Testing Requirements and RACT Recordkeeping and Reporting Requirements that were approved specifically for Caesars. As noted above, AQR Section 120 would allow the use of this RACT determination if it meets the requirements of AQR Section 120 within the past 36 months and the basis of that determination is still relevant. However, since certain aspects of the analysis performed in 2022 did not meet specific requirements in AQR Section 120, Caesars is not able to use the currently approved AQR Section 121 RACT determination to satisfy AQR Section 120. As is the case for many of the other facilities included in AQR Section 121, the only requirement of AQR Section 120 that the 2022 RACT determination did not meet is the requirement that the baseline for cost-effectiveness analyses be based on each emission unit's PTE. This is because, under certain circumstances, DAQ allowed the use of actual emissions for the baseline for the moderate nonattainment classification RACT analyses that were performed. The cost-effectiveness calculations that were included in the RACT analysis performed by Caesars at that time used the actual emissions as the baseline.

This report summarizes the AQR Section 120 required revised RACT analysis performed by Caesars and contains its source specific recommendations for RACT.

## 2.0 RACT Applicability

Caesars owns and operates several adjacent and contiguous hotels and casinos and a convention center. The specific properties reviewed for this analysis are as follows:

- Harrah's Las Vegas, 3475 S. Las Vegas Blvd.
- Flamingo Las Vegas, 3555 S. Las Vegas Blvd.
- Horseshoe Las Vegas, 3645 S. Las Vegas Blvd.
- Caesars Palace, 3570 S. Las Vegas Blvd.
- The Cromwell Las Vegas, 3595 S. Las Vegas Blvd.
- Paris Las Vegas, 3655 S. Las Vegas Blvd.
- The LINQ Hotel & Casino, 3535 S. Las Vegas Blvd.
- Planet Hollywood, 3667 S. Las Vegas Blvd.
- LINQ Complex – High Roller, 3545 S. Las Vegas Blvd.
- Forum Meeting Center, 3911 Koval Lane

Consolidating all of the emissions from the various properties, Caesars currently operates as a Part 70 major stationary source according to the conditions contained in the Part 70 Operating Permit Source ID 257 issued by DAQ. RACT is required only if the permitted PTE for either VOC or $NO_X$ exceeds the serious area major source thresholds (50 tons per year for both VOC and $NO_X$). According to the Source PTE summary contained in the facility's current Part 70 operating permit, the PTE for $NO_X$ emissions is 440.30 tons per year, and the PTE for VOC emissions is 27.24 tons per year. Therefore, based on the current permit, only $NO_X$ emissions exceed the serious area major source thresholds, and the analysis can be limited to $NO_X$ emissions.

## 3.0 Affected Emission Units Subject to RACT

DAQ delineated the emission unit applicability requirement to a so-called "affected unit" that includes only those individual emission units at the major stationary source with a PTE that exceeds five tons per

year. Table 1 lists the emission units in the current permit that exceed this threshold for $NO_X$. Although the $NO_X$ PTE for several diesel emergency generators exceeds five tons per year, these emission units are not included in Table 1 since the source has requested to implement annual hourly restrictions to where emissions for those units fall below the five ton per year threshold.

**Table 1 – Affected Emission Units Subject to RACT**

| Emission Unit ID[1] | Description | Maximum Rating | Manufacturer | Model | Fuel Type | $NO_X$ PTE[2] (tons per year) |
|---|---|---|---|---|---|---|
| CP01 | Natural Gas Boiler | 35.40 MMBtu/hr | Hurst | S4-G-800-150 | Natural gas | 5.46 |
| CP02 | Natural Gas Boiler | 35.40 MMBtu/hr | Hurst | S4-G-800-150 | Natural gas | 5.46 |
| CP03 | Natural Gas Boiler | 33.475 MMBtu/hr | Burnham | 3P80050GBNM | Natural gas | 5.35 |
| CP04 | Natural Gas Boiler | 33.475 MMBtu/hr | Burnham | 3P80050GBNM | Natural gas | 5.35 |
| CP05 | Natural Gas Boiler | 33.475 MMBtu/hr | Burnham | 3P80050GBNM | Natural gas | 5.35 |

Notes: [1] Emission Unit ID from Part 70 Operating Permit Table 1-13: Summary of EUs – Caesars Palace.
[2] PTE from Part 70 Operating Permit Table 1-14: PTE (tons per year) – Caesars Palace.

In addition, each emission unit listed in Table 1 has emission limits in pounds per hour and exhaust gas $NO_X$ concentrations in ppm. These additional limitations are summarized in Table 2.

**Table 2 – Emission Unit Emissions Limitations**

| Emission Unit ID | Fuel Type | $NO_X$ Concentration (ppm) | $NO_X$ Emission Rate (lb/hr) |
|---|---|---|---|
| CP01 | Natural gas | 29 @ 3% $O_2$ | 1.24 |
| CP02 | Natural gas | 29 @ 3% $O_2$ | 1.24 |
| CP03 | Natural gas | 30 @ 3% $O_2$ | 1.23 |
| CP04 | Natural gas | 30 @ 3% $O_2$ | 1.23 |
| CP05 | Natural gas | 30 @ 3% $O_2$ | 1.23 |

## 4.0 RACT Analysis

The RACT analysis consists of various steps:

- Identification of existing equipment and baseline emissions
- Identification of available control options
- Elimination of technically infeasible control options
- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options

- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping, and reporting requirements

RACT emissions limitations can take various forms depending on the type of source and as long as the emissions limitations achieve the required emissions reductions and are legally and practically enforceable through appropriate monitoring, recordkeeping, and reporting requirements. In addition, RACT is a continuous emissions reduction requirement and must apply over the range of operations [steady-state, startup, shutdown, and malfunctions (SSM)]; however, RACT can include alternative emissions limitations or work practices for SSM.

For uniformity of comparison, AQR Section 120 requires major sources to use a 6% interest rate to compute annualized costs. This rate was used in all cost analyses contained in this report. In addition, AQR Section 120 requires sources to use the permitted PTE from each emission unit as the base case for determining potential emission reductions associated with any control measures being evaluated for RACT. A cost-effectiveness threshold of $5,500/ton was used for this review, which is consistent with the October 19, 2023, DAQ RACT review report prepared for the ozone serious nonattainment implementation plan.

## 5.0 $NO_X$ RACT Assessment

This RACT analysis follows the same procedures and incorporates many of the same assumptions that were used in the 2022 analysis. This also results in a more conservative analysis of the natural gas boilers. EUs CP01 – CP05 utilize natural gas as the fuel supply. There are no limitations on hours of operation or fuel consumption. $NO_X$ emissions are limited to 29 ppm at 3% $O_2$ (1.24 lb/hr) for EUs CP01 and CP02 and 30 ppm at 3% $O_2$ (1.23 lb/hr) for EUs CP03, CP04 and CP05. All five emissions units are similar (3-pass, firetube type and rated at 800 bhp). The only difference between the emission units is the manufacturer and maximum heat input rating of the burners. For these reasons, this evaluation is being performed for EUs C01 and C02 as a group and EUs C03 – C05 as a group.

### 5.1 Baseline Emissions

As noted above, the baseline emissions used for an AQR Section 120 RACT analysis are required to be equal to the permitted PTE for each emission unit evaluated. The permitted $NO_X$ PTE used as presented in Table 1 in this analysis is 5.46 tons per year for EUs C01 and C02 and 5.35 tons per year for EUs C03 – C05.

### 5.2 Identification of Available Controls

Each boiler is currently equipped with a low $NO_X$ burner for $NO_X$ control. A review of the most recent (5 years) determinations contained in the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) was conducted to identify any recent determinations for boilers of the same or comparable size. In addition, various U.S. EPA control technology reports were reviewed and the current contractor responsible for servicing the Caesars' boilers was consulted to identify potential controls. Based on the information obtained, the proposed $NO_X$ control technologies for EUs CP01-CP05 are summarized in Table 3 on the next page.

**Table 3 – Available $NO_X$ Control Technology Methods for EUs CP01 - CP05**

| Control Equipment | $NO_X$ Reduction Potential (%) | Range of Application | Commercial Availability/ R&D Status |
|---|---|---|---|
| Flue Gas Recirculation (FGR) | 30-60 | FGR requires physical space around the boiler that is not always available | Commercially available with certain boilers |
| Radiant Ceramic Burner | 30-50 (15 ppm) | Burner changeout is normally an option for any boiler. | Commercially available |
| Ultra-Low $NO_X$ Burner | 30-70 (9 ppm) | Burner changeout is normally an option for any boiler. | Commercially available |
| Selective Catalytic Reduction (SCR) | 75-90 | Limited range of application and normally not with boiler exhaust profiles | Commercially available |
| Selective Non-Catalytic Reduction (SNCR) | 75-90 | Limited range of application and normally not with boiler exhaust profiles | Commercially available |

Each of these technologies were evaluated in the 2022 analysis but only the Ultra-Low $NO_X$ burner option was found to be technically feasible. The calculation of the potential emissions reductions associated with the control technologies evaluated assumes that the Ultra-Low $NO_X$ burner replacement option would be capable of reducing current $NO_X$ emissions from 30 ppm to 9 ppm (70% reduction). The most stringent control level of 9 ppm used is consistent with the 2022 analysis conducted and the review of the U.S. EPA RBLC.

### 5.3 Cost Effectiveness of Controls

In order to determine the cost-effectiveness of the control option, the total annualized capital and operating costs are compared to the potential emissions reduction to derive a value of cost per ton of pollutant removed ($/ton). The total annualized capital cost is calculated by applying a capital recovery factor to the total capital investment which includes both the initial capital investment and any direct and indirect costs. The capital recovery factor is based on the estimated equipment life in years and the applicable investment interest rate.

For the purposes of this analysis, the capital cost is based on an actual quote from an equipment vendor, a copy of which is included with Attachment A. For the Ultra-Low $NO_X$ burner control option, these amounts include both the initial capital investment and any direct and indirect costs.

As noted in Section 4, an interest rate of 6% was used in the calculation of the capital recovery factor. An estimated equipment life of 30 years was used for the Ultra-Low $NO_X$ burner option. The detailed cost effectiveness calculations for each boiler are provided in Attachment A. A summary of the results is provided in Table 4 below.

**Table 4 – Cost-Effectiveness Calculation Summary**

| Method of Control | Annualized Cost ($/yr) | Estimated $NO_X$ Removal (tons/yr) | Cost Effectiveness ($/ton removed) |
|---|---|---|---|
| Ultra-Low $NO_X$ Burner (CP01) | $24,192 | 3.82 | $6,330 |
| Ultra-Low $NO_X$ Burner (CP02) | $24,192 | 3.82 | $6,330 |
| Ultra-Low $NO_X$ Burner (CP03) | $24,192 | 3.75 | $6,460 |
| Ultra-Low $NO_X$ Burner (CP04) | $24,192 | 3.75 | $6,460 |
| Ultra-Low $NO_X$ Burner (CP05) | $24,192 | 3.75 | $6,460 |

As shown above, the calculated cost-effectiveness of the Ultra-Low $NO_X$ burner analyzed for each boiler exceeds the RACT threshold of $5,500.

### 5.4 Evaluation of the Benefits and Disadvantages

Evaluation of the benefits and disadvantages includes an evaluation of any additional environmental, energy and economic impacts associated with the control technologies evaluated for RACT. These additional impacts are discussed in this section.

Environmental Impacts

As shown in Table 4, there is only a minimal potential reduction in $NO_X$ emissions associated with the installation of Ultra-Low $NO_X$ burners. Installation of Ultra-Low $NO_X$ burners would result in an increase in carbon monoxide (CO) emissions and necessitate a revision to the current permit. Potential CO emissions would increase by a factor of five for each boiler retrofitted with an Ultra-Low $NO_X$ burner.

Energy Impacts

It is anticipated that only minimal adverse energy impacts would be associated with an Ultra-Low $NO_X$ burner technology since there would be a minimal decrease in burner efficiency.

Economic Impacts

The economic impacts analysis is based on the cost effectiveness of a technology in terms of the cost per ton of removed pollutant as evaluated in Section 5.3. A maximum cost effectiveness threshold for $NO_X$ RACT of $5,500 per ton has been established by DAQ. Installation of Ultra-Low $NO_X$ burners on the existing natural gas boilers at Caesars would entail significant capital costs. As shown above in Section 5.3, the cost-effectiveness of the control options evaluated exceeds the RACT threshold of $5,500 per ton.

### 5.5 $NO_X$ RACT Determination

After reviewing similar facilities for emission control technologies, eliminating technically infeasible options, and evaluating the remaining technologies for environmental, energy, and economic impacts it is determined that the existing emission limitations, monitoring, testing and recordkeeping requirements for EUs C01 – C05 satisfy RACT for compliance with AQR Section 120.

The specific RACT control, monitoring, testing, recordkeeping, and reporting conditions necessary to ensure compliance are described below.

RACT Control Requirements

For natural gas boilers (EUs: CP01 – C05):

(1) Limit $NO_X$ emissions to 29 ppm at 3% $O_2$ (EUs: CP01 and CP02);
(2) Limit $NO_X$ emissions to 30 ppm at 3% $O_2$ (EUs: CP03 – CP05); and
(3) Operate and maintain the units using good combustion practices and in accordance with the manufacturer's O&M manual.

RACT Monitoring Requirements

For natural gas boilers (EUs: CP01 – C05):

(1) Install and utilize nonresettable fuel meters such that the monthly consumption of natural gas can be established for each applicable boiler;
(2) Perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven; and
(3) Demonstrate compliance with $NO_X$ emissions limits.

RACT Testing Requirements

No additional testing requirements are required.

RACT Recordkeeping and Reporting Requirements

For natural gas boilers (EUs: CP01 – C05):

(1) Maintain records of required reporting, including records of all inspections, maintenance, and repairs;
(2) Maintain records of monthly natural gas fuel consumed by each boiler;
(3) Maintain records of burner efficiency test results;
(4) Submit performance test reports;
(5) Submit semiannual reports;
(6) Submit an annual emissions inventory report; and
(7) Submit an annual compliance certification.

# Attachment A – Cost Effectiveness Calculations

**Cost Effectiveness Calculation**

**Emission Unit/Control Technology**

| | |
|---|---|
| Emission Units | CP01 & CP02 |
| Emission Unit Description | Hurst Boilers |
| Control Technology | Ultra-Low $NO_X$ Burner |
| Baseline Emission Rate[1] (tons/year) | 5.46 |
| Emission Reduction[2] (%) | 70% |
| Controlled Emissions (tons/year) | 1.64 |

**Annualized Capital Costs**

| | |
|---|---|
| Initial Capital Investment[3] | $330,000 |
| Direct & Indirect Costs[4] | $3,000 |
| Total Capital Investment | $333,000 |
| Estimated Equipment Life (years) | 30 |
| Interest Rate (%) | 6.0% |
| Capital Recovery Factor | 0.073 |
| Annualized Total Capital Investment | $24,192 |

**Annual Operating Costs**

No additional annual operating cost identified

| | |
|---|---|
| **Total Annualized Cost** | $24,192 |

**Cost Effectiveness**

| | |
|---|---|
| Emissions Reduction (tons/year) | 3.82 |
| Cost Effectiveness of $NO_X$ Reduction ($/ton) | $6,330 |

Notes:

[1] Potential to Emit.

[2] $NO_X$ emissions reduced from 29 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

Caesars Entertainment, Inc.

**Attachment A**
**Cost Effectiveness Calculation**

Source ID 257

**Emission Unit/Control Technology**

| | |
|---|---|
| Emission Units | CP03-CP05 |
| Emission Unit Description | Burnham Boilers |
| Control Technology | Ultra-Low $NO_X$ Burner |
| Baseline Emission Rate[1] (tons/year) | 5.35 |
| Emission Reduction[2] (%) | 70% |
| Controlled Emissions (tons/year) | 1.61 |

**Annualized Capital Costs**

| | |
|---|---|
| Initial Capital Investment[3] | $330,000 |
| Direct & Indirect Costs[4] | $3,000 |
| Total Capital Investment | $333,000 |
| Estimated Equipment Life (years) | 30 |
| Interest Rate (%) | 6.0% |
| Capital Recovery Factor | 0.073 |
| Annualized Total Capital Investment | $24,192 |

**Annual Operating Costs**

No additional annual operating cost identified

| | |
|---|---|
| **Total Annualized Cost** | $24,192 |

**Cost Effectiveness**

| | |
|---|---|
| Emissions Reduction (tons/year) | 3.75 |
| Cost Effectiveness of $NO_X$ Reduction ($/ton) | $6,460 |

Notes:

[1] Potential to Emit.

[2] $NO_X$ emissions reduced from 30 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

PYRO
COMBUSTION & CONTROLS
A THERMOGENICS COMPANY

| Date | Estimate No |
|---|---|
| 7/21/2025 | 251384 |

Attention: Sergy Orlov
Company: Broadbent & Associates, Inc.
Phone: 702-497-9743
Fax:

Pyro Combustion & Controls, Inc, is pleased to offer, for your consideration the following:

REFERENCE REPLACE BURNER ON 1(ONE) BOILER IN CENTRAL PLANT
Location: Caesars Palace

* 1(one)- Powerflame 9PPM Nox 50ppm CO Burner
* Siemens LMV Linkageless with VFD
* 1(one)- Refractory Ring
* Remove existing burner
* Install new refractory ring
* Mount burner to boiler
* Wire to existing controls
* Start-up and check safety controls for proper operation

**Budget Pricing Only

Sales Tax - Clark County

Lead Time:

***Our price, including labor, materials, applicable taxes and freight..... $329,543.00***

Thank you for your consideration, we look forward to receiving your response.
Terms: Orders in excess of $25,000 will require payment of 25% Down, 50% upon Shipping and 25% on Completion.
If payment is made via credit card a 4.5% non-cash transaction fee will apply on all orders over $5,000.00.

*Annie Caraboolad*

If this quotation meets with your approval please sign, date and indicate its purchase order number below and fax back to (702) 385-7976 or email annie@pyrocombustion.com
Quote Valid for 30 Days

Acceptance: _____ Date: _____

Purchase Order # _____

# APPLICABLE REQUIREMENTS AND EXEMPTIONS

## Applicable Requirements

### Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

***Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines***

Diesel emergency generators EUs HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CP13-CP17, PA17, PA18, IP07-IP09, and PH10-PH12 are not subject to 40 CFR 60 Subpart IIII because the engines were manufactured prior to April 1, 2006.

Diesel emergency generators EUs CR07, CP28, CP29, PH13, LI06, and LI07 are subject to 40 CFR 60 Subpart IIII because the engines were manufactured after April 1, 2006.

***§ 60.4200 Am I subject to this subpart?***

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines,

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006 and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

***§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?***

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing

authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

**Title 40: Protection of Environment**

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

***Subpart ZZZZ— National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines***

Diesel emergency generators EUs HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CP13-CP17, PA17, PA18, IP07-IP09, and PH10-PH12 are not subject to 40 CFR 63 Subpart ZZZZ because they are existing commercial stationary RICE located at an area source of HAP. However, it should be noted that the engines are subject to the recordkeeping requirements of 40 CFR 63 Subpart ZZZZ.

Diesel emergency generators EUs CR07, CP28, CP29, PH13, LI06, and LI07 meet the requirements of 40 CFR 63 Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII.

***§63.6585 Am I subject to this subpart?***

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in §63.6675, which includes operating according to the provisions specified in §63.6640(f).

(1) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate §63.6640(f)(4)(ii).

***§ 63.6590 What part of my plant does this subpart cover?***

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(2) New stationary RICE.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

***§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?***

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for the purpose specified in paragraphs (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency

situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

### *§63.6675 What definitions apply to this subpart?*

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

*Commercial emergency stationary RICE* means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

*Emergency stationary RICE* means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

# COMPLIANCE PLAN AND CERTIFICATION

## Compliance Plan and Certification

Based on an evaluation of applicable requirements associated with this significant revision, a compliance plan is not necessary, and no further evaluation is warranted.

# ATTACHMENT 3B: Caesars RACT Supplemental

BROADBENT
8 West Pacific Ave., Henderson, NV 89015
[T] 702-563-0600 [F] 702-563-0610
broadbentinc.com



RECEIVED CC DEQ
2025 DEC 18 PM12:40

December 17, 2025

Project No. 13-01-207

Clark County Department of Environment and Sustainability
Division of Air Quality
Attn: Michael Rael
4701 West Russell Road, Suite 200
Las Vegas, Nevada 89118

**RE: Caesars Entertainment, Inc. – Source 257**
**RACT Analysis**

On behalf of Caesars Entertainment, Inc. (Caesars), Broadbent & Associates, Inc. (Broadbent) is pleased to present the attached Reasonable Available Control Technology (RACT) analysis in response to the letter issued by the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) on December 4, 2025. Should you have any questions or concerns regarding this submittal, please feel free to contact me at (702) 917-6468 or sorlov@broadbentinc.com.

Sincerely,
BROADBENT & ASSOCIATES, INC.

Sergy Orlov
Associate Environmental Scientist

Reviewed and approved by:

Jeri Ruskowitz
Director Environmental Compliance

Attachment: RACT Analysis

EC: Jeri Ruskowitz, jruskowitz1@caesars.com
Gina Wilder, gwilder1@caesars.com

Attachment: RACT Analysis

# AQR Section 120 Reasonably Available Control Technology Analysis

**Clark County Department of Environment and Sustainability**
**Division of Air Quality**

Caesars Entertainment, Inc.
Caesars Consolidated Properties
One Caesars Palace Drive
Las Vegas, Nevada 89109

Source ID 257

December 17, 2025

Prepared by:

Broadbent & Associates, Inc.
8 West Pacific Avenue
Henderson, Nevada 89015

Project No. 13-01-207

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## 1.0 Background

On July 31, 2025, Caesars Entertainment, Inc. (Caesars) submitted a significant revision application to the Clark County Department of Environment & Sustainability, Division of Air Quality (DAQ). As part of that application, a Reasonably Available Control Technology (RACT) analysis was conducted for five boilers located at Caesars Place, emission units (EUs) CP01-CP05. On December 4, 2025, Michael Rael from DAQ requested that Caesars evaluate the following technologies for feasibility and cost effectiveness for EUs CP01-CP05:

1. Overfire Air
2. Oxygen Trim
3. Burner Tuning
4. Fuel Induced Recirculation

This RACT analysis presents the findings as requested by DAQ.

## 2.0 RACT Analysis

The RACT analysis consists of various steps:

- Identification of existing equipment and baseline emissions
- Identification of available control options
- Elimination of technically infeasible control options
- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options
- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping, and reporting requirements

RACT emissions limitations can take various forms depending on the type of source and as long as the emissions limitations achieve the required emissions reductions and are legally and practically enforceable through appropriate monitoring, recordkeeping, and reporting requirements. In addition, RACT is a continuous emissions reduction requirement and must apply over the range of operations [steady-state, startup, shutdown, and malfunctions (SSM)]; however, RACT can include alternative emissions limitations or work practices for SSM.

It should be noted the technologies listed above were all evaluated in the document titled *Case-By-Case RACT for Major VOC and $NO_X$ Sources in Hydrographic Area 212* dated October 19,2023. Since that document was published there have been no additional changes in technological feasibility for the Caesars boilers. Therefore, this document will reiterate the findings summarized in the 2023 document.

## 3.0 $NO_X$ RACT Assessment

This RACT analysis follows the same procedures and incorporates many of the same assumptions that were used in the 2023 analysis. EUs CP01 – CP05 utilize natural gas as the fuel supply. There are no limitations on hours of operation or fuel consumption. $NO_X$ emissions are limited to 29 ppm at 3% $O_2$ (1.24 lb/hr) for EUs CP01 and CP02 and 30 ppm at 3% $O_2$ (1.23 lb/hr) for EUs CP03, CP04 and CP05. All

five emissions units are similar (3-pass, firetube type and rated at 800 bhp). The only difference between the emission units is the manufacturer and maximum heat input rating of the burners. For these reasons, this evaluation is being performed for EUs C01 and C02 as a group and EUs C03 – C05 as a group.

### 3.1 Baseline Emissions

The baseline emissions used for an AQR Section 120 RACT analysis are required to be equal to the permitted PTE for each emission unit evaluated. The permitted $NO_X$ PTE used in this analysis is 5.46 tons per year for EUs C01 and C02 and 5.35 tons per year for EUs C03 – C05.

### 3.2 Identification of Available Controls

Each boiler is currently equipped with a low $NO_X$ burner for $NO_X$ control. As requested by DAQ, the proposed $NO_X$ control technologies for EUs CP01-CP05 are summarized in Table 1 below.

**Table 1 – Available $NO_X$ Control Technology Methods for EUs CP01 - CP05**

| Control Equipment | $NO_X$ Reduction Potential (%) | Range of Application | Commercial Availability/ R&D Status |
|---|---|---|---|
| Overfire Air | 30-58 | Overfire air diverts a portion of combustion air above the primary combustion zone to limit $NO_X$ formation | Commercially available with certain boilers |
| Oxygen Trim | 0-15 | Oxygen trim monitors flue-gas oxygen and adjusts combustion air to minimize excess air | Commercially available |
| Burner Tuning | 0-15 | Burner tuning involves adjustment of air-to-fuel ratios to optimize combustion | Commercially available |
| Fuel Induced Recirculation | 48-68 | Fuel induced recirculation recirculates cooled flue gas to the burner to suppress thermal $NO_X$ formation | Commercially available |

#### 3.2.1 Overfire Air

Overfire Air (OFA) is supplementary air injected into the upper part of a furnace, above the main burners, to complete combustion, improve efficiency, and significantly reduce $NO_X$ formation while ensuring complete burnout of fuel before gases exit. This air staging technique controls emissions and optimizes combustion in boilers by staging air introduction, allowing for tunable, efficient, and cleaner burning of fuels. Below is the excerpt from the 2023 analysis:

*This is often used in conjunction with LNB, so may already be a part of the Caesars boilers. If not, OFA requires modifications to the boiler and is not available for some boiler configurations. The emissions*

*reductions available are estimated at 30–58%. DAQ assumed 50% control efficiency and cost similar to FGR; the CE is $6,327/ton $NO_X$. DAQ has determined that this technology is not RACT because it is not available or cost-effective.*

Per the Caesars boiler maintenance contractor, this technology is not common practice for firetube boilers. Additionally, the physical layout does not allow for this application. For these reasons, OFA is not a technically feasible option for these boilers.

### 3.2.2 Oxygen Trim/Burner Tuning

Oxygen trim (OT) is a system that is used to maintain excess air at the desired level in a boiler. It is designed to continuously measure and maintain an optimum air-to-fuel ratio in the boiler combustion zone. The amount of oxygen present in the exhaust gas of the boiler indicates how much excess air was present in the gas mixture. An oxygen trim system measures the amount of oxygen in the exhaust gas stream and provides feedback to automatically position the air damper to the proper position to maintain a set point of excess air. Burner tuning (BT) is process of adjusting the fuel and air mix, plus other settings, to achieve maximum heat efficiency and minimize pollution. It involves using a combustion analyzer to fine-tune the air/fuel ratio across the boiler's entire operating range (low to high fire) for optimal performance and compliance. Below is the excerpt from the 2023 analysis:

*OT and BT are two relatively simple operational modifications that can be performed to limit the amount of excess oxygen available for combustion. In certain cases, these adjustments can reduce $NO_X$ emissions by as much as 15%, but the actual degree of $NO_X$ reduction depends on the fuel characteristics and burning conditions. For LNBs equipped with automatic rather than manual OT, it is sometimes possible to achieve excess air levels of 5% or less without adversely affecting boiler performance. An EPA publication mentions specific installations and 15–25% control. These techniques, which are a form of LEA control, are often done in conjunction with other control techniques. Since the Caesars boilers are already equipped with LNB, which are designed for LEA, there may be little or no benefit trying to use OT or BT to reduce excess air further. There is little cost information, but one publication mentions an OT retrofit costing $100 per MMBtu/hr in 1992 dollars. For a 33-MMBtu/hr burner, that is a $3,300 capital cost, which in 2022 dollars would be $3,300 x ($824.5/$358.2) = $7,596. The report notes that the monitoring instrumentation (CEM) needed to ensure proper operation and safety could cost as much, so doubling the cost gives a capital cost of $15,192. Assuming $2,000 in annual maintenance, a 30-year life, and 15% reduction in emissions, CE = $7,552/ton. DAQ concludes that LEA is not RACT because it is not cost-effective.*

The burners associated with the Caesars boilers are already low $NO_X$, therefore, implementing oxygen trim would not reduce $NO_X$ any further. In addition, the Caesars burners have outdated components and since parts for these burners are obsolete, further reducing $NO_X$ levels via burning tuning is not feasible. For the reasons stated above, these technologies are not considered technically feasible options.

### 3.2.3 Fuel Induced Recirculation

Fuel Induced Recirculation (FIR) is a technique for natural gas-fired boilers where hot flue gas is mixed directly with the fuel before combustion, diluting it to a lower volatile content and significantly reducing both prompt NO (from fuel nitrogen) and thermal NO (from high temperatures) for lower emissions. The excerpt from the 2023 analysis is on the next page:

*FIR2 "involves the recirculation of a portion of the boiler flue gas and mixing it with the gas fuel at some point upstream of the burner. Although FIR has not yet been widely applied, it has been demonstrated commercially in an industrial unit in California, achieving $NO_X$ emission readings as low as 17 ppm with little adverse effect on CO emissions." Reductions of 48–68% have been demonstrated on a utility boiler; cost information is difficult to find, but the Reese study indicated that capital costs are low. It is difficult to determine whether the existing units can be readily modified for FRI2, and whether the reductions LNB already achieved mean the reductions FRI2 can achieve would be lower. Assuming the cost is about the same as that of an FGR retrofit (estimated at $94,920) and the reduction achievable is 43% (assuming a reduction from 30 ppm down to 17 ppm), the CE is $6,038/ton. DAQ finds that FRI2 is not RACT because is not cost-effective.*

According to the Caesars boiler maintenance contractor, the existing boilers with Riello burners cannot be retrofitted with FIR due to the configuration of the components for the combustion air supply for the burners. Additionally, Riello, the burner manufacturer, stated that this burner is obsolete and parts support is no longer available. The burners would have to be replaced for this technology to be implemented. Therefore, an FIR retrofit is not technically feasible for these boilers.

### 3.3 Cost Effectiveness of Controls

None of the technologies evaluated were deemed technically feasible, therefore, a cost effectiveness analysis was not conducted. However, it should be noted that based on the 2023 analysis, all of the technologies evaluated in section 3.2 of this analysis were deemed not cost effective.

### 3.4 Evaluation of the Benefits and Disadvantages

Evaluation of the benefits and disadvantages includes an evaluation of any additional environmental, energy and economic impacts associated with the control technologies evaluated for RACT. These additional impacts are discussed in this section.

Environmental Impacts

There are no environmental impacts from the technologies evaluated as none of them were deemed technically feasible.

Energy Impacts

There are no energy impacts from the technologies evaluated as none of them were deemed technically feasible.

Economic Impacts

The economic impacts analysis is based on the cost effectiveness of a technology in terms of the cost per ton of removed pollutant. A maximum cost effectiveness threshold for $NO_X$ RACT of $5,500 per ton has been established by DAQ. As shown in Section 3.2, the cost effectiveness of the control options evaluated exceeds the RACT threshold of $5,500 per ton.

### 3.5 $NO_X$ RACT Determination

After eliminating technically infeasible options, and evaluating the remaining technologies for environmental, energy, and economic impacts it is determined that the existing emission limitations, monitoring, testing, and recordkeeping requirements for EUs C01 – C05 satisfy RACT for compliance with AQR Section 120.

The specific RACT control, monitoring, testing, recordkeeping, and reporting conditions necessary to ensure compliance are described below.

RACT Control Requirements

For natural gas boilers (EUs: CP01 – C05):

(1) Limit $NO_X$ emissions to 29 ppm at 3% $O_2$ (EUs: CP01 and CP02);
(2) Limit $NO_X$ emissions to 30 ppm at 3% $O_2$ (EUs: CP03 – CP05); and
(3) Operate and maintain the units using good combustion practices and in accordance with the manufacturer's O&M manual.

RACT Monitoring Requirements

For natural gas boilers (EUs: CP01 – C05):

(1) Install and utilize nonresettable fuel meters such that the monthly consumption of natural gas can be established for each applicable boiler;
(2) Perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven; and
(3) Demonstrate compliance with $NO_X$ emissions limits.

RACT Testing Requirements

No additional testing requirements are required.

RACT Recordkeeping and Reporting Requirements

For natural gas boilers (EUs: CP01 – C05):

(1) Maintain records of required reporting, including records of all inspections, maintenance, and repairs;
(2) Maintain records of monthly natural gas fuel consumed by each boiler;
(3) Maintain records of burner efficiency test results;
(4) Submit performance test reports;
(5) Submit semiannual reports;
(6) Submit an annual emissions inventory report; and
(7) Submit an annual compliance certification.

# ATTACHMENT 4: MGMRI RACT

RECEIVED CC DAQ
2025 JUL 14 PM3:40

MGM RESORTS INTERNATIONAL®

July 8, 2025

Permitting Manager
Clark County Department of Environment and Sustainability
Division of Air Quality
4701 West Russell Road, Suite 200
Las Vegas, NV 89118

RE: *Application for a Significant Permit Revision with RACT Demonstration for a Part 70 Operating Permit Source #00825 – MGM Resorts International*

To Whom it May Concern:

Enclosed is an application for a Significant Permit Revision to the Part 70 Operating Permit issued to MGM Resorts International (MGMRI) by the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) for Source # 00825, on May 19, 2022, and revised on February 12, 2025. MGMRI is submitting an updated Major Source Reasonably Available Control Technology (RACT) Demonstration for all stationary sources located at the MGMRI properties that exceed 5 tons per year (tpy) for either oxides of nitrogen (NOx) or volatile organic compounds (VOC) per the April 3, 2025 regulatory notification from Clark County Department of Environment and Sustainability Division of Air Quality (DAQ).

The enclosed application satisfies the Significant Permit Revision Procedures required by Clark County Air Quality Regulations (CCAQR) Section 12.5 and Section 120. The required DAQ Part 70 Operating Permit Application Forms including the responsible official certification is included in Appendix A of the enclosed application.

If you have technical questions, please contact Krystle Wright at (702) 692-4570, or you may contact me at (702) 692-2105.

Sincerely,

J. Henry Shields
Vice President of Research and Analytics
MGM Resorts International

cc: Blair Stanert, MGMRI
Krystle Wright, MGMRI

RECEIVED CC DAQ
2025 JUL 14 PM3:40

# PROJECT REPORT

## Clark County Division of Air Quality
## Application for a Significant Permit Revision to a Part 70 Operating Permit




**MGM Resorts International / Las Vegas, NV / Source 00825**

**Prepared By:**

**TRINITY CONSULTANTS**
1575 Delucchi Lane
Suite 203
Reno, NV 89502

July 2025

Trinity Consultants

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# 1. EXECUTIVE SUMMARY

MGM Resorts International (MGMRI) is an entertainment company that owns and operates twelve properties located in Las Vegas, Nevada under the jurisdiction of the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ). MGMRI operates the MGM Grand, New York-New York, Park MGM, The Signature at MGM Grand, Mandalay Bay, The Four Seasons, Luxor, Excalibur, Bellagio, CityCenter, T-Mobile Arena, and The Cosmopolitan of Las Vegas (MGMRI Properties). The MGMRI Properties currently operate under a Part 70 Operating Permit (the Permit) for Source 825 issued by DAQ on May 19, 2022, and revised on February 12, 2025.

MGMRI is submitting a significant permit revision (SPR) to include an updated Major Source Reasonably Available Control Technology (RACT) Demonstration for all stationary sources located at the MGMRI properties that exceed 5 tons per year (tpy) for either oxides of nitrogen (NOx) or volatile organic compounds (VOC) per an April 3, 2025 regulatory notification from Clark County Department of Environment and Sustainability Division of Air Quality (DAQ).

This report and associated appendices include all information required for a complete SPR application pursuant to Clark County Air Quality Regulation (CCAQR) Section 12.5.2.14(c) and a complete RACT Demonstration per CCAQR Section 120.

The required DAQ SPR Form is included in Appendix A of this application. The required certification by a responsible official is included in the DAQ Part 70 Operating Permit Application Form. The RACT demonstration, affected emission units, and the RACT/BACT/LAER Clearinghouse (RBLC) Summary is included in Appendix B.

# 2. REGULATORY APPLICABILITY

MGMRI is subject to federal and local air regulations. This section summarizes the air permitting requirements and the key air quality regulations that apply to the equipment at the MGMRI.

Specifically addressed are Clark County Air Quality Regulations. Applicability to certain general provisions is not detailed in this narrative summary.

## 2.1 Clark County Air Quality Regulations

DAQ establishes air quality regulations (CCAQR) applicable at the emission unit level and at the facility level. The regulations also contain requirements related to the need for construction and/or operating permits. The rules potentially applicable to the Project are detailed in the following sections.

### *2.1.1 CCAQR Section 12.2: Permit Requirements for Major Sources in Attainment Areas (PSD)*

MGMRI Properties are located in Clark County, Nevada (Hydrographic Area 212) which, as of the date of this application, is designated as an "attainment" area for all criteria pollutants with the exception of ozone. Under CCAQR Section 12.2, pre-construction review is triggered if an existing PSD major source proposes a major modification for each individual NSR pollutant in attainment status. MGMRI Properties are considered an existing PSD major source as the PTE for at least one PSD pollutant exceeds the major source thresholds provided in CCAQR Section 12.2.2(ff). As the Project does not involve the construction, modification, or reconstruction of any emission units, MGMRI Properties will not cause a significant increase in the emission of any NSR pollutant, therefore, PSD review and permitting procedures are not required.

### *2.1.2 CCAQR Section 12.3: Permit Requirements for Major Sources in Nonattainment Areas*

Permitting requirements under CCAQR Section 12.3 are triggered if a facility proposes a major modification to an existing major stationary source for each NSR pollutant designated as nonattainment. The portion of Clark County that lies in Hydrographic Area 212 (where MGMRI's operations exist) is considered in serious nonattainment for the 2015 Ozone. [1] MGMRI Properties are now considered a major source of VOC, as defined under CCAQR Section 12.3.2(r) because the facility-wide PTE is greater than 50 tpy. As the Project does not involve the construction, modification, or reconstruction of any emission units, Section 12.3 requirements do not apply to the Project.

### *2.1.3 CCAQR Section 12.4: ATC Application and Permit Requirements for Part 70 Sources*

CCAQR Section 12.4.1.1 requires an Authority to Construct (ATC) permit to be issued before beginning actual construction, modification, or reconstruction of a Part 70 source which meets the preconstruction review applicability criteria per CCAQR Section 12.4.1.1(a). As the Project does not involve the construction, modification, or reconstruction of any emission units, Section 12.4 requirements do not apply to the Project.

[1] EPA Green Book website (https://www3.epa.gov/airquality/greenbook/anayo_nv.html) accessed March 5, 2025.

### *2.1.4 CCAQR Section 12.5: Part 70 Operating Permit Requirements*

CCAQR Section 12.5 outlines the requirements for Part 70 Operating Permits in Clark County. The Facility is currently subject to this section and, as a result, is evaluating the Project against the permit revision requirements contained in Section 12.5.2.14.

CCAQR Section 12.5.2.14 allows for changes to be made at the Facility with a significant permit revision such that the following requirements are met:

> *A significant permit revision is any revision to a Part 70 Operating Permit that cannot be accomplished under the Section 12.5.2.14 provisions for minor or administrative permit revisions. Any permit revision for purposes of the "acid rain" portion of the permit shall be governed by regulations promulgated by the Administrator under Title IV of the Act and shall require a significant permit revision.*

The proposed Project involves a RACT Demonstration and a significant permit revision is required per 12.5.2.14(c). CCAQR Section 12.5.2.14(c)(1) and (2) outlines significant permit revision procedures that must be adhered to:

> 1. *Significant permit revision procedures shall be used for applications requesting permit modifications that do not qualify as minor permit revisions or as administrative permit revisions, including the creation of a PAL pursuant to Section 12.2.19. At a minimum, every significant change in existing monitoring permit terms or conditions, and every relaxation of reporting or recordkeeping permit terms or conditions, shall be considered significant. Nothing herein shall be construed to preclude the permittee from making changes consistent with this part that would render existing permit compliance terms and conditions irrelevant.*
>
> 2. *Significant permit revisions shall meet all requirements for issuance and renewal of a Part 70 Operating Permit under Sections 12.5.2.10 and 12.5.2.11, including those for applications, public participation, review by affected states, and review by EPA, as they apply to permit issuance and permit renewal. The Control Officer shall complete review on the majority of significant permit revisions within nine (9) months after receipt of a complete application.*

All requirements for issuance and renewal of a Part 70 Operating Permit under Sections 12.5.2.10 and 12.5.2.11, including the requirement for a complete application pursuant to CCAQR Section 12.5.2.1(b), which are described in detail below:

> *(1) To be deemed complete, an application must provide all information necessary to evaluate the subject source and its application and to determine all applicable requirements, including the emission rates information required by paragraph (a)(3) of Section 12.4.3.1. Applications for permit revisions need supply only such information as is related to the proposed change. A responsible official shall certify the submitted information consistent with Section 12.5.2.4.*

As discussed in Section 1 and Appendix B, MGMRI is not applying for an ATC under Section 12.4 and all information necessary to evaluate the subject source and its application and to determine all applicable requirements of Section 12.5, including the ton per year (tpy) emission information, is included in this application. A certification from the responsible official is provided in Appendix C.

> *(2) Unless the Control Officer notifies the source in writing within sixty (60) days of receipt of the application that an application is not complete, such application shall be deemed to be complete.*

MGMRI will promptly respond to any written requests from the Control Officer for the completeness determination.

*(3) A completeness determination shall not be required for a minor permit revision.*

As discussed above, this application is not for a minor permit revision.

*(4) If, while processing an application that has been determined or deemed to be complete, the Control Officer determines that additional information is necessary to evaluate or take final action on that application, the Control Officer may request such information in writing and set a reasonable deadline for a response. Failure to provide the information requested in a timely manner may result in a determination that the application is incomplete.*

MGMRI will promptly respond to any written requests from the Control Officer.

*(5) The submittal of a complete application shall not affect the requirement that any source shall have an Authority to Construct Permit issued pursuant to Section 12.4.3 prior to construction.*

As discussed above, MGMRI is not applying for an ATC permit as part of this application.

### *2.1.5 CCAQR Section 13: National Emission Standards for Hazardous Air Pollutants*

CCAQR Section 13 incorporates the NESHAP codified at 40 CFR Part 61 and Part 63 by reference, which are discussed in Section 2.1.3 of this report.

### *2.1.6 CCAQR Section 14: New Source Performance Standards*

CCAQR Section 14 incorporates the NSPS codified at 40 CFR Part 60 by reference, which are discussed in Section 2.1.2 of this report.

### *2.1.7 CCAQR Section 18: Permit and Technical Service Fees*

CCAQR Section 18 specifies fees that must be paid as part of permit applications and various other compliance activities.

### *2.1.8 CCAQR Section 26: Emission of Visible Air Contaminants*

CCAQR Section 26 prohibits a single source to discharge any air contaminant which exceeds an average of 20 percent opacity for a period of more than six consecutive minutes. MGMRI is subject to the requirements of this rule and will operate all equipment in a manner to meet the opacity requirements of CCAQR Section 26.

### *2.1.9 CCAQR Section 40: Prohibitions of Nuisance Conditions*

CCAQR Section 40 prohibits the discharge of air contaminants which are injurious to health, offensive to the senses, or otherwise interfere with the reasonable or comfortable enjoyment of life or property. MGMRI is subject to the requirements of this rule and will operate all equipment in a manner to avoid any public nuisance as stipulated under CCAQR Section 40.

### 2.1.10 *CCAQR Section 120: Reasonably Available Control Technology Demonstration and Determination Requirements for Major Stationary Sources In Ozone Nonattainment Areas*

CCAQR Section 120 establishes and implements RACT demonstration and determination requirements for major stationary sources of NOx and/or VOC as required by Section 182(b)(2) of the Clean Air Act (Act) under Title 42, Section 7511a of the U.S. Code (42 U.S.C. 7511a). MGMRI is submitting this SPR to satisfy the requirements of Section 120 and detailed information can be found in Appendix B including the RACT demonstration, the RBLC summary, and the affected emission units at MGMRI. MGMRI will operate all equipment in a manner to satisfy the rules stipulated under CCAQR Section 120 once the final RACT determination has been made by DAQ and incorporated into the operating permit, if required.

# APPENDIX A. SPR APPLICATION FORM

# Title V (Part 70) Permit Application

## Clark County Department of Environment & Sustainability Division of Air Quality

**Submit Application to:**
**Division of Air Quality**
**4701 W. Russell Road, Suite 200**
**Las Vegas NV 89118**

**For DAQ Use Only**

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## Section A: Permit Application Basis (check all that apply):

- ☐ Initial Permit
- ☐ Renewal Permit
- ☐ Administrative Revision
- ☐ Minor Revision*
- ■ Significant Revision*

*For all AQR 12.4.3.2 modifications, including Title V permit revisions based on AQR 12.4.3.2(d) and (e), use the Title V ATC application form (see Section G, "Application Instructions").

If applying for a revision: Has an NSR Authority to Construct already been issued? ■ Yes ☐ No

***Application Description:*** Describe the Title V permitting action being proposed, e.g., new process, change to equipment, change to permit conditions, Voluntarily Accepted Emission Limit (VAEL), incorporating ATC, etc.

MGMRI is submitting an updated Major Source Reasonably Available Control Technology (RACT) Demonstration for all stationary sources located at the MGMRI properties that exceed 5 tons per year (tpy) for either oxides of nitrogen (NOx) or volatile organic compounds (VOC) per an April 3, 2025 regulatory notification from Clark County Department of Environment and Sustainability Division of Air Quality (DAQ).

**Applications for a Part 70 permit shall include the information requested in Sections B–F.**

***Complete the fields in Sections B–F even if there is no change from the previous application.***

## Section B: Source Information

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**

Source ID No: 825

Source Name (as listed on Clark County/State of Nevada business license): MGM Resorts International

Permit Expiration Date (existing permits only): 05/18/2027

City/County Business License #: 2001566.071-221

**Source Location Information**

| Number: | Direction (E., W.): | Street Name: | Cross Streets: |
|---|---|---|---|
| 3600 | S | Las Vegas Boulevard | |

City: Las Vegas | State: NV | Zip: 89109

**Phone Numbers**

Office: 702-692-5664 | Fax:

**North American Industry Classification System (NAICS) / Source Industry Classification Code**

Primary NAICS: 721120 | Additional NAICS (optional):

***Source Description:*** Describe the nature of your business, including processes and products.

MGMRI operates equipment and activities that support the operation of the MGMRI Hotels. This equipment includes natural gas-fired boilers and water heaters, diesel-fired emergency generators and fire pumps, natural gas-fired turbines, gasoline storage and dispensing facilities, woodworking equipment, heat dissipating cooling towers, and surface coating operations.

## Section C: Company Information (AS LISTED ON THE SECRETARY OF STATE'S BUSINESS CERTIFICATE/FILING)

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**
If company ownership and/or name has changed, separately submit a Transfer of Ownership / Change of Name form+ fee (SS-PER-020-01).

Company Name: MGM Resorts International

**Location Information**

| Number: | Direction (W., E.): | Street Name: | Street Type (Rd., Ave.): | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| 3600 | S | Las Vegas | Boulevard | | |
| City: Las Vegas | | | State: NV | ZIP: 89109 | |

***Proof of Company Name:*** Have you selected "New Permit" for the action type above? ☐ YES ■ NO

If YES, attach a printout of your company's business listing on the Nevada Secretary of State website, or other formal documentation that includes your company's full legal name.

**Phone Numbers**

| Office: 702-692-6494 | Fax: |
|---|---|

**Type of Organization**

■ Corporation ☐ Individual Owner ☐ Partnership ☐ Government Entity ☐ Other

## Section D: Responsible Official (RO) Information

Has any of this information changed since the previous application? ■ YES ☐ NO **(Existing Permit Holders Only)**
If the RO has changed, separately submit a Declaration of Responsible Official form (RO-PER-003).

| Name: J. Henry Shields | Title: Vice President of Research and Analytics |
|---|---|

**Location Information**

| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| 3260 | | Sammy Davis Jr. | Drive | BLDG A | |
| City: Las Vegas | | | State: NV | Zip: 89109 | |
| Email: jshields@mgmresorts.com | | | Primary Communication Method: ■ Email ☐ U.S. Postal | | |

**Phone Numbers**

| Office: 702-692-2105 | Extension: | Cell: | Fax: |
|---|---|---|---|

## Section E: Plant Manager/Environmental Representative Contact Information

| Name: Krystle Wright | Title: Sr. Manager, Energy and Compliance |
|---|---|

**Location Information**

| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| 3730 | S | Las Vegas | Boulevard | | |
| City: Las Vegas | | | State: | Zip: | |
| Email: kwright@mgmresorts.com | | | Primary Communication Method: ■ Email ☐ U.S. Postal | | |

**Phone Numbers**

| Office: 702-692-4570 | Extension: | Cell: 702-209-5149 | Fax: |
|---|---|---|---|

## Section F: Billing Contact (Accounts Payable) Information (Optional)

| Name: | Title: |
|---|---|
| Email: | Primary Communication Method: ☐ Email ☐ U.S. Postal |

**Phone Numbers**

| Office: | Extension: | Cell: | Fax: |
|---|---|---|---|

## Section G: Application Instructions

1. For all construction, modification, or reconstruction, the owner or operator shall use the Title V ATC Application Form instead of this Title V Application Form.
2. An owner or operator of an existing or new Part 70 source shall obtain an Authority to Construct (ATC) Permit from the Control Officer before beginning actual construction or continuing with any of the following:
   a. Operating a new Part 70 source;
   b. "Major modification," as defined in AQR 12.2 or 12.3;
   c. Modification that increases the Part 70 source's potential to emit (PTE) by an amount equal to or greater than the minor New Source Review (NSR) significant level in AQR 12.4.2.1;
   d. Construction, modification, or reconstruction of an affected facility that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 60;
   e. Construction or reconstruction of a new source or of an affected source that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 63, including, but not limited to, construction or modification that requires preconstruction review under 40 CFR Part 63.5; or
   f. Modification to a solid waste incinerator unit, as defined by an applicable standard under 40 CFR Part 60.
3. For each Part 70 source, the owner or operator shall submit a timely and complete permit application in accordance with AQR 12.5.2.1.
4. Claims of confidentiality as to information submitted to EPA shall be made pursuant to applicable federal requirements in 40 CFR Part 2. Claims of confidentiality as to information submitted to the department shall be made pursuant to AQR 12.6.

## Section H: Application Supplemental Documents

*Information worksheets for common source types and emission units are posted on the DES website under **Applications/Forms → Stationary Source Permitting Forms → Emission Unit/Control Device Worksheets & Tools**. Applicants can use these documents to provide some of the technical information requested below.*

1. To comply with the requirements of AQR 12.5, the applicant shall submit all of the following information for initial and renewal Title V permit applications. For all other applications, the applicant may omit information that is not related to the proposed changes.
   A. Process description, including any alternative operating scenarios or federally enforceable emissions caps. Emission unit descriptions, including material/fuel usage and/or operating schedules.
   B. Emissions information with supporting calculations for all regulated air pollutants and HAPs, including fugitive emission rates, which shall include calculations of emission rates, short-term limits, hourly rates and tons per year emissions of each emission unit..
   C. Emission information in tons per year for each emission unit and the entire source.
   D. Description of all applicable requirements and/or exemptions, including Voluntarily Accepted Emission Limits (VAEL) and/or Plant-wide Applicability Limits (PAL).
   E. Air pollution control information with associated monitoring and testing requirements (example: for a baghouse, opacity test, pressure drop range and periodic inspections).
   F. Information related to stack height limitations and stack parameters.
   G. An explanation of any proposed exemptions from otherwise applicable requirements.
   H. Any alternative operating scenarios that are proposed in the application pursuant to paragraph (j) of Section 12.5.2.6, such information as is necessary for the Control Officer to define those scenarios and determine the applicable requirements for each proposed scenario.
   I. Compliance plan for all applicable requirements, as set forth in AQR 12.5.2.3(j).
   J. Compliance certification, as set forth in AQR 12.5.2.3(k).
   K. Compliance Assurance Monitoring plan, if determined to be applicable.
   L. Acid rain application, if applicable.

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M. Permit shield (optional).

N. Other information that may be necessary to implement and enforce other requirements of the Clean Air Act or determine the applicability of such requirements.

2. In addition to the requirements above, an application for a minor revision shall include the following:

   A. A description of the change, the emissions estimated to result from the change, and any new applicable requirements that will apply if the change occurs.

   B. Suggested draft permit conditions from the source, including a markup of the operating permit with the changes.

   C. Justification that the proposed modifications meet the criteria for use of minor revision procedures.

   D. All relevant forms, completed, for the Control Officer to submit to EPA and affected states or tribes.

## Section I: Application Advisories

**Permit Applications: Duty to Supplement or Correct (AQR 12.5.2.2).** When an applicant learns of missing or incorrect information in its permit application, it must provide or correct the information as soon as practicable. If additional requirements are deemed to apply after an applicant files a complete application but before the draft permit is released, the applicant must furnish all information needed to address them. The applicant's Responsible Official shall certify the additional information consistent with the requirements of Section 12.5.2.4.

1. **Small Business Assistance.** A DAQ program that offers free assistance on permitting and compliance matters to small businesses (100 employees or fewer). Please ask for an SBA representative at our front counter or call (702) 455-5942 to schedule an appointment.

2. **Fees and Payments.**

   A. Application Filing Fee: There is no application filing fee for Title V permits.

   B. Permit Issuance: All outstanding invoices for the source and associated with the parent company of the source must be paid in full; otherwise, DAQ cannot issue the source any permits. This includes the invoice for the permit fees resulting from this application.

   C. Payment: Invoices must be paid by check, money order, or credit card. Make checks and money orders payable to Division of Air Quality or DAQ. Credit card payments must be made in person at DAQ's main office.

## Section J: Grant of Authority

I authorize DAQ to transmit all communications, permits, and billing invoices by the primary communication method selected in Section D of this application. I acknowledge that if I select "Email," DAQ will transmit all listed items electronically. I further acknowledge that if I select "U.S. Postal Service," I may incur applicable postage fees.

## Section K: Certification of Truth, Accuracy, and Completeness

As the Responsible Official, I declare, under penalty of perjury under the laws of the state of Nevada, that the statements and information in this application and the attached supplemental documents and worksheets are true and correct. My signature acknowledges that I am subject to liability for perjury under NRS Chapter 199.145.

J. Henry Shields — 7/14/2025

Responsible Official Certification (original "wet" signature) — Date

J. Henry Shields

Printed Name of Responsible Official

**If this application is being submitted for an existing permit holder, it must be signed by an RO on file for this source.**

# APPENDIX B. RACT DEMONSTRATION

# REASONABLY AVAILABLE CONTROL TECHNOLOGY DEMONSTRATION




## MGM Resorts International / Las Vegas, NV

**Prepared By:**

**TRINITY CONSULTANTS**
1575 Delucchi Lane
Suite 203
Reno, NV 89502

July 2025



Trinity Consultants

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**ATTACHMENT B: EMISSION UNITS SUBJECT TO RACT** B

# 1. EXECUTIVE SUMMARY

MGM Resorts International (MGMRI) has been requested by Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) to prepare and submit a Reasonably Available Control Technology (RACT) analysis for certain emission units at the contiguous group of hotels owned by MGMRI and located in Las Vegas, Nevada. MGMRI operates the MGM Grand, New York-New York, Park MGM, The Signature at MGM Grand, Mandalay Bay, The Four Seasons, Luxor, Excalibur, Bellagio, CityCenter, T-Mobile Arena, and The Cosmopolitan of Las Vegas (MGMRI Properties). The MGMRI Properties currently operate under a Part 70 Operating Permit (the Permit) for Source 00825 issued by DAQ on May 19, 2022, and revised on February 12, 2025.

DAQ requested that a RACT analysis be submitted by August 1, 2025, for emission units with a potential-to-emit (PTE) exceeding five tons per year (tpy) of oxides of nitrogen ($NO_x$) or volatile organic compounds (VOCs) at major sources (>50 tpy) of $NO_x$ or VOCs, respectively, within Hydrographic Area (HA) 212. This request was triggered as a result of the proposed reclassification of hydrographic area 212 from moderate to serious nonattainment for ozone.[1] The new classification requires HA 212 to establish emissions control requirements in its State Implementation Plan (SIP), including RACT requirements.[2] RACT should be considered as the lowest emissions an industrial source is allowed to emit through the use of a control technology that is reasonably available considering technological and economic feasibility.[3]

MGMRI submitted a RACT determination on October 3, 2022 to comply with the DAQ requested RACT analysis for the reclassification of HA 212 from marginal to moderate non-attainment for ozone. While the previous RACT determination was completed within 36 months and met the requirements of Section 120 at the time, MGMRI has since added the Cosmopolitan of Las Vegas to the permit and due to the decreased major source thresholds for NOx and VOC, became a major since for VOC as well as with respect to Nonattainment New Source Review permitting. As such, MGMRI is submitting this revised RACT determination to account for newly subject emission units and demonstrate that previous determinations are still valid.

The MGMRI Hotels are currently a major source of $NO_x$ and VOC (i.e., site-wide $NO_x$ and VOC PTE are both greater than 50 tpy), therefore this analysis considers any emission units at the MGMRI Hotels with PTE greater than five (5) tpy of $NO_x$ or VOC. As part of this new RACT demonstration, MGMRI identified various diesel-fired engines driving emergency generators that have potential emissions greater than five tpy of $NO_x$ and one (1) surface coating operation (spray booth) that has potential emissions greater than five (5) tpy of VOC which were not previously reviewed and are therefore are included in this RACT analysis. The site-wide PTE is presented in Table 1-1 of this report and the emission units subject to RACT are summarized in Appendix B.[4]

[1] 87 FR 103657.

[2] Per CCAQR Section 120 FAQ's accessed at https://webfiles.clarkcountynv.gov/FAQ%20AQR%20120%20HA212.pdf

[3] Ibid.

[4] Site-wide PTE per the Permit.

**Table 1-1. Site-Wide PTE (tpy)**

| Pollutant | $PM_{10}$ | $PM_{2.5}$ | $NO_x$ | CO | $SO_2$ | VOC | HAP | GHG |
|---|---|---|---|---|---|---|---|---|
| Source Total | 82.74 | 79.25 | 784.83 | 350.03 | 3.95 | 75.61 | 21.61 | 578,164.37 |

Per CCAQR Section 120.5 and the previous MGMRI RACT determination, the Major Source RACT determination requirements are summarized below and should be included in the submittal as applicable:

- General Information, such as:
  - Confirmation of Major Source PTE (Potential to Emit)
  - List of emission units potentially subject to a RACT Requirement
  - Rated size or maximum capacity of each emission unit, and the type of fuel combusted or the types and quantities of materials processed or produced from the production process in which the emission unit is located
- RACT Specific Information, such as:
  - Information sources relied on to identify available control options
  - Ranking of available control options based on control effectiveness
  - Evaluation of technical feasibility
  - Annual cost effectiveness ($/ton)
  - Baseline and controlled tpy emission estimates (and basis)
  - Environmental, energy, and other impacts (benefits and disbenefits); GHG, HAP or other pollutants
  - Proposed RACT emission limitation or averaging approach
  - Proposed testing, monitoring, and recordkeeping and reporting meeting periodic or CAM monitoring requirements.

MGMRI has reviewed the technical and economic feasibility of control methods for the diesel-fired emergency engines and the spray booth identified in Appendix B. MGMRI determined that complying with the applicable 40 CFR Part 60 Subpart IIII requirements including emission standards for stationary compression ignition (CI) internal combustion emergency engines constitutes RACT for LX024, LX025, TM01, CO07, CO08, and CO09 and complying with good combustion practices (GCP) constitutes RACT for all other diesel-fired emergency engines. Additionally, the Facility's diesel-fired emergency engines currently comply with relevant RACT prohibitory rules of other air agencies.

Additionally, MGMRI determined that complying with work practice standards and limiting as possible the maximum VOC content of the paints, paint thinners, solvents etc. used in the spray booth as well as ensuring proper maintenance of the ancillary equipment constitutes RACT.

Therefore, there are no proposed changes to the emission limitations and testing, monitoring, and recordkeeping requirements contained in the Permit for the applicable diesel-fired emergency engines and the spray booth. Section 2 contains a detailed RACT analysis and discussion.

# 2. REASONABLY ACHIEVABLE CONTROL TECHNOLOGY ASSESSMENT

A RACT evaluation consists of a technical and economic feasibility analysis for implementation of either passive or active methods for reducing emissions. Various options, including control devices and process changes are evaluated to determine their technical feasibility. Those that are deemed technically feasible are evaluated to determine their economic feasibility, which is based on the cost effectiveness of the reduction technique in terms of the cost per ton of pollutant controlled. The cost is the sum of the annualized capital cost and the annual operating cost. Those that exceed a certain threshold are deemed economically infeasible. The technically and economically feasible option that results in the largest decrease in emissions is deemed RACT. MGMRI believes the controls associated with the current level of $NO_x$ emissions from the emergency engines and the current level of VOC from the spray booth are considered RACT and no additional control technology is technically or economically feasible.

## 2.1 Technically Feasible Options

MGMRI has evaluated RACT for all applicable diesel-fired emergency engines and the spray booth at the MGMRI Hotels by determining what process changes and add-on emission controls are technically feasible for this specific type of equipment. Potential emission reduction measures were determined by a review of EPA's RACT/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The following sections provide details on the assessment methodology utilized in the RACT analysis for the affected emission units.

### 2.1.1 Characterization of Process Equipment

The cost and efficiency of $NO_x$ reduction technology is dependent on the nature of the equipment in which the control device will be installed. Thus, it is important to classify the process equipment properly for the purposes of determining RACT. The process equipment consists of 49 diesel-fired emergency engines with ratings approximately between 1,100 and 3,700 horsepower (hp) and one spray booth with an annual permitted throughput of 2,000 gallons of paint strippers, paints, basecoats, primers, reducers, thinners, solvents, etc., with a weighted average VOC content of 6.84 pounds per gallon (lb/gal). Therefore, the engines are classified as Large Internal Combustion Engines (> 500 hp) and the paint booth as miscellaneous metal parts and products surface coating and plastic parts and products surface coating for purposes of the RBLC. Please refer to Appendix B for a complete description of each applicable diesel-fired emergency engine and paint booth at the Facility.

### 2.1.2 Identification of Potential Control Technologies

Available $NO_x$ and VOC control technologies are identified for each emission unit in question. The following methods are used to identify potential technologies: (1) researching the RBLC database; (2) surveying regulatory agencies; (3) drawing from previous engineering experience; (4) surveying air pollution control equipment vendors; and (5) surveying available literature.

#### *2.1.2.1 RACT/BACT/LAER Clearinghouse (RBLC)*

The RBLC, a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emission units.

MGMRI performed searches of the RBLC in May of 2025 to identify the emission control technologies and emission levels that were determined by permitting authorities as RACT, BACT, or LAER. Searches were performed for determinations within the past ten (10) years for emission sources comparable to those at MGMRI Hotels. The following categories were searched:

- Large Internal Combustion Engines (> 500 hp)
  - Fuel Oil (ASTM #1,2, includes kerosene, aviation, diesel fuel) (RBLC Code 17.110)
- Miscellaneous metal parts and products surface coating and plastic parts and products surface coating (except 41.015)
  - RBLC Codes 41.013 and 41.016

The following control technologies are technologically feasible based on the RBLC database search results.

- For diesel-fired emergency engines,
  - Use of GCP
  - EPA Tier Certification
- For surface coating operations (spray booth)
  - Maximum VOC content of coating material.

The RBLC search results are available in Appendix A.

### *2.1.2.2 Technically Feasible Options for Diesel-Fired Emergency Engines*

#### 2.1.2.2.1 EPA Tier Certification

Certain emergency engines, based on date of manufacture and construction, are certified to comply with EPA Tier Emission Standards as outlined in 40 CFR Part 60 Subpart IIII for stationary CI internal combustion emergency engines or stationary fire pump engines, per the maximum engine power and model year.

#### 2.1.2.2.2 Good Combustion Practices

The use of GCP at the Facility includes operating diesel-fired emergency engines to obtain a good air/fuel mixture in the combustion zone by maintaining overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency and by providing sufficient residence time to complete combustion. GCP also includes operating the equipment in accordance with the manufacturer's recommended settings and preventative maintenance schedules. Following good combustion practices is in the interest of engine operators from an efficiency and reliability perspective.

### *2.1.2.3 Technical Feasibility Determination – Diesel-Fired Emergency Engines*

The Facility's diesel-fired emergency engines are assumed to use GCP as they are maintained and operated in accordance with manufacturer specifications. Additionally, applicable emission units (EUs) (e.g., LX024, LX025, TM01, CO07, CO08, and CO09) are subject to and comply with 40 CFR Part 60 Subpart IIII requirements, including emission standards per the maximum engine power and model year, for stationary CI internal combustion emergency engines. The use of GCP is technically feasible and has been demonstrated in practice for all applicable emergency engines at the Facility.

Additionally, in its 2010 MACT (Maximum Achievable Control Technology) /GACT (Generally Available Control Technology) evaluation for RICE (Reciprocating Internal Combustion Engines), EPA concluded for emergency RICE: "Because these engines are typically used only a few number of hours per year, the costs

of emission control are not warranted when compared to the emission reductions that would be achieved."[5] Based on EPA's assessment and the fact that the RBLC contains no records of add on controls (i.e., SCR) installation on emergency-use RICE, add on controls are eliminated from consideration as RACT.

Furthermore, MGMRI reviewed the current RACT requirements for emergency engines in other agency jurisdictions. For example, San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 4702 limits emissions of $NO_x$ from internal combustion engines greater than 25 brake horsepower (BHP).[6] Pursuant to SJVAPCD Rule 4702 Section 4.2, emergency engines comply with the Rule by:

- Limiting annual operation and only operating for specific purposes (e.g., testing, maintenance, and emergency purposes),
- Utilizing a non-resettable hour meter,
- Operating and maintaining the engine as recommended by the engine manufacturer, and
- Maintaining records of operation.

Similarly, South Coast Air Quality Management District (SCAQMD) Rule 1110-2 limits $NO_x$ emissions from engines. Per Subsection (i) of that Rule, emergency engines are not subject to the emission standards of the Rule (and associated requirements).[7] MGMRI concludes that the current Permit requirements for the Facility's diesel-fired emergency engines are consistent with the RACT prohibitory requirements of other jurisdictions, such as SJVAPCD and SCAMQD. As such, the installation of add on controls or implementation of additional emission standards is eliminated from consideration as RACT.

### *2.1.2.4 Technical Feasible Options for the Surface Coating Operations (Spray Booth)*

#### 2.1.2.4.1 Maximum VOC Content

VOCs are emitted from surface coating operations due to the volatilization of VOCs from VOC containing aerosols during transfer to the coated material. The emissions occur within a spray booth with an induced draft to direct the aerosolized particles to a dust collector. While the dust collector removes particulates, there is no post emissions control for VOC. Therefore, emissions of VOC can be most readily controlled by limiting the VOC content in the coating materials (paints, paint thinners, solvents etc.). Clark County issued CTG RACT requirements (CCAQR Section 103)[8] for surface coating operations and while it was determined that MGMRI is not subject to the rule, the control technologies listed in the rule included maximum VOC content restrictions.

### *2.1.2.5 Technical Feasibility Determination- Surface Coating Operations (Spray Booth)*

The potential control for the surface coating operations from the RBLC review is listed below:

- Maximum VOC content of paints, paint thinners, solvent, etc.

---

[5] U.S. EPA, Memorandum: Response to Public Comments on Proposed National Emission Standards for Hazardous Air Pollutants for Existing Stationary Reciprocating Internal Combustion Engines Located at Area Sources of Hazardous Air Pollutant Emissions or Have a Site Rating Less Than or Equal to 500 Brake HP Located at Major Sources of Hazardous Air Pollutant Emissions, August 10, 2010, p. 172-173. (EPA-HQ-OAR-2008-0708).

[6] SJVAPCD Rule 4702, Amended August 19, 2021. https://www.valleyair.org/rules/currntrules/r4702.pdf

[7] SCAQMD Rule 1110-2, Amended November 1, 2019. http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf?sfvrsn=4

[8] CCAQR Section 103 https://webfiles.clarkcountynv.gov//103_20250204_AQR.pdf

The applicable paint booth at the MGMRI Hotels has an annual throughput of 2,000 gallons of paint strippers, paints, basecoats, primers, reducers, thinners, solvents, etc., with a weighted average VOC content of 6.84 lb/gal per 1.1.3.1.4 of the Permit. Therefore, it is assumed that limiting the weighted average VOC content to 6.84 lb/gal will be implemented for the spray booth regardless of other emission controls. As limiting the VOC content of the coating material is the only technically feasible option, no further control technology review or cost analysis is needed.

The RBLC review in Table A-2 showed BACT determinations for PSD sites with 99.99 ton per year emissions of VOC using maximum VOC content (6.5 lb/gal) as the control. While MG39 is limited to a weighted average VOC content of 6.84 lb/gal, which is slightly higher than the BACT-PSD determination value, MG39 has a total potential emission rate of only 6.84 tpy. As the overall emissions are significantly lower than the comparable facilities and are not expected to increase significantly, MGMRI has determined that continuing to limit the weighted average VOC content to 6.84 lb/gal satisfies RACT.

### 2.1.3 Selection of $NO_x$ RACT for the Diesel-Fired Emergency Engines

As discussed in Section 2.1.2.6, the Facility's diesel-fired emergency engines use GCP as they are maintained and operated in accordance with manufacturer specifications. EUS LX024, LX025, TM01, CO07, CO08, and CO09 are certified to comply with the applicable emission standards as outlined in 40 CFR Part 60 Subpart IIII for stationary CI internal combustion emergency engine, per the maximum engine power and model year. As discussed previously, the installation of add-on controls to the existing emergency engines is not feasible per EPA and other agencies' RACT prohibitory rules (e.g., SCAQMD and SJVAPCD) do not require compliance with specific $NO_x$ emission standards for emergency engines. Therefore, the use of GCP is technically feasible and is selected as meeting RACT for the diesel-fired emergency engines. Additionally, compliance with applicable 40 CFR Part 60 Subpart IIII requirements, such as emission standards, will be selected as RACT for EUs subject to this regulation (e.g., EUS: LX024, LX025, TM01, CO07, CO08, and CO09).

MGMRI intends to maintain the current emission limits for $NO_x$ as contained in the Permit for each of the affected diesel emergency engines. MGMRI will utilize the existing Permit conditions to monitor compliance with the $NO_x$ emission limits contained in the Permit.

### 2.1.4 Selection of VOC RACT for the Surface Coating Operations (Spray Booth)

The result of the RACT analysis shows that limiting the weighted average VOC content of the surface coating materials to 6.84 lb/gal satisfies RACT for the spray booth.

MGMRI intends to maintain the current emission limits for VOC as contained in the Permit for MG39. MGMRI will utilize the existing Permit conditions to monitor compliance with the VOC emission limits contained in the Permit.

# ATTACHMENT A: SUMMARY OF RBLC

Table A-1. NOx RBLC Data for Diesel Generators

| RBLCID | Facility Name | Permit No. | SIC | NAICS | Permit Issuance Date | Process | Process Type | Fuel | Throughput | Unit | Pollutant | Control Method | Emission Limit (1) | Unit | Determination Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AQ1201CPT03 | 1382 | 211111 | 01/23/2015 | Remote Incinerator Generator Engine | 21.4 | Ultra Low Sulfur Diesel | 102 | hp | Nitrogen Oxides (NOx) | | 3 | LB/TON | BACT-PSD |
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AQ1201CPT03 | 1382 | 211111 | 01/23/2015 | Emergency Camp Generators | 17.11 | Ultra Low Sulfur Diesel | 2695 | hp | Nitrogen Oxides (NOx) | | 4.8 | GRAMS/ HP-H | BACT-PSD |
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AQ1201CPT03 | 1382 | 211111 | 01/23/2015 | Airstrip Generator Engine | 17.21 | Ultra Low Sulfur Diesel | 490 | hp | Nitrogen Oxides (NOx) | | 4.8 | GRAMS/ HP-H | BACT-PSD |
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AQ1201CPT03 | 1382 | 211111 | 01/23/2015 | Agitator Generator Engine | 17.21 | Ultra Low Sulfur Diesel | 98 | hp | Nitrogen Oxides (NOx) | | 5.6 | GRAMS/ HP-H | BACT-PSD |
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AQ1201CPT03 | 1382 | 211111 | 01/23/2015 | Incinerator Generator Engine | 17.21 | Ultra Low Sulfur Diesel | 102 | hp | Nitrogen Dioxide (NO2) | | 4.9 | GRAMS/ HP-H | BACT-PSD |
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AQ1201CPT03 | 1382 | 211111 | 01/23/2015 | Boilers and Heaters | 13.22 | Ultra Low Sulfur Diesel | 7 | MMBTU/H | Nitrogen Oxides (NOx) | | 20 | LB/1,000 GAL | BACT-PSD |
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AQ1201CPT03 | 1382 | 211111 | 01/23/2015 | Fine Water Pumps | 17.11 | Ultra Low Sulfur Diesel | 610 | hp | Nitrogen Oxides (NOx) | | 3 | GRAMS/ HP-H | BACT-PSD |
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AQ1201CPT03 | 1382 | 211111 | 01/23/2015 | Bulk Tank Generator Engines | 17.11 | Ultra Low Sulfur Diesel | 891 | hp | Nitrogen Oxides (NOx) | | 4.8 | GRAMS/ HP-H | BACT-PSD |
| AK-0084 | DONLIN GOLD PROJECT | AQ0934CPT01 | 1041 | 212221 | 06/30/2017 | Black Start and Emergency Internal Cumbustion Engines | 17.11 | Diesel | 1500 | kWe | Nitrogen Oxides (NOx) | Good Combustion Practices | 8 | G/KW-HR | BACT-PSD |
| AK-0084 | DONLIN GOLD PROJECT | AQ0934CPT01 | 1041 | 212221 | 06/30/2017 | Fire Pump Diesel Internal Combustion Engines | 17.21 | Diesel | 252 | hp | Nitrogen Oxides (NOx) | Good Combustion Practices | 3.7 | G/KW-HR | BACT-PSD |
| AK-0085 | GAS TREATMENT PLANT | AQ1524CPT01 | 4922 | 486210 | 08/13/2020 | One (1) Black Start Generator Engine | 17.11 | ULSD | 186.6 | gph | Nitrogen Oxides (NOx) | Good combustion practices, limit operation to 500 hours per year. | 3.3 | G/HP-HR | BACT-PSD |
| AK-0085 | GAS TREATMENT PLANT | AQ1524CPT01 | 4922 | 486210 | 08/13/2020 | Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators | 17.21 | ULSD | 19.4 | gph | Nitrogen Oxides (NOx) | Good combustion practices, limit operation to 500 hours per year per engine | 3.6 | G/HP-HR | BACT-PSD |
| AK-0088 | LIQUEFACTION PLANT | AQ1539CPT01 | 4922 | 488999 | 07/07/2022 | Diesel Fire Pump Engine | 17.11 | Diesel | 27.9 | Gal/hr | Nitrogen Oxides (NOx) | Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII | 3.6 | G/HP-HR | BACT-PSD |
| AK-0088 | LIQUEFACTION PLANT | AQ1539CPT01 | 4922 | 488999 | 07/07/2022 | Auxiliary Air Compressor Engine | 17.21 | Diesel | 14.6 | Gal/hr | Nitrogen Oxides (NOx) | Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII | 0.45 | G/HP-HR | BACT-PSD |
| AL-0318 | TALLADEGA SAWMILL | 309-0075 | 2421 | 321113 | 12/18/2017 | 250 Hp Emergency CI, Diesel-fired RICE | 17.11 | Diesel | 0 | | Nitrogen Oxides (NOx) | | 0 | | N/A |
| AL-0328 | PLANT BARRY | 503-1001 | 4911 | 221112 | 11/09/2020 | Diesel Emergency Engines | 17.11 | Diesel | 0 | | Nitrogen Oxides (NOx) | | 3 | GR/BHP-HR | BACT-PSD |
| AR-0161 | SUN BIO MATERIAL COMPANY | 2384-AOP-R0 | 2611 | 322110 | 09/23/2019 | Emergency Engines | 17.11 | Diesel | 0 | | Nitrogen Oxides (NOx) | Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII | 0.4 | G/KW-H | BACT-PSD |
| AR-0163 | BIG RIVER STEEL LLC | 2305-AOP-R6 | 3312 | 331111 | 06/09/2019 | Emergency Engines | 17.11 | Diesel | 0 | | Nitrogen Oxides (NOx) | Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII | 4.86 | G/KW-HR | BACT-PSD |
| AR-0177 | NUCOR STEEL ARKANSAS | 1139-AOP-R27 | 3312 | 331111 | 11/21/2022 | SN-230 Galvanizing Line No, 2 Emergency Generator | 17.11 | Diesel | 3634 | Horsepower | Nitrogen Oxides (NOx) | | 5.6 | G/KW-HR | BACT-PSD |
| AR-0180 | HYBAR LLC | 2470-AOP-R0 | 3312 | 331111 | 04/28/2023 | Emergency Generators | 17.11 | Diesel | 0 | | Nitrogen Oxides (NOx) | Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII | 3.9 | G/BHP-HR | BACT-PSD |

**Table A-1. NOx RBLC Data for Diesel Generators**

| RBLCID | Facility Name | Permit No. | SIC | NAICS | Permit Issuance Date | Process | Process Type | Fuel | Throughput | Unit | Pollutant | Control Method | Emission Limit (1) | Unit | Determination Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AR-0180 | HYBAR LLC | 2470-AOP-R0 | 3312 | 331111 | 04/28/2023 | Emergency Water Pumps | 17.21 | Diesel | 0 | | Nitrogen Oxides (NOx) | Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII | 14.06 | G/BHP-HR | BACT-PSD |
| FL-0367 | SHADY HILLS COMBINED CYCLE FACILITY | 1010524-001-AC | 4911 | 221112 | 07/27/2018 | 1,500 kW Emergency Diesel Generator | 17.11 | ULSD | 14.82 | MMBtu/hour | Nitrogen Oxides (NOx) | Operate and maintain the engine according to the manufacturer's written instructions | 6.4 | G/KW-HOUR | BACT-PSD |
| FL-0367 | SHADY HILLS COMBINED CYCLE FACILITY | 1010524-001-AC | 4911 | 221112 | 07/27/2018 | Emergency Fire Pump Engine (347 HP) | 17.21 | ULSD | 8700 | gal/year | Nitrogen Oxides (NOx) | Operate and maintain the engine according to the manufacturer's written instructions | 4 | G/KW-HR | BACT-PSD |
| FL-0371 | SHADY HILLS COMBINED CYCLE FACILITY | 1010524-003-AC (PSD-FL-444A) | 4911 | 221112 | 06/07/2021 | 1,500 kW Emergency Diesel Generator | 17.11 | ULSD | 14.82 | MMBtu/hour | Nitrogen Oxides (NOx) | | 6.4 | G/KW-HOUR | BACT-PSD |
| FL-0371 | SHADY HILLS COMBINED CYCLE FACILITY | 1010524-003-AC (PSD-FL-444A) | 4911 | 221112 | 06/07/2021 | Emergency Fire Pump Engine (347 HP) | 17.21 | ULSD | 2.46 | MMBtu/hour | Nitrogen Oxides (NOx) | | 4 | G/KW-HOUR | BACT-PSD |
| IL-0129 | CPV THREE RIVERS ENERGY CENTER | 16060032 | 4911 | 221112 | 07/30/2018 | Emergency Engines | 17.11 | Ultra-low sulfur diesel | 0 | | Nitrogen Oxides (NOx) | | 0 | | LAER |
| IL-0129 | CPV THREE RIVERS ENERGY CENTER | 16060032 | 4911 | 221112 | 07/30/2018 | Firewater Pump Engine | 17.21 | Ultra-low sulfur diesel | 0 | | Nitrogen Oxides (NOx) | | 0 | | LAER |
| IL-0130 | JACKSON ENERGY CENTER | 17040013 | 4911 | 221112 | 12/31/2018 | Firewater Pump Engine | 17.21 | Ultra-Low Sulfur Diesel | 420 | horsepower | Nitrogen Oxides (NOx) | | 4 | G/KW-HR | LAER |
| IL-0130 | JACKSON ENERGY CENTER | 17040013 | 4911 | 221112 | 12/31/2018 | Emergency Engine | 17.11 | Ultra-Low Sulfur Diesel | 1500 | kW | Nitrogen Oxides (NOx) | | 6.4 | G/KW-HR | LAER |
| IL-0133 | LINCOLN LAND ENERGY CENTER | 18040008 | 4911 | 221112 | 07/29/2022 | Emergency Engines | 17.11 | Ultra-Low Sulfur Diesel | 1250 | kW | Nitrogen Oxides (NOx) | | 6.4 | GRAMS | BACT-PSD |
| IL-0133 | LINCOLN LAND ENERGY CENTER | 18040008 | 4911 | 221112 | 07/29/2022 | Fire Water Pump Engine | 17.21 | Ultra-Low Sulfur Diesel | 320 | horsepower | Nitrogen Oxides (NOx) | | 4 | GRAMS | BACT-PSD |
| IL-0134 | CRONUS CHEMICALS | 19110020 | 2873 | 325311 | 12/21/2023 | Emergency Generator Engine | 17.11 | Diesel Fuel | 3985 | hp | Nitrogen Oxides (NOx) | | 6.4 | G/KW-HR | BACT-PSD |
| IL-0134 | CRONUS CHEMICALS | 19110020 | 2873 | 325311 | 12/21/2023 | Firewater Pump Engine | 17.21 | Diesel Fuel | 369 | hp | Nitrogen Oxides (NOx) | | 4 | G/KW-HR | BACT-PSD |
| IN-0263 | MIDWEST FERTILIZER COMPANY LLC | 129-36943-00059 | 2873 | 325311 | 03/23/2017 | EMERGENCY GENERATORS (EU014A AND EU-014B) | 17.11 | DISTILLATE OIL | 3600 | HP EACH | Nitrogen Oxides (NOx) | GOOD COMBUSTION PRACTICES | 4.42 | G/HP-H EACH | BACT-PSD |
| IN-0317 | RIVERVIEW ENERGY CORPORATION | T147-39554-00065 | 2911 | 324110 | 06/11/2019 | Emergency generator EU-6006 | 17.11 | Diesel | 2800 | HP | Nitrogen Oxides (NOx) | Tier II diesel engine | 6.4 | G/KWH | BACT-PSD |
| IN-0317 | RIVERVIEW ENERGY CORPORATION | T147-39554-00065 | 2911 | 324110 | 06/11/2019 | Emergency fire pump EU-6008 | 17.11 | Diesel | 750 | HP | Nitrogen Oxides (NOx) | Engine that complies with Table 4 to Subpart IIII of Part 60 | 4 | G/KWH | BACT-PSD |
| IN-0324 | MIDWEST FERTILIZER COMPANY LLC | 129-44510-00059 | 2873 | 325311 | 05/06/2022 | emergency generator EU 014a | 17.11 | distillate oil | 3600 | HP | Nitrogen Oxides (NOx) | | 4.42 | G/HP-HR | BACT-PSD |
| IN-0359 | NUCOR STEEL | 107-45480-00038 | 3312 | 331111 | 03/30/2023 | Emergency Generator (CC-GEN1) | 17.11 | diesel | 3000 | Horsepower | Nitrogen Oxides (NOx) | certified engine | 4.8 | G/HP-HR | BACT-PSD |
| IN-0359 | NUCOR STEEL | 107-45480-00038 | 3312 | 331111 | 03/30/2023 | Emergency Generator (CC-GEN2) | 17.21 | diesel | 500 | Horsepower | Nitrogen Oxides (NOx) | certified engine | 3 | G/HP-HR | BACT-PSD |
| *IN-0365 | MAPLE CREEK ENERGY LLC | T153-45909-00056 | 4911 | 221112 | 06/19/2023 | Emergency generator | 17.11 | Ultra low sulfur diesel | 2012 | hp | Nitrogen Oxides (NOx) | | 4.8 | G/HP-HR | BACT-PSD |
| *IN-0365 | MAPLE CREEK ENERGY LLC | T153-45909-00056 | 4911 | 221112 | 06/19/2023 | Emergency fire pump | 17.11 | Diesel | 420 | brake hp | Nitrogen Oxides (NOx) | | 4 | G/KW-HR | BACT-PSD |
| IN-0371 | WABASH VALLEY RESOURCES, LLC | 167-45208-00091 | 2869 | 325199 | 01/11/2024 | Emergency Generator (400 kW) | 17.11 | Diesel | 619 | HP | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements. | 2.29 | G/HP-HR | BACT-PSD |
| IN-0371 | WABASH VALLEY RESOURCES, LLC | 167-45208-00091 | 2869 | 325199 | 01/11/2024 | Emergency Generator (1000 kW) | 17.11 | Diesel | 1000 | kW | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements. | 3.81 | G/HP-HR | BACT-PSD |
| IN-0371 | WABASH VALLEY RESOURCES, LLC | 167-45208-00091 | 2869 | 325199 | 01/11/2024 | Emergency Generator (2000 kW) | 17.11 | Diesel | 2000 | kW | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements. | 3.81 | G/HP-HR | BACT-PSD |
| IN-0371 | WABASH VALLEY RESOURCES, LLC | 167-45208-00091 | 2869 | 325199 | 01/11/2024 | Ammonia Plant Emergency Generator | 17.11 | Diesel | 500 | kW | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements. | 4.8 | G/HP-HR | BACT-PSD |
| IN-0384 | SYCAMORE RIVERSIDE ENERGY LLC | 153-47292-00062 | 4911 | 221112 | 03/31/2025 | Black Start Emergency Generators | 17.11 | ultra-low sulfur diesel | 3000 | kWe, each | Nitrogen Oxides (NOx) | GOOD COMBUSTION PRACTICES AND LOW SULFUR FUELS | 4.56 | G | BACT-PSD |
| IN-0384 | SYCAMORE RIVERSIDE ENERGY LLC | 153-47292-00062 | 4911 | 221112 | 03/31/2025 | plant emergency generator | 17.11 | ultra-low sulfur diesel | 1500 | kWe | Nitrogen Oxides (NOx) | good combustion practices and low sulfur fuel | 4.56 | G | BACT-PSD |

**Table A-1. NOx RBLC Data for Diesel Generators**

| RBLCID | Facility Name | Permit No. | SIC | NAICS | Permit Issuance Date | Process | Process Type | Fuel | Throughput | Unit | Pollutant | Control Method | Emission Limit (1) | Unit | Determination Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IN-0384 | SYCAMORE RIVERSIDE ENERGY LLC | 153-47292-00062 | 4911 | 221112 | 03/31/2025 | emergency fire water pump | 17.21 | ultra-low sulfur diesel | 282 | bhp | Nitrogen Oxides (NOx) | Good combustion practices, low sulfur fuel | 2.85 | G | BACT-PSD |
| KY-0110 | NUCOR STEEL BRANDENBURG | V-20-001 | 3312 | 331111 | 07/23/2020 | EP 10-02 - North Water System Emergency Generator | 17.11 | Diesel | 2922 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 4.77 | G/HP-HR | BACT-PSD |
| KY-0110 | NUCOR STEEL BRANDENBURG | V-20-001 | 3312 | 331111 | 07/23/2020 | EP 10-03 - South Water System Emergency Generator | 17.11 | Diesel | 2922 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 4.77 | G/HP-HR | BACT-PSD |
| KY-0110 | NUCOR STEEL BRANDENBURG | V-20-001 | 3312 | 331111 | 07/23/2020 | EP 10-04 - Emergency Fire Water Pump | 17.11 | Diesel | 920 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 4.77 | G/HP-HR | BACT-PSD |
| KY-0110 | NUCOR STEEL BRANDENBURG | V-20-001 | 3312 | 331111 | 07/23/2020 | EP 11-01 - Melt Shop Emergency Generator | 17.21 | Diesel | 260 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 2.98 | G/HP-HR | BACT-PSD |
| KY-0110 | NUCOR STEEL BRANDENBURG | V-20-001 | 3312 | 331111 | 07/23/2020 | EP 11-02 - Reheat Furnace Emergency Generator | 17.21 | Diesel | 190 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 2.98 | G/HP-HR | BACT-PSD |
| KY-0110 | NUCOR STEEL BRANDENBURG | V-20-001 | 3312 | 331111 | 07/23/2020 | EP 10-07 - Air Separation Plant Emergency Generator | 17.11 | Diesel | 700 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 4.77 | G/HP-HR | BACT-PSD |
| KY-0110 | NUCOR STEEL BRANDENBURG | V-20-001 | 3312 | 331111 | 07/23/2020 | EP 10-01 - Caster Emergency Generator | 17.11 | Diesel | 2922 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 4.77 | G/HP-HR | BACT-PSD |
| KY-0110 | NUCOR STEEL BRANDENBURG | V-20-001 | 3312 | 331111 | 07/23/2020 | EP 11-03 - Rolling Mill Emergency Generator | 17.21 | Diesel | 440 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 2.98 | G/HP-HR | BACT-PSD |
| KY-0110 | NUCOR STEEL BRANDENBURG | V-20-001 | 3312 | 331111 | 07/23/2020 | EP 11-04 - IT Emergency Generator | 17.21 | Diesel | 190 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 2.98 | G/HP-HR | BACT-PSD |
| KY-0110 | NUCOR STEEL BRANDENBURG | V-20-001 | 3312 | 331111 | 07/23/2020 | EP 11-05 - Radio Tower Emergency Generator | 17.21 | Diesel | 61 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 3.5 | G/HP-HR | BACT-PSD |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | V-20-015 | 3316 | 331111 | 04/19/2021 | New Pumphouse (XB13) Emergency Generator #1 (EP 08-05) | 17.11 | Diesel | 2922 | HP | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan | 0 | | BACT-PSD |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | V-20-015 | 3316 | 331111 | 04/19/2021 | Tunnel Furnace Emergency Generator (EP 08-06) | 17.11 | Diesel | 2937 | HP | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan | 0 | | BACT-PSD |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | V-20-015 | 3316 | 331111 | 04/19/2021 | Caster B Emergency Generator (EP 08-07) | 17.11 | Diesel | 2937 | HP | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan | 0 | | BACT-PSD |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | V-20-015 | 3316 | 331111 | 04/19/2021 | Air Separation Unit Emergency Generator (EP 08-08) | 17.11 | Diesel | 700 | HP | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan | 0 | | BACT-PSD |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | V-20-015 | 3316 | 331111 | 04/19/2021 | Cold Mill Complex Emergency Generator (EP 09-05) | 17.21 | Diesel | 350 | HP | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan | 0 | | BACT-PSD |
| LA-0292 | HOLBROOK COMPRESSOR STATION | PSD-LA-769(M-1) | 4922 | 486210 | 01/22/2016 | Emergency Generators No. 1 & No. 2 | 17.11 | Diesel | 1341 | HP | Nitrogen Oxides (NOx) | Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart IIII | 14.16 | LB/HR | BACT-PSD |
| LA-0305 | LAKE CHARLES METHANOL FACILITY | PSD-LA-803(M1) | 2869 | 325199 | 06/30/2016 | Diesel Engines (Emergency) | 17.11 | Diesel | 4023 | hp | Nitrogen Oxides (NOx) | Complying with 40 CFR 60 Subpart IIII | 0 | | BACT-PSD |
| LA-0307 | MAGNOLIA LNG FACILITY | PSD-LA-792 | 4922 | 221210 | 03/21/2016 | Diesel Engines | 17.11 | Diesel | 0 | | Nitrogen Oxides (NOx) | good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII | 0 | | BACT-PSD |
| LA-0309 | BENTELER STEEL TUBE FACILITY | PSD-LA-774(M1) | 3312 | 331111 | 06/04/2015 | Firewater Pump Engines | 17.21 | Diesel | 288 | hp (each) | Nitrogen Oxides (NOx) | Complying with 40 CFR 60 Subpart IIII | 3 | G/BHP-HR | BACT-PSD |
| LA-0309 | BENTELER STEEL TUBE FACILITY | PSD-LA-774(M1) | 3312 | 331111 | 06/04/2015 | Emergency Generator Engines | 17.11 | Diesel | 2922 | hp (each) | Nitrogen Oxides (NOx) | Complying with 40 CFR 60 Subpart IIII | 6.4 | G/KW-HR | BACT-PSD |
| *LA-0312 | ST. JAMES METHANOL PLANT | PSD-LA-780(M-1) | 2869 | 325998 | 06/30/2017 | DFP1-13 - Diesel Fire Pump Engine (EQT0013) | 17.11 | Diesel | 650 | horsepower | Nitrogen Oxides (NOx) | Compliance with NSPS Subpart IIII | 6.6 | LB/HR | BACT-PSD |

**Table A-1. NOx RBLC Data for Diesel Generators**

| RBLCID | Facility Name | Permit No. | SIC | NAICS | Permit Issuance Date | Process | Process Type | Fuel | Throughput | Unit | Pollutant | Control Method | Emission Limit (1) | Unit | Determination Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *LA-0312 | ST. JAMES METHANOL PLANT | PSD-LA-780(M-1) | 2869 | 325998 | 06/30/2017 | DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012) | 17.11 | Diesel | 1474 | horsepower | Nitrogen Oxides (NOx) | Compliance with NSPS Subpart IIII | 19.23 | LB/HR | BACT-PSD |
| LA-0313 | ST. CHARLES POWER STATION | PSD-LA-804 | 4911 | 221112 | 08/31/2016 | SCPS Emergency Diesel Generator 1 | 17.11 | Diesel | 2584 | HP | Nitrogen Oxides (NOx) | Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel). | 27.34 | LB/H | BACT-PSD |
| LA-0313 | ST. CHARLES POWER STATION | PSD-LA-804 | 4911 | 221112 | 08/31/2016 | SCPS Emergency Diesel Firewater Pump 1 | 17.21 | Diesel | 282 | HP | Nitrogen Oxides (NOx) | Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel). | 1.87 | LB/H | BACT-PSD |
| LA-0316 | CAMERON LNG FACILITY | PSD-LA-766(M3) | 4922 | 221210 | 02/17/2017 | firewater pump engines (8 units) | 17.21 | diesel | 460 | hp | Nitrogen Dioxide (NO2) | Complying with 40 CFR 60 Subpart IIII | 0 | | BACT-PSD |
| LA-0316 | CAMERON LNG FACILITY | PSD-LA-766(M3) | 4922 | 221210 | 02/17/2017 | emergency generator engines (6 units) | 17.11 | diesel | 3353 | hp | Nitrogen Oxides (NOx) | Complying with 40 CFR 60 Subpart IIII | 0 | | BACT-PSD |
| LA-0317 | METHANEX - GEISMAR METHANOL PLANT | PSD-LA-761(M4) | 2869 | 325199 | 12/22/2016 | Emergency Generator Engines (4 units) | 17.11 | Diesel | 0 | | Nitrogen Oxides (NOx) | complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ | 0 | | BACT-PSD |
| LA-0317 | METHANEX - GEISMAR METHANOL PLANT | PSD-LA-761(M4) | 2869 | 325199 | 12/22/2016 | Firewater pump Engines (4 units) | 17.11 | diesel | 896 | hp (each) | Nitrogen Oxides (NOx) | complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ | 0 | | BACT-PSD |
| LA-0323 | MONSANTO LULING PLANT | PSD-LA-890 | 2879 | 325320 | 01/09/2017 | Fire Water Diesel Pump No. 3 Engine | 17.11 | Diesel Fuel | 600 | hp | Nitrogen Oxides (NOx) | Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII | 0 | | BACT-PSD |
| LA-0323 | MONSANTO LULING PLANT | PSD-LA-890 | 2879 | 325320 | 01/09/2017 | Fire Water Diesel Pump No. 4 Engine | 17.11 | Diesel Fuel | 600 | hp | Nitrogen Oxides (NOx) | Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII | 0 | | BACT-PSD |
| LA-0323 | MONSANTO LULING PLANT | PSD-LA-890 | 2879 | 325320 | 01/09/2017 | Standby Generator No. 9 Engine | 17.21 | Diesel Fuel | 400 | hp | Nitrogen Oxides (NOx) | Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII | 0 | | BACT-PSD |
| LA-0324 | COMMONWEALTH LNG FACILITY | PSD-LA-841 | 4925 | 221210 | 03/28/2023 | Firewater Pump Engine (EQT0017 - EQT0020) | 17.11 | diesel | 0 | | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage. | 5.53 | G/KW-HR | BACT-PSD |
| LA-0324 | COMMONWEALTH LNG FACILITY | PSD-LA-841 | 4925 | 221210 | 03/28/2023 | Generator Engines (EQT0016) | 17.11 | diesel | 4290 | kw | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage. | 8.46 | G/KW-HR | BACT-PSD |
| LA-0331 | CALCASIEU PASS LNG PROJECT | PDS-LA-805 | 4925 | 221210 | 09/21/2018 | Firewater Pumps | 17.11 | Diesel Fuel | 634 | kW | Nitrogen Oxides (NOx) | Good Combustion and Operating Practices. | 3.1 | G/HP-H | BACT-PSD |
| LA-0331 | CALCASIEU PASS LNG PROJECT | PDS-LA-805 | 4925 | 221210 | 09/21/2018 | Large Emergency Engines (>50kW) | 17.11 | Diesel Fuel | 5364 | HP | Nitrogen Oxides (NOx) | Good Combustion and Operating Practices | 5.6 | G/KW-H | BACT-PSD |
| LA-0364 | FG LA COMPLEX | PSD-LA-812 | 2869 | 325110 | 01/06/2020 | Emergency Generator Diesel Engines | 17.11 | Diesel Fuel | 550 | hp | Nitrogen Oxides (NOx) | Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage. | 0 | | BACT-PSD |
| LA-0364 | FG LA COMPLEX | PSD-LA-812 | 2869 | 325110 | 01/06/2020 | Emergency Fire Water Pumps | 17.11 | Diesel Fuel | 550 | hp | Nitrogen Oxides (NOx) | Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage. | 0 | | BACT-PSD |

**Table A-1. NOx RBLC Data for Diesel Generators**

| RBLCID | Facility Name | Permit No. | SIC | NAICS | Permit Issuance Date | Process | Process Type | Fuel | Throughput | Unit | Pollutant | Control Method | Emission Limit (1) | Unit | Determination Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LA-0379 | SHINTECH PLAQUEMINES PLANT 1 | PSD-LA-709(M-4) | 2821 | 325211 | 05/04/2021 | PVC Emergency Combustion Equipment A | 17.21 | Diesel | 450 | hp | Nitrogen Oxides (NOx) | Good combustion practices/gaseous fuel burning. | 6.9 | G/HP-HR | BACT-PSD |
| LA-0379 | SHINTECH PLAQUEMINES PLANT 1 | PSD-LA-709(M-4) | 2821 | 325211 | 05/04/2021 | PVC Emergency Combustion Equipment 2A and 2B | 17.21 | Diesel | 300 | hp | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII. | 0.4 | G/KW-HR | BACT-PSD |
| LA-0382 | BIG LAKE FUELS METHANOL PLANT | PSD-LA-781(M1) | 2869 | 325199 | 04/25/2019 | Emergency Engines (EQT0014 - EQT0017) | 17.11 | Diesel | 0 | | Nitrogen Oxides (NOx) | Comply with standards of 40 CFR 60 Subpart IIII | 0 | | BACT-PSD |
| LA-0383 | LAKE CHARLES LNG EXPORT TERMINAL | PSD-LA-838 | 4925 | 486210 | 09/03/2020 | Emergency Engines (EQT0011 - EQT0016) | 17.11 | Diesel | 0 | | Nitrogen Oxides (NOx) | Comply with 40 CFR 60 Subpart IIII | 0 | | BACT-PSD |
| LA-0391 | MAGNOLIA POWER GENERATING STATION UNIT 1 | PSD-LA-839 | 4911 | 221112 | 06/03/2022 | Emergency Diesel Generator Engine | 17.11 | Diesel | 2937 | hp | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra low sulfur diesel fuel. | 4.8 | G/HP-HR | BACT-PSD |
| LA-0391 | MAGNOLIA POWER GENERATING STATION UNIT 1 | PSD-LA-839 | 4911 | 221112 | 06/03/2022 | Emergency Diesel Fired Water Pump Engine | 17.21 | Diesel | 355 | hp | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra low sulfur diesel fuel. | 3 | G/HP-HR | BACT-PSD |
| *LA-0394 | GEISMAR PLANT | PSD-LA-647(M-9) | 2869 | 325110 | 12/12/2023 | 05-22 - AO-5 BDL Area PAD Sump Pump Driver | 17.21 | Diesel | 200 | horsepower | Nitrogen Oxides (NOx) | Use of good combustion practices and compliance with NSPS Subpart IIII | 1.26 | LB/HR | BACT-PSD |
| *LA-0394 | GEISMAR PLANT | PSD-LA-647(M-9) | 2869 | 325110 | 12/12/2023 | 06-22 - AO-5 Emergency Generator | 17.11 | Diesel | 670.5 | horsepower | Nitrogen Oxides (NOx) | Use of good combustion practices and compliance with NSPS Subpart IIII | 4.24 | LB/HR | BACT-PSD |
| *LA-0394 | GEISMAR PLANT | PSD-LA-647(M-9) | 2869 | 325110 | 12/12/2023 | 52-22 - PAO Area PAD Sump Pump Driver | 17.21 | Diesel | 200 | horsepower | Nitrogen Oxides (NOx) | Use of good combustion practices, compliance with NSPS Subpart IIII | 1.26 | LB/HR | BACT-PSD |
| *LA-0394 | GEISMAR PLANT | PSD-LA-647(M-9) | 2869 | 325110 | 12/12/2023 | 53-22 - PAO Emergency Generator | 17.11 | Diesel | 670.5 | horsepower | Nitrogen Oxides (NOx) | Use of good combustion practices, compliance with NSPS Subpart IIII | 4.24 | LB/HR | BACT-PSD |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | PSD-LA-851 | 2869 | 325199 | 12/20/2023 | EGEN - Plant Emergency Generator | 17.11 | Diesel | 3634 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 38.24 | LB/HR | BACT-PSD |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | PSD-LA-851 | 2869 | 325199 | 12/20/2023 | FWP-01 - Firewater Pump Engine No. 1 | 17.21 | Diesel | 422 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 3.96 | LB/HR | BACT-PSD |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | PSD-LA-851 | 2869 | 325199 | 12/20/2023 | FWP-02 - Firewater Pump Engine No. 2 | 17.21 | Diesel | 422 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 3.96 | LB/HR | BACT-PSD |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | PSD-LA-851 | 2869 | 325199 | 12/20/2023 | FWP-03 - Firewater Pump Engine No. 3 | 17.21 | Diesel | 237 | horsepower | Nitrogen Oxides (NOx) | Compliance with the requirements of 40 CFR 60 Subpart IIII | 1.49 | LB/HR | BACT-PSD |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | PSD-LA-851 | 2869 | 325199 | 12/20/2023 | E. GEN 01 - Generac SD 2000 | 17.11 | Diesel | 2923 | horsepower | Nitrogen Oxides (NOx) | Compliance with the requirements of 40 CFR 60 Subpart IIII | 28.48 | LB/HR | BACT-PSD |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | PSD-LA-851 | 2869 | 325199 | 12/20/2023 | E. GEN 02 - Generac SD 2000 | 17.11 | Diesel | 2923 | horsepower | Nitrogen Oxides (NOx) | Compliance with the requirements of 40 CFR 60 Subpart IIII | 28.48 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4C-6A - C/A Emergency Generator A | 17.11 | Diesel | 2346 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 18.41 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4C-6B - C/A Emergency Generator B | 17.11 | Diesel | 2346 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 18.41 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4C-6C - C/A Emergency Generator C | 17.11 | Diesel | 2346 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 18.41 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4U-7A - Fire Water Pump A | 17.11 | Diesel | 552 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 2.71 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4U-7B - Fire Water Pump B | 17.11 | Diesel | 552 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 2.71 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4U-7C - Fire Water Pump C | 17.11 | Diesel | 552 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 2.71 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4U-10 - Utility Emergency Generator | 17.11 | Diesel | 2012 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 15.79 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4U-11 - Substation Emergency Generator | 17.21 | Diesel | 70 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 0.4 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4U-12 - VCM/CA/UT CCR Emergency Generator | 17.11 | Diesel | 760 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 5.97 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4M-11A - VCM Emergency Generator A | 17.11 | Diesel | 2346 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 18.41 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4M-11B - VCM Emergency Generator B | 17.11 | Diesel | 2346 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 18.41 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4M-11C - VCM Emergency Pump A | 17.21 | Diesel | 200 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 0.98 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4M-11D - VCM Emergency Pump B | 17.21 | Diesel | 200 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 0.98 | LB/HR | BACT-PSD |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | PSD-LA-857 | 2821 | 325211 | 12/16/2024 | 4M-11E - VCM Emergency Pump C | 17.21 | Diesel | 200 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 0.98 | LB/HR | BACT-PSD |

**Table A-1. NOx RBLC Data for Diesel Generators**

| RBLCID | Facility Name | Permit No. | SIC | NAICS | Permit Issuance Date | Process | Process Type | Fuel | Throughput | Unit | Pollutant | Control Method | Emission Limit (1) | Unit | Determination Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *LA-0406 | MCA GEIMAR SITE | PSD-LA-850 | 2821 | 325211 | 07/24/2024 | Diesel Emergency Generator (EQT0012) | 17.11 | diesel | 1140 | hp | Nitrogen Oxides (NOx) | Proper equipment design and good combustion practices.□ Use ultra-low sulfur diesel as fuel.□ Low emission combustion.□ Compliance with 40 CFR 60 Subpart IIII. | 4.8 | G/HP-HR | BACT-PSD |
| MA-0043 | MIT CENTRAL UTILITY PLANT | NE-15-018 | 8221 | 611310 | 06/21/2017 | Cold Start Engine | 17.11 | ULSD | 19.04 | MMBTU/HR | Nitrogen Oxides (NOx) | | 35.09 | LB/HR | OTHER CASE-BY-CASE |
| MI-0418 | WARREN TECHNICAL CENTER | 160-11B | 3711 | 336211 | 01/14/2015 | FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines) | 17.11 | Diesel | 3490 | KW | Nitrogen Oxides (NOx) | No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation. | 8 | G/KW-H | BACT-PSD |
| MI-0418 | WARREN TECHNICAL CENTER | 160-11B | 3711 | 336211 | 01/14/2015 | Four (4) emergency engines in FG-BACKUPGENS | 17.11 | Diesel | 2710 | KW | Nitrogen Oxides (NOx) | No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation. | 7.13 | G/KW-H | BACT-PSD |
| MI-0421 | GRAYLING PARTICLEBOARD | 59-16 | 2493 | 321219 | 08/26/2016 | Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE) | 17.11 | Diesel | 500 | H/YR | Nitrogen Oxides (NOx) | Certified engines, limited operating hours. | 22.6 | LB/H | BACT-PSD |
| MI-0421 | GRAYLING PARTICLEBOARD | 59-16 | 2493 | 321219 | 08/26/2016 | Dieself fire pump engine (EUFIREPUMP in FGRICE) | 17.11 | Diesel | 500 | H/YR | Nitrogen Oxides (NOx) | Certified engines, limited operating hours. | 3.53 | LB/H | BACT-PSD |
| MI-0423 | INDECK NILES, LLC | 75-16 | 4911 | 221112 | 01/04/2017 | EUEMENGINE (Diesel fuel emergency engine) | 17.11 | Diesel Fuel | 22.68 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS IIII requirements. | 6.4 | G/KW-H | BACT-PSD |
| MI-0423 | INDECK NILES, LLC | 75-16 | 4911 | 221112 | 01/04/2017 | EUFPENGINE (Emergency engine--diesel fire pump) | 17.21 | Diesel | 1.66 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 3 | G/BHP-H | BACT-PSD |
| MI-0425 | GRAYLING PARTICLEBOARD | 59-16A | 2493 | 321219 | 05/09/2017 | EUEMRGRICE1 in FGRICE (Emergency diesel generator engine) | 17.11 | Diesel | 500 | H/YR | Nitrogen Oxides (NOx) | Certified engines, limited operating hours. | 21.2 | LB/H | BACT-PSD |
| MI-0425 | GRAYLING PARTICLEBOARD | 59-16A | 2493 | 321219 | 05/09/2017 | EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine) | 17.11 | Diesel | 500 | H/YR | Nitrogen Oxides (NOx) | Certified engines, limited operating hours | 4.4 | LB/H | BACT-PSD |
| MI-0425 | GRAYLING PARTICLEBOARD | 59-16A | 2493 | 321219 | 05/09/2017 | EUFIREPUMP in FGRICE (Diesel fire pump engine) | 17.11 | Diesel | 500 | H/YR | Nitrogen Oxides (NOx) | Certified engines. Limited operating hours. | 3.53 | LB/H | BACT-PSD |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | 167-17 AND 168-17 | 4911 | 221112 | 06/29/2018 | EUFPENGINE (South Plant): Fire pump engine | 17.21 | Diesel | 300 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 3 | G/BHP-H | BACT-PSD |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | 167-17 AND 168-17 | 4911 | 221112 | 06/29/2018 | EUEMENGINE (North Plant): Emergency Engine | 17.11 | Diesel | 1341 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 6.4 | G/KW-H | BACT-PSD |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | 167-17 AND 168-17 | 4911 | 221112 | 06/29/2018 | EUFPENGINE (North Plant): Fire pump engine | 17.21 | Diesel | 300 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 3 | G/BHP-H | BACT-PSD |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | 167-17 AND 168-17 | 4911 | 221112 | 06/29/2018 | EUEMENGINE (South Plant): Emergency Engine | 17.11 | Diesel | 1341 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS IIII requirements. | 6.4 | G/KW-H | BACT-PSD |
| MI-0434 | FLAT ROCK ASSEMBLY PLANT | 122-17 | 8741 | 561110 | 03/22/2018 | EUENGINE01 through EUENGINE08 | 17.11 | Diesel | 3633 | BHP | Nitrogen Oxides (NOx) | Good combustion practices. | 6.4 | G/KW-H | BACT-PSD |
| MI-0434 | FLAT ROCK ASSEMBLY PLANT | 122-17 | 8741 | 561110 | 03/22/2018 | EUFIREPUMPENGS (2 emergency fire pump engines) | 17.21 | Diesel | 250 | BHP | Nitrogen Oxides (NOx) | Good combustion practices. | 3 | G/B-HP-H | BACT-PSD |
| MI-0434 | FLAT ROCK ASSEMBLY PLANT | 122-17 | 8741 | 561110 | 03/22/2018 | EULIFESAFETYENG - One diesel-fueled emergency engine/generator | 17.21 | Diesel | 500 | KW | Nitrogen Oxides (NOx) | Good combustion practices. | 4 | G/KW-H | BACT-PSD |
| MI-0435 | BELLE RIVER COMBINED CYCLE POWER PLANT | 19-18 | 4911 | 221112 | 07/16/2018 | EUEMENGINE: Emergency engine | 17.11 | Diesel | 2 | MW | Nitrogen Oxides (NOx) | State of the art combustion design. | 6.4 | G/KW-H | BACT-PSD |
| MI-0435 | BELLE RIVER COMBINED CYCLE POWER PLANT | 19-18 | 4911 | 221112 | 07/16/2018 | EUFPENGINE: Fire pump engine | 17.21 | Diesel | 399 | BHP | Nitrogen Oxides (NOx) | State of the art combustion design. | 4 | G/KW-H | BACT-PSD |
| MI-0441 | LBWL--ERICKSON STATION | 74-18 | 4911 | 221112 | 12/21/2018 | EUEMGD1--A 1500 HP diesel fueled emergency engine | 17.11 | Diesel | 1500 | HP | Nitrogen Oxides (NOx) | Good combustion practices and will be NSPS compliant. | 6.4 | G/KW-H | BACT-PSD |
| MI-0441 | LBWL--ERICKSON STATION | 74-18 | 4911 | 221112 | 12/21/2018 | EUEMGD2--A 6000 HP diesel fuel fired emergency engine | 17.11 | Diesel | 6000 | HP | Nitrogen Oxides (NOx) | Good combustion practices and will be NSPS compliant. | 6.4 | G/KW-H | BACT-PSD |
| MI-0442 | THOMAS TOWNSHIP ENERGY, LLC | 210-18 | 4911 | 221112 | 08/21/2019 | FGEMENGINE | 17.11 | Diesel | 1100 | KW | Nitrogen Oxides (NOx) | | 5.3 | G/HP-H | BACT-PSD |

Table A-1. NOx RBLC Data for Diesel Generators

| RBLCID | Facility Name | Permit No. | SIC | NAICS | Permit Issuance Date | Process | Process Type | Fuel | Throughput | Unit | Pollutant | Control Method | Emission Limit (1) | Unit | Determination Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *MI-0445 | INDECK NILES, LLC | 75-16B | 4911 | 221112 | 11/26/2019 | EUFPENGINE (Emergency engine-diesel fire pump | 17.21 | diesel fuel | 1.66 | MMBTU/H | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements | 3 | G/BHP-H | BACT-PSD |
| *MI-0445 | INDECK NILES, LLC | 75-16B | 4911 | 221112 | 11/26/2019 | EUEMENGINE (diesel fuel emergency engine) | 17.11 | diesel fuel | 22.68 | MMBTU/H | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements | 6.4 | G/KW-H | BACT-PSD |
| MI-0448 | GRAYLING PARTICLEBOARD | 59-16E | 2493 | 321219 | 12/18/2020 | Emergency diesel generator engine (EUEMRGRICE1 in FGRICE) | 17.11 | Diesel | 500 | h/yr | Nitrogen Oxides (NOx) | Certified engines, limited operating hours | 21.2 | LB/H | BACT-PSD |
| MI-0448 | GRAYLING PARTICLEBOARD | 59-16E | 2493 | 321219 | 12/18/2020 | Emergency diesel generator engine (EUEMRGRICE2 in FGRICE) | 17.11 | Diesel | 500 | h/yr | Nitrogen Oxides (NOx) | Certified Engines, Limited Operating Hours | 4.4 | LB/H | BACT-PSD |
| MI-0448 | GRAYLING PARTICLEBOARD | 59-16E | 2493 | 321219 | 12/18/2020 | Diesel fire pump engine (EUFIREPUMP in FGRICE) | 17.11 | Diesel | 500 | h/yr | Nitrogen Oxides (NOx) | Certified Engines, Limited Operating Hours | 3.53 | LB/H | BACT-PSD |
| MI-0451 | MEC NORTH, LLC | 167-17B | 4911 | 221112 | 06/23/2022 | EUFPENGINE (North Plant): Fire Pump Engine | 17.21 | Diesel | 300 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 3 | G/B-HP-H | BACT-PSD |
| MI-0451 | MEC NORTH, LLC | 167-17B | 4911 | 221112 | 06/23/2022 | EUEMENGINE (North Plant): Emergency engine | 17.11 | Diesel | 1341 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 6.4 | G/KW-H | BACT-PSD |
| MI-0452 | MEC SOUTH, LLC | 168-17B | 4911 | 221112 | 06/23/2022 | EUEMENGINE (South Plant): Emergency engine | 17.11 | Diesel | 1341 | HP | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements | 6.4 | G/KW-H | BACT-PSD |
| MI-0452 | MEC SOUTH, LLC | 168-17B | 4911 | 221112 | 06/23/2022 | EUFPENGINE (South Plant): Fire pump engine | 17.21 | Diesel | 300 | HP | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements | 3 | G/B-HP-H | BACT-PSD |
| MI-0454 | LBWL-ERICKSON STATION | 74-18D | 4911 | 221112 | 12/20/2022 | EUFPRICE--A 315 HP diesel-fueled emergency engine | 17.21 | Diesel | 2.5 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices. | 3 | G/HP-H | BACT-PSD |
| MI-0454 | LBWL-ERICKSON STATION | 74-18D | 4911 | 221112 | 12/20/2022 | EUEMGD | 17.11 | Diesel | 4474.2 | KW | Nitrogen Oxides (NOx) | Good combustion practices and will be NSPS compliant. | 6.4 | G/KW-H | BACT-PSD |
| MI-0459 | LANSING BOARD OF WATER AND LIGHT--DELTA ENERGY PARK | 71-24 | 4911 | 221112 | 06/27/2024 | EUEMGEN | 17.11 | Diesel | 762 | bhp | Nitrogen Oxides (NOx) | | 6.4 | G/KW-H | BACT-PSD |
| MI-0459 | LANSING BOARD OF WATER AND LIGHT--DELTA ENERGY PARK | 71-24 | 4911 | 221112 | 06/27/2024 | EUFIREPUMP | 17.21 | Diesel | 500 | bhp | Nitrogen Oxides (NOx) | | 4 | G/KW-H | BACT-PSD |
| MN-0095 | BLUE LAKE | 13900010-105 | 4911 | 221112 | 08/07/2024 | Emergency Generator 2 (EQUI 26) | 17.11 | Ultra low sulfur diesel | 1049 | horsepower | Nitrogen Oxides (NOx) | Emergency classification, hourly restriction, and NSPS compliance | 4.8 | G/HP-HR | BACT-PSD |
| MN-0095 | BLUE LAKE | 13900010-105 | 4911 | 221112 | 08/07/2024 | Emergency Generator 3 (EQUI 27) | 17.11 | Ultra low sulfur diesel | 1049 | horsepower | Nitrogen Oxides (NOx) | Emergency classification, hourly restriction, and NSPS compliance | 4.8 | G/HP-HR | BACT-PSD |
| MN-0095 | BLUE LAKE | 13900010-105 | 4911 | 221112 | 08/07/2024 | Emergency Generator 4 (EQUI 28) | 17.11 | Ultra low sulfur diesel | 1049 | horsepower | Nitrogen Oxides (NOx) | Emergency classification, hourly restriction, and NSPS compliance | 4.8 | G/HP-HR | BACT-PSD |
| MN-0095 | BLUE LAKE | 13900010-105 | 4911 | 221112 | 08/07/2024 | Emergency Generator 5 (EQUI 43) | 17.11 | Ultra low sulfur diesel | 772 | horsepower | Nitrogen Oxides (NOx) | Emergency classification, hourly restriction, and NSPS compliance | 4.8 | G/HP-HR | BACT-PSD |
| MN-0095 | BLUE LAKE | 13900010-105 | 4911 | 221112 | 08/07/2024 | Emergency Generator 6 (EQUI 43) | 17.11 | Ultra low sulfur diesel | 772 | horsepower | Nitrogen Oxides (NOx) | Emergency classification, hourly restriction, and NSPS compliance | 4.8 | G/HP-HR | BACT-PSD |
| NE-0064 | NORFOLK CRUSH, LLC | CP22-017 | 2075 | 311223 | 11/21/2022 | Emergency Fire Water Pump Engine 1 | 17.11 | Diesel | 510 | hp | Nitrogen Oxides (NOx) | | 2.38 | G/HP-HR | BACT-PSD |
| NE-0064 | NORFOLK CRUSH, LLC | CP22-017 | 2075 | 311223 | 11/21/2022 | Emergency Fire Water Pump Engine 2 | 17.21 | Diesel | 510 | hp | Nitrogen Oxides (NOx) | | 2.38 | G/HP-HR | BACT-PSD |
| NJ-0084 | PSEG FOSSIL LLC SEWAREN GENERATING STATION | 18068/BOP150001 | 4911 | 221112 | 03/10/2016 | Diesel Fired Emergency Generator | 17.11 | ULSD | 44 | H/YR | Nitrogen Oxides (NOx) | use of ultra low sulfur diesel a clean burning fuel. | 42.3 | LB/H | LAER |
| NJ-0084 | PSEG FOSSIL LLC SEWAREN GENERATING STATION | 18068/BOP150001 | 4911 | 221112 | 03/10/2016 | Emergency Diesel Fire Pump | 17.21 | ULSD | 100 | H/YR | Nitrogen Oxides (NOx) | use of ULSD a clean burning fuel, and limited hours of operation | 1.7 | LB/H | LAER |
| NY-0103 | CRICKET VALLEY ENERGY CENTER | 3-1326-00275/00009 | 4911 | 221112 | 02/03/2016 | Black start generator | 17.11 | ultra low sulfur diesel | 3000 | KW | Nitrogen Oxides (NOx) | Generator equipped with selective catalytic reduction.□ Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations. | 2.11 | G/BHP-H | LAER |

**Table A-1. NOx RBLC Data for Diesel Generators**

| RBLCID | Facility Name | Permit No. | SIC | NAICS | Permit Issuance Date | Process | Process Type | Fuel | Throughput | Unit | Pollutant | Control Method | Emission Limit (1) | Unit | Determination Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NY-0103 | CRICKET VALLEY ENERGY CENTER | 3-1326-00275/00009 | 4911 | 221112 | 02/03/2016 | Emergency fire pump | 17.21 | ultra low sulfur diesel | 460 | hp | Nitrogen Oxides (NOx) | Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations. | 2.6 | G/BHP-H | LAER |
| OH-0366 | CLEAN ENERGY FUTURE - LORDSTOWN, LLC | P0117655 | 4911 | 221112 | 08/25/2015 | Emergency fire pump engine (P004) | 17.21 | Diesel fuel | 140 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 0.81 | LB/H | BACT-PSD |
| OH-0366 | CLEAN ENERGY FUTURE - LORDSTOWN, LLC | P0117655 | 4911 | 221112 | 08/25/2015 | Emergency generator (P003) | 17.11 | Diesel fuel | 2346 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 21.6 | LB/H | BACT-PSD |
| OH-0367 | SOUTH FIELD ENERGY LLC | P0119495 | 4911 | 221112 | 09/23/2016 | Emergency fire pump engine (P004) | 17.21 | Diesel fuel | 311 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 1.79 | LB/H | BACT-PSD |
| OH-0367 | SOUTH FIELD ENERGY LLC | P0119495 | 4911 | 221112 | 09/23/2016 | Emergency generator (P003) | 17.11 | Diesel fuel | 2947 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 27.18 | LB/H | BACT-PSD |
| OH-0368 | PALLAS NITROGEN LLC | P0118959 | 2873 | 325311 | 04/19/2017 | Emergency Fire Pump Diesel Engine (P008) | 17.21 | Diesel fuel | 460 | HP | Nitrogen Oxides (NOx) | good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII | 0.3 | LB/H | BACT-PSD |
| OH-0368 | PALLAS NITROGEN LLC | P0118959 | 2873 | 325311 | 04/19/2017 | Emergency Generator (P009) | 17.11 | Diesel fuel | 5000 | HP | Nitrogen Oxides (NOx) | good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII | 5.5 | LB/H | BACT-PSD |
| OH-0370 | TRUMBULL ENERGY CENTER | P0122331 | 4911 | 221112 | 09/07/2017 | Emergency generator (P003) | 17.11 | Diesel fuel | 1529 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 16.07 | LB/H | BACT-PSD |
| OH-0370 | TRUMBULL ENERGY CENTER | P0122331 | 4911 | 221112 | 09/07/2017 | Emergency fire pump engine (P004) | 17.21 | Diesel fuel | 300 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 1.97 | LB/H | BACT-PSD |
| OH-0372 | OREGON ENERGY CENTER | P0121049 | 4911 | 221112 | 09/27/2017 | Emergency generator (P003) | 17.11 | Diesel fuel | 1529 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 16.1 | LB/H | BACT-PSD |
| OH-0372 | OREGON ENERGY CENTER | P0121049 | 4911 | 221112 | 09/27/2017 | Emergency fire pump engine (P004) | 17.21 | Diesel fuel | 300 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 1.97 | LB/H | BACT-PSD |
| OH-0374 | GUERNSEY POWER STATION LLC | P0122594 | 4911 | 221112 | 10/23/2017 | Emergency Generators (2 identical, P004 and P005) | 17.11 | Diesel fuel | 2206 | HP | Nitrogen Oxides (NOx) | Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). □ Good combustion practices per the manufacturer's operating manual. | 23.21 | LB/H | BACT-PSD |
| OH-0374 | GUERNSEY POWER STATION LLC | P0122594 | 4911 | 221112 | 10/23/2017 | Emergency Fire Pump (P006) | 17.21 | Diesel fuel | 410 | HP | Nitrogen Oxides (NOx) | Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer's operating manual | 2.7 | LB/H | BACT-PSD |
| OH-0375 | LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER | P0122829 | 4911 | 221112 | 11/07/2017 | Emergency Diesel Generator Engine (P001) | 17.11 | Diesel fuel | 2206 | HP | Nitrogen Oxides (NOx) | Good combustion design | 24.71 | LB/H | BACT-PSD |
| OH-0375 | LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER | P0122829 | 4911 | 221112 | 11/07/2017 | Emergency Diesel Fire Pump Engine (P002) | 17.11 | Diesel fuel | 700 | HP | Nitrogen Oxides (NOx) | Good combustion design | 4.97 | LB/H | BACT-PSD |
| OH-0376 | IRONUNITS LLC - TOLEDO HBI | P0123395 | 3312 | 331111 | 02/09/2018 | Emergency diesel-fueled fire pump (P006) | 17.21 | Diesel fuel | 250 | HP | Nitrogen Oxides (NOx) | Comply with NSPS 40 CFR 60 Subpart IIII | 1.6 | LB/H | BACT-PSD |
| OH-0376 | IRONUNITS LLC - TOLEDO HBI | P0123395 | 3312 | 331111 | 02/09/2018 | Emergency diesel-fired generator (P007) | 17.11 | Diesel fuel | 2682 | HP | Nitrogen Oxides (NOx) | Comply with NSPS 40 CFR 60 Subpart IIII | 28.2 | LB/H | BACT-PSD |
| OH-0377 | HARRISON POWER | P0122266 | 4911 | 221112 | 04/19/2018 | Emergency Diesel Generator (P003) | 17.11 | Diesel fuel | 1860 | HP | Nitrogen Oxides (NOx) | Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII | 19.68 | LB/H | BACT-PSD |
| OH-0377 | HARRISON POWER | P0122266 | 4911 | 221112 | 04/19/2018 | Emergency Fire Pump (P004) | 17.21 | Diesel fuel | 320 | HP | Nitrogen Oxides (NOx) | Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII | 2.12 | LB/H | BACT-PSD |
| OH-0378 | PTTGCA PETROCHEMICAL COMPLEX | P0124972 | 2869 | 325110 | 12/21/2018 | Firewater Pumps (P005 and P006) | 17.21 | Diesel fuel | 402 | HP | Nitrogen Oxides (NOx) | Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual | 2.64 | LB/H | BACT-PSD |
| OH-0378 | PTTGCA PETROCHEMICAL COMPLEX | P0124972 | 2869 | 325110 | 12/21/2018 | Emergency Diesel-fired Generator Engine (P007) | 17.11 | Diesel fuel | 3353 | HP | Nitrogen Oxides (NOx) | certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual | 37.41 | LB/H | BACT-PSD |

**Table A-1. NOx RBLC Data for Diesel Generators**

| RBLCID | Facility Name | Permit No. | SIC | NAICS | Permit Issuance Date | Process | Process Type | Fuel | Throughput | Unit | Pollutant | Control Method | Emission Limit (1) | Unit | Determination Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| OH-0378 | PTTGCA PETROCHEMICAL COMPLEX | P0124972 | 2869 | 325110 | 12/21/2018 | 1,000 kW Emergency Generators (P008 - P010) | 17.11 | Diesel fuel | 1341 | HP | Nitrogen Oxides (NOx) | certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual | 14.96 | LB/H | BACT-PSD |
| OH-0379 | PETMIN USA INCORPORATED | P0125024 | 3312 | 331111 | 02/06/2019 | Black Start Generator (P007) | 17.21 | Diesel fuel | 158 | HP | Nitrogen Oxides (NOx) | Tier IV engine□ Tier IV NSPS standards certified by engine manufacturer. | 0.104 | LB/H | BACT-PSD |
| OH-0379 | PETMIN USA INCORPORATED | P0125024 | 3312 | 331111 | 02/06/2019 | Emergency Generators (P005 and P006) | 17.11 | Diesel fuel | 3131 | HP | Nitrogen Oxides (NOx) | Tier IV engine□ Tier IV NSPS standards certified by engine manufacturer. | 3.45 | LB/H | BACT-PSD |
| OH-0383 | PETMIN USA INCORPORATED | P0127678 | 3312 | 331111 | 07/17/2020 | Diesel-fired emergency fire pumps (2) (P009 and P010) | 17.11 | Diesel fuel | 3131 | HP | Nitrogen Oxides (NOx) | Tier IV NSPS standards certified by engine manufacturer. | 0 | | BACT-PSD |
| OH-0387 | INTEL OHIO SITE | P0132323 | 3674 | 334414 | 09/20/2022 | 5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046 | 17.11 | Diesel fuel | 5051 | HP | Nitrogen Oxides (NOx) | Certified to meet Tier 2 standards and good combustion practices | 6.4 | G/KW-H | BACT-PSD |
| OH-0387 | INTEL OHIO SITE | P0132323 | 3674 | 334414 | 09/20/2022 | 275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine | 17.21 | Diesel fuel | 275 | HP | Nitrogen Oxides (NOx) | Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices | 4 | G/KW-H | BACT-PSD |
| PA-0309 | LACKAWANNA ENERGY CTR/JESSUP | 35-00069A | 4911 | 221112 | 12/23/2015 | Fire pump engine | 17.21 | Ultra-low sulfur diesel | 15 | gal/hr | Nitrogen Oxides (NOx) | | 3 | GM/HP-HR | LAER |
| PA-0309 | LACKAWANNA ENERGY CTR/JESSUP | 35-00069A | 4911 | 221112 | 12/23/2015 | 2000 kW Emergency Generator | 17.11 | Ultra-low sulfur Diesel | 0 | | Nitrogen Oxides (NOx) | | 5.45 | GM/HP-HR | LAER |
| PA-0310 | CPV FAIRVIEW ENERGY CENTER | 11-00536A | 4911 | 221112 | 09/02/2016 | Emergency Generator Engines | 17.11 | ULSD | 0 | | Nitrogen Oxides (NOx) | | 4.8 | G/BHP-HR | LAER |
| PA-0310 | CPV FAIRVIEW ENERGY CENTER | 11-00536A | 4911 | 221112 | 09/02/2016 | Emergency Fire Pump Engine | 17.21 | ULSD | 0 | | Nitrogen Oxides (NOx) | | 3 | G/BHP-HR | LAER |
| PA-0311 | MOXIE FREEDOM GENERATION PLANT | 40-00129A | 4911 | 221112 | 09/01/2015 | Fire Pump Engine | 17.11 | diesel | 0 | | Nitrogen Oxides (NOx) | | 3 | G/HP-HR | LAER |
| TX-0728 | PEONY CHEMICAL MANUFACTURING FACILITY | 118239, N200 | 2813 | 325311 | 04/01/2015 | . Emergency Diesel Generator | 17.11 | Diesel | 1500 | hp | Nitrogen Oxides (NOx) | Minimized hours of operations Tier II engine | 0.0218 | G/HP HR | LAER |
| TX-0876 | PORT ARTHUR ETHANE CRACKER UNIT | PSDTX1546 AND GHGPSDTX186 | 2869 | 325110 | 02/06/2020 | Emergency generator | 17.11 | DIESEL | 0 | | Nitrogen Oxides (NOx) | Tier 4 exhaust emission standards specified in 40 CFR SS 1039.101, limited to 100 hours per year of non-emergency operation | 0 | | BACT-PSD |
| TX-0879 | MOTIVA PORT ARTHUR TERMINAL | 7238 AND PSDTX1548 | 5171 | 424710 | 02/19/2020 | Emergency Firewater Engine | 17.11 | Ultra-low sulfur diesel | 0 | | Nitrogen Oxides (NOx) | Meeting the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight). Limited to 100 hrs/yr of non-emergency operation. Have a non-resettable runtime meter. | 0 | | BACT-PSD |
| TX-0888 | ORANGE POLYETHYLENE PLANT | 155952 PSDTX1556 GHGPSDTX192 | 2821 | 325211 | 04/23/2020 | EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES | 17.11 | Ultra-low Sulfur Diesel | 0 | | Nitrogen Oxides (NOx) | well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use. | 0 | | BACT-PSD |
| TX-0904 | MOTIVA POLYETHYLENE MANUFACTURING COMPLEX | 156571, PSDTX1564, GHGPSDTX195 | 2869 | 325199 | 09/09/2020 | EMERGENCY GENERATOR | 17.11 | ULTRA LOW SULFUR DIESEL | 0 | | Nitrogen Oxides (NOx) | 100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR SS 1039.101 | 0 | | BACT-PSD |
| TX-0905 | DIAMOND GREEN DIESEL PORT ARTHUR FACILITY | 160299, PSDTX1576, GHGPSDTX200 | 2869 | 325998 | 09/16/2020 | EMERGENCY GENERATOR | 17.11 | ULTRA LOW SULFUR DIESEL | 0 | | Nitrogen Oxides (NOx) | limited to 100 hours per year of non-emergency operation | 0 | | BACT-PSD |
| TX-0933 | NACERO PENWELL FACILITY | 164137 PSDTX1594 GHGPSDTX207 | 2869 | 325110 | 11/17/2021 | Emergency Generators | 17.11 | Ultra-low sulfur diesel (no more than 15 | 0 | | Nitrogen Oxides (NOx) | limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR SS 1039.101) exhaust emission standards | 0 | | BACT-PSD |
| TX-0955 | INEOS OLIGOMERS CHOCOLATE BAYOU | 136130, N250M2 | 2869 | 325199 | 03/14/2023 | Engine Emergency Generator | 17.11 | DIESEL | 0 | | Nitrogen Oxides (NOx) | TIER III ENGINE, OPERATIONS LIMITED TO 100 HRS/YR | 3.9 | G/HP HR | LAER |
| VA-0325 | GREENSVILLE POWER STATION | 52525 | 4911 | 221112 | 06/17/2016 | DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1) | 17.11 | DIESEL FUEL | 0 | | Nitrogen Oxides (NOx) | Good Combustion Practices/Maintenance | 6.4 | G/KW | N/A |

**Table A-1. NOx RBLC Data for Diesel Generators**

| RBLCID | Facility Name | Permit No. | SIC | NAICS | Permit Issuance Date | Process | Process Type | Fuel | Throughput | Unit | Pollutant | Control Method | Emission Limit (1) | Unit | Determination Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| VA-0325 | GREENSVILLE POWER STATION | 52525 | 4911 | 221112 | 06/17/2016 | DIESEL-FIRED WATER PUMP 376 bph (1) | 17.21 | DIESEL FUEL | 0 | | Nitrogen Oxides (NOx) | Good Combustion Practices/Maintenance | 0 | | N/A |
| VA-0328 | C4GT, LLC | 52588 | 4911 | 221112 | 04/26/2018 | Emergency Diesel GEN | 17.11 | Ultra Low Sulfur Diesel | 500 | H/YR | Nitrogen Oxides (NOx) | good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. | 4.8 | G/HP H | BACT-PSD |
| VA-0328 | C4GT, LLC | 52588 | 4911 | 221112 | 04/26/2018 | Emergency Fire Water Pump | 17.21 | Ultra Low Sulfur Diesel | 500 | HR/YR | Nitrogen Oxides (NOx) | Good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. | 3 | G/HP-HR | BACT-PSD |
| VA-0332 | CHICKAHOMINY POWER LLC | 52610-1 | 4911 | 221112 | 06/24/2019 | Emergency Diesel Generator - 300 kW | 17.11 | Ultra Low Sulfur Diesel | 500 | H/YR | Nitrogen Oxides (NOx) | good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. | 4.8 | G/HP-H | BACT-PSD |
| VA-0332 | CHICKAHOMINY POWER LLC | 52610-1 | 4911 | 221112 | 06/24/2019 | Emegency Fire Water Pump | 17.21 | Ultra Low Sulfur Diesel | 500 | HR/YR | Nitrogen Oxides (NOx) | good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. | 3 | G/HP-HR | BACT-PSD |
| WI-0284 | SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT | 18-JJW-017 | 4911 | 221112 | 04/24/2018 | Diesel-Fired Emergency Generators | 17.11 | Diesel Fuel | 0 | | Nitrogen Oxides (NOx) | The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices | 5.36 | G/KWH | BACT-PSD |
| WI-0286 | SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT | 18-JJW-022 | 3679 | 334419 | 04/24/2018 | P42 -Diesel Fired Emergency Generator | 17.11 | Diesel Fuel | 0 | | Nitrogen Oxides (NOx) | Good Combustion Practices, The Use of an Engine Turbocharger and Aftercooler. | 5.36 | G/KWH | BACT-PSD |
| WI-0300 | NEMADJI TRAIL ENERGY CENTER | 18-MMC-168 | 4911 | 221121 | 09/01/2020 | Emergency Diesel Fire Pump (P06) | 17.21 | Diesel | 282 | HP | Nitrogen Oxides (NOx) | Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturer's recommendations. | 3 | G/HP-H | BACT-PSD |
| WI-0300 | NEMADJI TRAIL ENERGY CENTER | 18-MMC-168 | 4911 | 221121 | 09/01/2020 | Emergency Diesel Generator (P07) | 17.11 | Diesel | 1490 | HP | Nitrogen Oxides (NOx) | Operation limited to 500 hours/year and operate and maintain according to the manufacturer's recommendations. | 4.8 | G/HP-H | BACT-PSD |
| WV-0027 | INWOOD | R14-0015M | 3296 | 327993 | 09/15/2017 | Emergency Generator - ESDG14 | 17.11 | ULSD | 900 | bhp | Nitrogen Oxides (NOx) | Engine Design | 4.77 | G/HP-HR | BACT-PSD |
| *WV-0033 | MAIDSVILLE | R14-0038 | 4911 | 221112 | 01/05/2022 | Emergency Generator | 17.11 | ULSD | 2100 | hp | Nitrogen Oxides (NOx) | Combustion Control (retarded timing and/or lean burn) | 24.6 | LB/HR | BACT-PSD |
| *WV-0033 | MAIDSVILLE | R14-0038 | 4911 | 221112 | 01/05/2022 | Fire Water Pump | 17.11 | ULSD | 240 | bhp | Nitrogen Oxides (NOx) | Combustion control (retarded timing and/or lean burn) | 1.59 | LB/HR | BACT-PSD |

* Indicates that the facilities are draft determination in the RBLC database.

Table A-2. VOC RBLC Data for Surface Coating (Spray Booth) Operations

| RBLCID | Facility Name | Permit No. | SIC | NAICS | Permit Issuance Date | Process | Process Type | Material | Throughput | Unit | Pollutant | Control Method | Emission Limit (1) | Unit | Emission Limit (2) | Unit | Determination Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IN-0309 | GRAND DESIGN RV | 039-40105-00747 | 3792 | 336214 | 11/30/2018 | RV-6 Line 1 | 41.013 | -- | 0 | -- | Volatile Organic Compounds (VOC) | Total VOC usage shall be less than 30 tpy.□ VOC content limit for adhesives, sealants, glue, and cleaning materials shall not exceed 6.5 lbs/gallon. | 30 | TPY | 6.5 | LBS/GALLON | BACT-PSD |
| IN-0310 | FOREST RIVER, INC., COLLEGE AVENUE COMPLEX | 039-39722-00011 | 3792 | 336214 | 12/07/2018 | FE-16 (Plant 420) | 41.013 | -- | 0 | -- | Volatile Organic Compounds (VOC) | Total VOC input: 99.99 tpy□ Cleaners and solvents limit: 6.5 lbs/gal□ Use HVLP spray applicators□ Best management practices for VOC | 99.99 | TPY | 6.5 | LBS/GAL | BACT-PSD |
| IN-0310 | FOREST RIVER, INC., COLLEGE AVENUE COMPLEX | 039-39722-00011 | 3792 | 336214 | 12/07/2018 | FE-13 (Plant 3) | 41.013 | -- | 0 | -- | Volatile Organic Compounds (VOC) | Total VOC input: 99.99 tpy□ Cleaners and solvents limit: 6.5 lbs/gal□ Use HVLP spray applicators□ Best management practices for VOC | 99.99 | TPY | 6.5 | LBS/GAL | BACT-PSD |
| IN-0310 | FOREST RIVER, INC., COLLEGE AVENUE COMPLEX | 039-39722-00011 | 3792 | 336214 | 12/07/2018 | FE-14c (Plant 44) | 41.013 | -- | 0 | -- | Volatile Organic Compounds (VOC) | Total VOC input: 99.99 tpy□ Cleaners and solvents limit: 6.5 lbs/gal□ Use HVLP spray applicators□ Best management practices for VOC | 99.99 | TPY | 6.5 | LBS/GAL | BACT-PSD |
| IN-0310 | FOREST RIVER, INC., COLLEGE AVENUE COMPLEX | 039-39722-00011 | 3792 | 336214 | 12/07/2018 | FE-14d (Plant 27) | 41.013 | -- | 0 | -- | Volatile Organic Compounds (VOC) | Total VOC input: 99.99 tpy□ Cleaners and solvents limit: 6.5 lbs/gal□ Use HVLP spray applicators□ Best management practices for VOC | 99.99 | TPY | 6.5 | LBS/GAL | BACT-PSD |

# ATTACHMENT B: EMISSION UNITS SUBJECT TO RACT

**Table B-1. List of EUs Subject to RACT**

| EU | Description | NOx (tpy) | VOC (tpy) |
|---|---|---|---|
| MG17 | Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02910 | 15.12 | 0.44 |
| MG18 | Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02931 | 15.12 | 0.44 |
| MG19 | Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02927 | 15.12 | 0.44 |
| MG20 | Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02913 | 15.12 | 0.44 |
| MG21 | Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02929 | 15.12 | 0.44 |
| MG22 | Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02932 | 15.12 | 0.44 |
| MG23 | Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02916 | 15.12 | 0.44 |
| NY27 | Caterpillar Emergency Generator, M/N: 3512TA, S/N: 24Z06937 | 10.91 | 0.32 |
| NY28 | Caterpillar Emergency Generator, M/N: 3512TA, S/N: 24Z06932 | 10.91 | 0.32 |
| NY29 | Caterpillar Emergency Generator, M/N: 3512TA, S/N: 24Z06931 | 10.91 | 0.32 |
| MC019 | Caterpillar Emergency Generator, M/N: 3512, S/N: 6WN00081 | 13.03 | 0.38 |
| MC020 | Caterpillar Emergency Generator, M/N: 3512, S/N: 6WN00082 | 13.03 | 0.38 |
| TBA15 | Caterpillar Emergency Generator, M/N: 3412CTA, S/N: 1EZ07104 | 7.08 | 0.21 |
| TBB15 | Caterpillar Emergency Generator, M/N: 3516BTA, S/N: GZR00237 | 15.12 | 0.44 |
| MB061 | Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 25Z06027 | 13.01 | 0.38 |
| MB062 | Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 25Z02994 | 13.01 | 0.38 |
| MB063 | Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 25Z03002 | 13.01 | 0.38 |
| MB066 | Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 3NS00234 | 15.11 | 0.44 |
| MB067 | Cummins Emergency Generator, M/N: KTA50-G9, S/N: 33146939 | 13.32 | 0.39 |
| MB093 | Caterpillar Emergency Generator, M/N: 3512, S/N: 1GZ01339 | 13.03 | 0.38 |
| LX009 | Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z03005 | 13.01 | 0.38 |
| LX010 | Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02998 | 13.01 | 0.38 |
| LX011 | Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02999 | 13.01 | 0.38 |
| LX024 | Caterpillar Emergency Generator, M/N: 3512C, S/N: EGB00199 | 7.5 | 0.18 |
| LX025 | Caterpillar Emergency Generator, M/N: 3512C, S/N: EGB00203 | 7.5 | 0.18 |
| EX007 | Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02774 | 9.55 | 0.28 |
| EX008 | Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02784 | 9.55 | 0.28 |
| EX009 | Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02770 | 9.55 | 0.28 |
| EX010 | Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02753 | 9.55 | 0.28 |
| BE80 | Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05330 | 15.12 | 0.44 |
| BE81 | Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05335 | 15.12 | 0.44 |
| BE82 | Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05333 | 15.12 | 0.44 |
| BE83 | Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05332 | 15.12 | 0.44 |
| BE84 | Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05339 | 15.12 | 0.44 |
| BE85 | Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05338 | 15.12 | 0.44 |
| BE86 | Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05340 | 15.12 | 0.44 |
| BE87 | Caterpillar Emergency Generator, M/N: 3416, S/N: 1LZ00545 | 15.12 | 0.41 |
| BE88 | Caterpillar Emergency Generator, M/N: 3416, S/N: 1LZ00546 | 15.12 | 0.41 |
| CC009 | Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBK00196 | 12.03 | 0.29 |
| CC010 | Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBK00197 | 12.03 | 0.29 |
| CC011 | Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBK00198 | 12.03 | 0.29 |
| CC012 | Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00378 | 10.47 | 0.28 |
| CC013 | Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00379 | 10.47 | 0.28 |
| CC014 | Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00380 | 10.47 | 0.28 |
| CC015 | Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00382 | 10.47 | 0.28 |
| TM01 | Caterpillar Diesel Emergency Generator, M/N: 3516DITA, S/N: DD501118 | 10.83 | 0.2 |
| CO07 | Caterpillar Diesel Emergency Generator, M/N: SR4BGD, S/N: G5H00391 | 8.73 | 0.01 |
| CO08 | Caterpillar Diesel Emergency Generator, M/N: SR4BGD, S/N: G5H00375 | 8.73 | 0.01 |
| CO09 | Caterpillar Diesel Emergency Generator, M/N: SR4BGD, S/N: G5H00376 | 8.73 | 0.01 |
| MG39 | McMaster-Carr Spray Booth | 0 | 6.84 |

# ATTACHMENT 5A: Calnev Pipeline LVT RACT

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2025 JUL 8 AM10:25

KINDER MORGAN
CALNEV PIPE LINE LLC

July 1, 2025

Mr. Ted Lendis
Permitting Manager
Clark County DAQ
4701 West Russell Road
Suite 200
Las Vegas NV 89118-2231

**Subject: 2025 RACT Requirements Review**
**Calnev Pipe Line, LLC – Las Vegas Terminal, Part 70 Permit Number 13**
**5049 North Sloan Lane, Las Vegas, NV 89115**

Dear Mr. Lendis:

Please find the enclosed the RACT requirements review for emissions at the Calnev Pipe Line, LLC Las Vegas Terminal. Calnev Pipe Line LLC has been subject to a major source RACT determination in the past 36 months that meets the requirements of Section 120 and the basis of that determination is still valid. Please see attached the relevant portions of the previously approved case-by-case RACT for Major VOC and NOx sources in Hydrographic Area 212, dated October 19, 2023 and the portions of Section 121 detailing Calnev's RACT requirements.

If you have any questions, please contact Seth Tate at (713) 420-6076 or via email at Seth_Tate@KinderMorgan.com.

In accordance with Section 120.5(c), I certify that based on information and belief formed after reasonable inquiry, the attached determination continues to represent the reasonably available control technology (RACT) requirements. There have been no changes to available control technologies, technical feasibility, control effectiveness, cost-effectiveness, or environmental, energy, and other impacts since the original determination.

Duncan Sinclair
Director of Operations
For Calnev Pipe Line, LLC

**Products EHS Compliance – 14th Floor 1001 Louisiana Street Houston, TX 77002-5089**
**(713) 369-9000 Fax (713) 420-1603**

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KINDER MORGAN
CALNEV PIPE LINE LLC

Enclosures:

1. Relevant Portions of October 2023 Case-by-Case RACT for Major VOC and NOx sources in Hydrographic Area 212
2. Relevant Portions of Section 121

**Products EHS Compliance – 14th Floor 1001 Louisiana Street Houston, TX 77002-5089**
**(713) 369-9000 Fax (713) 420-1603**

ORIGIN ID:EIXA (713) 420-6076
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KMP
1001 LOUISIANA ST, SUITE 1000

HOUSTON, TX 77002
UNITED STATES US

SHIP DATE: 07JUL25
ACTWGT: 1.00 LB
CAD: 105965339/WSXI3300

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**CLARK COUNTY DIVISION OF AIR QUALIT**
**4701 WEST RUSSELL ROAD**
**SUITE 200**
**LAS VEGAS NV 89118**
(702) 455-5942 REF:
INV:
PO: KM772025112436965 DEPT:

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# DES
## DEPARTMENT OF ENVIRONMENT AND SUSTAINABILITY

air quality | desert conservation program | sustainability

4701 W. Russell Road 2nd Floor
Las Vegas, NV 89118-2231
Phone: (702) 455-5942 Fax: (702) 383-9994
Marci Henson, Director


**For DAQ Use Only**

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## Certification Statement

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the attached document(s) are true, accurate, and complete. This certification applies to the following stationary source:

| Source ID: | Source Name: |
|---|---|
| 00013 | Calnev Pipe Line, LLC Las Vegas Terminal |

## Certification

| Name of Responsible Official: | Responsible Official's Title: | Company/Organization: |
|---|---|---|
| Duncan Sinclair | Director of Operations | Calnev Pipe Line, LLC |

| Responsible Official's Signature | Certification Date |
|---|---|
| Duncan Sinclair | 7/1/25 |

KINDER MORGAN
CALNEV PIPE LINE LLC

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2025 JUL 8 AM10:25

# Attachment 1.
# Relevant Portions of October 2023 Case-by-Case RACT for Major VOC and NOx sources in Hydrographic Area 212

Products EHS Compliance – 14th Floor 1001 Louisiana Street Houston, TX 77002-5089
(713) 369-9000 Fax (713) 420-1603

# ATTACHMENT D:

# Major Source
# Reasonably Available Control Technology Analysis

# Case-By-Case RACT for Major VOC and $NO_x$ Sources in Hydrographic Area 212

Prepared For:
Clark County Department of Environment and Sustainability
4701 West Russell Road, Suite 200
Las Vegas, NV 89118
(702) 455-5942

Prepared by:
RTP Environmental Associates ("RTP")
304A West Millbrook Road
Raleigh, North Carolina 27609

**October 19, 2023**

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## ACRONYMS AND ABBREVIATIONS

Acronyms

| | |
|---|---|
| AFR | air-to-fuel injection ratio |
| AQR | Clark County Air Quality Regulation |
| ARA | Air Register Adjustment |
| BACT | Best Available Control Technology |
| BF | biased firing |
| BOOS | burner out of service |
| BT | burner tuning |
| CAM | compliance assurance monitoring |
| CCB | cyclonic combustion burner |
| CGS | Clark Generating Station |
| CCM | combined combustion modification |
| CCU | combined cycle units |
| CE | cost effectiveness |
| CEMS | continuous emission monitoring system |
| CEPCI | Chemical Engineering Plant Cost Index |
| CFB | ceramic fiber burners |
| CI | compression ignition |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| CT | combustion turbine |
| CTG | Control Techniques Guidelines (EPA) |
| DAQ | Division of Air Quality |
| DEFR | domed external floating roof |
| DES | Department of Environment and Sustainability |
| DLN | dry low $NO_x$ |
| DLNC | dry low $NO_x$ combustor |
| EAR | excess air reduction |
| EFRT | External Floating Roof Tank |
| EGR | exhaust gas recirculation |
| EPA | U.S. Environmental Protection Agency |
| EPMS | Engine Performance Management System |
| EU | emission unit |
| FBR | fluidized bed reactor |
| FGR | flue gas recirculation |
| FIR | forced internal recirculation |
| FIR2 | fuel-induced recirculation |
| FRT | floating roof tank |
| GCP | good combustion practices |
| GFFM | gas flow fuel modifier |
| GHG | greenhouse gases |
| GMP | good maintenance practices |
| HA | hydrographic area |
| HAP | hazardous air pollutants |

| | |
|---|---|
| HC | hydrocarbons |
| HRSG | heat recovery steam generator |
| IFR | internal floating roof |
| ITR | injection timing retard |
| LAER | lowest achievable emission rate |
| LEA | low excess air |
| LNB | low $NO_x$ burner |
| LVT | Las Vegas Terminal |
| MAT | manifold air temperature |
| MGMRI | MGM Resorts International |
| NAFB | Nellis Air Force Base |
| NAICS | North American Industrial Classification System |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NGR | natural gas reburning |
| NMHC | nonmethane hydrocarbon |
| $NO_2$ | nitrogen dioxide |
| $NO_x$ | nitrogen oxide(s) |
| NRDC | Natural Resources Defense Council, Inc. |
| NSCR | non-selective catalytic reduction |
| NSPS | New Source Performance Standards |
| NSR | New Source Review |
| $O_2$ | Oxygen |
| OC | oxidation catalyst |
| O&M | operations and maintenance |
| OFA | overfired air |
| OP | (Title V) Operating Permit |
| OT | Oxygen Trim |
| PTE | potential to emit |
| RACM | reasonably available control measure |
| RACT | reasonably available control technology |
| RAP | reduced air preheat |
| RBLC | RACT / BACT / LAER Clearinghouse (database) |
| RCB | radiant ceramic burner |
| REA | reduce excess air |
| RICE | reciprocating internal combustion engine |
| RVP | Reid vapor pressure |
| SCA | Staged Combustion Air |
| SCR | selective catalytic reduction |
| SIC | Standard Industrial Classification |
| SLN | $SoLoNO_x$ |
| SNCR | selective non-catalytic reduction |
| $SO_x$ | sulfur oxide(s) |
| SPC | Saguaro Power Company |
| SPGS | Sun Peak Generation Station |
| SVE | soil vapor extraction |
| TCI | total cost investment |

| | |
|---|---|
| TVP | true vapor pressure |
| ULNB | ultra-low NOx burner |
| VOC | volatile organic compound |
| VRU | vapor recovery unit |
| WFR | water-to-fuel ratio |
| WSI | water/steam injection |

Abbreviations (units of measurement)

| | |
|---|---|
| % | percent |
| % $O_2$ | percent oxygen |
| bbl | barrels (of oil) |
| hp | horsepower |
| hr | hour |
| kPa | kilopascal |
| kW | kilowatt |
| lb | pound |
| MM Btu | million Btu (heat input) |
| MM Btu/hr | million Btu per hour |
| Pa | pascal |
| Ppm | parts per million |
| ppmvd | parts per million volume dry |
| psi(a) | pounds per square inch (absolute) |
| tpd | tons per day |
| tpy | tons per year |

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# 1.0 INTRODUCTION AND SUMMARY

## 1.1 INTRODUCTION

This document provides a series of case-by-case reasonably available control technology (RACT) analyses for individual major stationary sources of volatile organic compounds (VOCs) and nitrogen oxides ($NO_x$) within the Hydrographic Area (HA) 212 ozone nonattainment area in Clark County, NV. The analyses are based on (1) sources' self-determinations of RACT, and (2) supplemental information and additional analyses by the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ), as needed. This report presents the resulting RACT determinations for existing major stationary sources (as defined in Title 40, Part 70 of the Code of Federal Regulations (40 CFR Part 70)).

Based on the limited number of major sources in HA 212's emissions inventory, DAQ has determined that the most appropriate course is to determine RACT on a case-by-case basis for each one. DAQ does not believe it is necessary to determine RACT for all future new or replacement emission units at this time because the Clark County Air Quality Regulations already require RACT, best available control technology (BACT), or lowest achievable emission rate (LAER) determinations for stationary sources that construct or modify above minor New Source Review (NSR) significant levels.

## 1.2 SUMMARY

DAQ conducted RACT analyses for emission units at eight major stationary sources in HA 212. Most units had relatively low levels of $NO_x$ and/or VOC actual emissions, and many were close to or below the 5 tons per year (tpy) potential-to-emit (PTE) threshold that DAQ established for conducting a RACT analysis. This section summarizes the results for each source.

### 1.2.1 Nellis Air Force Base

The emission units at NAFB that were analyzed consisted of nine diesel generators, eight of them emergency generators, and a hush house with two aircraft engine test cells. Eighteen control technologies were considered in the analyses of the generators; only selective catalytic reduction (SCR) was considered for the hush house. For the generators, the permit already requires good combustion practices (GCP) and good maintenance practices (GMP); turbocharging; Injection Timing Retard (ITR) for A032, G032, and G033; and aftercoolers for all but the nonemergency A032. No other technologies were considered cost-effective. For the hush house, only SCR appears to have been addressed as a control technology. Information on SCR costs, feasibility, and even the level of control was unavailable, but given the nature of the unit (intermittent testing of aircraft engines), DAQ concluded that SCR is not cost-effective. Therefore, RACT for these NAFB units consists of the control technologies; emissions limits; monitoring, reporting, and recordkeeping; and startup, shutdown, and malfunction provisions already required in the NAFB Title V operating permit (OP).

- Have and use turbochargers and aftercoolers (except the eight units (EX007-010 & NY 27-29, and TM01) that are not required to have aftercoolers); and
- Have one unit Tier-Certified unit (TM01). It must meet the appropriate limit in 40 CFR Part 60, Subpart IIII.

DAQ has determined that the current control techniques (GCP/GMP, turbochargers, and after-coolers except as noted above) constitute RACT for all the units reviewed. RACT for TM01, in addition to GCP/GMP, includes meeting the Tier Certification requirements, including emissions limits. MGMRI's Title V OP includes compliance and monitoring requirements to ensure all the above conditions are met; DAQ concludes these conditions constitute adequate monitoring, reporting, and recordkeeping to ensure RACT compliance.

### 1.2.5 Calnev Pipe Line

Calnev Pipe Line, LLC ("Calnev"), a Kinder Morgan subsidiary, owns and operates a petroleum products distribution terminal facility in HA 212. The Las Vegas Terminal's (LVT's) operations include receiving petroleum fuel products via pipeline or truck and transferring gasoline, diesel, and biodiesel from storage tanks into trucks via loading racks.

LVT had a VOC PTE of 187.4 tpy and actual VOC emissions of 59.31 tpy in 2017. Most of the individual units have a PTE below 5 tons per year, but DAQ asked that LVT address at least a majority of the emission units that contribute to its PTE.

LVT therefore grouped individual emission units so the group PTE exceeded 5 tpy, then conducted RACT analyses on these groups: (1) storage tanks (total PTE of 61.3 tpy VOC),[2] (2) a vapor recovery unit (14.5 tpy VOC),[3] (3) loading racks (65.7 tpy VOC),[4] (4) a remediation system (37.7 tpy VOC),[5] and (5) fugitive components, such as valves, flanges, fittings, and pump seals (6.6 tpy VOC). For each of these units or groups, DAQ conducted a RACT analysis and determined existing controls and compliance measures (specified in the Title V OP) constitute RACT. Therefore, no decrease in emissions will result from this determination.

### 1.2.6 Clark Generating Station

The emission units at CGS that were analyzed consisted of thirteen simple cycle combustion turbines (CTs) (Unit 4 and Units 11–22) and four combined cycle units (Units 5–8). All turbines were subject to RACT for NOx and Units 4 and 5–8 were subject to RACT for VOC.

For the $NO_x$ RACT evaluation, DAQ considered the use of SCR, water injection, and GCP for Unit 4. For Units 5-8, DAQ considered the installation of SCR with the existing dry low $NO_x$ combustors (DLNC) and for Units 11–12, DAQ considered the installation of DLNC with the current use of SCR and water injection. For the VOC RACT evaluation, DAQ considered the

[2] Table 3-1, LVT RACT Analysis. No tank has a PTE of 5 tpy or more.

[3] The vapor recovery unit is itself a control device that LVT says is considered BACT.

[4] There are 15 loading racks. Most of the 65.7 tpy PTE is from gasoline dispensing. Assuming each rack has the same PTE, 65.7/15 = 4.38 tpy per rack, less than the 5 tpy PTE threshold for RACT review.

[5] This system is also considered BACT, per LVT.

# 2.0 MAJOR VOC AND $NO_X$ SOURCES IN HA 212

Through a review of the 2017 National Emissions Inventory and major source (Part 70) OPs, DAQ identified the following major sources that could be subject to VOC or $NO_x$ RACT requirements.

**Table 2-1. Major Sources in HA 212 Nonattainment Areas**

| $NO_X$ Major Sources | | | | |
|---|---|---|---|---|
| **Facility ID** | **Facility Name** | **Total Facility $NO_x$ PTE (tpy)** | **2017 NEI Emissions (tpy)** | **2017 NEI Emissions (tpd)** |
| 114 | Nellis AFB | 199.0[8] | 19.81 | 0.05 |
| 257 | Caesars Consolidated Properties | 370.1 | 19.9 | 0.05 |
| 16304 | Switch, Ltd. | 246.18 | 33.23 | 0.09 |
| 825 | MGMRI Resorts International | 757.05 | 65.07 | 0.18 |
| 7 | Clark Generating Station | 2465.9 | 115.40 | 0.32 |
| 423 | Sun Peak Generating Station | 249.4 | 15.89 | 0.04 |
| 393 | Saguaro Power Company | 164.1 | 102.79 | 0.28 |
| **VOC Major Sources** | | | | |
| **Facility ID** | **Facility Name** | **Total Facility VOC PTE (tpy)** | **2017 NEI Emissions tpy** | **2017 NEI Emissions (tpd)** |
| 13 | Calnev Pipe Line LLC | 187.4 | 59.31 | 0.16 |
| 7 | Clark Generating Station | 216.5 | 14.12 | 0.04 |

DAQ asked each major source to prepare and submit RACT analyses for its emission units. All the major sources agreed to provide this information.

[8] NAFB's most recent Authority to Construct (ATC) permit, issued 10/13/22, states that $NO_x$ PTE is now 200.47 tpy.

# 3.0 MACT SOURCE RACT METHODOLOGY

Appendix 1, "Final RACT Methodology for HA 212 2015 8-Hour Ozone NAAQS," provides a complete description of the methodology used for making RACT determinations. To summarize: DAQ provided each major source the opportunity to submit a control technology analysis with a proposed RACT demonstration for its emission units, then invited these sources to submit the following information relative to a case-by-case RACT requirement:

1. Information sources relied on to identify available control options.
2. Ranking of available control options based on control effectiveness.
3. Evaluation of technical feasibility.
4. Annual and incremental cost effectiveness ($/ton).
5. Baseline and controlled tpy emissions estimates (and basis).
6. Environmental, energy, and other impacts (benefits and disbenefits); greenhouse gases (GHG), hazardous air pollutants (HAP), or other pollutants.
7. Proposed RACT emissions limitation or averaging approach.
8. Schedule for installing and operating any new or additional emissions control resulting from the RACT determination.
9. Proposed testing, monitoring, recordkeeping, and reporting methods that meet periodic or Compliance Assurance Monitoring (CAM) requirements.

To assure uniformity among major sources in the cost estimates, DAQ asked them to submit cost information using a 6% interest rate and the remaining useful life of the emission unit (assuming an original useful life of 30 years unless the source submits information justifying a different useful life). Sources could also provide information on actual interest rates available to them, which DAQ stated would be considered in determining their RACT.

DAQ advised major sources that the baseline emissions for CE calculations should be based on an emission unit's PTE, including consideration of existing, enforceable control technologies. Alternatively, if either the major source's or a particular emission unit's actual emissions over a representative period of operation were less than 70% of PTE, then the major source could elect to provide cost-effectiveness information based on actual emissions. This meant that actual emissions might be used as a baseline for all emission units if the major source's actual emissions were 70% below its PTE, or for an individual emissions unit if a unit's actual emissions were 70% below its PTE.

DAQ advised major sources to submit RACT analysis information on each emission unit having a PTE equal to or greater than 5 tpy, although in a few cases sources were asked to evaluate RACT for a group of similar emission units, such as storage tanks for VOCs. All of the major sources submitted self-determinations and generally followed DAQ guidance, providing

information on their emission units, available control technologies, and cost-effectiveness. Information from the sources' self-analyses are included in this document's RACT analyses.

After receiving self-analyses from the major sources, DAQ reviewed the information for thoroughness and reliability and to determine if the source:

1. Included all applicable emission units;
2. Searched the RACT/BACT/LAER Clearinghouse (RBLC) and literature for potential control technologies;
3. Listed all available control technologies;
4. Followed the guidelines for determining RACT; and
5. Documented critical determinations (e.g., how the remaining useful life of equipment was determined).

The self-determined RACT analyses proved useful in DAQ's final RACT determinations. In determining the suitability of a given control option for RACT, DAQ was guided by the cost-effectiveness values DAQ has approved in past control technology determinations, the cost-effectiveness guidance provided by EPA, and the cost thresholds found acceptable by other states. A cost-effectiveness threshold of $5,500/ton was used for this review, which was among the highest in a survey of state agencies.[9]

For its cost-effectiveness analyses, DAQ used a 30-year equipment life term and 6% interest and made conservative estimates, i.e., the values selected would result in a lower CE (in $/ton removed) than a less conservative estimate for items like maintenance costs. The remaining life is estimated for either: (1) the control device, if it can continue to serve when the emission unit it serves is replaced by a new emission unit; or (2) the emission unit if the control technique will be inherent to the unit. An example of the first is an SCR system that treats the exhaust gas from a diesel generator; if the generator is replaced, the SCR system could be connected to the new generator and continue operating. An example of the second is modifying a generator for ITR; that technology would be part of the existing unit, so the remaining life of the generator would be used. DAQ's guidelines are to use 30 years' remaining life unless a shorter remaining life is adequately documented; some of the source RACT analyses used less than 30 years but did not provide adequate documentation, so DAQ revised those analyses using 30 years. However, a useful life of less than 30 years may be more appropriate; if adequate documentation of a shorter life is provided, DAQ reviewed that information and decided whether to revise its analysis to reflect the shorter life.

Developing a CE value is an iterative process. The CE analyses are generally first-order approximations based on information available in the literature; in a few cases, vendor information on

[9] See, e.g., "2020 Reasonably Available Control Technology Demonstrations for the National Ambient Air Quality Standards for Ozone in San Diego County," Air Pollution Control District County of San Diego (October 2020), which used a $5,000/ton cost-effectiveness threshold.

cost or applicability is available. Costs are not corrected for inflation unless the first CE calculation for that emission unit was below the threshold, meaning it would be considered cost-effective. In such cases, cost is adjusted for inflation and the CE is recalculated. If the inflation-adjusted CE is still below the threshold CE of $5,500/ton, DAQ further reviews the parameters to determine whether a less conservative value is warranted; if so, one or more revised parameters are developed and CE is again recalculated. A CE value that is still below the CE threshold indicates the control technology for that emission unit is reasonable for RACT. Note, however, that most of the CEs developed in these analyses rely on literature values for at least some of the parameters used in the calculations. Sources affected by a RACT determination may elect to develop parameters based on vendor quotes for application of that control technology on their specific emission units and request that DAQ use those parameters instead. Since vendor quotes for specific units are more accurate and up to date than literature values, those parameters are usually preferred, so DAQ would usually accept them to recalculate CE.

Once DAQ determines the appropriate control measures that qualify as RACT, it next determines the RACT emissions limitation. If DAQ determines that the existing level of control is RACT, it will review the source's permit to ensure it contains an effective emissions limit (or equivalent) and adequate monitoring, reporting, and recordkeeping conditions to ensure compliance; if it does not, DAQ will revise the permit conditions as needed. If DAQ determines that no control measure is cost-effective because of reduced equipment life expectancy, it will consider requiring the emissions unit to shut down by a certain date and whether any interim measures are available to reduce emissions before the mandated shutdown date.

The RACT emissions limitation derived from this process represents the lowest achievable emissions level with which the emission unit(s) can continuously comply using the proposed RACT control option. The proposed limitation also includes requirements for startup, shutdown, and malfunction periods, with proposed definitions to govern the operations. The provisions may be included in a single RACT emission limitation recommendation, or as a separate emissions limitation recommendation when including these emissions in a generally applicable emission limitation would cause the proposed limitation to be too lax during times of normal operations. DAQ also considered using work practice requirements when numerical emissions limitations were not feasible.

# 5.0 STORAGE TANKS AND OTHER VOC RACT

## 5.1 CALNEV PIPE LINE—LAS VEGAS TERMINAL

Calnev's LVT (Source ID: 13) is a bulk petroleum distribution terminal with a SIC code of 4226 and a NAICS code of 424710. The terminal receives petroleum fuel products via pipeline or truck and transfers gasoline, diesel, and biodiesel from storage tanks into trucks via loading racks. Denatured ethanol stored and distributed at the LVT is received via railcar; the terminal also has the capability to unload ethanol via tank trucks.

In 2017, LVT had a VOC PTE of 187.4 tpy and actual VOC emissions of 59.31 tpy. Since its $NO_x$ PTE is below the major source applicability threshold, LVT is subject to major source VOC RACT, but not NOx RACT. In its RACT analysis (Appendix 6), LTV listed all the emission units potentially subject to VOC RACT. Most individual units have a PTE below 5 tons per year, but DAQ asked that LVT address at least a majority of the emission units that contribute to the major source's PTE.

LVT grouped individual emission units so their group PTE exceeded 5 tpy and then conducted RACT analyses on these groups: (1) storage tanks with a total PTE of 61.3 tpy VOC,[180] (2) a vapor recovery unit with a total PTE of 14.5 tpy VOC,[181] (3) loading racks with a total PTE of 65.7 tpy VOC,[182] (4) a remediation system with a total PTE of 37.7 tpy VOC,[183] and (5) fugitive components (e.g., valves, flanges, fittings, pump seals) with a total PTE of 6.6 tpy VOC. LVT also listed the emission units not evaluated for VOC RACT (Appendix 6, p. 2).

### 5.1.1 Storage Tanks

LVT included three vertical fixed roof tanks ("FRT"); four fixed roof tanks; 21 internal floating roof tanks ("IFR"); 12 external floating roof tanks ("EFR"); and three domed external floating roof tanks ("DEFR") in the analysis. Except for D01, a small 5.9-barrel (about 250-gallon) tank, and consistent with LVT's RACT analysis, DAQ did not include tanks below 1,000 gallons[184] in the RACT analysis after determining that it would not be cost-effective to impose emission controls on these units.

According to LVT, all the floating roof tanks except 501 (A27) and 522 (A18), which are authorized to store only denatured ethanol, are designed and permitted to store multiple liquids, but several of the tanks are authorized for only a few liquids.[185] LVT assumed that gasoline with a Reid vapor pressure (RVP) of 11 pounds per square inch (psi) represents the average annual vapor pressure of the gasoline stored and loaded at LVT, and DAQ agrees with this approach.

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[180] Table 3-1, LVT RACT Analysis. No tank has a PTE of 5 tpy or more.

[181] The vapor recovery unit is itself a control device that LVT says is considered BACT.

[182] There are 15 loading racks. Most of the 65.7 tpy PTE is from gasoline dispensing. Assuming each rack has the same PTE, 65.7/15 = 4.38 tpy per rack, less than the 5 tpy PTE threshold for RACT review.

[183] This system is also considered BACT, per LVT.

[184] One barrel equals 42 gallons or 160 liters.

[185] Diesel/Biodiesel only: A14-15; Jet Fuel and Diesel/Biodiesel: A23-24.

There are two main losses (VOC emissions) associated with storage tanks: working losses (during transfer of the stored liquid) and standing losses (due to evaporation resulting from temperature swings, seal leaks, etc.).

The following recommended RACT control measures apply to EFRT larger than 150,000 liters (approximately 943 barrels (bbl))[186] storing petroleum liquids. They do not apply to fixed roof tanks or tanks with or without internal floating roofs, nor do they apply to small production tanks. In general, RACT for EFRT is defined as follows:

- A welded EFRT equipped with primary metallic shoe or liquid-mounted seals is required to retrofit with a rim-mounted secondary seal if the true vapor pressure (TVP) of the stored liquid exceeds 27.6 kilopascals (kPa) (4 psi).[187,188]
- A welded or riveted EFRT equipped with primary vapor-mounted seals is required to retrofit with a rim-mounted secondary seal if the TVP of the stored liquid exceeds 10.5 kPa (1.5 psi).
- A riveted EFRT equipped with primary metallic shoe or liquid-mounted seals is also required to retrofit with a rim-mounted secondary seal if the TVP of the stored liquid exceeds 10.5 kPa (1.5 psi).

Information on the controls already on the tanks is included in the LVT analysis (Appendix 6, Table 3-1) and summarized in LVT's Title V OP, as shown in Table 5.1-1.

**Table 5.1-1. Tank Control Requirements**

| EU | Facility ID | Control Requirements |
|---|---|---|
| A01 | 530 | External floating roof with primary and secondary seals |
| A02 | 531 | External floating roof with primary and secondary seals |
| A03 | 532 | External floating roof with primary and secondary seals |
| A04 | 533 | External floating roof with primary and secondary seals |
| A05 | 534 | External floating roof with primary and secondary seals |
| A06 | 535 | External floating roof with primary and secondary seals |
| A07 | 536 | External floating roof with primary and secondary seals |
| A08 | 537 | External floating roof with primary and secondary seals |
| A09 | 538 | External floating roof with primary and secondary seals |
| A10 | 539 | External floating roof with primary and secondary seals |
| A11 | 540 | Internal floating roof with primary and secondary seals |
| A12 | 541 | Domed external floating roof with primary and secondary seals |
| A13 | 524 | Internal floating roof with primary and secondary seals |
| A14 | 542 | Internal floating roof with primary seal |
| A15 | 543 | Internal Floating Roof, primary Seal |

[186] All of the tanks in Table 3-1 have a capacity greater than 950 bbl (approximately 39,900 gallons).

[187] For a Reid vapor pressure (RVP) of 11 psi, the TVP of 4 psi would be exceeded any time the stock temperature was higher than about 45 F. See: AP-42, Chapter 7, Figure 7.1-14a (https://www.epa.gov/sites/default/files/2020-10/documents/ch07s01.pdf) for the conversion, assuming S = 3.0.

[188] EPA-450/2-78-047, OAQPS No._ 1.2-116, Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks, December 1978.

| EU | Facility ID | Control Requirements |
|---|---|---|
| A16 | 545 | Internal floating roof with primary and secondary seals |
| A17 | 546 | Internal floating roof with primary and secondary seals |
| A18 | 522 | Internal floating roof with primary and secondary seals |
| A19 | 525 | Fixed roof |
| A20 | 526 | Fixed roof |
| A21 | 547 | Internal floating roof with primary and secondary seals |
| A22 | 512 | Fixed roof |
| A23 | 510 | External floating roof with primary seal |
| A24 | 511 | External floating roof with primary seal |
| A25 | ASA Conductivity Improver | Fixed roof |
| A26 | 500 AIA | Fixed roof |
| A27 | 501 | Internal floating roof with primary and secondary seals |
| A28 | 523 | Internal floating roof with primary and secondary seals |
| A29 | 544 | Internal floating roof with primary and secondary seals |
| A30 | 533 A | Fixed roof |
| A31 | 537 A | Fixed roof |
| A32 | 541 A | Fixed roof |
| A33 | 541 B | Fixed roof |
| A34 | 542D | Fixed roof |
| A35 | 542A | Fixed roof |
| A36 | 531A | Fixed roof |
| A37 | 542C | Fixed roof |
| A38 | 537 B | Fixed roof |
| A39 | 531B | Fixed roof |
| A45 | 548 | Domed external floating roof with primary and secondary seals |
| A46 | 549 | Domed external floating roof with primary and secondary seals |
| A47 | 550 | Internal floating roof with primary and secondary seals |
| A48 | 551 | Internal floating roof with primary and secondary seals |
| A53 | 548B | Fixed roof |
| A54 | 548A | Fixed roof |
| A56 | 513 | Internal floating roof with primary and secondary seals |

EPA's control technology documents indicate that for IFR and EFR tanks, the use of primary and secondary seals is the best control; all but four of these tanks are already equipped with primary and rim-mounted secondary seals, so RACT is the current technology. The four floating roof tanks with only primary seals (A14–15 and A23–24) are used only for diesel and biodiesel, which has a TVP at 60°F of only 0.006 pounds per square inch absolute (psia).[189] Therefore, the diesel-only tanks are not subject to CTG requirements and the current primary seals constitute RACT.

The fixed roof tanks are the most likely candidates for finding cost-effective add-on emissions controls, since they emit more than IFR and EFR tanks. EPA's CTG document for storage tanks states:

[189] AP-42, Chapter 7, Table 7.1-2.

> Existing fixed roof tanks with greater than 150,000-liter capacity containing petroleum liquids with true vapor pressure greater than 10.5 kilopascals should be controlled by retrofitting with internal floating roofs or equivalent external floating roofs, vapor recovery, vapor disposal systems, or other equivalent control technology. Bolted tanks generally cannot be retrofitted with internal floating roofs, and thus will require alternative equivalent control technology.[190]

Only low-volatility liquids are stored in these tanks, with the most volatile being "jet fuel" in Tank A22. Jet fuel could be either jet naphtha (JP-4) or jet kerosene (Jet A). JP-4 has a TVP at 60°F of 1.3 psia (8.97 kPa), below the TVP threshold in the EPA CTG for RACT.[191] DAQ concludes that RACT for the fixed roof tanks is current controls (primary rim seals).

### 5.1.2 Vapor Recovery Unit and Loading Racks

The 15 LVT loading racks have a total permitted throughput of 35,379,927 barrels/yr. Gasoline and diesel are loaded directly into trucks, while biodiesel, ethanol, and additives are blended during loading. Emissions are controlled by a collection system (98.7% capture efficiency) that captures vapor from the empty trucks as they are loaded; approximately 65 tpy of VOC are fugitive emissions not captured by the recovery system. The captured emissions are routed to a high-efficiency adsorption-absorption John Zink Vapor Recovery Unit (VRU) with an estimated 99.7% efficiency; the approximately 4,893 tpy treated by the VRU is reduced to about 14 tpy of VOC emissions from the VRU. LVT operates a flare as backup if the VRU is unable to operate.

LVT does not mention any RBLC searches for VOC controls for loading racks, so DAQ conducted an independent search to identify potentially available control technologies. A review of the 1977 CTG[192] for loading terminals indicates that a vapor control system with a flare as backup is considered RACT. The CTG mentions three systems (compression-refrigeration-absorption, refrigeration, and thermal oxidation), but the adsorption-absorption system appears to be different (DAQ found a 1976 patent on such a system). The best system the CTG mentioned was thermal oxidation (99+% efficiency). DAQ finds the John Zinc VRU at LVT, at 99.7% efficiency on captured VOC and with the backup flare, would qualify as RACT.[193]

The bulk of emissions from the loading rack are fugitive (65.7048 tpy, of which 64.37 tpy is from gasoline loading). The CTG indicates that fugitive emissions occur during truck filling as a result of faulty seals, overfilling, and other leakage (vapor capture efficiency is 98.70%), but does not address additional control measures for fugitive emissions from loading. For some sources, VOC fugitive emissions reductions from improving operating and maintenance practices may be feasible, but LVT's system is already subject to the NSPS requirements in 40 CFR

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[190] EPA-450/2-77-036, EPA-450/2-77-036 (OAQPS No. 1.~-089), p. 1-2. *Guideline Series: Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed-Roof Tanks.* December 1977. EPA Office of Air and Waste Management.

[191] Even if the fixed roof tanks were subject to CTG, the highest PTE, for Tank A19, is 1.84 tpy, which would make it very unlikely to have a cost-effective CE.

[192] EPA-450/2-77-026, "Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals." See also: "Control Techniques for Volatile Organic Emissions from Stationary Sources." May 1978.

[193] The Title V permit specifies that the control system be maintained and operated per the manufacturer's specifications (Condition III.B.3.n).

Part 60, Subpart XX, "Standards of Performance for Bulk Gasoline Terminals" (OP Condition III.B.3). This includes using the John Zinc system during loading, maintaining the gauge pressure to the delivery tank to no more than 4,500 pascals during loading, and operating so the pressure vacuum vents don't open if the system pressure is less than 4,500 pascals. Conditions III.B.3.q–u specify tanker loading requirements and measures to minimize vapor releases by minimizing gasoline spills, cleaning up spills as expeditiously as possible, covering all open gasoline containers with a gasketed seal when not in use, and minimizing gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices. DAQ identified no additional measures after conducting a literature search, so finds that RACT for the fugitive emissions from the loading racks consists of the requirements already in place.

### 5.1.3 Remediation Systems

LVT has two soil vapor extraction (SVE) systems (both permitted) to treat historical contamination of soil. The first SVE system, termed a "combustion system" in the analysis, has a 98.5% VOC destruction efficiency but is not currently being used; the second system, which is being used, consists of carbon beds and a fluidized bed reactor ("FBR") for 95+% control of the VOC. LVT used a control efficiency of 98.5% for the cost-effectiveness calculations regardless of the system in use.

LVT did not conduct a search of the RBLC or the literature to identify potential available control technology, so DAQ conducted an independent search and identified the following potential control technologies:

- Thermal destruction (e.g., direct flame thermal oxidation, catalytic oxidizers);
- Adsorption (e.g., granular activated carbon, zeolites, polymers);
- Biofiltration;
- Nonthermal plasma destruction;
- Photolytic/photocatalytic destruction;
- Membrane separation;
- Gas absorption; and
- Vapor condensation.

Both SVE and FBR are highly efficient combustion devices that burn most of the VOC in the extracted gas. LVT currently operates its FBR system in a manner that achieves the same level of emission reductions allowable for the SVE combustion system. Accordingly, DAQ concludes that these technologies, as applied based on contaminate treatment conditions, are equally effective. Replacing these systems with a different control technology, even if one of the other technologies had a control efficiency greater than the current system efficiency of 98.5%, would yield few additional emissions reductions from the estimated 37.57 tpy. DAQ concludes that replacing the existing control systems with a different control technology is not economically reasonable for RACT; therefore, the existing control system is RACT.

### 5.1.4 Fugitive Emissions

LVT states that it inspects fugitive components for leaks on a consistent basis and repairs any leaks in the system, and that "these leak monitoring protocols are considered to meet the requirements of RACT." DAQ supplemented LVT's analysis by first checking the RBLC, then documents such as EPA's "Control Techniques for Volatile Organic Emissions from Stationary Sources" (1978). This document discusses leaks found at petroleum refineries, but the information pertains to all pumps, valves, flanges, and other fugitive emissions at a variety of sources (see page 144, for instance). EPA notes that flanges produce the least fugitive emissions and that there are some pump and valve options when switching out old ones, but that for existing equipment, proper maintenance is the key to reducing leaks around packing and seals. DAQ finds that the extensive leak monitoring requirements already in LVT's Title V permit for the tanks and other equipment are sufficient to ensure compliance and therefore constitute RACT.

LVT is also subject to the leak monitoring requirements in 40 CFR Part 63, Subpart BBBBBB– National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities. The requirements in this recently promulgated standard represent the most effective control technology for leak detection. Although the standard regulates HAPs, these HAP emissions are generally also VOC emissions, so DAQ expects a similar level of emission reduction from LVT compliance with the standard. Among the many leak monitoring requirements in Subpart BBBBBB (at 40 CFR 63.11092(a)(1)(i)) is a requirement for the source to conduct vapor collection leak monitoring during a performance test on the vapor recovery system using Method 21, with a 500 ppm threshold for doing maintenance and repair. DAQ finds that using EPA Method 21 to monitor for leaks and repairing leaks with readings at or above 500 ppm (as methane) represent RACT for this equipment.

# Appendix 1

Final RACT Methodology for
HA 212 2015 8-hour Ozone NAAQS

| EU | Description | Rating | Make | Operating Conditions | NOx (tpy) | VOC (tpy) |
|---|---|---|---|---|---|---|
| G062[1,2] | Generator or Fire Pump | 65 | Wisconsin | N/A | 0.08 | |
| G104[1] | Generator or Fire Pump | 64.5 | Deutz | 11/2012 | 0.05 | |
| G150[1] | Generator or Fire Pump | 64.5 | Deutz | 4/2015 | 0.05 | |
| G105[1] | Generator or Fire Pump | 64.5 | Deutz | 11/2012 | 0.05 | |
| G151[1] | Generator or Fire Pump | 64.5 | Deutz | 4/2015 | 0.05 | |
| G145[1] | Generator or Fire Pump | 64.5 | Deutz | 11/2014 | 0.05 | |
| G148[1] | Generator or Fire Pump | 64.5 | Deutz | 11/2014 | 0.05 | |
| G152[1] | Generator or Fire Pump | 64.5 | Deutz | 4/2015 | 0.05 | |
| G153[1] | Generator or Fire Pump | 64.5 | Deutz | 4/2015 | 0.05 | |
| G117[1,2] | Generator or Fire Pump | 65 | Wisconsin | N/A | 0.08 | |
| G058[1,2] | Generator or Fire Pump | 65 | Wisconsin | 10/2002 | 0.08 | |
| G147[1] | Generator or Fire Pump | 64.5 | Deutz | 11/2014 | 0.05 | |
| G146[1] | Generator or Fire Pump | 64.5 | Deutz | 11/2014 | 0.05 | |
| G163 | Generator or Fire Pump | 350 kW | Caterpillar | 2017 | 1.28 | |
| | Generator or Fire Pump | 531 hp | Caterpillar | | | |
| G168 | Generator or Fire Pump | 100 kW | Caterpillar | | 0.16 | |
| | | 111.3 hp | Caterpillar | | | |
| A01 | Tank 530 | 11,200 bbl | External Floating Roof AST w/Primary and Secondary Seal | 28,560,000 | | |
| A02 | Tank 531 | 12,890 bbl | External Floating Roof AST w/Primary and Secondary Seal | 32,460,000 | | |
| A03 | Tank 532 | 8,080 bbl | External Floating Roof AST w/Primary and Secondary Seal | 20,340,000 | | |

| EU | Description | Rating | Make | Operating Conditions | NOx (tpy) | VOC (tpy) |
|---|---|---|---|---|---|---|
| A04 | Tank 533 | 11,330 bbl | External Floating Roof AST w/Primary and Secondary Seal | 28,560,000 | | |
| A05 | Tank 534 | 8,080 bbl | External Floating Roof AST w/Primary and Secondary Seal | 20,340,000 | | |
| A06 | Tank 535 | 8,080 bbl | External Floating Roof AST w/Primary and Secondary Seal | 20,340,000 | | |
| A07 | Tank 536 | 17,550 bbl | External Floating Roof AST w/Primary and Secondary Seal | 44,220,000 | | |
| A08 | Tank 537 | 22,250 bbl | External Floating Roof AST w/Primary and Secondary Seal | 90,000,000 | | |
| A09 | Tank 538 | 11,330 bbl | External Floating Roof AST w/Primary and Secondary Seal | 28,560,000 | | |
| A10 | Tank 539 | 11,330 bbl | External Floating Roof AST w/Primary and Secondary Seal | 50,000,000 | | |

| EU | Description | Rating | Make | Operating Conditions | NOx (tpy) | VOC (tpy) |
|---|---|---|---|---|---|---|
| A11 | Tank 540 | 16,320 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 137,000,000 | | |
| A12 | Tank 541 | 25,100 bbl | Domed External Floating Roof AST w/Primary and Secondary Seal | 864,000,000 | | |
| A13 | Tank 524 | 18,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 50,760,000 | | |
| A14 | Tank 542 | 45,000 bbl | Internal Floating Roof AST w/Primary Seal | 118,500,000 | | |
| A15 | Tank 543 | 35,000 bbl | Internal Floating Roof AST w/Primary Seal | 114,660,000 | | |
| A16 | Tank 545 | 37,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 88,200,000 | | |
| A17 | Tank 546 | 40,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 100,800,000 | | |
| A18 | Tank 522 | 4,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 9,000,000 | | |
| A19 | Tank 525 | 50,000 bbl | Fixed Roof AST | 350,000,000 | | |

| EU | Description | Rating | Make | Operating Conditions | NOx (tpy) | VOC (tpy) |
|---|---|---|---|---|---|---|
| A20 | Tank 526 | 50,000 bbl | Fixed Roof AST | 220,500,000 | | |
| A21 | Tank 547 | 50,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 100,800,000 | | |
| A22 | Tank 512 | 50,000 bbl | Fixed Roof AST | 126,000,000 | | |
| A23 | Tank 510 | 40,000 bbl | External Floating Roof AST w/Primary Seal | 100,800,000 | | |
| A24 | Tank 511 | 40,000 bbl | External Floating Roof AST w/Primary Seal | 100,800,000 | | |
| A25 | ASA Conductivity Improver | 1.3 bbl | Fixed Roof AST | 5,040 | | |
| A26 | Tank 500AIA | 252 bbl | Fixed Roof AST | 95,949 | | |
| A27 | Tank 501 | 4,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 9,540,000 | | |
| A28 | Tank 523 | 10,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 23,580,000 | | |
| A29 | Tank 544 | 11,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 27,720,000 | | |
| A30 | Tank 533A | 252 bbl | Fixed Roof AST | 95,949 | | |
| A31 | Tank 537A | 464 bbl | Fixed Roof AST | 95,949 | | |

| EU | Description | Rating | Make | Operating Conditions | NOx (tpy) | VOC (tpy) |
|---|---|---|---|---|---|---|
| A32 | Tank 541A | 380 bbl | Fixed Roof AST | 148,050 | | |
| A33 | Tank 541B | 380 bbl | Fixed Roof AST | 148,050 | | |
| A34 | Tank 542D | 215 bbl | Fixed Roof AST | 81,207 | | |
| A35 | Tank 542A | 143 bbl | Fixed Roof AST | 79,286 | | |
| A36 | Tank 531A | 143 bbl | Fixed Roof AST | 55,661 | | |
| A37 | Tank 542C | 12 bbl | Fixed Roof AST | 5,040 | | |
| A38 | Tank 537B | 447 bbl | Fixed Roof AST | 95,949 | | |
| A39 | Tank 531B | 119 bbl | Fixed Roof AST | 44,100 | | |
| | | | | | | |
| A45 | Tank 548 | 12,890 bbl | Domed External Floating Roof AST w/Primary and Secondary Seal | 32,460,000 | | |
| A46 | Tank 549 | 12,890 bbl | Domed External Floating Roof AST w/Primary and Secondary Seal | 32,460,000 | | |
| A47 | Tank 550 | 20,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 70,000,000 | | |
| A48 | Tank 551 | 10,100 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 50,400,000 | | |
| A49 | Tank 542B | 4 bbl | Fixed Roof AST | 5,040 | | |
| A53 | Tank 548B | 238 bbl | Fixed Roof AST | 57,519 | | |
| A54 | Tank 548A | 238 bbl | Fixed Roof AST | 95,949 | | |
| A56 | Tank 513 | 50,000 bbl | Internal Floating Roof AST | 189,000,000 | | |

| EU | Description | Rating | Make | Operating Conditions | NOx (tpy) | VOC (tpy) |
|---|---|---|---|---|---|---|
| | | | w/Primary and Secondary Seal | | | |
| A57 | Tank 514 | 50,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 189,000,000 | | |
| A58 | Tank 553 | 80,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 302,400,000 | | |
| A59 | Tank 554 | 80,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 604,800,000 | | |
| A60 | Tank 555 | 80,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 604,800,000 | | |
| A61 | Tank 552 | 40,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 126,000,000 | | |
| B01 | Loading Racks | 35,379,927 bbl per year | 15 Loading Lanes | | | |
| | | | | | | |
| B04 | Tank 500 | 3,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 7,560,000 | | |

| EU | Description | Rating | Make | Operating Conditions | NOx (tpy) | VOC (tpy) |
|---|---|---|---|---|---|---|
| B05 | Tank 521 | 5,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | 12,720,000 | | |
| B01A | B-100 | 147,168,000 gallons/yr | Biodiesel Offloading Rack | | | |
| B02 | John Zink VRU | | Vapor control unit; loading lanes | | | |
| B06 | Piping and Fittings | | Misc. Losses/Leaks from Valves, Flanges, Pumps and VCU | | | |
| B10 | Flare Processing | | Vapor control unit for loading lanes (includes saturator and vapor holding tank) | | | |
| B11 | | 48 hp | | | | |
| D01 | Tank DG | 250 gal | Fixed Roof AST | 25,000 | | |
| D02 | | 208 hp | | | | |
| | | | | | | |
| H02 | Mainline Sump | 1,000 gal | Mainline Sump UST | 302,400 | | |
| H03 | Rack Sump | 3,000 gal | Rack Sump UST | 806,400 | | |
| H04 | Mainline Sump | 4,200 gal | New Mainline Sump UST | 100,800 | | |
| H05 | Cooling Tower | 220 gpm | Baltimore Aircoil; M/N: F2841KE; S/N: | | | |

| EU | Description | Rating | Make | Operating Conditions | NOx (tpy) | VOC (tpy) |
|---|---|---|---|---|---|---|
| | | | U013422001MAD | | | |
| H06 | Nellis Sump | 2,000 gal | Nellis Delivery System Sump, UST | 75,600 | | |
| H07 | Rack Sump | 1,000 gal | Rack 6 Sump, UST | 36,000 | | |
| H08 | QC Sump | 100 gal | Quality Control Lab Sump UST | | | |
| H09 | Ethanol | 76,104,000 gal/year | Ethanol unloading system | | | |
| H10 | Tank 500B | 10,000 gal | Fixed Roof vertical AST | 132,000 | | |
| H11 | OWS Tank | | Oil-water separator tank | 15,768,000 | | |
| H12 | OST-100- DW | 1,000 gal | Fixed Roof Horizontal AST w/Dual Wall | 365,000 | | |
| H14 | ASA Tote | 350 gal | Fixed Roof Rectangular AST | 390 | | |
| H15 | CI Tote | 350 gal | Fixed Roof Rectangular AST | 3,300 | | |
| H16 | Lane 7 Red Dye Tote | 350 gal | Fixed Roof Rectangular AST | 6,150 | | |
| H17 | Lane 12 Red Dye Tote | 350 gal | Fixed Roof Rectangular AST | 6,150 | | |
| SR04 | SVE and GW Treatment System | | Soil Vapor Extraction and Groundwater Treatment | | | |

| EU | Description | Rating | Make | Operating Conditions | NOx (tpy) | VOC (tpy) |
|---|---|---|---|---|---|---|
| | | | System (includes control units) | | | |

## ATTACHMENT 2 EPA CTG DOCUMENT

| Pollutant | EPA Report | Description |
|---|---|---|
| **Control Techniques Guidelines (CTG)** | | |
| VOC | EPA-450/R-75-102<br>*1975/11* | Design Criteria for Stage I Vapor Control Systems – Gasoline Service Stations (PDF 15 pp, 766KB)<br>*Note – This document is regarded as a CTG although it was never published with an EPA document number.* |
| VOC | EPA-450/2-76-028<br>*1976/11* | Control of Volatile Organic Emissions from Existing Stationary Sources – Volume I: Control Methods for Surface Coating Operations (PDF 174 pp, 4.6MB)<br>*Note – Although often listed with the CTGs for historical reasons, this document does not define RACT for any source. It is a compilation of control techniques.* |
| VOC | EPA-450/2-77-008<br>*1977/05* | Control of Volatile Organic Emissions from Existing Stationary Sources – Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks (PDF 232 pp, 2.7MB) |
| VOC | EPA-450/2-77-022<br>*1977/11* | Control of Volatile Organic Emissions from Solvent Metal Cleaning (PDF 229 pp, 7.0MB) |
| VOC | EPA-450/2-77-025<br>*1977/10* | Control of Refinery Vacuum Producing Systems, Wastewater Separators, and Process Unit Turnarounds (PDF 50 pp, 1.3MB) |
| VOC | EPA-450/2-77-026<br>*1977/10* | Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals (PDF 62 pp, 1.6MB) |
| VOC | EPA-450/2-77-032<br>*1977/12* | Control of Volatile Organic Emissions from Existing Stationary Sources – Volume III: Surface Coating of Metal Furniture (PDF 66 pp, 1.9MB) |
| VOC | EPA-450/2-77-033<br>*1977/12* | Control of Volatile Organic Emissions from Existing Stationary Sources – Volume IV: Surface Coating of Insulation of Magnet Wire (PDF 44 pp, 1.1MB) |

| Pollutant | EPA Report | Description |
|---|---|---|
| VOC | EPA-450/2-77-034<br>*1977/12* | Control of Volatile Organic Emissions from Existing Stationary Sources – Volume V: Surface Coating of Large Appliances (PDF 70 pp, 2.1MB) |
| VOC | EPA-450/2-77-035<br>*1977/12* | Control of Volatile Organic Emissions from Bulk Gasoline Plants (PDF 49 pp, 1.3MB) |
| VOC | EPA-450/2-77-036<br>*1977/12* | Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed-Roof Tanks (PDF 43 pp, 1.1MB) |
| VOC | EPA-450/2-77-037<br>*1977/12* | Control of Volatile Organic Emissions from Use of Cutback Asphalt (PDF 18 pp, 481KB) |
| VOC | EPA-450/2-78-022<br>*1978/05* | Control Techniques for Volatile Organic Emissions from Stationary Sources (PDF 580 pp, 21.9MB)<br>*Note – This document is often listed with CTGs, but it does not define RACT for any particular source* |
| VOC | EPA-450/2-78-015<br>*1978/06* | Control of Volatile Organic Emissions from Existing Stationary Sources – Volume VI: Surface Coating of Miscellaneous Metal Parts and Products (PDF 82 pp, 2.6MB) |
| VOC | EPA-450/2-78-032<br>*1978/06* | Control of Volatile Organic Emissions from Existing Stationary Sources – Volume VII: Factory Surface Coating of Flat Wood Paneling (PDF 66 pp, 2.0MB) |
| VOC | EPA-450/2-78-036<br>*1978/06* | Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment (PDF 78 pp, 6.0MB) |
| VOC | EPA-450/2-78-029<br>*1978/12* | Control of Volatile Organic Emissions from Manufacture of Synthesized Pharmaceutical Products (PDF 134 pp, 3.8MB) |
| VOC | EPA-450/2-78-030<br>*1978/12* | Control of Volatile Organic Emissions from Manufacture of Pneumatic Rubber Tires (PDF 72 pp, 1.6MB) |
| VOC | EPA-450/2-78-033<br>*1978/12* | Control of Volatile Organic Emissions from Existing Stationary Sources – Volume VIII: Graphic Arts-Rotogravure and Flexography (PDF 64 pp, 1.9MB) |
| VOC | EPA-450/2-78-047<br>*1978/12* | Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks (PDF 66 pp, 2.0MB) |

| Pollutant | EPA Report | Description |
|---|---|---|
| VOC | EPA-450/2-78-050<br>*1978/12* | Control of Volatile Organic Emissions from Perchloroethylene Dry Cleaning Systems (PDF 76 pp, 2.5MB)<br>*Note – Perchloroethylene has been exempted as a VOC, so this CTG is no longer relevant. However, there is a MACT standard for perchloroethylene dry cleaners.* |
| VOC | EPA-450/2-78-051<br>*1978/12* | Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems (PDF 32 pp, 887KB) |
| VOC | EPA-450/3-82-009<br>*1982/09* | Control of Volatile Organic Compound Emissions from Large Petroleum Dry Cleaners (PDF 174 pp, 5.0MB) |
| VOC | EPA-450/3-83-008<br>*1983/11* | Control of Volatile Organic Compound Emissions from Manufacture of High-Density Polyethylene, Polypropylene, and Polystyrene Resins (PDF 308 pp, 14.0MB) |
| VOC | EPA-450/3-83-007<br>*1983/12* | Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants (PDF 194 pp, 6.3MB) |
| VOC | EPA-450/3-83-006<br>*1984/03* | Control of Volatile Organic Compound Leaks from Synthetic Organic Chemical Polymer and Resin Manufacturing Equipment (PDF 148 pp, 6.2MB) |
| VOC | EPA-450/3-84-015<br>*1984/12* | Control of Volatile Organic Compound Emissions from Air Oxidation Processes in Synthetic Organic Chemical Manufacturing Industry (PDF 259 pp, 9.4MB) |
| VOC | EPA-450/4-91-031<br>*1993/08* | Control of Volatile Organic Compound Emissions from Reactor Processes and Distillation Operations in Synthetic Organic Chemical Manufacturing Industry (PDF 277 pp, 8.7MB) |
| VOC | EPA-453/R-96-007<br>*1996/04* | Control of Volatile Organic Compound Emissions from Wood Furniture Manufacturing Operations (PDF 288 pp, 13.8MB)<br>*Note – Wood Furniture (CTG-MACT) – Draft MACT out 5-1994; Final CTG issued 4-1996. See also 61 FR-25223, May 20, 1996 and 61 FR-50823, September 27, 1996.* |
| VOC | EPA-453/R-94-032<br>*1994/04* | Alternative Control Technology Document – Surface Coating Operations at Shipbuilding and Ship Repair Facilities (PDF 217 pp, |

| Pollutant | EPA Report | Description |
|---|---|---|
| | | 9.8MB)<br>*Note – For CTG, see 61 FR-44050, August 27,1996* |
| VOC | 61 FR-44050 8/27/96<br>*1996/08* | Control Techniques Guidelines for Shipbuilding and Ship Repair Operations (Surface Coating) (PDF 30 pp, 4.0MB)<br>*Note – See also EPA-453/R-94-032.* |
| VOC | 59 FR-29216 6/06/94<br>*1994/06* | Aerospace MACT (PDF 37 pp, 6MB)<br>*Note – See also EPA-453/R-97-004.* |
| VOC | EPA-453/R-97-004<br>*1997/12* | Aerospace (CTG & MACT) (PDF 62 pp, 288KB)<br>*Note – See also 59 FR-29216, June 6, 1994.* |
| VOC | EPA-453/R-06-001<br>*2006/09* | Control Techniques Guidelines for Industrial Cleaning Solvents (PDF 290 pp, 7.6MB) |
| VOC | EPA-453/R-06-002<br>*2006/09* | Control Techniques Guidelines for Offset Lithographic Printing and Letterpress Printing (PDF 52 pp, 349KB) |
| VOC | EPA-453/R-06-003<br>*2006/09* | Control Techniques Guidelines for Flexible Package Printing (PDF 33 pp, 216KB) |
| VOC | EPA-453/R-06-004<br>*2006/09* | Control Techniques Guidelines for Flat Wood Paneling Coatings (PDF 27 pp, 212KB) |
| VOC | EPA 453/R-07-003<br>*2007/09* | Control Techniques Guidelines for Paper, Film, and Foil Coatings (PDF 102 pp, 488KB) |
| VOC | EPA 453/R-07-004<br>*2007/09* | Control Techniques Guidelines for Large Appliance Coatings (PDF 44 pp, 374KB) |
| VOC | EPA 453/R-07-005<br>*2007/09* | Control Techniques Guidelines for Metal Furniture Coatings (PDF 100 pp, 293KB) |
| VOC | EPA 453/R-08-003<br>*2008/09* | Control Techniques Guidelines for Miscellaneous Metal and Plastic Parts Coatings (PDF 143 pp, 897KB) |
| VOC | EPA 453/R-08-004<br>*2008/09* | Control Techniques Guidelines for Fiberglass Boat Manufacturing Materials (PDF 41 pp, 336KB) |
| VOC | EPA 453/R-08-005<br>*2008/09* | Control Techniques Guidelines for Miscellaneous Industrial Adhesives (PDF 47 pp, 350KB) |

| Pollutant | EPA Report | Description |
|---|---|---|
| VOC | EPA 453/R-08-006<br>*2008/09* | Control Techniques Guidelines for Automobile and Light-Duty Truck Assembly Coatings (PDF 44 pp, 2.64MB)<br>*Note – See also EPA-453/R-08-002.* |
| VOC | EPA 453/R-08-002<br>*2008/09* | Protocol for Determining the Daily Volatile Organic Compound Emission Rate of Automobile and Light-Duty Truck Primer-Surfacer and Topcoat Operations (PDF 129 pp, 450KB)<br>*Note – See also EPA-453/R-08-006.* |
| VOC | EPA-453/B-16-001<br>*2016/10* | Control Techniques Guidelines for the Oil and Natural Gas Industry (343 pp, 1.6 MB) |

# Appendix 6

CAL/NEV Pipeline RACT Analysis

KINDER MORGAN
CALNEV PIPE LINE LLC

October 3, 2022

Mr. Ted Lendis
Permitting Manager
Clark County DAQ
4701 West Russell Road
Suite 200
Las Vegas NV 89118-2231

**Subject: RACT Requirements Review**
**Calnev Pipe Line, LLC – Las Vegas Terminal, Part 70 Permit Number 13**
**5049 North Sloan Lane, Las Vegas, NV 89115**

Dear Mr. Lendis:

Please find the enclosed the RACT requirements review for emissions at the Calnev Pipe Line, LLC Las Vegas Terminal. If you have any questions please contact Nina McAfee at (713) 420-5610 or Cinnamon Smith at (281) 731-8854.

Sincerely,

William Toepfer
Director of Operations
For Calnev Pipe Line, LLC

Enclosures:
1. RACT Requirements Review

**Products EHS Compliance – 14th Floor 1001 Louisiana Street Houston, TX 77002-5089**
**(713) 369-9000 Fax (713) 420-1603**

# Calnev Pipe Line, LLC
# Las Vegas Terminal

## 5049 North Sloan Lane
## Las Vegas, NV 89115

## Part 70 Permit No. 13

## October 2022

## Prepared by:

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# RACT Requirement Report

# RACT Requirement Report

Prepared for:

**Calnev Pipe Line, LLC**
**Las Vegas Terminal**
**5049 North Sloan Lane**
**Las Vegas, NV 89115**

October 2022


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# RACT Requirement Report

## 1.0 INTRODUCTION

Kinder Morgan's subsidiary Calnev Pipe Line, LLC (Calnev) owns and operates a petroleum products distribution terminal facility located at 5049 North Sloan Lane in Las Vegas, Nevada. The Las Vegas Terminal's (LVT's) operations include receiving petroleum fuel products via pipeline or truck and transferring gasoline, diesel, and biodiesel from storage tanks into trucks via loading racks.

The Clark County Department of Air Quality (DAQ) recently contacted Kinder Morgan regarding implementation of the State Implementation Plan (SIP) to comply with the 2015 ozone standard. As part of this process, the Clark County DAQ has asked Kinder Morgan to conduct a Reasonably Achievable Control Technology (RACT) analysis for volatile organic compound (VOC) emissions and supply facility-specific information to determine the appropriate RACT controls for the terminal. The information on facility operations and emissions contained herein is primarily based on the LVT's 2021 Title V Renewal, which was submitted in 2021.

## 2.0 GENERAL INFORMATION REQUEST

### 2.1 Background

Clark County DAQ has requested the following general information related to facility operations:

- Confirmation of major source potential to emit (PTE);
- List of emissions units potentially subject to RACT;
- Rated size or maximum capacity of each emissions unit;
- Description of emissions patterns over the year; and
- Information on emissions related to training, certification, or testing requirements.

### 2.2 Confirmation of Major Source PTE

The LVT is a bulk petroleum distribution terminal; with a standard industrial classification (SIC) code of 4226 and a North American Industry Classification System (NAICS) code of 424710. The terminal receives petroleum fuel products via pipeline or truck and transfers gasoline, diesel, and biodiesel from storage tanks into trucks via loading racks. Denatured ethanol stored and distributed at the LVT is received via railcar; the terminal also has the capability to unload ethanol via tank trucks.

Based on the PTE results, the emission calculations included in Appendix A demonstrate that the LVT is a Major Source for VOC emissions and a Minor Source of nitrogen oxides ($NO_x$), carbon monoxide (CO), sulfur dioxide ($SO_2$), particulate matter less than 10 microns in size ($PM_{10}$), particulate matter less than 2.5 microns in size ($PM_{2.5}$), and hazardous air pollutants (HAPs). The emissions of $NO_x$, CO, $SO_2$, $PM_{10}$, and $PM_{2.5}$ are each below 10 tons per year. Total HAP emissions are below 25 tons per year, and emissions of any single HAP are below 10 tons per year.


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Therefore, only the provisions of VOC RACT apply to the LVT; a review of $NO_x$ RACT is not applicable. Based on guidance given by DAQ, Phase 1 of the County's review will focus on emissions units with a PTE of greater than 5 tons per year (tpy).

## 2.3 Emission Sources Evaluated for VOC RACT

- Fuel storage tanks (61.3 tpy), consisting of:
  - Three vertical fixed roof tanks;
  - 21 internal floating roof tanks;
  - 12 external floating roof tanks; and
  - Three domed external floating roof tanks;
- One vapor recovery unit (14.5 tpy);
- Loading Racks (65.7 tpy);
- Remediation system (37.7 tpy); and
- Fugitive components such as valves, flanges, fittings, and pump seals (6.6 tpy).

## 2.4 Emissions Sources Not Evaluated for VOC RACT

Sources with a VOC PTE of less than 5 tons per year are excluded from this analysis.

These include:

- Six sumps (2.1 tpy);
- Parts washer (1.17 tpy);
- 20 fuel additive storage tanks (0.12 tpy);
- Two provers (0.16 tpy);
- Ethanol unloading system (0.18 tpy);
- Biofuel unloading system, including a portable prover (0.04 tpy);
- Water treatment system that includes two underground surge storage tanks, an oil-water separator, and an evaporation pond (0.1 tpy);
- Cooling tower that serves the vapor recovery unit (0.0 tpy);
- One auxiliary flare (0.0 tpy);
- Two internal combustion engines; one engine serves the air compressor and the other serves the emergency fire pump (0.13 tpy); and
- One 90,000-gallon horizontal pressurized tank storing butane (0.0 tpy).

## 2.5 Rated Size or Maximum Capacity of each Emissions Unit

A complete listing of equipment capacities for all equipment with a VOC PTE of great than 5 tons per year is included in the following sections. Other than Tanks 501 and 522, both of which are permitted to only store denatured ethanol, all the floating-roof aboveground storage tanks are designed and permitted to store multiple liquids. Tanks that are currently in gasoline service may occasionally be used to store other, lower vapor pressure petroleum products depending on market needs.


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### 2.6 Description of Emissions Patterns Over the Year

The operating schedule for the facility is 24 hours per day, 7 days per week, and 52 weeks per year. At various times throughout the year, gasoline with different vapor pressure is loaded. The emissions from the multi-product tanks and loading racks were calculated using gasoline with an average Reid Vapor Pressure (RVP) of 11. An RVP of 11 is the annual average vapor pressure of gasoline stored and loaded at the LVT. There is not expected to be a significant difference in VOC emissions over the course of the year.

### 2.7 Information on Emissions Related to Training, Certification, or Testing Requirements

A fixed-volume meter-prover (prover) is operated at the LVT to verify the calibration of flow meters used for measurement of the liquid delivered to the LVT via pipelines. A single prover is used on the multiple products pipelines entering the LVT. Verification of pipeline flow rate is accomplished by tracking the time required for an internal float to be conveyed through the prover loop. During normal operation, petroleum products from the pipeline are routed through the prover and then returned to the pipeline. There are no emissions to the atmosphere during normal operation. When it is necessary to empty the prover loop and prepare it for service, liquid contained in the prover is drained into its subsurface sump. The sump has a vent open to atmosphere. The liquid product in the sump is periodically pumped back to the dedicated tank. There are emissions associated with draining the prover and venting it during the refilling process, summarized in Appendix A. The prover is taken out of service up to 12 times per year.

## 3.0 RACT REQUIREMENTS

### 3.1 RACT for Storage Tanks

VOC emissions at bulk petroleum product terminals occur when fuel products are transferred through storage tanks ("working losses"), as well as losses associated with daily temperature cycles while the liquid is stored ("standing losses"). Four types of aboveground storage tanks are utilized at the LVT: (1) Internal Floating Roof (IFR) tanks, (2) External Floating Roof (EFR) tanks, (3) Domed External Floating Roof (DEFR) tanks, and (4) Fixed Roof tanks (FRT), including both vertical and horizontal tanks.


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**Table 3-1: Fuel Storage Tank Information and PTE at Las Vegas Terminal**

| Emission Unit | Tank No. | Tank Type | Capacity (bbl) | Max Throughput (bbl) | Potential to Emit (tpy) | Rim Seal(s) | Permitted Product |
|---|---|---|---|---|---|---|---|
| A01 | 530 | EFR | 11,200 | 28,560,000 | 1.33 | Primary and Secondary | Multi fuel |
| A02 | 531 | EFR | 12,890 | 32,460,000 | 1.41 | Primary and Secondary | Multi fuel |
| A03 | 532 | EFR | 8,080 | 20,340,000 | 1.14 | Primary and Secondary | Multi fuel |
| A04 | 533 | EFR | 11,330 | 28,560,000 | 1.33 | Primary and Secondary | Multi fuel |
| A05 | 534 | EFR | 8,080 | 20,340,000 | 1.14 | Primary and Secondary | Multi fuel |
| A06 | 535 | EFR | 8,080 | 20,340,000 | 1.14 | Primary and Secondary | Multi fuel |
| A07 | 536 | EFR | 17,550 | 44,220,000 | 1.64 | Primary and Secondary | Multi fuel |
| A08 | 537 | EFR | 22,250 | 90,000,000 | 1.88 | Primary and Secondary | Multi fuel |
| A09 | 538 | EFR | 11,330 | 28,560,000 | 2.76 | Primary and Secondary | Multi fuel |
| A10 | 539 | EFR | 11,330 | 50,000,000 | 1.38 | Primary and Secondary | Multi fuel |
| A11 | 540 | IFR | 16,320 | 137,000,000 | 1.90 | Primary and Secondary | Multi fuel |
| A12 | 541 | DEFR | 25,100 | 864,000,000 | 1.86 | Primary and Secondary | Multi fuel |
| A13 | 524 | IFR | 18,000 | 50,760,000 | 0.75 | Primary and Secondary | Multi fuel |
| A14 | 542 | IFR | 45,000 | 118,500,000 | 0.17 | Primary | Diesel/Biodiesel |
| A15 | 543 | IFR | 35,000 | 114,660,000 | 0.18 | Primary | Diesel/Biodiesel |
| A16 | 545 | IFR | 37,000 | 88,200,000 | 2.14 | Primary and Secondary | Multi fuel |
| A17 | 546 | IFR | 40,000 | 100,800,000 | 2.94 | Primary and Secondary | Multi fuel |
| A18 | 522 | IFR | 4,000 | 9,000,000 | 0.28 | Primary and Secondary | Denatured Ethanol |
| A19 | 525 | FRT | 50,000 | 350,000,000 | 1.84 | N/A | Diesel/Biodiesel |
| A20 | 526 | FRT | 50,000 | 220,500,000 | 1.46 | N/A | Diesel/Biodiesel |
| A21 | 547 | IFR | 50,000 | 100,800,000 | 2.58 | Primary and Secondary | Multi fuel |
| A22 | 512 | FRT | 50,000 | 126,000,000 | 1.77 | N/A | Jet Fuel, Diesel/Biodiesel |
| A23 | 510 | EFR | 40,000 | 100,800,000 | 0.18 | Primary | Jet Fuel, Diesel/Biodiesel |
| A24 | 511 | EFR | 40,000 | 100,800,000 | 0.18 | Primary | Jet Fuel, Diesel/Biodiesel |
| A27 | 501 | IFR | 4,000 | 9,540,000 | 0.32 | Primary and Secondary | Denatured Ethanol |
| A28 | 523 | IFR | 10,000 | 23,580,000 | 1.53 | Primary and Secondary | Multi fuel |


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| Emission Unit | Tank No. | Tank Type | Capacity (bbl) | Max Throughput (bbl) | Potential to Emit (tpy) | Rim Seal(s) | Permitted Product |
|---|---|---|---|---|---|---|---|
| A29 | 544 | IFR | 11,000 | 27,720,000 | 1.72 | Primary and Secondary | Multi fuel |
| A45 | 548 | DEFR | 12,890 | 32,460,000 | 2.00 | Primary and Secondary | Multi fuel |
| A46 | 549 | DEFR | 12,890 | 32,460,000 | 1.04 | Primary and Secondary | Multi fuel |
| A47 | 550 | IFR | 20,000 | 70,000,000 | 1.81 | Primary and Secondary | Multi fuel |
| A48 | 551 | IFR | 10,100 | 50,400,000 | 1.75 | Primary and Secondary | Multi fuel |
| A56 | 513 | IFR | 50,000 | 189,000,000 | 0.49 | Primary and Secondary | Jet Fuel, Diesel/Biodiesel |
| A57 | 514 | IFR | 50,000 | 189,000,000 | 0.49 | Primary and Secondary | Jet Fuel, Diesel/Biodiesel |
| A58 | 553 | IFR | 80,000 | 302,400,000 | 4.29 | Primary and Secondary | Multi fuel |
| A59 | 554 | IFR | 80,000 | 604,800,000 | 4.98 | Primary and Secondary | Multi fuel |
| A60 | 555 | IFR | 80,000 | 604,800,000 | 3.41 | Primary and Secondary | Multi fuel |
| A61 | 552 | IFR | 40,000 | 126,000,000 | 2.26 | Primary and Secondary | Multi fuel |
| B04 | 500 | IFR | 3,000 | 7,560,000 | 0.55 | Primary and Secondary | Multi fuel |
| B05 | 521 | IFR | 5,000 | 12,720,000 | 1.24 | Primary and Secondary | Multi fuel |
| D01 | DG | FRT | 5.9 | 595 | 0.01 | N/A | Diesel/Biodiesel |


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As shown in Table 3-1, no individual storage tank at the LVT has a PTE of greater than 5 tons per year VOC; the following discussion details how these tanks employ stringent control technologies to comply with storage tank standards, as specified in the facility's Title V Permit.

### *3.1.1 Internal Floating Roof Tanks*

IFR tanks offer better control of evaporative emissions than fixed roof tanks. The floating roof structure, usually of a pontoon or floating pan type, essentially eliminates the vapor headspace above the liquid surface. On most IFRs, primary and secondary seals of various types are installed along the edge of the floating roof to control evaporation through the gap between the floating roof structure and inner tank wall.

IFR storage tanks are not routinely emptied of product. The tanks are operated to maintain a heel of product between the roof and the floor. Since the floating roof remains suspended on the liquid contents, a vapor space does not form in the heel space. However, vapors may escape in small amounts as fugitive emissions through rim seals, deck fittings, or deck seals. Emissions can also occur while the product is withdrawn from an IFR and the floating roof is lowered. The portion of the interior tank wall that used to be covered by product is exposed to the headspace of the IFR tank.

IFR storage tanks are typically considered Best Available Control Technology (BACT) and therefore meet the requirements of RACT.

### *3.1.2 External Floating Roof Tanks, With and Without Domes*

EFR tanks also offer better control of evaporative emissions than fixed roof tanks but are used for less volatile products than those in IFR tanks due to their greater exposure to the atmosphere and wind and weather conditions. The floating roof is usually heavier than a floating roof in an IFR tank.

A DEFR is an EFR tank where a dome was subsequently built over the roof, supported by the tank shell. It is different from an IFR tank only in that the dome was not built contemporaneously to the rest of the tank, and the roof fittings and rim seals are those of an EFR tank.

EFR and DEFR storage tanks are considered to meet BACT and therefore meet the requirements of RACT.

### *3.1.3 Fixed Roof Tanks*

FRTs do not have an internal floating roof or pan. This allows vapors to evaporate from the liquid surface and accumulate in the headspace in response to daily temperature cycles that cause daily cycles in differential pressure between the tank and surroundings, representing breathing losses. During refilling, hydrocarbon vapor in the headspace is displaced by the incoming liquid and vented to the atmosphere, resulting in working losses.

At the LVT, the three fixed roof tanks in operation are used for low-volatility products, such as diesel, biodiesel, and jet fuel. Each tank has a PTE of less than 5 tons per year. As such, these sources have not been evaluated for RACT.


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## 3.2 RACT for Loading Racks and Vapor Recovery Units

The LVT dispenses petroleum fuel products at loading racks, numbered 1 through 15, with a total permitted throughput of 35,379,927 barrels per year. Gasoline and diesel from storage tanks are loaded into trucks at the loading racks. Biodiesel, ethanol, and additives are blended during loading of petroleum products. VOC emissions from loading racks occur as organic vapors in empty tanker trucks that are displaced to the atmosphere by the liquid being loaded into the vessel. The vapors from the loading racks are controlled by the John Zink Vapor Recovery Unit (VRU), with the flare as a backup, to ensure that emissions to the atmosphere do not exceed 0.02 pounds per 1,000 gallons (2.4 milligrams per liter) of gasoline loaded. Each lane has vapor recovery hoses, such that hydrocarbon vapor contained in the tanker truck is displaced through a connection that vents the top of the truck tank. The captured vapor from the loading racks is routed to a vapor collection/processing system, which undergoes periodic source testing to confirm compliance with emission limits. Control efficiency for each of the vapor control/processing systems at the LVT is sufficient to continuously meet the limit specified in DAQ regulations. This system is considered to meet BACT and therefore meet the requirements of RACT.

**Table 3-2: Loading Rack Emissions at Las Vegas Terminal**

| Product | Throughput (gal/yr) | Uncontrolled Emission Factor for Bulk Loading (lb/1,000 gal) | Vapor Generated (lbs) | Truck Loading Vapor Capture Efficiency (%) | Fugitive VOC Emissions (lbs/yr) | Fugitive VOC Emissions (ton/yr) |
|---|---|---|---|---|---|---|
| Gasoline | 977,278,302 | 10.13 | 9,903,493 | 98.70% | 128,745.40 | 64.37 |
| Diesel/Biodiesel | 366,790,872 | 0.03 | 10,151 | 98.70% | 131.96 | 0.07 |
| Jet Fuel | 81,545,856 | 0.03 | 2,758 | 98.70% | 35.86 | 0.02 |
| Ethanol | 51,307,116 | 2.82 | 144,804 | 98.70% | 1,882.46 | 0.94 |
| Transmix | 7,174,440 | 6.46 | 46,340 | 98.70% | 602.42 | 0.30 |
| Additive | 1,680,000 | 0.44 | 733 | 98.70% | 9.53 | 0.0048 |

### *3.2.1 Emissions from VOC Control Devices*

The John Zink VRU is the primary control device for the loading rack emissions. It is a high-efficiency adsorption-absorption hydrocarbon VRU. Captured hydrocarbon vapors from the loading racks are allowed to accumulate in a vapor holding tank. The vapor holding tank collects vapors until a pre-set level limit is reached. Level controls on the holding tank modulate the delivery of vapors to the downstream control device. The holding tank, because of its sealed design, does not emit air pollutants. Emissions from the VRU are shown in Table 3-3.

**Table 3-3: Vapor Recovery Unit Emissions at Las Vegas Terminal**

| Product | Vapors to Control Units | Controlled VOC Emissions (ton/yr) |
|---|---|---|
| Gasoline | 9,774,747.24 | 14.17 |
| Diesel/Biodiesel | 10,018.62 | 0.015 |
| Jet Fuel | 2,722.33 | 0.0039 |


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| Product | Vapors to Control Units | Controlled VOC Emissions (ton/yr) |
|---|---|---|
| Ethanol | 142,922.03 | 0.207 |
| Transmix | 45,737.74 | 0.066 |
| Additive | 723.38 | 0.0010 |

There is also an auxiliary flare from Flare Industries (now part of Aereon), which is available for the control of loading rack vapors whenever the John Zink VRU is unavailable and/or inoperable. The combustion of hydrocarbons in the auxiliary flare also generates emissions of criteria pollutants, including CO, $NO_x$, and with minimal amounts of $SO_x$ and $PM_{10}$. In addition, certain HAPs present in the vapors collected from the loading racks are also emitted from the auxiliary flare. Emissions from the auxiliary flare are shown in Table 3-4.

**Table 3-4: Auxiliary Flare Emissions at Las Vegas Terminal**

| Pollutant | Vapors to Flare | Emission Factor | Emissions (lbs/yr) | Emissions (ton/yr) |
|---|---|---|---|---|
| $NO_x$ | 498,843.57 | 0.068 lb/MMBtu | 637.38 | 0.32 |
| CO | | 0.31 lb/MMBtu | 2905.71 | 1.45 |
| $SO_x$ | | 0.0006 lb/lb | 296.31 | 0.15 |
| PM | | 0.0077 lb/MMBtu | 71.71 | 0.04 |

These control technologies are considered BACT and therefore meet the requirements of RACT.

## 3.3 RACT for Fugitive Components

Fugitive hydrocarbon emissions may occur from imperfect fittings when liquid petroleum products are contained in the various pipelines and components throughout the terminal. Hydrocarbon vapors can be released from various piping components, such as valves, flanges, pump seals, sampling ports, and other fittings. The emission rate is based on default factors dependent on the type of component or fitting, the number of each type of component, and the category of fluid service (gas, light liquid, or heavy liquid). PTE is quantified based on the facility-wide component counts for the facility and is summarized in Table 3-5.

**Table 3-5: Fugitive Emission Sources Las Vegas Terminal**

| Fitting Type | Number of Fittings | Factor (lbs/unit-hr) | VOC Emissions (lbs/yr) | VOC Emissions (ton/yr) |
|---|---|---|---|---|
| Valves (Gas Service) | 2,376 | 2.87E-05 | 597.35 | 0.30 |
| Valves (Light Liquid Service) | 1,693 | 9.48E-05 | 1405.95 | 0.70 |
| Valves (Heavy Liquid Service) | 1,598 | 9.48E-05 | 1327.06 | 0.66 |
| Fittings (Gas) | 6,455 | 9.26E-05 | 5236.14 | 2.62 |
| Fittings (Light Liquid) | 4,311 | 1.76E-05 | 664.65 | 0.33 |
| Fittings (Heavy Liquid) | 4,620 | 1.76E-05 | 712.29 | 0.36 |
| Pump Seals (Gas) | 56 | 1.43E-04 | 70.15 | 0.04 |
| Pump Seals (Light Liquid) | 29 | 1.19E-03 | 302.31 | 0.15 |
| Pump Seals (Heavy Liquid) | 27 | 1.19E-03 | 281.46 | 0.14 |


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| Fitting Type | Number of Fittings | Factor (lbs/unit-hr) | VOC Emissions (lbs/yr) | VOC Emissions (ton/yr) |
|---|---|---|---|---|
| Relief Devices (Light Liquid) | 12 | 2.87E-04 | 30.17 | 0.02 |
| Relief Devices (Heavy Liquid) | 24 | 2.87E-04 | 60.34 | 0.03 |
| Relief Devices (Gas) | 35 | 2.87E-04 | 87.99 | 0.04 |
| Other (Gas) | 434 | 2.65E-04 | 1007.49 | 0.50 |
| Other (Light Liquid) | 239 | 2.87E-04 | 600.87 | 0.30 |
| Other (Heavy Liquid) | 321 | 2.87E-04 | 807.03 | 0.40 |
| **Total** | | | **13,191.26** | **6.60** |

As specified in the facility's Title V permit, the facility inspects fugitive components for leaks on a consistent basis and repairs any leaks in the system. These leak monitoring protocols are considered to meet the requirements of RACT.

### 3.4 RACT for Remediation Systems

The LVT has a permit to operate a soil vapor extraction (SVE) combustion system to control emissions from historical soil contamination. This system can process a maximum of 6,000 standard cubic feet per minute (scfm) and has a destruction efficiency of 98.5%.

A fluidized bed reactor (FBR) system, using carbon beds for VOC control of greater than 95%, was permitted in 2014 to allow for an alternative to the SVE for this remediation system. This was due to high combined concentrations of VOC and methane in the remediation system vapors. Despite not typically using the combustion system, Calnev wishes to retain the allowable emission limits (and therefore PTE) associated with the SVE in the event that remediation conditions may once again favor combustion. VOC emissions from the vapor extraction system were calculated using the maximum vapor flow rate, maximum VOC inlet concentration, and 98.5% destruction efficiency for a thermal oxidizer. As shown in the April 2014 and September 2015 notifications, emissions from the FBR system are significantly lower than the allowable VOC limit for the combustion system.

**Table 3-6: PTE of Vapor Extraction System at the Las Vegas Terminal**

| Pollutant | Emissions from Fuel Combustion (ton/yr) | Controlled Remediation Emissions (ton/yr) | Total Emissions (ton/yr) |
|---|---|---|---|
| $NO_x$ | 1.26 | – | 1.26 |
| VOC | 0.10 | 37.57 | 37.67 |
| CO | 0.73 | – | 0.73 |
| $SO_x$ | 0.002 | – | 0.0017 |
| PM | 0.07 | – | 0.07 |

This system exists to control emissions from historical contamination. The control systems, either combustion or carbon adsorption, are both considered to meet BACT and therefore meet the requirements of RACT.


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## 4.0 CONCLUSION

LVT has determined that all sources having a PTE of greater than 5 tons per year to already meet RACT-levels of VOC emissions control. Therefore, a detailed evaluation of cost effectiveness for additional controls or effectiveness is not necessary. The facility has sufficient permit conditions to ensure compliance with all emissions limits and monitoring requirements.


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# APPENDIX A – EMISSION CALCULATIONS

| Equipment | Emission Unit ID | VOC | CO | NOx | SOx | PM | Total HAPs |
|---|---|---|---|---|---|---|---|
| Petroleum Product Storage Tanks | Multiple | 61.32 | | | | | 0.00 |
| Additive and Insignificant Storage Tanks | Multiple | 0.12 | | | | | 0.01 |
| Loading Racks - Fugitive Emissions | B01 | 65.70 | | | | | 3.40 |
| Vapor Recovery Unit | B02 | 14.47 | | | | | 0.75 |
| Flare | B10 | | 1.45 | 0.32 | 0.15 | 0.04 | |
| Ethanol Offloading | H09 | 0.18 | | | | | 4.63E-04 |
| B-100 Biofuel Offloading and B-100 Prover | B01A | 0.04 | | | | | |
| Component Fugitives | B06 | 6.60 | | | | | 0.35 |
| Provers | P01 & P02 | 0.16 | | | | | 0.01 |
| Internal Combustion Engines | D02 & B11 | 0.13 | 0.35 | 1.61 | 0.11 | 0.11 | 4.39E-04 |
| Haul Roads | E01 | | | | | 6.61 | |
| Service Roads | H01 | | | | | 0.52 | |
| Cooling Tower | H05 | | | | | 0.01 | |
| Parts Washer | H13 | 1.17 | | | | | |
| Sumps | H02, H03, H04, H06, H07, H08 | 2.07 | | | | | 0.11 |
| Contact Water Treatment System | F01, F04, F05, F06 | 0.10 | | | | | 0.05 |
| Remediation - Soil and Groundwater Vapor Extraction System | SR04 | 37.67 | 0.73 | 1.26 | 1.74E-03 | 0.07 | |
| Remediation - OWS and OST | H11 & H12 | 0.79 | | | | | 0.04 |
| | Total Emissions | **190.50** | **2.53** | **3.19** | **0.26** | **7.36** | **4.71** |


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KINDER MORGAN
CALNEV PIPE LINE LLC

# Attachment 2.
# Relevant Portions of Section 121

Products EHS Compliance – 14th Floor 1001 Louisiana Street Houston, TX 77002-5089
(713) 369-9000 Fax (713) 420-1603

# SECTION 121: REASONABLY AVAILABLE CONTROL TECHNOLOGY DETERMINATIONS FOR SPECIFIC MAJOR STATIONARY SOURCES IN THE 2015 8-HOUR OZONE NAAQS MODERATE NONATTAINMENT AREA HA 212


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## 121.1 PURPOSE

(a) Section 121 establishes and implements Reasonably Available Control Technology (RACT) requirements for existing major stationary sources of nitrogen oxide ($NO_x$) and/or volatile organic compounds (VOC) as required by Section 182(b)(2) of the Clean Air Act (Act) under Title 42, Section 7511a of the U.S. Code (42 U.S.C. 7511a).

## 121.2 APPLICABILITY

(a) Section 121 applies to owners or operators of major stationary sources:

(1) That are existing major sources for $NO_x$ and/or VOC, as defined in Section 12.3.2;

(2) That are located in Hydrographic Area (HA) 212 (Las Vegas Valley);

(3) That are affected sources that contain affected units, as defined in Section 121.3; and

(4) For which a case-by-case RACT analysis was conducted after EPA reclassified HA 212 to moderate nonattainment status for ozone.

(b) Except as provided in paragraphs (1) and (2) of this section, once Section 121 RACT requirements have been implemented, the modification or reconstruction of an affected unit at an affected source will require an evaluation (or re-evaluation) of RACT for that unit. The affected source shall conduct this evaluation according to current Clark County RACT methodology, and the evaluation shall involve the whole unit, not just the modification. The only exceptions are:

(1) Any emissions units that are, or will be (because of a modification or reconstruction), subject to Lowest Achievable Emissions Rate (LAER) for $NO_x$ and/or VOC.

(2) Modifications to or reconstruction of an emission unit that shall not cause its potential to emit (PTE) of $NO_x$ and/or VOC to exceed 5 tons per year (tpy).

(c) A requirement to comply with Section 121 does not exempt a stationary source from any other control technology requirements, including any preconstruction review RACT requirements under Sections 12.1, "Permit Requirements for Minor Sources," and 12.4, "Authority to Construct Application and Permit Requirements for Part 70 Sources," as well as any CTG RACT requirements in other Clark County Air Quality Regulations (AQRs). This may result in more than one RACT determination; if so,

each RACT determination shall be included in the resulting permit as a separate limitation unless the owner or operator demonstrates that compliance with one RACT (usually the most stringent) also demonstrates compliance with one or more of the other RACT determinations for that affected unit under all scenarios (i.e., under all levels of operation, with all types of raw materials and/or fuels, etc.), and the Control Officer approves.

## 121.3 DEFINITIONS

Unless the context requires otherwise, the following terms shall have the meanings set forth below for the purposes of this section. When a term is not defined, it shall have the meaning provided in Sections 0, 12.0–12.5, or 12.11 of the AQRs, Chapter 445B of the Nevada Revised Statutes (NRS), the Act, or common usage, in that order of priority.

"Affected source" means a major stationary source required to comply with major source RACT for $NO_x$ and/or VOC under Section 121.

"Affected unit" means any existing emission unit at an affected source, as defined in Section 121, to which major source RACT applies.

1. For the purposes of Section 121, insignificant activities, as determined in Section 12.5, shall not be considered affected units. Also for the purposes of Section 121, no activities with a PTE greater than 2 tons per year of $NO_x$ or VOC individually—with no threshold for a combination of pollutants—shall be eligible to be determined insignificant activities.

"Compliance certification" means a document submitted by a Responsible Official certifying compliance with the terms and conditions of an operating permit. It must include the identification of each permit term or condition the certification is based on, the method used for determining compliance, whether that method provided continuous data, any other material information, and compliance status. It must also identify each permit deviation during the certification period.

"Control Techniques Guidelines Reasonably Available Control Technology" (CTG RACT) means an AQR that implements RACT (including emissions limitations and, if applicable, work practice standards) for stationary sources in accordance with the CTGs issued by the Administrator under Section 108 of the Act (42 U.S.C. 7408), as required by Section 182(b)(2)(A) of the Act (42 U.S.C. 7511a).

"Emissions inventory report" means a report that includes the actual quantity of emissions from each permitted emissions unit along with the total calculated actual emissions from the entire source for the reporting period.

"Existing major stationary source" or "existing major source," for the purposes of Section 121, means a stationary source that is defined in Section 12.3.2 as a major source for $NO_x$ and/or VOC and began actual construction before January 5, 2023.

"Good combustion practices" (GCP) means operating an emission unit to maximize its energy output or thermal efficiency while maintaining optimized oxygen levels to assure complete combustion. Where GCP in a permit conflicts with manufacturer recommendations, the owner or operator shall follow the GCP in the permit.

"Good maintenance practices" (GMP) means maintenance of an emission unit in a manner that minimizes air pollution emissions. Where GMP in a permit conflicts with manufacturer recommendations, the owner or operator shall follow the GMP in the permit.

"Injection timing retardation" (ITR) means changing the timing so that fuel ignition happens later to reduce the maximum combustion temperature and pressure, which decreases $NO_x$ formation.

"Major source RACT" means the RACT required by Section 182(b)(1)(A)(ii)(II) of the Act (42 U.S.C. 7511a) for existing major sources of $NO_x$ and/or VOC in ozone nonattainment areas classified as moderate or higher. It differs from CTG RACT, which applies only to VOC emissions from emission units and activities for which EPA has published a CTG document. It also differs from RACT for preconstruction review for a new emission unit, which generally applies only to new sources and modifications to existing sources under Sections 12.1 and 12.4 of the AQRs.

"Quality assurance/quality control (QA/QC) procedure" or "QA procedure" means a procedure that includes the continuous emission monitoring system (CEMS) description, calibration checks, preventative maintenance, data recording and calculations, accuracy audits, and corrective action plan for malfunctions.

"Reasonably Available Control Technology" (RACT) means the lowest emissions limitation an affected unit is capable of meeting by applying control technology that is reasonably available, considering technological and economic feasibility.

"Relative Accuracy Test Audit" (RATA) means a test procedure consisting of at least nine test runs, in which the accuracy of the concentrations measured by a CEMS is evaluated by comparison against concurrent measurements made with a reference method. Relative accuracy tests repeated on a regular, on-going basis are referred to as relative accuracy test audits or RATAs.

## 121.4 GENERAL CONDITIONS

(a) Affected units subject to Section 121 are identified by emission unit (EU) numbers and described in Attachment 1.

(b) Affected sources subject to Section 121 are identified by source identification (ID) number.

(c) Owners or operators of a stationary source subject to Section 121 shall comply with the major source RACT requirements of Section 121 for all affected units.

(4) CEMS $NO_x$ data; and

(5) Date, time, and duration of each startup and shutdown.

(d) Submit an annual emissions inventory report; and

(e) Submit an annual compliance certification.

## 121.6 CALNEV PIPE LINE—LAS VEGAS TERMINAL (SOURCE ID: 00013)

### 121.6.1 RACT Control Requirements

The owner or operator shall implement the following RACT controls.

(a) For the storage tanks listed in Table 1, the owner or operator shall:

(1) Operate and maintain all according to the seal control requirements in the table; and

(2) Operate all in compliance with applicable federal regulations incorporated by reference in AQRs 13.3 and 14.2, as identified in the table.

**Table 1. Seal Control Requirements**

| EU | Site Tank Number | Seal Control Requirements | Applicable Requirement(s)[1] |
|---|---|---|---|
| A01 | 530 | External Floating Roof with primary and secondary seals | AQR 13.3 |
| A02 | 531 | External Floating Roof with primary and secondary seals | AQR 13.3 |
| A03 | 532 | External Floating Roof with primary and secondary seals | AQR 13.3 |
| A04 | 533 | External Floating Roof with primary and secondary seals | AQR 13.3 |
| A05 | 534 | External Floating Roof with primary and secondary seals | AQR 13.3 |
| A06 | 535 | External Floating Roof with primary and secondary seals | AQR 13.3 |
| A07 | 536 | External Floating Roof with primary and secondary seals | AQR 13.3 |
| A08 | 537 | External Floating Roof with primary and secondary seals | AQR 13.3 |
| A09 | 538 | External Floating Roof with primary and secondary seals | AQR 13.3 |
| A10 | 539 | External Floating Roof with primary and secondary seals | AQR 13.3 |
| A23 | 510 | External Floating Roof with primary seal | N/A |
| A24 | 511 | External Floating Roof with primary seal | N/A |
| A11 | 540 | Internal Floating Roof with primary and secondary seals | AQR 13.3 |
| A13 | 524 | Internal Floating Roof with primary and secondary seals | AQR 13.3 |
| A16 | 545 | Internal Floating Roof with primary and secondary seals | AQR 13.3<br>AQR 14.2 |
| A17 | 546 | Internal Floating Roof with primary and secondary seals | AQR 13.3<br>AQR 14.2 |

| EU | Site Tank Number | Seal Control Requirements | Applicable Requirement(s)[1] |
|---|---|---|---|
| A21 | 547 | Internal Floating Roof with primary and secondary seals | AQR 13.3<br>AQR 14.2 |
| A27 | 501 | Internal Floating Roof with primary and secondary seals | N/A |
| A28 | 523 | Internal Floating Roof with primary and secondary seals | AQR 13.3 |
| A29 | 544 | Internal Floating Roof with primary and secondary seals | AQR 13.3<br>AQR 14.2 |
| A47 | 550 | Internal Floating Roof with primary and secondary seals | AQR 13.3 |
| A48 | 551 | Internal Floating Roof with primary and secondary seals | AQR 13.3 |
| A56 | 513 | Internal Floating Roof with primary and secondary seals | N/A |
| A14 | 542 | Internal Floating Roof with primary seal | N/A |
| A15 | 543 | Internal Floating Roof with primary seal | N/A |
| A12 | 541 | Domed External Floating Roof with primary and secondary seals | AQR 13.3 |
| A45 | 548 | Domed External Floating Roof with primary and secondary seals | AQR 13.3 |
| A46 | 549 | Domed External Floating Roof with primary and secondary seals | AQR 13.3 |
| A19 | 525 | Fixed Roof | N/A |
| A20 | 526 | Fixed Roof | N/A |
| A22 | 512 | Fixed Roof | N/A |
| A25 | ASA Con-ductivity Improver | Fixed Roof | N/A |
| A26 | 500 AIA | Fixed Roof | N/A |
| A30 | 533 A | Fixed Roof | N/A |
| A31 | 537 A | Fixed Roof | N/A |
| A32 | 541 A | Fixed Roof | N/A |
| A33 | 541 B | Fixed Roof | N/A |
| A34 | 542 D | Fixed Roof | N/A |
| A35 | 542 A | Fixed Roof | N/A |
| A36 | 531 A | Fixed Roof | N/A |
| A37 | 542 C | Fixed Roof | N/A |
| A38 | 537 B | Fixed Roof | N/A |
| A39 | 531 B | Fixed Roof | N/A |
| A53 | 548 B | Fixed Roof | N/A |
| A54 | 548 A | Fixed Roof | N/A |

[1] Some tanks may not have an applicable requirement due to construction year, tank size, and/or product stored.

(b) The owner or operator shall operate the loading racks (EU: B01):

(1) With a vapor recovery unit (VRU) (EU: B02) during loading;

(2) With a flare (EU: B10) as backup if the VRU is inoperable; and

(3) In compliance with tanker loading requirements to minimize leaks, spills, and fugitive emissions.

(c) The owner or operator shall operate and maintain the soil vapor extraction and groundwater treatment system (EU: SR04):

(1) Using a control device capable of 98.5% VOC destruction efficiency;

(2) Using only propane as the auxiliary fuel;

(3) At a temperature specified by the manufacturer; and

(4) In accordance with the manufacturer's O&M manual.

(d) The owner or operator shall operate the vapor-phase carbon adsorber (Fluidized Bed Reactor) such that it demonstrates a minimum control efficiency of 95% or a maximum outlet VOC emissions concentration of 100 parts per million volume (ppmv).

### 121.6.2 RACT Monitoring Requirements

The owner or operator shall:

(a) Visually inspect and monitor all storage tanks listed in Table 1 for throughput volume;

(b) Monitor the loading racks (EU: B01) for throughput;

(c) For the VRU (EU: B02):

(1) Install, calibrate, maintain, operate, and certify the CEMS for VOC;

(2) Require QA procedures for the CEMS;

(3) Conduct a RATA of the VOC CEMS;

(4) Monitor CEMS VOC data; and

(5) Demonstrate compliance with VOC emissions limits.

(d) For fugitive components (EU: B06):

(1) Monitor for leaks; and

(2) Inspect daily for leaks (e.g., by sight, sound, and/or smell).

(e) Monitor the flare (EU: B10) and visually inspect flame quality; and

(f) Monitor the soil vapor extraction and groundwater treatment system (EU: SR04) for use of auxiliary fuel.

### 121.6.3 RACT Testing Requirements

The owner or operator shall:

(a) Conduct subsequent performance testing every five years (EUs: B02 and SR04) after the initial performance test;

(b) Conduct a performance test when a combustion unit is operated for either the soil vapor extraction or the groundwater treatment system (EU: SR04); and

(c) Determine compliance with emissions limitations (EUs: B02 and SR04).

### 121.6.4 RACT Recordkeeping and Reporting Requirements

The owner or operator shall:

(a) Maintain records of hours of operation for the flare (EU: B10);

(b) For the VRU (EU: B02), maintain records of:

(1) QA procedures;

(2) CEMS audit and calibration results, along with any corrective actions taken;

(3) The time, duration, nature, and probable cause of any CEMS downtime, and of any corrective actions taken; and

(4) CEMS VOC data.

(c) Submit performance test reports;

(d) Submit an annual emissions inventory report; and

(e) Submit an annual compliance certification.

## 121.7 NELLIS AIR FORCE BASE (SOURCE ID: 00114)

### 121.7.1 RACT Control Requirements

The owner or operator shall implement the following RACT controls.

# ATTACHMENT 1

| EU | Rating | Manufacturer | Model | Serial Number |
|---|---|---|---|---|
| **NV Energy: Clark Generating Station (Source ID: 00007)** | | | | |
| A00704D (UNIT 4) | 60 MW | General Electric | 7B (7000) | N/A |
| A00701A (UNIT 5) | 85 MW | Westinghouse | 501B6 | N/A |
| A00702B (UNIT 6) | 85 MW | Westinghouse | 501B6 | N/A |
| A00705 (UNIT 7) | 85 MW | Westinghouse | 501B6 | N/A |
| A00708 (UNIT 8) | 85 MW | Westinghouse | 501B6 | N/A |
| A27 (UNIT 11) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| A28 (UNIT 12) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| A29 (UNIT 13) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| A30 (UNIT 14) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| A31 (UNIT 15) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| A32 (UNIT 16) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| A33 (UNIT 17) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| A34 (UNIT 18) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| A35 (UNIT 19) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| A36 (UNIT 20) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| A37 (UNIT 21) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| A38 (UNIT 22) | 57.9 MW | Pratt & Whitney | FT8-3 Swift Pac | N/A |
| **CalNev Pipe Line (Source ID: 00013)** | | | | |
| A01 | 11,200 bbl | N/A | N/A | N/A |
| A02 | 12,890 bbl | N/A | N/A | N/A |
| A03 | 8,080 bbl | N/A | N/A | N/A |
| A04 | 11,330 bbl | N/A | N/A | N/A |
| A05 | 8,080 bbl | N/A | N/A | N/A |
| A06 | 8,080 bbl | N/A | N/A | N/A |
| A07 | 17,550 bbl | N/A | N/A | N/A |
| A08 | 22,250 bbl | N/A | N/A | N/A |
| A09 | 11,330 bbl | N/A | N/A | N/A |
| A10 | 11,330 bbl | N/A | N/A | N/A |
| A11 | 16,320 bbl | N/A | N/A | N/A |
| A12 | 25,100 bbl | N/A | N/A | N/A |
| A13 | 18,000 bbl | N/A | N/A | N/A |
| A14 | 45,000 bbl | N/A | N/A | N/A |
| A15 | 35,000 bbl | N/A | N/A | N/A |
| A16 | 37,000 bbl | N/A | N/A | N/A |
| A17 | 40,000 bbl | N/A | N/A | N/A |
| A19 | 50,000 bbl | N/A | N/A | N/A |

| EU | Rating | Manufacturer | Model | Serial Number |
|---|---|---|---|---|
| A20 | 50,000 bbl | N/A | N/A | N/A |
| A21 | 50,000 bbl | N/A | N/A | N/A |
| A22 | 50,000 bbl | N/A | N/A | N/A |
| A23 | 40,000 bbl | N/A | N/A | N/A |
| A24 | 40,000 bbl | N/A | N/A | N/A |
| A25 | 1.3 bbl | N/A | N/A | N/A |
| A26 | 252 bbl | N/A | N/A | N/A |
| A27 | 4,000 bbl | N/A | N/A | N/A |
| A28 | 10,000 bbl | N/A | N/A | N/A |
| A29 | 11,000 bbl | N/A | N/A | N/A |
| A30 | 252 bbl | N/A | N/A | N/A |
| A31 | 464 bbl | N/A | N/A | N/A |
| A32 | 380 bbl | N/A | N/A | N/A |
| A33 | 380 bbl | N/A | N/A | N/A |
| A34 | 215 bbl | N/A | N/A | N/A |
| A35 | 143 bbl | N/A | N/A | N/A |
| A36 | 143 bbl | N/A | N/A | N/A |
| A37 | 12 bbl | N/A | N/A | N/A |
| A38 | 447 bbl | N/A | N/A | N/A |
| A39 | 119 bbl | N/A | N/A | N/A |
| A45 | 12,890 bbl | N/A | N/A | N/A |
| A46 | 12,890 bbl | N/A | N/A | N/A |
| A47 | 20,000 bbl | N/A | N/A | N/A |
| A48 | 10,100 bbl | N/A | N/A | N/A |
| A53 | 238 bbl | N/A | N/A | N/A |
| A54 | 238 bbl | N/A | N/A | N/A |
| A56 | 50,000 bbl | N/A | N/A | N/A |
| B01 (Loading Rack) | 35,379,927 bbl per year | N/A | N/A | N/A |
| B02 (VRU) | N/A | John Zink | N/A | N/A |
| B06 (Piping and Fittings) | N/A | N/A | N/A | N/A |
| B10 (Flare) | N/A | N/A | N/A | N/A |
| SR04 (SVE/GW treatment) | N/A | N/A | N/A | N/A |
| **Nellis Air Force Base (Source ID: 00114)** | | | | |
| A032 | 250 bhp | Cummins | M11 | 60425136 |
| G009 | 1635 bhp | Mitsubishi | PS6 | 12588 |
| G010 | 1350 bhp | Cummins | QST30-G3 | 37205939 |
| G032 | 1586 bhp | Caterpillar | 3512 | 24Z04351 |

KINDER MORGAN
CALNEV PIPE LINE LLC

# Attachment 3.
# Title V Permit Demonstrating RACT

Products EHS Compliance – 14th Floor 1001 Louisiana Street Houston, TX 77002-5089
(713) 369-9000 Fax (713) 420-1603

DES
DEPARTMENT OF ENVIRONMENT AND SUSTAINABILITY
air quality desert conservation PROGRAM sustainability

4701 W. Russell Rd Suite 200
Las Vegas, NV 89118-2231
Phone (702) 455-5942
Fax (702) 383-9994

# PART 70 OPERATING PERMIT

## SOURCE ID: 00013

Calnev Pipe Line LLC
5049 North Sloan Lane
Las Vegas, Nevada 89115

**ISSUED ON: January 29, 2024** **EXPIRES ON: January 28, 2029**

**Current action: Minor Revision**

**Revised On: XXX**

**Issued to:**
Calnev Pipe Line LLC
1001 Louisiana Street
Products EHS Compliance Fl 8, Suite 1000
Houston, Texas 77002

**Responsible Official:**
John Pannell
Vice President of Operations
PHONE: (713) 420-4945
EMAIL: john_pannell@kindermorgan.com

**NATURE OF BUSINESS:**

SIC code 4226, "Special warehousing and Storage, Not Elsewhere Classified"

NAICS code 493190, "Other Warehousing and Storage"

**Issued by the Clark County Department of Environment and Sustainability/Division of Air Quality in accordance with Section 12.5 of the Clark County Air Quality Regulations.**

Santosh Mathew, Permitting Manager

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# EXECUTIVE SUMMARY

Calnev Pipe Line LLC is a bulk fuel storage and transfer operation located in the Las Vegas Valley (Hydrographic Area 212), which is currently designated as an attainment area for all regulated air pollutants except ozone. Hydrographic Area 212 was designated a serious nonattainment area for ozone on January 21, 2025. Clark County has drafted or imposed new requirements to address this designation. The source is classified as a Categorical Stationary Source, as defined by AQR 12.2.2(j)(23): "Petroleum storage and transfer units with total storage capacity exceeding 300,000 barrels." The source is a major source for VOC pollutants and a minor source for all other criteria pollutants and HAP. It is also a source of GHG pollutants. The source consists of petroleum storage tanks, vapor holding tank, loading lanes, diesel-powered air compressor, diesel-powered fire water engine, cooling tower, wastewater treatment system, and haul roads. The source falls under SIC code 4226, "Special Warehousing and Storage, Not Elsewhere Classified" and NAICS code 493190, "Other Warehousing and Storage."

Fuels are delivered to the site by two underground pipelines originating in southern California. Incoming fuels are diverted to storage tanks; from there, fuels are piped to other terminals or loaded onto delivery trucks. As the trucks are filled, specialized additives are injected according to the customer's specifications.

This Part 70 Operating Permit (OP) is issued based on the Title V renewal application submitted on November 16, 2021 and the minor revision application submitted on May 13, 2025. Pursuant to AQR 12.5.2, all terms and conditions in Sections 1–8 in this permit are federally enforceable unless explicitly denoted otherwise.

The following table summarizes the source's potential to emit (PTE) of each regulated air pollutant from all emission units addressed by this Part 70 OP.

**Table 1: Source-wide Potential to Emit**

| Pollutant | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_2$ | VOC | HAPs[1] | Pb | $H_2S$ | GHG[2] |
|---|---|---|---|---|---|---|---|---|---|---|
| Tons/year | 9.85 | 1.58 | 3.26 | 2.55 | 0.18 | 188.01 | 9.30 | 0 | 0 | 11,440.88 |

[1] A major source is defined as 10 tons for any individual HAP or 25 tons for combination of all HAPs.
[2] Metric tons per year of carbon dioxide equivalent. GHG = greenhouse gas pollutants.

DAQ received the Title V minor revision application on May13, 2025. Based on information submitted by the applicant and a technical review performed by DAQ staff, DAQ proposes the issuance of a revised Part 70 OP to Calnev Pipe Line LLC.

DAQ will continue to require the permittees to estimate their GHG PTE in terms of each individual pollutant ($CO_2$, $CH_4$, $N_2O$, $SF_6$ etc.) during subsequent permitting actions, and the corresponding TSDs will include these PTEs for informational purposes.

This bulk gasoline terminal is subject to 40 CFR Part 60, Subparts A, Ka, Kb, XX and 40 CFR Part 63, Subparts A, BBBBBB, WW, and ZZZZ.

Pursuant to AQR 12.5.2, all terms and conditions and attachments to this permit, are federally enforceable unless explicitly denoted otherwise.

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# Acronyms and Abbreviations

| | |
|---|---|
| API | American Petroleum Institute |
| AQR | Clark County Air Quality Regulation |
| AST | aboveground storage tank |
| ATC | Authority to Construct |
| CEMS | continuous emissions monitoring system |
| CFR | Code of Federal Regulations |
| CO | carbon monoxide |
| DAQ | Division of Air Quality |
| DOM | date of manufacture |
| EPA | U.S. Environmental Protection Agency |
| EU | emission unit |
| HAP | hazardous air pollutant |
| JZVRU | John Zink Vapor Recovery Unit |
| MMBtu/hr | Millions of British thermal units per hour |
| MSP | minor source permit |
| NAICS | North American Industry Classification System |
| NRS | Nevada Revised Statutes |
| NSR | New Source Review |
| OP | Operating Permit |
| PID | Photoionization detector |
| $PM_{2.5}$ | particulate matter less than 2.5 microns in diameter |
| $PM_{10}$ | particulate matter less than 10 microns in diameter |
| ppm(vd) | parts per million (volume dry) |
| PTE | potential to emit |
| RATA | relative accuracy test audits |
| RVP | Reid vapor pressure |
| SIC | Standard Industrial Classification |
| TDS | total dissolved solids |
| TOC | total organic compounds |
| TPH | total petroleum hydrocarbons |
| UST | underground storage tank |
| VEE | Visible Emissions Evaluation |
| VOC | volatile organic compound |
| VOL | volatile organic liquid |
| VRU | vapor recovery unit |

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# *1.0 EQUIPMENT*

## 1.1 EMISSION UNITS

The stationary source covered by this Part 70 Operating Permit (OP) consists of the emission units and associated appurtenances summarized in Table 1-1. *[Title V OP January 29, 2024; ATC June 2, 2019; ATC September 23, 2014; ATC April 8, 2014; ATC December 20, 2012; ATC August 31, 2010; ATC May 30, 2008; ATC April 10, 2008; ATC October 2, 2008; ATC March 5, 2007]*

**Table 1-1: List of Emission Units - Tanks, Racks, Fuel Unloading, VRU, and Miscellaneous Units**

| EU | Source ID No. | Rating | Description | Product Stored | Optional Stored Products[1] |
|---|---|---|---|---|---|
| **Bulk Petroleum Storage Tanks** | | | | | |
| A01 | Tank 530 | 11,200 bbl | External Floating Roof AST w/Primary and Secondary Seal | Diesel | Gasoline, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A02 | Tank 531 | 12,890 bbl | External Floating Roof AST w/Primary and Secondary Seal | Diesel | Gasoline, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A03 | Tank 532 | 8,080 bbl | External Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A04 | Tank 533 | 11,330 bbl | External Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A05 | Tank 534 | 8,080 bbl | External Floating Roof AST w/Primary and Secondary Seal | Transmix | Gasoline, Diesel, Biodiesel, Denatured Ethanol, Aviation Gasoline and Jet Fuel |
| A06 | Tank 535 | 8,080 bbl | External Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A07 | Tank 536 | 17,550 bbl | External Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A08 | Tank 537 | 22,250 bbl | External Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A09 | Tank 538 | 11,330 bbl | External Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A10 | Tank 539 | 11,330 bbl | External Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A11 | Tank 540 | 16,320 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Denatured Ethanol | Gasoline, Diesel, Biodiesel, Transmix, Aviation Gasoline and Jet Fuel |

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| EU | Source ID No. | Rating | Description | Product Stored | Optional Stored Products[1] |
|---|---|---|---|---|---|
| A12 | Tank 541 | 25,100 bbl | Domed External Floating Roof AST w/Primary and Secondary Seal | Biodiesel | Gasoline, Diesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A13 | Tank 524 | 18,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Denatured Ethanol | Gasoline, Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A14 | Tank 542 | 45,000 bbl | Internal Floating Roof AST w/Primary Seal | Diesel | Biodiesel |
| A15 | Tank 543 | 35,000 bbl | Internal Floating Roof AST w/Primary Seal | Diesel | Biodiesel |
| A16 | Tank 545 | 37,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A17 | Tank 546 | 40,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A18 | Tank 522 | 4,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Denatured Ethanol | |
| A19 | Tank 525 | 50,000 bbl | Fixed Roof AST | Diesel | Biodiesel |
| A20 | Tank 526 | 50,000 bbl | Fixed Roof AST | Diesel | Biodiesel |
| A21 | Tank 547 | 50,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A22 | Tank 512 | 50,000 bbl | Fixed Roof AST | Jet Fuel | Diesel and Biodiesel |
| A23 | Tank 510 | 40,000 bbl | External Floating Roof AST w/Primary Seal | Jet Fuel | Diesel and Biodiesel |
| A24 | Tank 511 | 40,000 bbl | External Floating Roof AST w/Primary Seal | Jet Fuel | Diesel and Biodiesel |
| A27 | Tank 501 | 4,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Denatured Ethanol | |
| A28 | Tank 523 | 10,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Transmix | Gasoline, Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A29 | Tank 544 | 11,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Denatured Ethanol | Gasoline, Diesel, Biodiesel, Transmix, Aviation Gasoline and Jet Fuel |
| A45 | Tank 548 | 12,890 bbl | Domed External Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A46 | Tank 549 | 12,890 bbl | Domed External Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A47 | Tank 550 | 20,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A48 | Tank 551 | 10,100 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |

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| EU | Source ID No. | Rating | Description | Product Stored | Optional Stored Products[1] |
|---|---|---|---|---|---|
| A56 | Tank 513 | 50,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Jet Fuel | Diesel and Biodiesel |
| A57 | Tank 514 | 50,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Jet Fuel | Diesel and Biodiesel |
| A58 | Tank 553 | 80,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A59 | Tank 554 | 80,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Diesel | Gasoline, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A60 | Tank 555 | 80,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| A61 | Tank 552 | 40,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline and Jet Fuel |
| B04 | Tank 500 | 3,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Transmix | Gasoline, Diesel, Biodiesel, Denatured Ethanol, Aviation Gasoline and Jet Fuel |
| B05 | Tank 521 | 5,000 bbl | Internal Floating Roof AST w/Primary and Secondary Seal | Transmix | Gasoline, Diesel, Biodiesel, Denatured Ethanol, Aviation Gasoline and Jet Fuel |
| **Additive Storage Tanks** | | | | | |
| A25 | ASA Conductivity Improver | 1.3 bbl | Fixed Roof AST | Anti-Static Agent (Jet Fuel Additive) | |
| A26 | Tank 500AIA | 252 bbl | Fixed Roof AST with Manway | Anti-Icing agent (Jet Fuel Additive) | |
| A30 | Tank 533A | 252 bbl | Fixed Roof AST | Gasoline Additive | |
| A31 | Tank 537A | 464 bbl | Fixed Roof AST | Gasoline Additive | |
| A32 | Tank 541A | 380 bbl | Fixed Roof AST | Gasoline Additive | |
| A33 | Tank 541B | 380 bbl | Fixed Roof AST | Gasoli e Additive | |
| A34 | Tank 542D | 215 bbl | Fixed Roof AST | Gasoline Additive | |
| A35 | Tank 542A | 143 bbl | Fixed Roof AST | Gasoline Additive | |
| A36 | Tank 531A | 143 bbl | Fixed Roof AST | Lubricity (Diesel Fuel Additive) | |
| A37 | Tank 542C | 12 bbl | Fixed Roof AST | Red Dye (Diesel Fuel Additive) | |
| A38 | Tank 537B | 447 bbl | Fixed Roof AST | Gasoline Additive | |
| A39 | Tank 531B | 119 bbl | Fixed Roof AST | Gasoline Additive | |
| A49 | Tank 542B | 4 bbl | Fixed Roof AST | Red Dye (Diesel Fuel Additive) | |
| A53 | Tank 548B | 238 bbl | Fixed Roof AST | Gasoline Additive | |
| A54 | Tank 548A | 238 bbl | Fixed Roof AST | Gasoline Additive | |
| H10 | Tank 500B | 10,000 gal | Fixed Roof vertical AST | Anti-Icing Agent (Jet Fuel Additive) | |

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| EU | Source ID No. | Rating | Description | Product Stored | Optional Stored Products[1] |
|---|---|---|---|---|---|
| H14 | ASA Tote | 350 gal | Fixed Roof Rectangular AST | Anti-static Agent (Jet Fuel Additive) | |
| H15 | CI Tote | 350 gal | Fixed Roof Rectangular AST | Corrosion Inhibitor (Jet Fuel Additive) | |
| H16 | Lane 7 Red Dye Tote | 350 gal | Fixed Roof Rectangular AST | Red Dye (Diesel Fuel Additive) | |
| H17 | Lane 12 Red Dye Tote | 40,000 bbl | Fixed roof Rectangular AST | Red Dye (Diesel Fuel Additive) | |
| **Loading Racks** | | | | | |
| B01 | Loading Racks | 35,379,927 bbl per year | 15 Loading Lanes | All Petroleum Products Stored on Site are Dispensed through Loading Racks | |
| **Fuel Unloading** | | | | | |
| B01A | B-100 | 147,168,000 gallons/yr | Biodiesel Offloading Rack | | |
| H09 | Ethanol | 76,104,000 gal/year | Ethanol unloading system | | |
| **Vapor Recovery Units** | | | | | |
| B02 | John Zink VRU | | Vapor control unit; loading lanes | | |
| B10 | Flare Processing | | Vapor control unit for loading lanes (includes saturator and vapor holding tank) | | |
| SR04 | SVE and GW Treatment System | | Soil Vapor Extraction and Groundwater Treatment System (includes control units) | | |
| **Underground Storage Tanks** | | | | | |
| H02 | Mainline Sump | 1,000 gal | Mainline Sump UST | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline, and Jet Fuel |
| H03 | Rack Sump | 3,000 gal | Rack Sump UST | Gas line | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline, and Jet Fuel |
| H04 | Mainline Sump | 4,200 gal | New Mainline Sump UST | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline, and Jet Fuel |
| H06 | Nellis Sump | 2,000 gal | Nellis Delivery System Sump, UST | Jet Fuel | |
| H07 | Rack Sump | 1,000 gal | Rack 6 Sump, UST | Diesel | Biodiesel |
| H08 | QC Sump | 100 gal | Quality Control Lab Sump UST | Gasoline | Diesel, Biodiesel, Denatured Ethanol, Transmix, Aviation Gasoline, and Jet Fuel |
| **Miscellaneous Tanks** | | | | | |
| D01 | Tank DG | 250 gal | Fixed Roof AST | Diesel | Biodiesel |
| H11 | OWS Tank | | Oil-water separator tank | Oil and Water | |
| H12 | OST-100-DW | 1,000 gal | Fixed Roof Horizontal AST w/Dual Wall | Gasoline | |

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| EU | Source ID No. | Rating | Description | Product Stored | Optional Stored Products[1] |
|---|---|---|---|---|---|
| H18 | Sample Recovery Tank | 125 gallons | Vertical Fixed Roof Sample Recovery Tank | Pre-butane Blended Gasoline | |
| **Miscellaneous Emission Units** | | | | | |
| B06 | Piping and Fittings | | Misc. Losses/Leaks from Valves, Flanges, Pumps and VCU | | |
| E01 | Haul Road - Paved | 0.5 mi round trip | Paved Haul Road | | |
| | Haul Road – Unpaved | 0.71 mi round trip | Unpaved Haul Road | | |
| H05 | Cooling Tower | 220 gpm | Baltimore Aircoil; M/N: F2841KE; S/N: U013422001MAD | | |

[1]The PTE and rule applicability is based on worse-case configuration

**Table 1-2: List of Emission Units - Engines**

| Internal Combustion Engines | | | | | |
|---|---|---|---|---|---|
| **EU** | **Rating** | **Description** | **Manufacturer** | **Model Number** | **Serial Number** |
| B11 | 48 hp | Air Compressor | Ingersoll Rand | P185WJD | 315261UHK231 |
| | | Diesel Engine; DOM: 2000 | John Deere | 4045DF150F | PE4045D107913 |
| D02 | 208 hp | Diesel Engine (engine to Peerless fire pump); DOM 4/20/1995 | Cummins | 6BTA5.9-F1 | 45175100 |

## 1.2 INSIGNIFICANT ACTIVITIES

The units in Table 1-3 are present at this source but are insignificant activities pursuant to AQR 12.5.2.5. The emissions from these units or activities, when added to the PTE of the source, will not make the source major for any additional pollutant.

**Table 1-3: Summary of Insignificant Activities**

| Equipment | Description |
|---|---|
| Tank 476 | Wastewater |
| Tank 479 | Free Product Extracted from Wells of the Groundwater System |
| Tank 535-A | Diesel Lubricity Additive Storage Tank, 10,000 gallons, 0.026 psia |
| Underground Storage Tanks (2) | Wastewater Runoff Collection |
| B-100 Prover | Portable Prover for B-100 fuel |
| Nellis Line Prover | Horizontal Loop Piping Circuit |
| Main Line Prover | Horizontal Loop Piping Circuit |
| Water Surge Tank | Wastewater Treatment (Oil and Water Separator) |
| Parts Washer | R&D Fountain Industries Company; 3.5 Gallon Tub; 35"W x 24"L x 17"D |
| Evaporation Tank/Pond | Wastewater Evaporation |
| Butane Blending Tank | 90,000-gallon horizontal pressurized tank storing butane |
| LNAPL Tanks (2) | 500-gallon Storage Tanks |

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## 1.3 NONROAD ENGINES

Pursuant to Title 40, Part 1068.30 of the Code of Federal Regulations (40 CFR Part 1068.30), nonroad engines that are portable or transportable (i.e., not used on self-propelled equipment) shall not remain at a location for more than 12 consecutive months; otherwise, the engine(s) will constitute a stationary reciprocating internal combustion engine (RICE) and be subject to the applicable requirements of 40 CFR Part 63, Subpart ZZZZ; 40 CFR Part 60, Subpart IIII; and/or 40 CFR Part 60, Subpart JJJJ. Stationary RICE shall be permitted as emission units upon commencing operation at this stationary source.

Records of location changes for portable or transportable nonroad engines shall be maintained and shall be made available to the Control Officer upon request. These records are not required for engines owned and operated by a contractor for maintenance and construction activities as long as records are maintained demonstrating that such work took place at the stationary source for periods of less than 12 consecutive months.

Nonroad engines used on self-propelled equipment do not have this 12-month limitation or the associated recordkeeping requirements.

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# 2.0 CONTROLS

## 2.1 CONTROL DEVICES

*Storage Tanks*

1. The permittee shall maintain and operate the fuel storage tanks and the fuel additive tanks according to the control requirements, as listed in Table 2-1 (where fixed roof is identified, no additional controls are included). *[NSR ATC/OP 13, Modification 6 (03/29/2004, and AQR 121.6]*

**Table 2-1: Tank Control Requirements**

| EU | Facility ID | Device Type | Applicable Requirement(s) |
|---|---|---|---|
| A01 | 530 | External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A02 | 531 | External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A03 | 532 | External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A04 | 533 | External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A05 | 534 | External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A06 | 535 | External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A07 | 536 | External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A08 | 537 | External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A09 | 538 | External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A10 | 539 | External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A11 | 540 | Internal Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A12 | 541 | Domed External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A13 | 524 | Internal Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A14 | 542 | Internal Floating Roof, primary Seal | |
| A15 | 543 | Internal Floating Roof, primary Seal | |
| A16 | 545 | Internal Floating Roof with primary and secondary seals | AQR 13.3 and 14.2 and 40 CFR 60, Subpart Kb; 40 CFR Part 63, Subparts BBBBBB and WW |
| A17 | 546 | Internal Floating Roof, with primary and secondary seals | AQR 13.3 and 14.2 and 40 CFR 60, Subpart Kb; 40 CFR Part 63, Subparts BBBBBB and WW |

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| EU | Facility ID | Device Type | Applicable Requirement(s) |
|---|---|---|---|
| A18 | 522 | Internal Floating Roof, with primary and secondary seals | |
| A19 | 525 | Fixed Roof | |
| A20 | 526 | Fixed Roof | |
| A21 | 547 | Internal Floating Roof with primary and secondary seals | AQR 13.3 and 14.2 and 40 CFR Part 60, Subpart Kb; 40 CFR Part 63, Subparts BBBBBB and WW |
| A22 | 512 | Fixed Roof | |
| A23 | 510 | External Floating Roof, primary seal | |
| A24 | 511 | External Floating Roof, primary seal | |
| A25 | ASA Conductivity Improver | Fixed Roof | |
| A26 | 500 AIA | Fixed Roof | |
| A27 | 501 | Internal Floating Roof, primary and secondary seals | |
| A28 | 523 | Internal Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A29 | 544 | Internal Floating Roof with primary and secondary seals | AQR 13.3 and 14.2 and 40 CFR Part 60, Subpart Ka; 40 CFR Part 63, Subparts BBBBBB and WW |
| A30 | 533 A | Fixed Roof | |
| A31 | 537 A | Fixed Roof | |
| A32 | 541 A | Fixed Roof | |
| A33 | 541 B | Fixed Roof | |
| A34 | 542D | Fixed Roof | |
| A35 | 542A | Fixed Roof | |
| A36 | 531A | Fixed Roof | |
| A37 | 542C | Fixed Roof | |
| A38 | 537 B | Fixed Roof | |
| A39 | 531B | Fixed Roof | |
| A45 | 548 | Domed External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A46 | 549 | Domed External Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A47 | 550 | Internal Floating Roof with primary and secondary seals | AQR 13.3 and 40 CFR Part 63, Subparts BBBBBB and WW |
| A48 | 551 | Internal Floating Roof with primary and secondary seals | 40 CFR Part 63, Subparts AQR 13.3 and BBBBBB a d WW |
| A49 | 542B | Fixed Roof | |
| A53 | 548B | Fixed Roof | |
| A54 | 548A | Fixed Roof | |
| A56 | 513 | Internal Floating Roof with primary and secondary seals | |

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| EU | Facility ID | Device Type | Applicable Requirement(s) |
|---|---|---|---|
| A57 | 514 | Internal Floating Roof, with primary and secondary seals | |
| A58 | 553 | Internal Floating Roof with primary and secondary seals | 40 CFR Part 60, Subpart 60 Kb; 40 CFR Part 63, Subparts BBBBBB and WW |
| A59 | 554 | Internal Floating Roof with primary and secondary seals | 40 CFR Part 60, Subpart 60 Kb; 40 CFR Part 63, Subparts BBBBBB and WW |
| A60 | 555 | Internal Floating Roof with primary and secondary seals | 40 CFR Part 60, Subpart 60 Kb; 40 CFR Part 63, Subparts BBBBBB and WW |
| A61 | 552 | Internal Floating Roof with primary and secondary seals | 40 CFR Part 60, Subpart 60 Kb; 40 CFR Part 63, Subparts BBBBBB and WW |
| B04 | 500 | Internal Floating Roof with primary and secondary seals | 40 CFR Part 60, Subpart 60 Kb; 40 CFR Part 63, Subparts BBBBBB and WW |
| B05 | 521 | Internal Floating Roof with primary and secondary seals | 40 CFR Part 60, Subpart 60 Kb; 40 CFR Part 63, Subparts BBBBBB and WW |
| D01 | DG | Fixed Roof | |
| H02 | Mainline sump | Fixed Roof UST with vent | |
| H03 | Rack sump | Fixed Roof UST with vent | |
| H04 | New Mainline sump | Fixed Roof UST with vent | |
| H06 | Nellis sump | Fixed Roof UST with vent | |
| H07 | Rack sump | Fixed Roof UST with vent | |
| H08 | QC sump | Fixed Roof UST with vent | |
| H10 | Tank 500B | AST VFR tank | |
| H11 | OWS tank | AST Tank with P/V valves and carbon adsorption unit with 95% control efficiency | |
| H12 | OST-1200-DW | Dual wall HFR AST with P/V valves and carbon adsorption unit with 95% control efficiency | |
| H14 | ASA Tote | Rectangular AST, fixed roof | |
| H15 | CI Tote | Rectangular AST, fixed roof | |
| H16 | Lane 7 Red Dye Tote | Rectangular AST, fixed roof | |
| H17 | Lane 12 Red Dye Tote | Rectangular AST, fixed roof | |
| H18 | Sample Recovery Tank | Vertical Fixed Roof Sample Recovery Tank | |

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*Sump Tanks, Oil Water Separator, and Oil Storage Tank*

2. The permittee shall control the vapors from the oil/water separator tank (OWS) (EU: H11) and the oil storage tank (EU: H12) by venting the vapors to a carbon adsorption system that has a minimum control efficiency of 95.0%. *[NSR ATC 13, Modification 21, Condition IV-B-5 (08/30/2010)]*

*Loading Racks: Vapor Recovery Unit*

3. The permittee shall use as the primary control device the John Zink Series 2000 high-efficiency adsorption-absorption hydrocarbon vapor recovery unit [JZVRU (EU: B02)] for all captured VOC loading rack emissions. *[NSR ATC/OP 13, Modification 6, Condition III-A-2 (03/29/2004) and 40 CFR Part 60, Subpart XX and AQR 121.6.1(b)(1)]*

*Loading Racks: Auxiliary Flare*

4. The permittee shall use the auxiliary flare (EU: B10) at all times the JZVRU is inoperable to control VOC loading rack emissions. The flare shall operate only during documented malfunctions, documented emergencies, or maintenance events of the JZVRU. *[NSR ATC/OP 13, Modification 6, Condition III-A-3 (03/29/2004)and AQR 121.1.6(b)(2)]*

*Offloading Rack B-100 Fuel (EU: B01A)*

5. The permittee shall only offload B-100 from tank trucks that are equipped with a vapor recovery collection system compatible with the terminal's vapor balance system. *[AQR 12.5.2.6(a) & (b)]*

*Soil Vapor Extraction and Groundwater Treatment System (EU: SR04)*

6. The permittee shall use a control device capable of 98.5 percent VOC destruction efficiency when the permittee operates a combustion unit for controlling VOC emissions from the soil vapor extraction and groundwater treatment system. *[NSR ATC/OP 13, Modification 6, Condition III-A-23 (03/29/2004)]*

## 2.2 CONTROL REQUIREMENTS

*General Requirements*

1. The permittee shall comply with all applicable control requirements of 40 CFR Part 60, Subparts A, Ka, Kb, and XX; 40 CFR Part 80; and 40 CFR Part 63, Subparts A, WW, and BBBBBB. *[NSR ATC/OP 13, Modification 6, Condition III-A-1 (03/29/2004)]*

2. Each gasoline storage tank is deemed in compliance with 40 CFR Part 63, Subpart BBBBBB, if that tank is subject to, and complies with, the control requirements of 40 CFR Part 60, Subpart Kb (EUs: A16, A17, A21, A58–A61, B04, and B05). *[40 CFR Part 63.11087(f)]*

3. The permittee shall take, but is not limited to, the following measures to minimize vapor releases to the atmosphere (EUs: A01-A13, A16, A17, A21, A28, A29, A45-A48, A58-A61, B04, and B05): *[NSR ATC/OP 13, Modification 6, Condition III-B-16 (03/29/2004) and 40 CFR Part 63.11086(d)]*

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a. Minimize gasoline spills;

b. Clean up spills as expeditiously as possible;

c. Cover all open gasoline containers with a gasketed seal when not in use; and

d. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

*Storage Tanks*

4. For the storage tanks listed in Table 2-1, the permittee shall: *[AQR 121.6.1(a)]*

   a. Operate and maintain each tank in accordance with the seal control requirements specified; and

   b. Operate each tank in compliance with the applicable local and federal regulations identified in the table.

5. The permittee shall comply with the applicable requirements for gasoline storage tanks, gasoline loading racks, vapor collection-equipped gasoline cargo tanks, and equipment.

6. For gasoline storage tanks with a capacity of $75m^3$ or greater (EUs: A01-A13, A16, A17, A21, A28, A29, A45–A48, A58–A61, B04, and B05), the permittee shall:

   a. Equip and operate each internal and external floating roof gasoline storage tank according to the applicable requirements in 40 CFR Part 63.1063(a)(1) & (b), except for the secondary seal requirements under 63.163(a)(1)(i)(C) & (D), and equip each external floating roof gasoline storage tank according to the requirements of 40 CFR Part 63.1063(a)(s) if that tank does not currently meet the requirements of 63.1063(a)(1).

7. The permittee shall apply the provisions of 40 CFR Part 63, Subpart WW for controlling air emissions from storage vessels, as referenced in 40 CFR Part 60, Subpart Kb. (EUs: A16, A17, A21, and A58-A61, B04, and B05). *[40 CFR Part 63, Subpart 63.1060]*

8. The permittee shall operate and maintain each storage vessel to which 40 CFR Part 63, Subpart WW applies with a floating roof in accordance with 40 CFR Part 63.1063 (EUs: A01-A13, A16, A17, A21, A28, A29, A45-A48, A58-A61, B04, and B05). *[40 CFR Part 63, Subpart 63.1062]*

9. The permittee shall limit the Reid vapor pressure (RVP) of all combined fuel products stored in each bulk storage tank listed in Table 3-1 to an annual average of 11. The 12-month rolling average RVP limit will not apply to a storage tank that is not in service for any consecutive 12 months. *[NSR ATC/OP 13, Modification 6, Condition III-B-18 (03/29/2004)]*

10. The permittee shall limit each storage tank to the product(s) noted for it in Table 1-1. *[NSR ATC/OP 13, Modification 6, Condition III-B-17 (03/29/2004)]*

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*Sump Tanks, Oil/Water Separator, and Oil Storage Tank*

11. The permittee shall keep all hatches and other openings on the OWS (EU: H11) and the oil storage tank (EU: H12) gasketed and closed at all times except when opened for active inspection, maintenance, sampling, gauging, or repair. *[NSR ATC 13, Modification 21, Condition IV-B-6 (08/30/2010)]*

12. The permittee shall operate and maintain all vents on the OWS (EU: H11) and the oil storage tank (EU: H12) with pressure/vacuum relief valves. The vents on the sumps (EUs: H02, H03, H04, H06, H07, and H08) are not required to be equipped with pressure/vacuum relief valves. *[NSR ATC 13, Modification 21, Condition IV-B-7 (08/30/2010)]*

*Loading Racks: Vapor Collection System*

13. The permittee shall limit the loading of gasoline into vapor-tight gasoline cargo tanks (tank trucks). *[40 CFR Part 60.502(e)]*

14. The permittee shall operate the JZVRU during all product loading unless there is a documented malfunction, documented emergency, or maintenance event with the JZVRU (EU: B02). *[NSR ATC/OP 13, Modification 6, Condition III-A-2 (03/29/2004); 40 CFR Part 60, Subpart XX, and AQR 121.6.1(b)(1)]*

15. The permittee shall maintain and operate the vapor collection and liquid loading equipment to limit gauge pressure in the delivery tank to 4,500 pascals (450 mm of water) during product loading. The pressure shall be measured by the procedures specified in 40 CFR Part 60.503(d) (EU: B02). *[NSR ATC/OP 13, Modification 6, Condition III-A-6 (03/29/2004) and 40 CFR Part 60.502(h)]*

16. The permittee shall maintain and operate the vapor collection system such that the pressure vacuum vents do not open if the system pressure is less than 4,500 pascals (450 mm of water) (EU: B02). *[40 CFR Part 60.502(i) and NSR ATC/OP 13, Modification 6, Condition III-A-7 (03/29/2004)]*

17. The permittee shall maintain and operate the JZVRU (EU: B02) per the operation and maintenance (O&M) manual. *[NSR ATC/OP 13, Modification 6, Condition III-E-3 (03/29/04)]*

18. The permittee shall design and operate the vapor collection system to prevent any vapors collected at one loading rack or lane from passing through another loading rack or lane to the atmosphere. *[40 CFR Part 60.502(d)]*

*Loading Racks: Auxiliary Flare*

19. The permittee shall use the auxiliary flare (EU: B10) at all times the JZVRU is inoperable to control VOC loading rack emissions. The flare shall operate only during a documented malfunction, documented emergencies, or JZVRU maintenance events. *[NSR ATC/OP 13, Modification 6, Condition III-A-3 (03/29/2004), and AQR 121.6.1(b)(2)]*

20. The permittee shall operate the flare (EU: B10) so that it utilizes a flame scanner/sensor and immediately shuts down operations if flame instability is detected. Only trucks loading prior to a flare shutdown shall be allowed to finish product loading, and then only if vapor holder

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capacity exists. Once the permittee has determined, documented, and repaired the cause of the flame instability, product loading of tanker trucks may resume with the flare being used as the control device. *[NSR ATC/OP 13, Modification 6, Condition III-A-5 (03/29/2004)]*

*Loading Racks: Tanker Loading Requirements*

21. The permittee shall follow all regulatory requirements related to fuel handling to minimize leaks, spills, and vapor releases to the atmosphere. *[NSR ATC/OP 13, Modification 6, Condition III-B-16 (03/29/2004), and AQR 121.6.1(b)(3)]*

22. The permittee shall assure that any non-vapor-tight gasoline tank truck will not be reloaded at the affected facility until vapor tightness documentation for that tank is obtained. *[40 CFR Part 60.502(e)(5) and NSR ATC/OP 13, Modification 6, Condition III-A-8 (03/29/2004)]*

23. The permittee shall only load tank trucks when the terminals and the tank truck's vapor collection systems are connected. *[40 CFR 60.502(g) and NSR ATC/OP 13, Modification 6, Condition III-B-9 (03/29/2004)]*

24. The permittee shall only load gasoline into tank trucks equipped with vapor collection equipment compatible with the terminal's vapor collection system. *[40 CFR Part 60.502(f) and NSR ATC/OP 13, Modification 6, Condition III-B-9 (03/29/2004)]*

*Ethanol Unloading System*

25. The permittee shall vent the vapors from the ethanol unloading system (EU: H09) to the existing VRU (EU: B02). *[NSR ATC 13, Modification 21, Condition IV-B-4 (08/30/2010)]*

*Offloading Rack B-100 Fuel*

26. The permittee shall ensure that only trucks with a current vapor tightness certification are offloaded from the B-100 offloading rack (EU: B01A). *[AQR 12.5.2.6(a) & (b)]*

27. The permittee shall only offload B-100 from tank trucks equipped with a vapor collection system compatible with the terminal's vapor balance system. *[AQR 12.5.2.6(a) & (b)]*

28. The permittee shall only offload B-100 from tank trucks when all vapor balance system equipment is connected and operating (EU: B01A). *[AQR 12.5.2.6(a) & (b)]*

*Haul Roads*

29. The permittee shall maintain onsite haul roads, including roads providing exclusive access, by immediately removing road debris and mud or dirt trackout. Maintenance may consist of washing, sweeping, vacuuming, or equivalent control measures (EU: E01). *[NSR ATC/OP 13, Modification 6, Condition III-A-27 (03/29/2004) and AQR 12.5.2.6(a)]*

30. Unpaved roads accessing or located on the site shall be treated with a chemical or organic dust suppressant and watered as necessary to keep from exhibiting an opacity greater than 20% for more than 3 minutes in any 60-minute period. Silt content shall not exceed 6% and silt loading shall not exceed 0.33 oz/ft$^2$, regardless of the average number of vehicles per day. *[NSR ATC/OP, Modification 6, Condition 28 3/29/2004]*

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*Soil Vapor Extraction and Groundwater Treatment System*

31. The permittee shall use a control device capable of 98.5% VOC destruction efficiency when operating a combustion unit to control VOC emissions from the soil vapor extraction or groundwater treatment system. *[NSR ATC/OP 13, Modification 6, Condition III-B-23 (03/29/2004), and AQR 121.6.1(c)(1)]*

    a. The permittee shall use only propane as the auxiliary fuel when operating the combustion unit (EU: SR04). *[NSR ATC/OP 13, Modification 6, Condition III-A-5 (03/29/2004), and AQR 121.6.1(c)(2)]*

    b. The permittee shall operate and maintain the combustion unit according to the O&M manual (EU: SR04). *[NSR ATC/OP 13, Modification 6, Condition III-A-7 (03/29/2004), and AQR 121.6.1(c)(4)]*

    c. The permittee shall operate the combustion unit at a temperature specified by the manufacturer (EU: SR04). *[NSR ATC/OP Section III-B, Condition 26 (3/29/2004), AQR 12.5.2.6, and AQR 121.6.1(c)(3)]*

32. The permittee shall demonstrate a minimum control efficiency of 95% or a maximum outlet emission concentration of 100 ppmvd of VOC if a vapor-phase carbon adsorber is used for emission control of the soil vapor extraction or groundwater treatment system (EU: SR04). *[AQR 12.5.2.6(a) and AQR 121.6.1(d)]*

*Cooling Tower*

33. The permittee shall equip the cooling tower (EU: H05) with drift eliminators that have a maximum drift rate of 0.001%. *[NSR ATC 13, Modification 21, Condition IV-B-1 (08/30/2010)]*

34. The permittee shall not allow the total dissolved solids (TDS) of the cooling tower (EU: H05) to exceed 2,000 ppm. *[NSR ATC 13, Modification 21, Condition IV-B-2 (08/30/2010)]*

35. The permittee shall operate and maintain the cooling tower (EU: H05) in accordance with the O&M manual. *[NSR ATC 13, Modification 21, Condition IV-B-3 (08/30/2010)]*

*Engines/Air Compressor/Fire Water Engine*

36. The permittee shall operate and maintain each diesel engine in accordance with the O&M manual (EUs: B11 and D02). *[AQR 12.5.2.6(a)]*

37. The permittee shall maintain the diesel-powered air compressor (EU: B11) as follows unless O&M manual requirements are more stringent: *[40 CFR Part 63.6603]*

    a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;

    b. Inspect air cleaners every 1,000 hours of operation or annually, whichever comes first; and

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c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. (The permittee may use an oil analysis program, as described in 40 CFR Part 63.6625(i), to extend the specified oil change requirement and petition the Control Officer on alternative work practices pursuant to the requirements of 40 CFR Part 63.6(g)).

d. During startup, the permittee shall minimize engine time spent at idle. The permittee shall minimize engine startup time to a period needed for appropriate and safe engine loading, not to exceed 30 minutes, after which time all non-startup emission limitations apply. *[40 CFR Part 63.6603(a)]*

38. The permittee shall maintain the diesel-powered fire water engine (EU: D02) as follows, unless the O&M manual are more stringent: *[40 CFR Part 63, Subpart 63.6603]*

a. Change oil and filter every 500 hours of operation or annually, whichever comes first;

b. Inspect air cleaners every 1,000 hours of operation or annually, whichever comes first; and

c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. (The permittee may utilize an oil analysis program as described in Subpart 63.6625(i) to extend the specified oil change requirement and can petition the Control Officer pursuant to the requirements of 40 CFR Part 63.6(g) for alternative work practices.)

*Other*

39. The permittee shall not cause or allow the handling, transporting, or storage of any material in a manner that may or does allow controllable particulate matter to become airborne. *[AQR 41.1.2]*

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# 3.0 LIMITATIONS AND STANDARDS

## 3.1 OPERATIONAL LIMITS

*General*

1. The permittee may comply with 40 CFR Part 63, Subpart WW to satisfy the compliance requirements of 40 CFR Part 60, Subpart Kb (EUs: A16, A17, A21, A58-A61, B04, and B05). *[40 CFR Part 60.110b(e)(5)]*

*Storage Tanks*

2. The permittee shall limit the total annual tank throughput of all tanks identified in Table 3-1 to 4,504,505,338 gallons (107,250,172 barrels) in any consecutive 12-month period. *[NSR ATC/OP (all modifications) and AQR 12.5]*

3. The permittee shall limit the throughput of individual tanks to the amounts identified in Table 3-1 in any consecutive 12-month period. *[NSR ATC/OP 13, Modification 6, Condition III-A-3 (03/29/2004)]*

**Table 3-1: Storage Tank Throughputs (in gallons)**

| EU | Annual Throughput (gallons) | EU | Annual Throughput (gallons) |
|---|---|---|---|
| **Bulk Storage Tanks** | | | |
| A01 | 28,560,000 | A27 | 9,540,000 |
| A02 | 32,460,000 | A28 | 23,580,000 |
| A03 | 20,340,000 | A29 | 27,720,000 |
| A04 | 28,560,000 | A45 | 32,460,000 |
| A05 | 20,340,000 | A46 | 32,460,000 |
| A06 | 20,340,000 | A47 | 70,000,000 |
| A07 | 44,220,000 | A48 | 50,400,000 |
| A08 | 90,000,000 | A56 | 189,000,000 |
| A09 | 28,560,000 | A57 | 189,000,000 |
| A10 | 50,000,000 | A58 | 302,400,000 |
| A11 | 137,000,000 | A59 | 604,800,000 |
| A12 | 864,000,000 | A60 | 604,800,000 |
| A13 | 50,760,000 | A61 | 126,000,000 |
| A14 | 118,500,000 | B04 | 7,560,000 |
| A15 | 114,660,000 | B05 | 12,720,000 |
| A16 | 88,200,000 | D01 | 25,000 |
| A17 | 100,800,000 | H02 | 302,400 |
| A18 | 9,000,000 | H03 | 806,400 |
| A19 | 350,000,000 | H04 | 100,800 |
| A20 | 220,500,000 | H06 | 75,600 |

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| EU | Annual Throughput (gallons) | EU | Annual Throughput (gallons) |
|---|---|---|---|
| A21 | 100,800,000 | H07 | 36,000 |
| A22 | 126,000,000 | H08 | 7,200 |
| A23 | 100,800,000 | H11 | 15,768,000 |
| A24 | 100,800,000 | H12 | 365,000 |
| **Fuel Additive Tanks** | | | |
| A25 | 5,040 | A38 | 95,949 |
| A26 | 95,949 | A39 | 44,100 |
| A30 | 95,949 | A49 | 5,040 |
| A31 | 95,949 | A53 | 57,519 |
| A32 | 148,050 | A54 | 95,949 |
| A33 | 148,050 | H10 | 132,000 |
| A34 | 81,207 | H14 | 390 |
| A35 | 79,286 | H15 | 3,300 |
| A36 | 55,661 | H16 | 6,150 |
| A37 | 5,040 | H17 | 6,150 |
| | | H18 | 13,000 |

4. The permittee shall operate each storage tank so that the floating roof floats on the stored liquid surface at all times except when supported by its legs or other support devices (EUs: A01–A13, A16, A17, A21, A28, A29, A45–A48, A58–A61, B04, and B05). *[40 CFR Part 63.1063(b)]*

5. If the liquid depth in a storage tank is insufficient to support the floating roof, the permittee shall fill the tank continuously as soon as practical until the roof refloats (EUs: A01–A13, A16, A17, A21, A28, A29, A45–A48, A58–A61, B04, and B05). *[40 CFR Part 63.1063(b)]*

6. The permittee shall keep each opening in the floating roof covered at all times except automatic bleeder (vacuum breaker) and rim space vents, and except when the cover must be open for access (EUs: A01–A13, A16, A17, A21, A28, A29, A45–A48, A58–A61, B04, and B05). *[40 CFR Part 63.1063(b)]*

7. The permittee shall keep each automatic bleeder (vacuum breaker) and rim space vent closed at all times except to relieve excess pressure or vacuum in accordance with the O&M manual (EUs: A01–A13, A16, A17, A21, A28, A29, A45–A48, A58–A61, B04, and B05). *[40 CFR Part 63.1063(b)]*

8. The permittee shall keep each unslotted guide pole cap closed at all times except when gauging the liquid level or taking liquid samples (EUs: A01–A13, A16, A17, A21, A28, A29, A45–A48, A58–A61, B04, and B05). *[40 CFR Part 63.1063(b)]*

*Loading Racks*

9. The permittee shall limit the total throughput of all petroleum products to the loading racks (EU: B01) to 1,485,956,934 gallons (35,379,927 barrels) in any consecutive 12-month period. *[NSR ATC/OP 13, Modification 6, Condition III-A-2 (03/29/2004)]*

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10. The permittee shall limit the total throughput of gasoline to the two loading racks and 15 lanes (EU: B01) to 977,278,302 gallons (23,268,531 barrels) in any consecutive 12-month period. *[NSR ATC/OP 13, Modification 6, Condition III-A-2 (03/29/2004)]*

*Offloading Rack*

11. The permittee shall limit total throughput of the B-100 offloading rack (EU: B01A) to 147,168,000 gallons in any consecutive 12-month period. *[Part 70 OP, Condition III-B-2(e) (12/20/2012)]*

*Loading Racks: Auxiliary Flare*

12. The permittee shall limit operation of the auxiliary flare (EU: B10) to 438 hours in any consecutive 12-month period. *[NSR ATC/OP 13, Modification 6, Condition III-A-4 (03/29/2004)]*

*Ethanol Unloading System*

13. The permittee shall limit the amount of ethanol unloaded through the ethanol loading system (EU: H09) to 76,104,000 gallons in any consecutive 12-month period. *[NSR ATC 13, Modification 21, Condition IV-2-b (08/31/2010)]*

*Haul Roads*

14. The permittee shall limit the vehicle miles traveled per year on unpaved roads (EU: E01) to 5,457 miles. *[Title V OP Application (11/13/2024), AQR 12.1.4.1(c)&(f)]*

15. The permittee shall limit the vehicle miles traveled per year on paved roads (EU: E01) to 99,630 miles. *[Title V OP January 29, 2024, AQR 12.1.4.1(c)&(f)]*

*Engines/Air Compressor/Fire Water Engine*

16. The permittee shall limit operation of the diesel-powered air compressor to 100 hours per year (EU: B11). *[Part 70 OP, Condition III-B-2(n) (09/23/2014)]*

17. The permittee shall limit operation of the diesel-powered fire water engine (EU: D02) for testing and maintenance purposes to 100 hours per year. The permittee may operate the fire water engine up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. *[40 CFR Part 63.6640]*

## 3.2 EMISSION LIMITS

*General*

1. The permittee shall not allow the actual emissions from the stationary source to exceed the PTE listed in Table 3-2 in any consecutive 12-month period, except for emission units intended only for use in emergencies. *[AQR 12.5.2.6(a)]*

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**Table 3-2. Potential to Emit (tons per year)**

| Pollutant | $PM_{10}$ | $PM_{2.5}$ | $NO_x$ | CO | $SO_2$ | VOC | $H_2S$ | Pb |
|---|---|---|---|---|---|---|---|---|
| Total | 9.85 | 1.58 | 3.26 | 2.55 | 0.18 | 188.01 | 0 | 0 |

2. The permittee shall not allow the actual emissions from the following individual emission units to exceed the PTE listed in Table 3-3 in any consecutive 12-month period, except for emission units intended only for use in emergencies. *[AQR 12.5.2.6(a)]*

**Table 3-3. PTE Summary—Emissions by Unit (tons per year)**

| EU | Source ID No. | Condition (gal/yr) | PTE (tpy) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_2$ | VOC | HAP |
| A01 | Tank 530 | 28,560,000 | 0 | 0 | 0 | 0 | 0 | 1.33 | 0.07 |
| A02 | Tank 531 | 32,460,000 | 0 | 0 | 0 | 0 | 0 | 1.41 | 0.07 |
| A03 | Tank 532 | 20,340,000 | 0 | 0 | 0 | 0 | 0 | 1.14 | 0.06 |
| A04 | Tank 533 | 28,560,000 | 0 | 0 | 0 | 0 | 0 | 1.33 | 0.07 |
| A05 | Tank 534 | 20,340,000 | 0 | 0 | 0 | 0 | 0 | 1.14 | 0.06 |
| A06 | Tank 535 | 20,340,000 | 0 | 0 | 0 | 0 | 0 | 1.14 | 0.06 |
| A07 | Tank 536 | 44,220,000 | 0 | 0 | 0 | 0 | 0 | 1.64 | 0.09 |
| A08 | Tank 537 | 90,000,000 | 0 | 0 | 0 | 0 | 0 | 1.88 | 0.10 |
| A09 | Tank 538 | 28,560,000 | 0 | 0 | 0 | 0 | 0 | 2.76 | 0.14 |
| A10 | Tank 539 | 50,000,000, | 0 | 0 | 0 | 0 | 0 | 1.38 | 0.07 |
| A11 | Tank 540 | 137,000,000 | 0 | 0 | 0 | 0 | 0 | 1.90 | 0.10 |
| A12 | Tank 541 | 864,000,000 | 0 | 0 | 0 | 0 | 0 | 1.61 | 0.08 |
| A13 | Tank 524 | 50,760,000 | 0 | 0 | 0 | 0 | 0 | 0.75 | 0.04 |
| A14 | Tank 542 | 118,500,000 | 0 | 0 | 0 | 0 | 0 | 0.17 | 0.01 |
| A15 | Tank 543 | 114,660,000 | 0 | 0 | 0 | 0 | 0 | 0.18 | 0.01 |
| A16 | Tank 545 | 88,200,000 | 0 | 0 | 0 | 0 | 0 | 2.14 | 0.11 |
| A17 | Tank 546 | 100,800,000 | 0 | 0 | 0 | 0 | 0 | 2.94 | 0.15 |
| A18 | Tank 522 | 9,000,000 | 0 | 0 | 0 | 0 | 0 | 0.28 | 0.01 |
| A19 | Tank 525 | 350,000,000 | 0 | 0 | 0 | 0 | 0 | 1.84 | 0.01 |
| A20 | Tank 526 | 220,500,000 | 0 | 0 | 0 | 0 | 0 | 1.47 | 0.01 |
| A21 | Tank 547 | 100,800,000 | 0 | 0 | 0 | 0 | 0 | 2.58 | 0.14 |
| A22 | Tank 512 | 126,000,000 | 0 | 0 | 0 | 0 | 0 | 1.77 | 0.01 |
| A23 | Tank 510 | 100,800,000 | 0 | 0 | 0 | 0 | 0 | 0.18 | 0.01 |
| A24 | Tank 511 | 100,800,000 | 0 | 0 | 0 | 0 | 0 | 0.18 | 0.01 |
| A27 | Tank 501 | 9,540,000 | 0 | 0 | 0 | 0 | 0 | 0.32 | 0.01 |
| A28 | Tank 523 | 23,580,000 | 0 | 0 | 0 | 0 | 0 | 1.53 | 0.08 |
| A29 | Tank 544 | 27,720,000 | 0 | 0 | 0 | 0 | 0 | 1.72 | 0.09 |
| A45 | Tank 548 | 32,460,000 | 0 | 0 | 0 | 0 | 0 | 1.85 | 0.10 |
| A46 | Tank 549 | 32,460,000 | 0 | 0 | 0 | 0 | 0 | 1.04 | 0.05 |
| A47 | Tank 550 | 70,000,000 | 0 | 0 | 0 | 0 | 0 | 1.81 | 0.09 |

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| EU | Source ID No. | Condition (gal/yr) | PTE (tpy) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_2$ | VOC | HAP |
| A48 | Tank 551 | 50,400,000 | 0 | 0 | 0 | 0 | 0 | 1.75 | 0.09 |
| A56 | Tank 513 | 189,000,000 | 0 | 0 | 0 | 0 | 0 | 0.23 | 0.01 |
| A57 | Tank 514 | 189,000,000 | 0 | 0 | 0 | 0 | 0 | 0.23 | 0.01 |
| A58 | Tank 553 | 302,400,000 | 0 | 0 | 0 | 0 | 0 | 4.29 | 0.23 |
| A59 | Tank 554 | 604,800,000 | 0 | 0 | 0 | 0 | 0 | 4.98 | 0.26 |
| A60 | Tank 555 | 604,800,000 | 0 | 0 | 0 | 0 | 0 | 3.41 | 0.18 |
| A61 | Tank 552 | 126,000,000 | 0 | 0 | 0 | 0 | 0 | 2.26 | 0.12 |
| B04 | Tank 500 | 7,560,000 | 0 | 0 | 0 | 0 | 0 | 0.55 | 0.03 |
| B05 | Tank 521 | 12,720,000 | 0 | 0 | 0 | 0 | 0 | 1.24 | 0.06 |
| A25 | ASA Conductivity Improver | 5,040 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| A26 | Tank 500AIA | 95,949 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| A30 | Tank 533A | 95,949 | 0 | 0 | 0 | 0 | 0 | 0.02 | 0.01 |
| A31 | Tank 537A | 95,949 | 0 | 0 | 0 | 0 | 0 | 0.02 | 0.01 |
| A32 | Tank 541A | 148,050 | 0 | 0 | 0 | 0 | 0 | 0.02 | 0.01 |
| A33 | 541B | 148,050 | 0 | 0 | 0 | 0 | 0 | 0.02 | 0.01 |
| A34 | 542D | 81,207 | 0 | 0 | 0 | 0 | 0 | 0.02 | 0.01 |
| A35 | 542A | 79,286 | 0 | 0 | 0 | 0 | 0 | 0.02 | 0.01 |
| A36 | 531A | 55,661 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| A37 | 542C | 5,040 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| A38 | 537B | 95,949 | 0 | 0 | 0 | 0 | 0 | 0.03 | 0.01 |
| A39 | 531B | 44,100 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| A49 | 542B | 5,040 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| A53 | 548B | 57,519 | 0 | 0 | 0 | 0 | 0 | 0.02 | 0.01 |
| A54 | 548A | 95,949 | 0 | 0 | 0 | 0 | 0 | 0.03 | 0.01 |
| H10 | 500B | 132,000 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| H14 | ASA Tote | 390 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| H15 | CI Tote | 3,300 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| H16 | Lane 7 Red Dye Tote | 6,150 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| H17 | Lane 12 Red Dye Tote | 6,150 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| H18 | Sample Recovery Tank | 13,000 | 0 | 0 | 0 | 0 | 0 | 0.34 | 0.03 |
| B01 | Loading Racks | Emissions included in B10 | | | | | | | |
| B01A | B-100 | 147,168,000 | 0 | 0 | 0 | 0 | 0 | 0.04 | 0.01 |
| H09 | Ethanol Unloading System | 76,104,000 | 0 | 0 | 0 | 0 | 0 | 0.18 | 0.01 |
| B02 | John Zink VRU | 1,485,776,586 | 0 | 0 | 0 | 0 | 0 | 14.48 | 0.72 |

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| EU | Source ID No. | Condition (gal/yr) | PTE (tpy) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | $PM_{10}$ | $PM_{2.5}$ | $NO_X$ | CO | $SO_2$ | VOC | HAP |
| B10 | Flare Processing | 498,843.57 lb/yr | 0.04 | 0.04 | 0.32 | 1.45 | 0.15 | 65.71 | 3.11 |
| SR04 | SVE and GW Treatment System | 8,760 hr/yr | 0.07 | 0.07 | 1.26 | 0.73 | 0.01 | 37.67 | 1.78 |
| H02 | Mainline Sump | 302,400 | 0 | 0 | 0 | 0 | 0 | 0.41 | 0.02 |
| H03 | Rack Sump | 806,400 | 0 | 0 | 0 | 0 | 0 | 1.13 | 0.06 |
| H04 | Mainline Sump | 100,800 | 0 | 0 | 0 | 0 | 0 | 0.51 | 0.03 |
| H06 | Waste Fuel | 75,600 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| H07 | Waste Fuel | 36,000 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| H08 | Waste Fuel | 7,200 | 0 | 0 | 0 | 0 | 0 | 0.02 | 0.01 |
| D01 | Diesel/Biodiesel | 25,000 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 |
| H11 | Oil/Water Separator | 15,768,000 | 0 | 0 | 0 | 0 | 0 | 0.08 | 0.01 |
| H12 | Waste Fuel/Oil/Water | 365,000 | 0 | 0 | 0 | 0 | 0 | 0.04 | 0.01 |
| B06 | Piping and Fittings | 21,888 | 0 | 0 | 0 | 0 | 0 | 6.57 | 0.35 |
| E01 | Haul Road - Paved | 99,630 VMT/yr | 7.54 | 1.14 | 0 | 0 | 0 | 0 | 0 |
| | Haul Road – Unpaved | 5,457 VMT/yr | 2.07 | 0.21 | 0 | 0 | 0 | 0 | 0 |
| H05 | Cooling Tower | 8,760 hr/yr | 0.01 | 0 | 0 | 0 | 0 | 0 | 0 |
| B11 | Air Compressor | 100 hr/yr | 0.01 | 0.01 | 0.07 | 0.02 | 0.01 | 0.01 | 0.01 |
| D02 | Fire Water Engine | 500 hr/yr | 0.11 | 0.11 | 1.61 | 0.35 | 0.01 | 0.13 | 0.01 |

Note: VMT = vehicle miles traveled.

3. The permittee shall at all times operate and maintain the storage tanks, gasoline loading racks, vapor collection-equipped gasoline cargo tanks, equipment components in vapor or liquid gasoline service, and monitoring equipment in a manner consistent with safety and with good air pollution control practices for minimizing emissions *[40 CFR Part 63.11085(a)]*

## *Vapor Recovery Unit*

4. The permittee shall not allow the actual emissions from the JZVRU (EU: B02) to exceed 2.4 mg of total VOC per liter of gasoline (0.02 lb/1,000 gal of product loaded) over a four-hour average. *[NSR ATC/OP 13, Modification 6, Condition III-A-26 (03/29/04)]*

## *Soil Vapor Extraction and Ground Water Treatment System*

5. The permittee shall operate the soil vapor extraction and groundwater treatment system (EU: SR04) so that emissions to the atmosphere do not contain visible black or white smoke while the combustion unit is operating. *[NSR ATC/OP 13, Modification 6, Condition III-E-17 (03/29/2004)]*

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6. The permittee shall not allow actual emissions from the soil vapor extraction and groundwater treatment system (EU: SR04) to exceed the calculated PTE listed in Table 3-4, irrespective of control efficiency, when the combustion unit is operated in any consecutive 12-month period. *[NSR ATC/OP 13, Modification 6, Condition III-A-26 (03/29/04)]*

**Table 3-4: PTE for Soil Vapor Extraction and Groundwater Treatment System (lb/hr)**

| EU | $PM_{10}$ | $NO_X$ | CO | $SO_2$ | VOC | HAP |
|---|---|---|---|---|---|---|
| SR04 | 0.02 | 0.29 | 0.17 | 0.01 | 8.60 | 0.01 |

*Other*

7. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant exceeding an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

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# *4.0 COMPLIANCE DEMONSTRATION REQUIREMENTS*

## 4.1 MONITORING

*General*

1. The permittee shall comply with all applicable requirements of 40 CFR Part 60, Subparts A, Ka, Kb, and XX; 40 CFR Part 80; and 40 CFR Part 63, Subparts A, WW, and BBBBBB. *[NSR ATC/OP 13, Modification 6, Condition III-E-1 (03/29/2004); AQR 12.5.2.6(d); and AQR 12.5.2.8(a)]*

2. The permittee shall perform a monthly leak inspection using sight, sound, or smell of all equipment in gasoline service. *[40 CFR Part 63.11089(a)]*

3. The permittee shall, at the completion of each inspection, maintain and sign a log book containing a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility. *[40 CFR 63.11089(b)]*

*Visible Emissions [AQR 12.5.2.6(d) & AQR 12.5.2.8]*

4. The Responsible Official shall sign and adhere to the *Visible Emissions Check Guide* (1/11/2021) and keep a copy of the signed guide on-site at all times.

5. The permittee shall conduct a daily visual emissions check of the haul roads (EUs: E01).

6. The permittee shall conduct a quarterly visual emissions check of the air compressor (EUs: B11) while it is in operation.

7. The permittee shall conduct a quarterly visual emissions check of the fire water engine (EUs: D02) while it is in operation.

8. The permittee shall conduct daily visual emissions observations on the exhaust stack of the catalytic or thermal oxidation control device, whichever is being used, while it is in operation (EU: SR04).

9. If no plume appears to exceed the opacity standard during the visible emissions check, the date, location, and results shall be recorded, along with the viewer's name.

10. If a plume appears to exceed the opacity standard, the permittee shall do one of the following:

    a. Immediately correct the perceived exceedance, then record the first and last name of the person who performed the emissions check, the date the check was performed, the unit(s) observed, and the results of the observation; or

    b. Call a certified Visible Emissions Evaluation (VEE) reader to perform a U.S. Environmental Protection Agency (EPA) Method 9 evaluation.

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i. For sources required to have a certified reader on-site, the reader shall start Method 9 observations within 15 minutes of the initial observation. For all other sources, the reader shall start Method 9 observations within 30 minutes of the initial observation.

ii. If no opacity exceedance is observed, the certified VEE reader shall record the first and last name of the person who performed the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each emission unit that was initially perceived to have exceeded the opacity limit, and the record shall also indicate:

(1) The cause of the perceived exceedance;

(2) The color of the emissions; and

(3) Whether the emissions were light or heavy.

iii. If an opacity exceedance is observed, the certified VEE reader shall take immediate action to correct the exceedance. The reader shall then record the first and last name of the person performing the VEE, the date the VEE was performed, the unit(s) evaluated, and the results. A Method 9 VEE form shall be completed for each reading identified, and the record shall also indicate:

(1) The cause of the exceedance;

(2) The color of the emissions;

(3) Whether the emissions were light or heavy;

(4) The duration of the emissions; and

(5) The corrective actions taken to resolve the exceedance.

11. Any scenario of visible emissions noncompliance can and may lead to enforcement action.

*Storage Tanks [AQR 12.5.2.6(d)/AQR 12.5.2.8(a)]*

12. The permittee shall visually inspect annually, storage tanks equipped with an internal roof, the floating roof deck, deck fittings, and rim seal through openings in the fixed roof (EUs: A01-A13, A16, A17, A21, A28, A29, A45–A48, A58–A61, B04, and B05). *[40 CFR Part 63.1063(c)(1) & (d)(2), 40 CFR Part 63.11092(e), and 40 CFR 60.110b(e)(5)]*

13. The permittee shall visually inspect from the top side floating roof deck of vessels equipped with an internal or external roof, the floating roof deck, deck fittings, and rim seal when the vessel is emptied and degassed or every 10 years whichever occurs first. (EUs: A01-A13, A16, A17, A21, A28, A29, A45–A48, A58–A61, B04, and B05). *[40 CFR Part 63.1063(c)(1) & (d)(1) & (2), 40 CFR Part 63.11092(e), , and 40 CFR 60.110b(e)(5)]*

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14. The permittee shall inspect the primary and secondary rim seals of external floating roofs for the presence and size of gaps between the rim seals and the wall of the storage vessel within 90 days of the initial filling. The secondary seal shall be inspected annually, and the primary seal shall be inspected every 5 years. (EUs: A01–A10). *[40 CFR 63.1063(c)(2) & (d)(3), 40 CFR Part 63.11092(e), and 40 CFR 60.110b(e)(5)]*

15. The permittee shall repair the items before refilling the storage vessel or empty and remove the storage vessel from service within 45 days. The permittee my use up to two extensions of 30 days each with the proper documentation (EUs: A01-A13, A16, A17, A21, A28, A29, A45–A48, A58–A61, B04, and B05). *[40 CFR 63.1063(e), 40 CFR Part 63.11092(e), and 40 CFR 60.110b(e)(5)]*

16. The permittee is exempt from monitoring the operations of each affected facility that stores petroleum liquids with an RVP of less than 6.9 kilopascals (1.0 pounds per square inch absolute [psia]) provided that the maximum true vapor pressure does not exceed that limit. *[40 CFR Part 60.113(d)(1); AQR 12.5.2.6(d)/AQR 12.5.2.8(a)]*

17. The permittee shall monitor the volume of throughput to each tank, including sumps and additives, in either gallons or barrels, and calculate monthly the combined throughput in any consecutive 12-month period (EUs: A01–A39, A45–A49, A53, A54, A56–A61, B04, B05, D01, H03, H04, H06–H12, H14–H18). *[AQR 121.6.2(a)]*

18. The permittee shall monitor the RVP of fuel products by sampling them monthly at their respective tanks, and calculate monthly the RVP of all combined fuel products stored in bulk storage tanks in any consecutive 12-month period. The consecutive 12-month period RVP limit will not apply to a storage tank that is not in service for 12 consecutive months (EUs: A01-A13, A16-A18, A21, A24, A27-A29, A45-A48, A58-A61, B04, B05).

## *Oil/Water Separator and Oil Storage Tank*

19. The permittee shall monitor weekly VOC concentrations at the inlet and outlet of the carbon adsorber system (EUs: H11 and H12) to determine its control efficiency. *[NSR ATC 13, Modification 21, Condition IV-C-2 (08/30/2010; AQR 12.5.2.6(d); and AQR 12.5.2.8(a)]*

20. The permittee shall utilize a photoionization detector (PID) for weekly VOC monitoring. The control efficiency of the carbon absorber shall be calculated as 1 minus the VOC outlet concentration measured by the PID divided by the VOC inlet concentration measured by the PID/FID (EUs: H11 and H12). *[NSR ATC 13, Modification 21, Condition IV-C-3 (08/30/2010)]*

21. The permittee shall maintain and calibrate the PID unit according to its O&M manual. *[NSR ATC 13, Modification 21, Condition IV-C-4 (08/30/2010)]*

## *Loading Racks*

22. The permittee shall monitor the volume of throughput of all products to the loading racks in either gallons or barrels (EU: B01) and calculate monthly the annual throughput as a 12-month rolling total. *[AQR 12.5.2.6(d), AQR 12.5.2.8(a), and AQR 121.6.2(b)]*

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23. The permittee shall monitor the volume of gasoline throughput to the loading racks in either gallons or barrels (EU: B01) and calculate monthly the combined annual gasoline throughput in any consecutive 12-month period. *[AQR 12.5.2.6(d) and AQR 12.5.2.8(a)]*

24. The permittee shall, at least once per day, inspect all loading lanes and review all normal operations. The loading lane inspections shall include, but not be limited to, inspecting all check valves, flanges, hoses, and loading arms. Review of all normal operations shall include a walk-through. Detection methods incorporating sight, sound, or smell are acceptable. Detection of a leak shall be recorded, and the source of the leak repaired within five calendar days after it is detected. *[NSR ATC/OP 13, Modification 6, Condition III-E-4 (03/29/2004)]*

25. The permittee shall, for each calendar month, conduct inspections of the vapor collection system, the vapor processing system, and each loading rack handling gasoline during the loading of gasoline tank trucks for total organic compound, liquid, or vapor leaks. Detection methods incorporating sight, sound, and smell are acceptable. Each leak detection shall be recorded, and the source of the leak repaired within 15 calendar days after it is detected. *[40 CFR Part 60.502(j) and NSR ATC/OP 13, Modification 6, Condition III-B-11 (03/29/2004)]*

26. Delay of repair of any leaking equipment will be allowed upon a demonstration to the Control Officer that repairs within five days are not feasible. The permittee shall provide the reason(s) a delay is needed and the date by which each repair is expected to be completed. *[NSR ATC/OP 13, Modification 6, Conditions III-E-5, 6, and 7 (03/29/04)]*

27. The permittee shall limit the loading of liquid product into gasoline tank trucks to vapor-tight gasoline tank trucks using the following procedures: *[NSR ATC/OP 13, Modification 6, Condition III-E-11 (03/29/2004)]*

    a. The permittee shall issue all tank truck drivers a driver identification card. No product can be loaded from any loading lane without a valid driver identification card and Personal Identification Number (PIN). Upon visiting the terminal for the first time, the driver shall present the operation staff with a valid driver's license, customer authorization letter, and current tank truck vapor tightness certification. All the information required under 40 CFR Part 60.505(b) will be entered into the permittee's data system, along with the expiration date for the truck vapor tightness certification. The expiration date can be no more than one year from the date of the issuance of the vapor tightness certificate.

    b. The permittee shall scan all tank truck driver identification cards into the data system and enter the truck and trailer numbers before loading product at the terminal. If the vapor tightness certificate has expired, the driver will be instructed to see the operator on duty. The driver must present the operator with a new vapor tightness certificate, which will then be entered into the data system, in order to load the truck. The truck cannot load until the driver presents a new vapor tightness certificate.

    c. The permittee shall monitor and record each reloading of a non-vapor-tight gasoline cargo tank at the facility before vapor tightness documentation for that cargo tank was obtained. *[40 CFR Part 63.11095(b)(2)]*

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*Loading Racks: Vapor Recovery Unit*

28. The permittee shall operate and maintain a nondispersive infrared (NDIR) analyzer on the JZVRU (EU: B02) as a continuous emissions monitoring system (CEMS) to monitor VOC emissions from the exhaust of the on-line carbon bed. Emission readings shall be recorded and stored in a data acquisition system compatible with the analyzer. *[NSR ATC/OP 13, Modification 6, Condition III-A-4 (03/29/2004), and AQR 121.6.2(c)(4)]*

29. The permittee shall operate and maintain the CEMS in conformance with all provisions of 40 CFR Part 60.13 and 40 CFR Part 63.11092(b). *[NSR ATC/OP 13, Modification 6, Condition III-E-7 (03/29/2004), and AQR 121.6.2(c)(1)]*

30. The permittee shall demonstrate compliance with fuel dispensing operational and emission limitations specified in this permit by monitoring the following parameters of the JZVRU (EU: B02): *[NSR ATC/OP 13, Modification 6, Condition III-E-7 (03/29/2004), and AQR 121.6.2(c)(5)]*

    a. Exhaust gas flow rate;

    b. Hourly VOC concentration from the exhaust gas in lb/1,000 gal of petroleum loaded and mg/L of petroleum loaded;

    c. Four-hour average VOC concentration from the exhaust gas in lb/1,000 gal of petroleum loaded and mg/L of petroleum loaded; and

    d. Continuous product dispensing in gallons and liters.

31. Any exceedance of the four-hour average or annual VOC emission limitations, as determined by the CEMS, shall be considered a violation of the emission limit imposed and may result in enforcement action. *[NSR ATC/OP 13, Modification 6, Condition III-E-7 (03/29/2004)]*

32. The permittee shall obtain an approved quality assurance plan for all CEMS required by this section. The quality assurance plan (approved by DAQ on September 7, 2011) shall comply with 40 CFR Part 60, Appendix F – Quality Assurance Procedures and contain auditing schedules, reporting schedules, and design specifications for the CEMS system. *[NSR ATC/OP 13, Modification 6, Condition III-E-7 (03/29/2004), and AQR 121.6.2(c)(2)]*

33. The permittee is required to conduct a relative accuracy test audit (RATA) annually for all affected emission units to demonstrate compliance with CEM requirements. The permittee is subject to 40 CFR Part 60, Appendix F, and the *Clark County Department of Air Quality Guideline for Source Testing (9/19/2019). [NSR ATC/OP 13, Modification 6, Condition III-F-7 (03/29/2004), and AQR 121.6.2(c)(3)]*

34. The permittee shall submit in writing all RATA protocols to the Control Officer for approval no less than 45 days before the proposed date for the audit.

35. The permittee shall submit the results of the RATA to the Control Officer within 60 days of the conclusion of the audit.

36. The permittee shall perform preventative daily, weekly, quarterly, and annual maintenance protocols on the JZVRU (EU: B02) in accordance with its O&M manual.

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37. The permittee shall sample the glycol solution from the JZVRU separator (EU: B02) annually. The glycol sample shall be tested for pH and glycol content. The pH of the glycol solution must meet or be adjustable to O&M manual specifications; the glycol content must be in a concentration of 50% or greater. If either of these conditions cannot be met, the glycol solution must be replaced. *[NSR ATC/OP 13, Modification 6, Condition III-E-8 (03/29/2004)]*

*Loading Racks: Auxiliary Flare*

38. The permittee shall monitor the hours of operation of the flare unit (EU: B10) and calculate monthly its annual operating hours in any consecutive 12-month period. *[AQR 12.5.2.6(d)/AQR 12.5.2.8(a)]*

39. The permittee shall monitor flame instability with an optical scanner/sensor fitted on the flare unit (EU: B10) that will continuously verify the presence of a flame while in operation. If the scanner/sensor detects flame instability, the flare unit shall immediately shut down operations. *[NSR ATC/OP 13, Modification 6, Condition III-A-5 (03/29/2004)]*

40. The permittee will visually inspect flame quality during operation of the flare unit (EU: B10), once upon startup and once every two hours thereafter, documenting the date and time of each observation. *[NSR ATC/OP 13, Modification 6, Condition III-E-9 (03/29/2004), and AQR 121.6.2(e)]*

41. If the flame is observed to be anything but clear blue, the permittee will increase visual inspections and perform any corrective actions dictated by the facility operating manual. *[NSR ATC/OP 13, Modification 6, Condition III-E-9 (03/29/2004)]*

42. The permittee shall test the saturator tank fluid on the flare unit (EU: B10) monthly and at the conclusion of any flare use in excess of 24 hours of cumulative operation. The test will consist of taking a representative sample from the saturator tank and analyzing it for American Petroleum Institute (API) gravity and vapor pressure. The fluid must be replaced if the analysis determines the API gravity to be less than 47 degrees or the RVP to be less than four psia. *[NSR ATC/OP 13, Modification 6, Condition III-E-10 (03/29/2004)]*

43. The permittee shall operate and maintain the flare unit (EU: B10) per the O&M manual. *[NSR ATC/OP 13, Modification 6, Condition III-E-3 (03/29/04)]*

*Ethanol Unloading System*

44. The permittee shall monitor the volume of ethanol throughput to the unloading system in gallons (EU: H09) and calculate monthly the annual throughput as a 12-month rolling total. *[AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

*Haul Roads*

45. Daily visual emissions check on the haul roads, including dates, observer names, locations, and results;

46. The permittee shall monitor daily the number of vehicle miles traveled on unpaved haul roads on-site by haul trucks entering and leaving.

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47. The permittee shall monitor daily the number of vehicle miles traveled on paved haul roads on-site by haul trucks entering and leaving.

48. The permittee shall determine compliance with the opacity limits for unpaved haul roads when required by the Control Officer in accordance with one of the following, as applicable:

    a. 40 CFR Part 60, Appendix A-4, "Test Methods 6 through 10B: Method 9—Visual Determination of the Opacity of Emissions from Stationary Sources"; or

    b. The test method set forth in AQR 94.15.4, "Instantaneous Method."

*Soil Vapor Extraction and Groundwater Treatment System*

49. When operating a combustion unit for emission control of either the soil vapor extraction or groundwater treatment system, the permittee shall:

    a. Operate and maintain a continuous flow monitor on the soil and groundwater treatment system (EU: SR04). *[NSR ATC/OP 13, Modification 6, Condition III-E-12 (03/29/2004); AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

    b. Operate and maintain a continuous combustion chamber temperature monitor on the control device (EU: SR04). *[NSR ATC/OP 13, Modification 6, Condition III-A-19 (03/29/2004); AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

    c. Cease operation of the combustion unit if the continuous combustion chamber temperature monitor malfunctions or shuts down (EU: SR04). *[NSR ATC/OP 13, Modification 6, Condition III-A-21 (03/29/2004); AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

    d. Monitor the total flow rate (in standard cubic feet per meter) of the vapor stream to the combustion unit with each sample collected (EU: SR04). *[NSR ATC/OP 13, Modification 6, Condition III-E-16 (03/29/2004); AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

    e. Monitor monthly the auxiliary fuel used by the combustion unit in standard cubic feet (EU: SR04). *[AQR 12.5.2.6(d); AQR 12.5.2.8(a); and AQR 121.6.2(f)]*

    f. Conduct a daily visual inspection of the combustion unit for smoke. If the unit exhibits black or white smoke at any time, it shall be shut down until the cause is determined and the unit repaired (EU: SR04). *[NSR ATC/OP 13, Modification 6, Condition III-E-17 (03/29/2004); AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

    g. Demonstrate compliance with the remediation operational and emission limitations specified in this permit by monitoring the following parameters of the soil vapor extraction unit (EU: SR04): *[NSR ATC/OP 13, Modification 6, Condition III-E-12 (03/29/2004); AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

        i. Hours of operation;

        ii. Continuous exhaust gas flow rate;

        iii. Continuous combustion chamber temperature; and

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iv. Hourly and quarterly accumulated mass emissions of VOC based on daily activities and monitoring data.

h. The permittee shall monitor weekly VOC concentrations at the inlet and outlet of the control device to determine emission rates and their control efficiency. *[NSR ATC/OP 13, Modification 6, Conditions III-A-25 & III-E-13 (03/29/2004); AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

i. The permittee shall use a PID for weekly VOC monitoring. *[NSR ATC/OP 13, Modification 6, Condition III-E-13 (03/29/2004); AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

j. The permittee shall calibrate and maintain the PID unit according to the O&M manual. *[NSR ATC/OP 13, Modification 6, Condition III-E-15 (03/29/2004); AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

k. The permittee shall collect air samples every two months to determine the concentration of VOC sent to the control devices and VOC emissions to the atmosphere. At a minimum, the samples shall be analyzed for total petroleum hydrocarbons (TPH) using EPA Test Method TO-3 (as modified for air use); for benzene, toluene, ethylbenzene, meta-, para-, and ortho-xylene, and methyl tert-butyl ether (MTBE) using Test Method TO-15 (as modified for air use); and for water vapor content. *[NSR ATC/OP 13, Modification 6, Condition III-E-14 (03/29/2004); AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

50. When operating a vapor-phase granular activated carbon adsorber unit for emission control of either the soil vapor extraction or the groundwater treatment system, the permittee shall: *[OP renewal application (04/28/2016)]*

a. Monitor weekly VOC concentrations at the inlet and outlet of the carbon adsorber system to determine its control efficiency.

b. Use a PID for weekly VOC monitoring. The control efficiency of the carbon absorber shall be calculated as 1 minus the VOC outlet concentration measured by the PID divided by the VOC inlet concentration measured by the PID/FID (EUs: H11 and H12).

c. Maintain and calibrate the PID unit according to the O&M manual.

d. Collect air samples every two months to determine the concentration of VOC sent to the control devices and the emissions to the atmosphere. At a minimum, the samples shall be analyzed for TPH using Test Method TO-3 (as modified for air use); for benzene, toluene, ethylbenzene, meta-, para-, and ortho-xylene, and MTBE using Test Method TO-15 (as modified for air use); and for water vapor content.

*Engines/Air Compressor/Fire Water Engine*

51. The permittee shall operate each diesel engine (EUs: B11 and D02) with a nonresettable hour meter. *[AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

52. The permittee shall monitor the hours of operation of the diesel-powered fire water engine (EU: D02) and calculate monthly the annual hours of operation for testing and maintenance, plus a separate calculation for emergencies. *[AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

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53. The permittee shall operate the diesel-powered air compressor (EU: B11) with a nonresettable hour meter, monitor the duration of operation and calculate monthly the annual hours of operation. *[AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

*Cooling Tower*

54. The permittee shall monitor the TDS content of the cooling tower circulation water monthly using a conductivity meter (EU: H05). *[AQR 12.5.2.6(d); AQR 12.5.2.8(a)]*

*Piping and Fittings (EU: B06)*

55. The permittee shall monitor leaks from valves, flanges, pumps and VCU by conducting daily inspections. Detection methods incorporating sight, sound, or smell are acceptable. *[AQR 121.6.2(d)(1&2)]*

## 4.2 TESTING

*General*

1. The permittee shall comply with all applicable testing requirements in 40 CFR Part 60, Subparts A, Ka, Kb, and XX; 40 CFR Part 80; and 40 CFR Part 63, Subparts A, WW, and BBBBBB. *[AQR 12.5.2.8(a)]*

2. Performance testing is subject to 40 CFR Part 60.8, Subpart A, Appendix A (as amended) and the *Clark County Department of Air Quality Guideline for Source Testing (9/19/2019)*. Performance testing shall be the instrument for determining initial and subsequent compliance with the emission limitations set forth in this Part 70 OP and all related and/or relevant 40 CFR Part 60 and 63 subparts. *[MSP, September 10, 2013, Condition IV-B-10 and AQR 12.5.2.8(a)]*

3. The permittee shall submit to the Control Officer for approval a performance testing protocol that contains testing, reporting, and notification schedules, test protocols, and anticipated test dates no less than 45 days, but no more than 90 days, before the anticipated date of the performance test unless otherwise specified in this permit. *[AQR 12.5.2.8]*

4. The permittee shall submit to EPA for approval any alternative test methods not already approved to demonstrate compliance with a requirement under 40 CFR Part 60. *[40 CFR Part 60.8(b)]*

5. The Control Officer will consider approving the permittee's request for alternative performance test methods if it is proposed in writing in the performance test protocols. *[AQR 12.5.2.8(a)]*

6. At the Control Officer's request, the permittee shall provide necessary holes in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices, as may be necessary for proper determination of the emission of air contaminants. *[AQR 4.2]*

7. At the Control Officer's request, the permittee shall test (or have tests performed) to determine emissions of air contaminants from any source whenever the Control Officer has reason to believe that an emission in excess of those allowed by the AQRs is occurring. The

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Control Officer may specify testing methods to be used in accordance with good professional practice, and may observe the testing. All tests shall be conducted by reputable, qualified personnel. *[AQR 4.2]*

8. The permittee shall submit a report describing the results of each performance test to the Control Officer within 60 days of the end of the performance tests. *[MSP: September 10, 2013, Condition IV-B-10 and AQR 12.5.2.8(a)]*

9. The permittee of any stationary source that fails to demonstrate compliance with emissions standards or limitations during any performance test shall submit a compliance plan to the Control Officer within 90 days of the end of the performance test. *[AQR 10.1 and AQR 12.5.2.8(a)]*

10. The Control Officer may require additional performance testing when operating conditions appear inadequate to demonstrate compliance with the emissions and/or limitations in this permit. *[AQR 4.2 and AQR 12.5.2.8(a)]*

*Loading Racks: Vapor Recovery Unit*

11. The permittee shall determine compliance with emission limitations for all units controlled by the vapor recovery unit (EU: B02). *[AQR 121.6.3(c)]*

12. The permittee shall conduct subsequent performance tests on the JZVRU (EU: B02) at five-year intervals on dates that do not exceed 90 days past the anniversary date of the previous performance test. *[AQR 12.5.2.6 and AQR 121.6.3(a)]*

13. The permittee shall, immediately before the performance test on the JZVRU (EU: B02), use EPA Test Method 21 to monitor for vapor leakage at all potential sources in the terminal's vapor collection system equipment while a gasoline tank truck is being loaded. The owner or operator shall repair all leaks with readings of 500 ppm (as methane) or greater before conducting the performance test. *[AQR 12.5.2.6 and 40 CFR Part 63.11092(a)(1)(i)]*

14. The performance test shall be six hours long, during which at least 300,000 liters of gasoline shall be loaded. If 300,000 liters cannot be loaded in six hours, the test may either be continued until 300,000 liters of gasoline are loaded or resumed the next day with another complete six-hour period. If the test is resumed, the 300,000-liter criterion need not be met; however, as much as possible, testing should be conducted during the six-hour period in which the highest throughput normally occurs. *[40 CFR Part 60.503(b), 40 CFR Part 60.503(b)(1), and NSR ATC/OP 13, Modification 6, Condition III-F-6 (03/29/2004)]*

15. The permittee shall employ performance testing methodologies for the JZVRU (EU: B02) as indicated in Table 4-1.

**Table 4-1: Performance Testing Methods for John Zink VRU (EU: B02)**

| Test Criteria | EPA Test Method |
|---|---|
| Determination of VOC leaks (pre-test) | 21 |
| Stack parameters | 1–4 |
| Combustion vapor processing system | 2B |
| All other vapor processing systems | 2A |
| Determination of total organic compound concentrations | 25A, 25B, or 18 |

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*Soil Vapor Extraction and Groundwater Treatment System*

16. The permittee shall determine compliance with emission limitations for the groundwater treatment system (EU: SR04). *[AQR 121.6.3(c)]*

17. The permittee shall, when beginning to operate a combustion unit for either the soil vapor extraction or groundwater treatment system, conduct an initial performance test to demonstrate compliance with the control efficiencies and emission rates established in the OP. *[AQR 12.5.2.6 and AQR 121.6.3(b)]*

18. The permittee shall conduct subsequent performance tests on the combustion unit at five-year intervals on dates that do not exceed 90 days past the anniversary date of the previous performance test. *[AQR 12.5.2.6 and AQR 121.6.3(a)]*

19. The permittee shall employ performance testing methodologies for the soil vapor extraction and groundwater treatment systems as indicated in Table 4-2. *[AQR 12.5.2.6]*

**Table 4-2: Performance Testing Methods**

| Test Criteria | EPA Test Method |
|---|---|
| Stack parameters | 1–4 |
| Determination of total organic compound concentrations | 25A |

## 4.3 RECORDKEEPING

1. The permittee shall keep records of all inspections, maintenance, and repairs as required by this OP. *[AQR 12.5.2.6(d) and AQR 12.5.2.8]*

2. The permittee shall comply with all applicable recordkeeping requirements of 40 CFR Part 60.7; 40 CFR Part 60, Subparts Ka, Kb and XX; and 40 CFR Part 63, Subparts A, BBBBBB, and ZZZZ. *[AQR 12.5.2.6]*

3. All records, logs, etc., or copies thereof, shall be kept on-site for a minimum of five years from the date the measurement or data was entered. *[AQR 12.5.2.6(d) and AQR 12.5.2.8]*

4. Records and data required by this permit to be maintained by the permittee may be audited at any time by a third party selected by the Control Officer. *[AQR 4.1]*

5. At a minimum, the permittee shall create and maintain the records identified in Section 4.3.1, all of which must be producible on-site to the Control Officer's authorized representative upon request and without prior notice during the permittee's hours of operation. *[AQR 12.5.2.6(d) and AQR 12.5.2.8]*

6. The permittee shall maintain the following records for reporting: *[AQR 12.5.2.6(d) and AQR 12.5.2.8]*

*General*

a. Calendar year annual emissions for the entire source (annual report only);

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*Storage Tanks*

b. Monthly total throughput of individual tanks and sumps (EUs: A01–A61, B04, B05, D01, H02–H04, H06–H08, and H10–H18);

c. Monthly, consecutive 12-month total throughput of all tanks combined, including additives (EUs: A01–A61, B04, B05, D01, H02–H04, H06–H08, and H10–H18);

d. Monthly, consecutive 12-month average RVP of all combined fuel products;

e. For storage vessels complying with 40 CFR Part 63.11087(b), the storage vessel's Notice of Compliance Status information can be included in the next semiannual compliance report in lieu of filing a separate Notification of Compliance Status report under Part 63.11093; *[40 CFR Part 63.11095(c)(iv)]*

*Oil / Water Separator and Oil Storage Tank*

f. Weekly monitoring results and calculated efficiency of the carbon adsorber on the OSW (EUs: H11 and H12);

*Loading/Offloading Racks*

g. Monthly, consecutive 12-month total throughput of all products through the loading racks;

h. Monthly, consecutive 12-month total throughput of gasoline through the loading racks;

i. Monthly, consecutive 12-month total throughput of B-100 fuel through the offloading racks;

*Loading Racks: Auxiliary Flare*

j. Monthly, consecutive 12-month total hours of operation of the auxiliary flare (EU: B10) *[AQR 121.6.4(a)]*;

*Ethanol Unloading System*

k. Monthly, consecutive 12-month total throughput of ethanol through the unloading system;

*Haul Roads (EU: E01)*

l. Monthly, consecutive 12-month total number of trips of the haul trucks and calculated VMT separately for paved and unpaved roads;

*Soil Vapor Extraction and Groundwater Treatment System (EU: SR04)*

m. Weekly PID monitoring results on the inlet and exhaust vapor streams;

n. Quarterly accumulated mass emissions of VOC;

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*Diesel Engines*

o. Monthly, consecutive 12-month total hours of operation of diesel-powered air compressor (EU: B11);

p. Monthly and annual hours of operation of the diesel-powered fire water engine for testing, maintenance, and nonemergency use (EU: D02);

q. Monthly and annual hours of operation of the diesel-powered fire water engine for emergency use, including documentation justifying use during the emergency (EU: D02);

*CEMS*

r. CEMS audit results or accuracy checks, corrective actions, etc., as required by 40 CFR Part 60, Appendix F; 40 CFR Part 63; and the CEMS quality assurance (QA) plan *[AQR 121.6.4(b)(1)&(2)]*;

s. All CEMS information required by the CEMS monitoring plan, as specified in Section 4.1 of this permit *[AQR 121.6.4(b)(4)]*;

t. Time, duration, nature, and probable cause of any CEMS downtime, and any corrective actions taken *[AQR 121.6.4(b)(3)]*;

u. Each exceedance or failure to maintain, as appropriate, the monitored operating parameter values; monitoring data for the days on which exceedances or failures to maintain occurred; and a description and the timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CEMS; *[40 CFR Part 63.11095(b)(3)]*

v. Each instance in which malfunctions discovered during the required monitoring and inspections for the CEMS were not resolved according to the necessary corrective actions described in the monitoring and inspection plan. This report shall include a description of the malfunction and the timing of the steps taken to correct it. *[40 CFR Part 63.11095(b)(4)]*

*Other*

w. Each instance of a non-vapor-tight gasoline cargo tank loading at the facility in which the permittee failed to assure that the cargo tank would not reload before obtaining vapor tightness documentation for that cargo tank; *[40 CFR Part 63.11095(b)(1)]*

x. Each reloading of a non-vapor-tight gasoline cargo tank at the facility before obtaining vapor tightness documentation for that cargo tank in accordance with 40 CFR Part 63.1109(b); *[40 CFR Part 63.11095(b)(2)]*

y. The number, duration, and a brief description of each type of malfunction that occurred during the reporting period and that caused, or may have caused, any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with 40 CFR Part 63.11085(a), including actions

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taken to correct a malfunction. The report may be submitted as part of the semiannual compliance report, if one is required; *[40 CFR Part 63.11095(d)]*

z. Vapor recovery system testing results, if applicable (reported as required by Section 4-2);

aa. Deviations from permit requirements resulting in excess emissions (report as required by Section 4-4); and

bb. Deviations from permit requirements not resulting in excess emissions;

cc. If no excess emission events have occurred during the previous 6-month period, no report is required. *[40 CFR Part 63.11095(c)]*

7. The permittee shall maintain records of the following on-site: *[AQR 12.5.2.6(d) and AQR 12.5.2.8]*

*Storage Tanks*

a. Monthly RVP sampled for all fuel products in their respective tanks;

b. Records of all fuel types serviced by each tank, with corresponding service dates and gasoline vapor pressures (EUs: A01–A24, A27–A29, A45–A48, A56–A61, B04, B05, and D01);

c. Records of visual inspections on the storage tanks as required by Section 4.1 of this permit. These shall be kept on-site for a minimum for two years and include the following: *[40 CFR Part 60.115b and 40 CFR Part 63.11081(j)]*

i. The storage vessel on which the inspection was performed;

ii. The date the vessel was inspected; and

iii. The observed condition of each component of the control equipment (seals, floating roof, and fittings).

d. Records of measurements of seal gaps on applicable storage tanks as required by Section 4.1 of this permit (EUs: A01–A10), as follows:

i. Date of measurement;

ii. Raw data obtained in the measurement; and

iii. The calculations described in 40 CFR Part 60.113b(b).

e. The information specified in 40 CFR Parts 60.115b(a), 60.115b(b), or 60115b(c) (Subpart Kb) if complying with 2(a), 2(b), or 2(c) in Table 1 of 40 CFR Part 63, Subpart BBBBBB, depending upon the control equipment installed; the information specified in 40 CFR Part 63.1066 if complying with option 2(d) in Table 1; *[40 CFR Part 63.11095(a)(1)]*

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f. The number of equipment leaks not repaired within 15 days after detection; *[40 CFR Part 63.11095(a)(3)]*

g. Each equipment leak where no repair attempt was made within 5 days or for which a repair was not completed within 15 days after detection and excess emission resulted, including the following: *[40 CFR Part 63.11095(b)(5)]*

i. The date the leak was detected;

ii. The date of each attempt to repair the leak;

iii. The reasons for delaying the repair; and

iv. The date of successful repair.

*Loading/Offloading Racks*

h. For loading racks, documentation of each loading of a gasoline cargo tank for which vapor tightness documentations had not been previously obtained by the facility; *[40 CFR Part 63.11095(a)(2)]*

i. Daily inspections of loading lanes;

j. Monthly inspections of loading racks, along with vapor collection and processing systems;

k. Maintenance and repairs associated with daily and monthly inspections of loading racks and loading lanes;

l. Tanker trucks entered into the data system for vapor tightness certification;

*Loading Racks: Vapor Recovery Unit*

m. Exhaust gas flow rate from the VRU (EU: B02);

n. Hourly VOC concentrations from the VRU exhaust gas (EU: B02);

o. Four-hour average VOC concentrations from the VRU exhaust gas (EU: B02);

p. Five-year vapor leakage monitoring results on the VRU (EU: B02), including corrective actions;

q. Five-year performance testing results on the VRU (EU: B02), including corrective actions;

r. Annual RATA audit results, including corrective actions;

s. Daily, weekly, quarterly, and annual maintenance of the VRU, including dates and corrective actions;

t. Annual glycol solution sampling results;

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*Loading Racks: Auxiliary Flare*

u. Dates and times of operation of the auxiliary flare (EU: B10);

v. Visual inspections of the flame quality on the auxiliary flare (EU: B10) during operation, including dates, times, and corrective actions;

w. Maintenance and repairs on the auxiliary flare (EU: B10);

x. Saturator tank fluid testing results and corrective actions (EU: B10);

*Haul Roads (EU: E01)*

y. Daily the number of vehicle miles traveled on unpaved haul roads on-site by haul trucks entering and leaving;

z. Daily the number of vehicle miles traveled on paved haul roads on-site by haul trucks entering and leaving;

aa. Log of dust control measures applied to unpaved roads accessing or located on the site and in vacant areas;

*Soil Vapor Extraction and Groundwater Treatment System (EU: SR04)*

bb. Continuous hours of operation;

cc. Continuous flow rate of the exhaust gas;

dd. If a combustion unit is used for control, a continuous combustion chamber temperature in the combustion unit;

ee. Dates of the mode of operation;

ff. Calibration of the PID;

gg. Maintenance and repair of the PID;

hh. Bimonthly sampling results on inlet and exhaust vapor streams, including total flow rate;

ii. If a combustion unit is used for control, daily visible emissions observations from the combustion unit;

jj. Maintenance and repair of the soil vapor extraction and groundwater treatment system and of the combustion unit, when operated;

kk. If a combustion unit is used for control, monthly volume of auxiliary fuel used by the combustion unit (in square cubic feet);

ll. Hourly accumulated mass emissions of VOC;

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*Diesel Engines (EUs: A03 and A07)*

mm. Visual emissions check when operating the diesel fire water engine (EU: D02) and air compressor engine (EU: B11), including dates, observer names, locations, and results;

nn. Records of air compressor (EU: B11) and fire water engine (EU: D02) inspection/maintenance;

*Cooling Towers*

oo. Monthly TDS content of cooling tower circulation water (EU: H05);

*Other*

pp. Location changes of nonroad engines, if applicable;

qq. Quality assurance plan that contains auditing schedules, reporting schedules, and design specifications for the CEMS. The CEMS shall conform to applicable provisions of 40 CFR Part 60, Subpart GG and 40 CFR Part 75 (the plan must have been approved by the Control Officer);

rr. Log of visible emissions checks on all emission units, including the air compressor and the fire water engine;

ss. Log of thermocouple calibrations, maintenance, and operation;

tt. Magnitude and duration of excess emissions, notifications, monitoring system performance, malfunctions, corrective actions taken, etc. as required by 40 CFR Part 60.7; and

uu. Summary of results of all performance testing *[AQR 121.6.4(c)]*.

## 4.4 REPORTING AND NOTIFICATIONS

1. The permittee shall certify compliance with the terms and conditions contained in this Part 70 OP, including emission limitations, standards, work practices, and the means for monitoring such compliance. *[AQR 12.5.2.8(e)]*

2. The permittee shall submit compliance certifications annually in writing to the Control Officer (4701 W. Russell Road, Suite 200, Las Vegas, NV 89118) and the Region 9 Administrator (Director, Air and Radiation Division, 75 Hawthorne St., San Francisco, CA 94105). A compliance certification for each calendar year will be due on January 30 of the following year and shall include the following: *[AQR 12.5.2.8(e) and AQR 121.6.4(e)]*

   a. The identification of each term or condition of the permit that is the basis for the certification;

   b. The identification of the methods or other means used by the permittee for determining the status of compliance with each term and condition during the certification period. These methods and means shall include, at a minimum, the monitoring and related recordkeeping and reporting requirements described in 40 CFR Part 70.6(a)(3). If

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necessary, the permittee shall also identify any other material information that must be included in the certification to comply with Section 113(c)(2) of the Clean Air Act, which prohibits knowingly making a false certification or omitting material information; and

c. The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the methods or means designated in 2.b above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify, as possible exceptions to compliance, any periods during which compliance was required and in which an excursion or exceedance, as defined under 40 CFR Part 64, occurred.

d. The permittee shall submit:

i. A compliance schedule for meeting the requirements of 40 CFR Part 68 by the dates provided in Subpart 68.10(a) through (f) and 68.96(a) and (b)(2)(i), or

ii. As part of the compliance certification under 40 CFR 70.6(c)(5), a certification statement that the source is in compliance with all requirements of this part, including the registration and submission of the risk management plan.

3. The permittee shall report to the Control Officer any startup, shutdown, malfunction, emergency, or deviation that causes emissions of regulated air pollutants in excess of any limits set by regulations or this permit. The report shall be in two parts, as specified below: *[AQR 12.5.2.6(d)(4)(B); AQR 25.6.1]*

a. Within 24 hours of the time the permittee learns of the excess emissions, the permittee shall notify DAQ by phone at (702) 455-5942, by fax at (702) 383-9994, or by email at airquality@clarkcountynv.gov.

b. Within 72 hours of the notification required by 3.a ab ve, the permittee shall submit a detailed written report to DAQ containing the information required by AQR 25.6.3.

4. With the semiannual monitoring report, the permittee shall report to the Control Officer all deviations from permit conditions that do not result in excess emissions, including those attributable to malfunction, startup, or shutdown. Reports shall identify the probable cause of each deviation and any corrective actions or preventative measures taken. *[AQR 12.5.2.6(d)(4)(B)]*

5. The owner or operator of any source required to obtain a permit under AQR 12 shall report to the Control Officer emissions in excess of an applicable requirement or emission limit that pose a potential imminent and substantial danger to public health and safety or the environment as soon as possible, but no later than 12 hours after the deviation is discovered, and submit a written report within two days of the occurrence. *[AQR 25.6.2]*

6. The permittee shall submit all compliance certifications to EPA and the Control Officer. *[AQR 12.5.2.8(e)(4)]*

7. Any application form, report, or compliance certification submitted to the Control Officer pursuant to the permit or the AQRs shall contain a certification by a Responsible Official,

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with an original signature, of truth, accuracy, and completeness. This certification, and any other required under AQR 12.5, shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. *[AQR 12.5.2.6(l)]*

8. The permittee shall furnish to the Control Officer, in writing and within a reasonable time, any information that the Control Officer may request to determine whether cause exists for revising, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Control Officer copies of records that the permit requires keeping. The permittee may furnish records deemed confidential directly to the Administrator, along with a claim of confidentiality. *[AQR 12.5.2.6(g)(5)]*

9. At the Control Officer's request, the permittee shall provide any information or analyses that will disclose the nature, extent, quantity, or degree of air contaminants that are or may be discharged by the source, and the type or nature of control equipment in use. The Control Officer may require such disclosures be certified by a professional engineer registered in the state. In addition to this report, the Control Officer may designate an authorized agent to make an independent study and report on the nature, extent, quantity, or degree of any air contaminants that are or may be discharged from the source. An agent so designated may examine any article, machine, equipment, or other contrivance necessary to make the inspection and report. *[AQR 4.1]*

10. The permittee shall submit annual emissions inventory reports based on the following: *[AQR 18.6.1, AQR 12.5.2.4, and AQR 121.6.4(d)]*

    a. The annual emissions inventory must be submitted to DAQ by March 31 of each calendar year (if March 31 falls on a Nevada or federal holiday, or on any day the office is not normally open for business, the submittal shall be due on the next regularly scheduled business day);

    b. The calculated actual annual emissions from each emission unit shall be reported even if there was no activity, along with the total calculated actual annual emissions for the source based on the emissions calculation methodology used to establish the PTE in the permit or an equivalent method approved by the Control Officer prior to submittal; and

    c. As the first page of text, a signed certification containing the sentence: "I certify that, based on information and belief formed after reasonable inquiry, the statements contained in this document are true, accurate, and complete." This statement shall be signed and dated by a Responsible Official of the company (a sample form is available from DAQ).

11. Stationary sources that emit 25 tons or more of nitrogen oxide ($NO_x$) and/or 25 tons or more of VOC from their emission units, insignificant activities, and exempt activities during a calendar year shall submit an annual emissions statement for both pollutants. Emissions statements must include actual annual $NO_x$ and VOC emissions from all activities, including emission units, insignificant activities, and exempt activities. Emissions statements are separate from, and additional to, the calculated annual emissions reported each year for all regulated air pollutants (i.e., the emissions inventory). *[AQR 12.9.1]*

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12. The permittee shall comply with all applicable notification and reporting requirements of 40 CFR Part 60, Subparts A, K, Kb, and XX; 40 CFR Part 80; and 40 CFR Part 63, Subparts A, WW, and BBBBBB. *[AQR 12.5.2.6(d)]*

13. The permittee shall submit semiannual monitoring reports to DAQ. *[AQR 12.5.2.6(d) and AQR 12.5.2.8]*

14. The following requirements apply to semiannual reports: *[AQR 12.5.2.6(d) and AQR 12.5.2.8]*

    a. The report shall include all items listed in Section 4.3.6.

    b. The report shall be based on a calendar semiannual period, which includes partial reporting periods.

    c. The report shall be received by DAQ within 30 calendar days after the semiannual period.

15. Regardless of the date of issuance of this OP, the source shall comply with the schedule for report submissions outlined in Table 4-3. *[AQR 12.5.2.6(d) and AQR 12.5.2.8]*

**Table 4-3: Required Submission Dates for Various Reports**

| Required Report | Applicable Period | Due Date |
|---|---|---|
| Semiannual report for 1st six-month period | January, February, March, April, May, June | July 30 each year[1] |
| Semiannual report for 2nd six-month period; any additional annual records required | July, August, September, October, November, December | January 30 each year[1] |
| Annual Compliance Certification | Calendar year | January 30 each year[1] |
| Annual Emissions Inventory Report | Calendar year | March 31 each year[1] |
| Annual Emissions Statement[2] | Calendar year | March 31 each year[1] |
| Notification of Malfunctions, Startup, Shutdowns, or Deviations with Excess Emission | As required | Within 24 hours of the permittee learns of the event |
| Excess Emissions that Pose a Potential Imminent and Substantial Danger | As required | No less than 45 days, but no more than 90 days, before the anticipated test date[1] |
| Report of Malfunctions, Startup, Shutdowns, or Deviations with Excess Emission | As required | Within 72 hours of the notification[1] |
| Deviation Report without Excess Emissions | As required | Along with semiannual reports[1] |
| Performance Testing Protocol | As required | No less than 45 days, but no more than 90 days, before the anticipated test date[1] |
| Performance Testing Results | As required | Within 60 days of end of test[1] |

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| Required Report | Applicable Period | Due Date |
|---|---|---|
| RATA Protocol | As required | No less than 45 days, but no more than 90 days, before the anticipated test date[1] |
| RATA Results | As required | Within 60 days of end of test[1] |

[1] If the due date falls on a state or federal holiday, or on any day the office is not normally open for business, the submittal is due on the next business day.
[2] Required only for stationary sources that emit 25 tons or more of $NO_x$ and/or 25 tons or more of VOC during a calendar year.

16. The Control Officer reserves the right to require additional reporting to verify compliance with permit emission limits, applicable permit requirements, and requirements of applicable federal regulations. *[AQR 4.1]*

## 4.5 MITIGATION

*Offsets*

The source has no federal offset requirements. *[AQR 12.7]*

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# *5.0 PERMIT SHIELD*

*Permit Shield*

1. The source has not requested a permit shield. *[AQR 12.5.2.9]*

*Streamlining (Requirements Specifically Identified as Applicable)*

2. The source has not requested a permit shield for any of the applicable requirements. However, the following requirements have been streamlined for the VRU (EU: B02); the most stringent requirements have been included in the permit.

3. The applicable requirements have been streamlined for DAQ convenience. *[AQR 12.5.2.9]*

**Table 5-1: Applicable Requirements Streamlined**

| EU | Reg. (40 CFR Part) | Reg. Std. | Permit Limit | Value Comparison (in Units of Permit Limit) | | | |
|---|---|---|---|---|---|---|---|
| | | | | Std. Value | Permit Limit Value | Permit Limit as or More Stringent? | Permit Limit as or More Stringent? |
| B02 | 63.11092(a)(2) | 80 mg/L | 2.4 mg/L | 80 mg/L | 2.4 mg/L | Yes | Yes |
| | 60.502 | 35 mg/L | 2.4 mg/L | 35 mg/L | 2.4 mg/L | Yes | Yes |

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## *6.0 OTHER REQUIREMENTS*

1. Any person who violates any provision of the AQRs, including, but not limited to, any application requirement; any permit condition; any fee or filing requirement; any duty to allow or carry out inspection, entry, or monitoring activities; or any requirements from DAQ is guilty of a civil offense and shall pay a civil penalty levied by the Air Pollution Control Hearing Board and/or the Hearing Officer of not more than $10,000. Each day of violation constitutes a separate offense. *[AQR 9.1; NRS 445B.640]*

2. Any person aggrieved by an order issued pursuant to AQR 9.1 is entitled to review, as provided in Chapter 233B of the NRS. *[AQR 9.12]*

3. The permittee shall comply with the requirements of 40 CFR Part 61, Subpart M—the National Emission Standard for Asbestos—for all demolition and renovation projects. *[AQR 13.1(b)(8)]*

4. The permittee shall not use, sell, or offer for sale any fluid as a substitute material for any motor vehicle, residential, commercial, or industrial air conditioning system, refrigerator freezer unit, or other cooling or heating device designated to use a chlorofluorocarbon or hydrochlorofluorocarbon compound as a working fluid unless such fluid has been approved for sale in such use by the Administrator. The permittee shall keep records of all paperwork relevant to the applicable requirements of 40 CFR Part 82 on-site. *[40 CFR Part 82]*

5. A risk management plan is required for the storing, handling and use of any applicable "Highly Hazardous Chemical" pursuant to 40 CFR Part 68. The permittee shall submit revisions of the risk management plan to the appropriate authority and a copy to DAQ. *[40 CFR Part 68.215 (a)(1)]*

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# *7.0 ADMINISTRATIVE REQUIREMENTS*

## 7.1 GENERAL

1. The permittee shall comply with all conditions of the Part 70 OP. Any permit noncompliance may constitute a violation of the Clark County Air Quality Regulations (AQRs), Nevada law, and the Clean Air Act, and is grounds for enforcement action; for permit termination, revocation and reissuance, or revision; or for denial of a renewal application. *[AQR 12.5.2.6(g)(1)]*

2. If any term or condition of this permit becomes invalid as a result of a challenge to a portion of this permit, the other terms and conditions of this permit shall be unaffected and remain valid. *[AQR 12.5.2.6(f)]*

3. The permittee shall pay all permit fees pursuant to AQR 18. *[AQR 12.5.2.6(h)]*

4. This permit does not convey property rights of any sort, or any exclusive privilege. *[AQR 12.5.2.6(g)(4)]*

5. The permittee agrees to allow inspection of the premises to which this permit relates by any authorized representative of the Control Officer at any time during the permittee's hours of operation without prior notice. The permittee shall not obstruct, hamper, or interfere with any such inspection. *[AQR 4.1; AQR 5.1.1; and AQR 12.5.2.8(b)]*

6. The permittee shall allow the Control Officer, upon presentation of credentials, to: *[AQR 4.1 and AQR 12.5.2.8(b)]*

    a. Access and copy any records that must be kept under the conditions of the permit;

    b. Inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit;

    c. Sample or monitor substances or parameters for the purpose of assuring compliance with the permit or applicable requirements; and

    d. Document alleged violations using such devices as cameras or video equipment.

7. Any permittee who fails to submit relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit the needed supplementary facts or corrected information. In addition, the permittee shall provide additional information as necessary to address any requirements that become applicable to the source after the date a complete application was filed but prior to release of a draft permit. A Responsible Official shall certify the additional information consistent with the requirements of AQR 12.5.2.4. *[AQR 12.5.2.2]*

8. Anyone issued a permit under AQR 12.5 shall post it in a location where it is clearly visible and accessible to facility employees and DAQ representatives. *[AQR 12.5.2.6(m)]*

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9. The permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[AQR 12.5.2.6(g)(2)]*

## 7.2 MODIFICATION, REVISION, AND RENEWAL REQUIREMENTS

1. No person shall begin actual construction of a new Part 70 source, or modify or reconstruct an existing Part 70 source that falls within the preconstruction review applicability criteria, without first obtaining an ATC Permit from the Control Officer. *[AQR 12.4.1.1(a)]*

2. This permit may be revised, revoked, reopened and reissued, or terminated for cause by the Control Officer. The filing of a request by the permittee for a permit revision, revocation, reissuance, or termination, or of a notification of planned changes or anticipated noncompliance, does not stay any permit condition. *[AQR 12.5.2.6(g)(3)]*

3. The permit shall be reopened under any of the following circumstances and when all applicable requirements pursuant to AQR 12.5.2.15 are met: *[AQR 12.5.2.15(a)]*

    a. New applicable requirements become applicable to a stationary source considered "major" (per the definition in AQR 12.2, AQR 12.3, or 40 CFR Part 70.3(a)(1)) with a remaining permit term of three or more years;

    b. Additional requirements (including excess emissions requirements) become applicable to an affected source under the Acid Rain Program;

    c. The Control Officer or EPA determines that the permit contains a material mistake, or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or

    d. The Administrator or Control Officer determines that the permit must be revised or revoked to assure compliance with applicable requirements.

4. A permit, permit revision, or permit renewal may be approved only if all the following conditions have been met: *[AQR 12.5.2.10(a)]*

    a. The permittee has submitted to the Control Officer a complete application for a permit, permit revision, or permit renewal, except that a complete application need not be received before a Part 70 general permit is issued pursuant to AQR 12.5.2.20; and

    b. The conditions of the permit provide for compliance with all applicable requirements and the requirements of AQR 12.5.

5. The permittee shall not build, erect, install, or use any article, machine, equipment, or other contrivance, the use of which, without resulting in a reduction in the total release of air contaminants to the atmosphere, reduces or conceals an emission that would otherwise constitute a violation of an applicable requirement. *[AQR 80.1 and 40 CFR Part 60.12]*

6. No permit revisions shall be required under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes for changes that are provided for in the permit. *[AQR 12.5.2.6(i)]*

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7. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application has been submitted. *[AQR 12.5.2.11(b)]*

8. For purposes of permit renewal, a timely application is a complete application that is submitted at least 6 months, but not more than 18 months, prior to the date of permit expiration. If a source submits a timely application under this provision, it may continue operating under its current Part 70 OP until final action is taken on its application for a renewed Part 70 OP. *[AQR 12.5.2.1(a)(2)]*

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# *8.0 ATTACHMENTS*

## 8.1 APPLICABLE REGULATIONS

*Requirements Specifically Identified as Applicable*

1. NRS, Chapter 445B.

2. Applicable AQRs listed in Table 8-1.

**Table 8-1: Applicable Clark County AQRs**

| Citation | Title |
|---|---|
| AQR 00 | "Definitions" |
| AQR 04 | "Control Officer" |
| AQR 05 | "Interference with Control Officer" |
| AQR 08 | "Persons Liable for Penalties – Punishment: Defense" |
| AQR 09 | "Civil Penalties" |
| AQR 10 | "Compliance Schedules" |
| AQR 11 | "Ambient Air Quality Standards" |
| AQR 12.0 | "Applicability and General Requirements" |
| AQR 12.4 | "Authority to Construct Application and Permit Requirements for Part 70 Sources" |
| AQR 12.5 | "Part 70 Operating Permit Requirements" |
| AQR 12.9 | "Annual Emissions Inventory Requirement" |
| AQR 13 | "National Emission Standards for Hazardous Air Pollutants" |
| AQR 14.1(b)(1) | "Subpart A – General Provisions" |
| AQR 18 | "Permit and Technical Service Fees" |
| AQR 25 | "Affirmative Defense for Excess Emissions due to Malfunctions, Startup, and Shutdown" |
| AQR 26 | "Emission of Visible Air Contaminants" |
| AQR 28 | "Fuel Burning Equipment" |
| AQR 40 | "Prohibitions of Nuisance Conditions" |
| AQR 41 | "Fugitive Dust", AQR 41.1.2 only |
| AQR 42 | "Open Burning" |
| AQR 43 | "Odors in the Ambient Air" |
| AQR 50 | "Storage of Petroleum Products" |
| AQR 51 | "Petroleum Product Loading into Tank Trucks and Trailers" |
| AQR 70 | "Emergency Procedures" |
| AQR 80 | "Circumvention" |

3. Clean Air Act Amendments (42 U.S.C. § 7401, et seq.)

4. Applicable 40 CFR sections are listed in Table 8-2.

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**Table 8-2: Federal Standards**

| Citation | Title |
|---|---|
| 40 CFR Part 52.21 | "Prevention of significant deterioration of air quality" |
| 40 CFR Part 52.1470 | "Approval and Promulgation of Implementation Plans, Subpart DD—Nevada" |
| 40 CFR Part 60, Subpart A | "General Provisions" |
| 40 CFR Part 60, Appendix A | Appendix A, Method 9 or equivalent (opacity) |
| 40 CFR Part 60, Appendix A-3 | "Test Methods 4 through 5I" (PM in grams/dry standard cubic meter) |
| 40 CFR Part 60, Appendix A-4 | "Test Methods 6 through 10B" (opacity) |
| 40 CFR Part 60, Subpart K | "Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978" |
| 40 CFR Part 60, Subpart Kb | "Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984" |
| 40 CFR Part 60, Subpart XX | "Standards of Performance for Bulk Gasoline Terminals" |
| 40 CFR Part 63, Subpart A | "General Provisions" |
| 40 CFR Part 63, Subpart BBBBBB | "National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities" |
| 40 CFR Part 63, Subpart WW | "National Emission Standards for Storage Vessels (Tanks) - Control Level 2" |
| 40 CFR Part 63, Subpart ZZZZ | "National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines" |
| 40 CFR Part 68, Subpart G | Risk Management Plan |
| 40 CFR Part 70 | "State Operating Permit Programs" |
| 40 CFR Part 82 | "Protection of Stratospheric Ozone" |

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# ATTACHMENT 5B: Calnev Pipeline LVT Supplemental

RECEIVED CC DAQ
2025 SEP 18 AM11:00

RECEIVED CC DAQ
2025 SEP 18 AM11:00

KINDER MORGAN
CALNEV PIPE LINE LLC

September 17, 2025

Mr. Michael Rael
Air Quality Supervisor
Clark County DAQ
4701 West Russell Road
Suite 200
Las Vegas NV 89118-2231

**RE: 2025 RACT Requirements Review**
**Calnev Pipe Line, LLC – Las Vegas Terminal, Part 70 Permit Number 13**
**5049 North Sloan Lane, Las Vegas, NV 89115**

Dear Mr. Rael:

Please find enclosed the response to the September 8, 2025 letter regarding New Source Performance Standard (NSPS) Subpart Kc and Calnev Pipe Line, LLC Las Vegas Terminal's (Calnev) Reasonably Available Control Technology (RACT).

Per the September 8, 2025 letter, Air Quality Regulation (AQR) 120.5(c) requires RACT determinations submitted within the past 36 months to continue to be RACT because there are no changes to the available control technologies, technical feasibility, control effectiveness, cost-effectiveness, or environmental, energy, or other impacts since that determination was initially performed. The letter also notes that since NSPS Subpart Kc was updated after the October 2022 RACT determination, it should be included in the current RACT submittal. The letter also notes that NSPS Subpart Kc, does not apply to Calnev, since the facility has not commenced construction, reconstruction, or modification of any applicable volatile organic liquid storage vessel after October 4, 2023.

As part of the evaluation of NSPS Kc, Calnev conducted a review of the NSPS Subpart Kc rule text, including the preamble as located in 89 FR 83296, originally published October 15, 2024 and a memorandum from the United States Environmental Protection Agency (USEPA) titled "Control Options for Storage Vessels (Docket ID No. EPA-HQ-OAR-2023-0358-0002)."

In the preamble text of NSPS Subpart Kc, the USEPA finalized standards which reflect the best source of emission reduction (BSER), which is the equivalent of the best available control technology (BACT) and stated that the final standards are consistent with the determinations explained in the rulemaking proposal (88 FR 68540-47; October 4, 2023), and the analysis in the Control Options for Storage Vessels memo. Under NSPS Subpart Kc, USEPA proposed emission controls based on vapor pressure thresholds and vessel size with an emission reduction cost of

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**(713) 369-9000 Fax (713) 420-1603**

approximately $6,000 and $7,000 dollars per ton of volatile organic compounds (VOCs) reduced respectively. To meet these thresholds, EPA proposed multiple different options with varying levels of control and cost. These options are described in detail below:

| **Detailed IFR Storage Vessel Parameters for each tank configuration.** | | | | |
|---|---|---|---|---|
| **Input Parameter** | **IFR-Kb** | **IFR-1** | **IFR-2** | **IFR-3** |
| **Tank Construction** | Welded | Welded | Welded | Welded |
| **Tank Surface Color** | Gray, Light | Gray, Light | Gray, Light | Gray, Light |
| **Tank Surface Condition** | Average | Average | Average | Average |
| **Shell Condition** | Light Rust | Light Rust | Light Rust | Light Rust |
| **Roof Support** | Self Supported | Self Supported | Self Supported | Self Supported |
| **Column Type** | N/A | N/A | N/A | N/A |
| **Seal Fit** | Average | Average | Average | Average |
| **Deck Type** | Bolted | Bolted | Bolted | *Welded* |
| **Deck Construction** | Panel - 5 x 7.5 ft rectangular | Panel - 5 x 7.5 ft rectangular | Panel - 5 x 7.5 ft rectangular | *N/A* |
| **Primary Seal** | Mechanical Shoe | Mechanical Shoe | Mechanical Shoe | Mechanical Shoe |

| | | | | |
|---|---|---|---|---|
| **Secondary Seal** | None | Rim mounted | Rim mounted | Rim mounted |
| **Access Hatch** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Guidepoles** | Slotted guidepole/sample well, gasketed sliding cover, with float and pole wiper | Slotted guidepole/sample well, gasketed sliding cover, with float and pole wiper | Slotted guidepole/sample well, gasketed sliding cover, with float and pole wiper | *Slotted guidepole/sample well, gasketed sliding cover, with pole sleeve and pole wiper* |
| **Gauge-float well** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Gauge-hatch/Sample Port** | Slit fabric seal, 10% open area | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Vacuum Breaker** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Deck Leg** | Adjustable | Adjustable | *Fixed* | Fixed |
| **Rim Vent** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |

Of the options listed above, it was determined that the IFR-Kb & IFR-1 options met the definition of BSER/BACT. As a base line, the USEPA evaluated additional IFR storage vessel configurations including the following for new or reconstructed storage vessels with a maximum true vapor pressure less than 11.1 psia:

- Baseline: NSPS Subpart Kb control requirements (with NSPS Subpart Kc proposed lower vapor pressure thresholds).

- Option IFR-1. NSPS Subpart Kb, but primary seal must be either liquid-mounted or mechanical shoe seal and must have a rim-mounted secondary seal.

- Option IFR-2. Option 1 requirements while requiring fixed roof legs or cable suspended roof (cannot have adjustable roof legs that penetrate through the floating roof)

- Option IFR-3. Option 2 requirements + requiring welded seams and best guidepole fittings.

All three of the listed options above also include provisions for requiring gauge-hatches/sample ports to be gasketed. It was determined that all of the IFR control options, BSER for vessels with a vapor pressure less than 11.1 psia is option IFR-1. Specifically, EPA proposed to require that the primary seal must either be liquid-mounted or mechanical shoe seal and must have a rim-mounted secondary seal, that gauge-hatches/sample ports to be gasketed, and that guide pole configurations incorporate the provisions outlined in the 2000 EPA Storage Tank Emission Reduction Partnership Program (STERPP) as the BSER.

For modified storage vessels, EPA assumed that modified storage vessels will have existing fixed roofs, because IFRs were not previously required by NSPS Subpart Kb. The costs of retrofitting a fixed roof storage vessel with an IFR are approximately the same as the cost of adding an IFR to a new storage vessel. Whereas some "modified" storage vessels that trigger into the NSPS, may already have an IFR, and upgrading only certain elements of the IFR can have significantly different costs than when installing a new IFR. Therefore, the BSER for modified storage vessels is separate depending on whether or not the vessel had existing IFRs prior to modification. Ultimately, it was determined that Option IFR-1 is the BSER for existing storage vessels with a maximum TVP less than 11.1 psia that modify and do not have an existing floating roof. However, for storage vessels with an existing IFR, the NSPS Subpart Kb control requirements without upgrading the rim seal requirements represent the application of BSER and EPA proposed to retain those standards for sources in NSPS Subpart Kc.

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For newly constructed/reconstructed external floating roof tanks, the US EPA proposed the following configurations:

| External Floating Roof vessel parameters for each tank configuration | | | | |
|---|---|---|---|---|
| **Input Parameter** | **EFR-Kb** | **EFR-1** | **EFR-2** | **EFR-3** |
| **Tank Surface Color** | Gray, Light | Gray, Light | Gray, Light | Gray, Light |
| **Tank Surface Condition** | Average | Average | Average | Average |
| **Internal Shell Condition** | Light Rust | Light Rust | Light Rust | Light Rust |
| **Roof Type** | Pontoon | Pontoon | Pontoon | Pontoon |
| **Tank Construction** | Welded | Welded | Welded | Welded |
| **Deck Construction** | Welded | Welded | Welded | Welded |
| **Seal Fit** | Average | Average | Average | Average |
| **Primary Seal** | Mechanical Shoe | Mechanical Shoe | *Liquid-mounted* | Liquid-mounted |
| **Secondary Seal** | Rim-Mounted | Rim-Mounted | Rim-Mounted | Rim-Mounted |

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| | | | | |
|---|---|---|---|---|
| **Access Hatch** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Guidepoles** | Slotted Guidepole/sample well, gasketed sliding cover, with float and pole wiper | *Unslotted guidepole and well, gasketed sliding cover w/ pole wiper* | *Slotted guidepole/sample well, gasketed sliding cover, with pole sleeve and pole wiper* | *Unslotted guidepole and well, gasketed sliding cover w/ pole wiper* |
| **Gauge-float well** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Gauge-hatch/sample port** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Vacuum Breaker** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Deck Leg (pontoon area of pontoon roofs)** | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed |
| **Deck Leg (double deck roofs and center area of pontoon roofs)** | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed |
| **Rim Vent** | Weighted mechanical | Weighted mechanical | Weighted mechanical | Weighted mechanical |

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| | | | | |
|---|---|---|---|---|
| | actuation, gasketed | actuation, gasketed | actuation, gasketed | actuation, gasketed |

For existing EFR storage vessels, like existing IFR storage vessels, improvements to the floating roof and guidepole design would not result in significant additional emission reductions beyond those achieved by the use of the EFR itself. As a result, for NSPS Subpart Kc, it was determined that if a modified tank has an existing EFR, the BSER and standard of performance is consistent with the EFR requirements in NSPS Subpart Kb.

Further information and analysis from the tables is provided in Attachments A & B.

The other control technology that is referenced in NSPS Subpart Kc is a closed vent system routed to a control device, fuel gas system, or process. Calnev does not utilize this method of control since this method generally applies to storage vessels storing an organic liquid with a true maximum vapor pressure of 11.1 psia or greater.

Based on this information, the US EPA is not proposing any new reasonably available control technologies in NSPS Subpart Kc, but is instead restating that for existing sources, the control requirements found in NSPS Subpart Kb are sufficient to meet BSER/BACT. In addition, it should be noted that there is currently an active petition for reconsideration and request for administrative stay of NSPS Subpart Kc (Case Nos.: 24-1377 and 24-1379). See Attachment C.

If you have any questions, please contact Seth Tate at (713) 420-6076 or via email at Seth_Tate@KinderMorgan.com.

In accordance with Section 120.5(c), I certify that based on information and belief formed after reasonable inquiry, the attached determination continues to represent the reasonably available control technology (RACT) requirements. There have been no changes to available control technologies, technical feasibility, control effectiveness, cost-effectiveness, or environmental, energy, and other impacts since the original determination.

Duncan Sinclair
Director of Operations
For Calnev Pipe Line, LLC

**FEDEX Tracking No.: 3932 7457 9136**

Cc: Troy Otramba, Jeremy Shenk, Nina McAfee, Seth Tate – Calnev Pipe Line LLC.

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Enclosures:

A. Relevant Portions of 88 Federal Register 68535 dated October 4, 2023 "Proposed Rules"
B. "Control Options for Storage Vessels" dated August 11, 2023
C. ILTA & ACC Petitions for Reconsideration (Case Nos.: 24-1377 & 24-1379)

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# Attachment A

Relevant Portions of 88 Federal Register 68535 dated October 4, 2023 "Proposed Rules"

## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Part 60

**[EPA–HQ–OAR–2023–0358; FRL–10655–01–OAR]**

**RIN 2060–AV93**

## New Source Performance Standards Review for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Proposed rule.

**SUMMARY:** The Environmental Protection Agency (EPA) is proposing amendments to the Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) as the preliminary results of the review of the New Source Performance Standards (NSPS) required by the Clean Air Act. The EPA is proposing revisions to the NSPS that are applicable to volatile organic liquid (VOL) storage vessels that commence construction, reconstruction, or modification after October 4, 2023 under a new NSPS subpart. In the new NSPS subpart, the EPA is proposing to reduce the vapor pressure applicability thresholds In addition, the EPA is proposing to revise the volatile organic compound (VOC) standards to reflect the best system of emissions reductions (BSER) for affected storage vessels. We are also proposing additional monitoring and operating requirements to ensure continuous compliance with the standard. In addition, the EPA is proposing degassing emission controls; clarification of startup, shutdown, and malfunction requirements; requirements for electronic reporting; and other technical improvements. The EPA is also proposing to amend NSPS subpart Kb to apply to VOL storage vessels that commence construction, reconstruction or modification after July 23, 1984 and on or before October 4, 2023 and to add electronic reporting requirements.

**DATES:**

*Comments.* Comments must be received on or before November 20, 2023. Comments on the information collection provisions submitted to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (PRA) are best assured of consideration by OMB if OMB receives a copy of your comments on or before November 3, 2023.

*Public Hearing.* If anyone contacts us requesting a public hearing on or before October 10, 2023, we will hold a virtual hearing. Please refer to the **SUPPLEMENTARY INFORMATION** for information on requesting and registering for a public hearing.

**ADDRESSES:** You may send comments, identified by Docket ID No. EPA–HQ–OAR–2023–0358, by any of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2023–0358 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2023–0358.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2023–0358, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal Holidays).

*Instructions:* All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov,* including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section of this document.

**FOR FURTHER INFORMATION CONTACT:** For questions about this proposed action, contact U.S. EPA, Attn: Michael Cantoni, Mail Drop: E143–01, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711; telephone number: (919) 541–5593; and email address: *Cantoni.Michael@epa.gov.*

**SUPPLEMENTARY INFORMATION:**

*Participation in virtual public hearing.* To request a virtual public hearing, contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.* If requested, the virtual hearing will be held on October 19, 2023. The hearing will convene at 11:00 a.m. Eastern Time (ET) and will conclude at 3:00 p.m. ET. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will announce further details at *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum.*

If a public hearing is requested, the EPA will begin pre-registering speakers for the hearing no later than 1 business day after the publication of this document in the **Federal Register**. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum* or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.* The last day to pre-register to speak at the hearing will be October 16, 2023. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers at: *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to submit a copy of their oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum.* While the EPA expects the hearing to go forward as described in this section, please monitor our website or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of a translator or a special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by October 11, 2023. The EPA may not be able to arrange accommodations without advanced notice.

*Docket.* The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2023–0358. All

documents in the docket are listed in the *Regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy.

*Written Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2023–0358, at *https://www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to EPA's docket at *https://www.regulations.gov* any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed in the *Submitting CBI* section of this document.

Multimedia submissions (audio, video, *etc.*) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the Web, cloud, or other file sharing system). Please visit *https://www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI or multimedia submissions; and general guidance on making effective comments.

The *https://www.regulations.gov* website allows you to submit your comment anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *https://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses.

*Submitting CBI.* Do not submit information containing CBI to the EPA through *https://www.regulations.gov.* Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, note the docket ID, mark the outside of the digital storage media as CBI, and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in the *Written Comments* section of this document. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the docket ID. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings and note the docket ID. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. If sending CBI information through the postal service, please send it to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404–02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711, Attention Docket ID No. EPA–HQ–OAR–2023–0358. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

*Preamble acronyms and abbreviations.* Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

API American Petroleum Institute
ASTM American Society for Testing and Materials
BSER best system of emission reduction
CAA Clean Air Act
CBI Confidential Business Information
CDX Central Data Exchange
CE cost effectiveness
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
EFR external floating roof
EIA economic impact analysis
EJ environmental justice
EPA Environmental Protection Agency
ET Eastern Time
FR Federal Register
HAP hazardous air pollutant(s)
ICE incremental cost effectiveness
ICR information collection request
IFR internal floating roof
kPa kilopascals
LEL lower explosive limit
$m^3$ cubic meters
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PRA Paperwork Reduction Act
psia pounds per square inch absolute
psig pounds per square inch gauge
RFA Regulatory Flexibility Act
RIN Regulatory Information Number
SCAQMD South Coast Air Quality Management District
SSM startup, shutdown, and malfunctions
TAC total annualized cost
TCI total capital investment
tpy tons per year
UMRA Unfunded Mandates Reform Act
U.S.C. United States Code
VOC volatile organic compound(s)
VOL volatile organic liquid(s)

*Organization of this document.* The information in this preamble is organized as follows:

**I. General Information**
A. Does this action apply to me?
B. Where can I get a copy of this document and other related information?
II. Background
A. What is the statutory authority for this action?
B. What is this source category and what are the current NSPS requirements?
C. How does the EPA perform the NSPS review?
D. What data and information were used to support this action?
III. What actions are we proposing?
A. What vapor pressure applicability thresholds are we proposing and why?

B. What other changes to applicability are we proposing and why?
C. What are the proposed BSER and compliance alternatives for newly constructed, modified, and reconstructed storage vessels?
D. What is the BSER and standard of performance for new and reconstructed storage vessels with maximum true vapor pressures less than 11.1 psia?
E. What compliance alternatives are available for new and reconstructed storage vessels with maximum true vapor pressures less than 11.1 psia?
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G. What actions constitute a modification for storage vessels and why?
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I. What control requirements are we proposing for IFR and EFR storage vessels emptying and degassing and why?
J. What requirements are we proposing for storage vessel testing, monitoring, and inspections and why?
K. Proposal of NSPS subpart Kc without startup, shutdown, and malfunction exemptions
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N. Compliance Dates
IV. Summary of Cost, Environmental, and Economic Impacts
A. What are the air quality impacts?
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E. What analysis of environmental justice did we conduct?
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D. Unfunded Mandates Reform Act (UMRA)
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F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51
J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

## I. General Information

### *A. Does this action apply to me?*

The source category that is the subject of this proposal is composed of VOL storage vessels regulated under Clean Air Act (CAA) section 111, New Source Performance Standards. The 2022 North American Industry Classification System (NAICS) codes for this source category are 325, 324, and 422710. The NAICS codes serve as a guide for readers outlining the entities that this proposed action is likely to affect. The proposed standards, once promulgated, will be directly applicable to affected facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Federal, State, local and Tribal government entities that own and/or operate storage vessels would be affected by this action.

### *B. Where can I get a copy of this document and other related information?*

In addition to being available in the docket, an electronic copy of this action is available on the internet at *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposal and key technical documents at this same website.

A memorandum showing the edits that would be necessary to incorporate the changes to 40 CFR part 60, subparts Kb and Kc proposed in this action is available in the docket (Docket ID No. EPA–HQ–OAR–2023–0358). Following signature by the EPA Administrator, the EPA also will post a copy of this document to *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum.*

## II. Background

### *A. What is the statutory authority for this action?*

The EPA's authority for this proposed rule is CAA section 111, which governs the establishment of standards of performance for stationary sources. Section 111(b)(1)(A) of the CAA requires the EPA Administrator to list categories of stationary sources that in the Administrator's judgment cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for new (and modified or reconstructed) sources in each source category pursuant to CAA section 111(b)(1)(B). These standards are referred to as new source performance standards, or NSPS. The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, set the emission level of the standards, and distinguish among classes, types, and sizes within categories in establishing the standards.

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years review and, if appropriate, revise" new source performance standards. However, the Administrator need not review any such standard if the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an existing performance standard, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." The term "standard of performance" in CAA section 111(a)(1) makes clear that the EPA is to determine both the best system of emission reduction (BSER) for the regulated sources in the source category and the degree of emission limitation achievable through application of the BSER. The EPA must then, under CAA section 111(b)(1)(B), promulgate standards of performance for new sources that reflect that level of stringency. CAA section 111(b)(5) generally precludes the EPA from prescribing a particular technological system that must be used to comply with a standard of performance. Rather, sources can select any measure or combination of measures that will achieve the standard. CAA section 111(h)(1) authorizes the Administrator to promulgate "a design, equipment, work practice, or operational standard, or combination thereof" if in his or her judgment, "it is not feasible to prescribe or enforce a standard of performance." CAA section 111(h)(2) provides the circumstances under which prescribing or enforcing a standard of performance is "not feasible," such as, when the pollutant

cannot be emitted through a conveyance designed to emit or capture the pollutant, or when there is no practicable measurement methodology for the particular class of sources.

Pursuant to the definition of new source in CAA section 111(a)(2), standards of performance apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Under CAA section 111(a)(4), "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Changes to an existing facility that do not result in an increase in emissions are not considered modifications. Under the provisions in 40 CFR 60.15, reconstruction means the replacement of components of an existing facility such that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

*B. What is this source category and what are the current NSPS requirements?*

The EPA promulgated NSPS subpart K, specific to storage vessels for petroleum liquids, in 1974 (39 FR 9317, March 8, 1974). These standards were amended several times before 1980, when EPA proposed to establish revised NSPS for storage vessels for petroleum liquids as NSPS subpart Ka (45 FR 23379, April 4, 1980). In 1982, the EPA published a list of priority sources for which additional NSPS should be established (47 FR 951, January 8, 1982), and VOL storage vessels at synthetic organic chemical manufacturers were included in the priority list. Pursuant to the EPA's authority under CAA section 111, the Agency proposed (49 FR 29698, July 23, 1984) and promulgated (52 FR 11420, April 8, 1987) NSPS for volatile organic liquid storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction, or modification commenced after July 23, 1984, as NSPS subpart Kb.[1] NSPS subpart Kb regulates storage vessels with a capacity of 75 cubic meters ($m^3$) (~20,000 gallons) or more that store VOLs with a true vapor pressure over 15.0 kilopascals (kPa) (~2.18 psia), and from storage vessels with a capacity of 151 $m^3$ (~40,000 gallons) or more that store organic liquids with a true vapor pressure over 3.5 kPa (~0.51 psia). VOC emissions controls are required on storage vessels with a capacity of 75 cubic meters ($m^3$) (~20,000 gallons) or more that store VOLs with a true vapor pressure over 27.6 KPa (~4.0 psia), and from storage vessels with a capacity of 151 $m^3$ (~40,000 gallons) or more that store organic liquids with a true vapor pressure over 5.2 kPa (~0.75 psia). NSPS subpart Kb emission controls include the use of either an external floating roof (EFR), an internal floating roof (IFR), or a closed vent system and a control device (see 40 CFR 60.110b(a) and 40 CFR 60.112b(a) and (b)).[2] NSPS subpart Kb also specifies testing, monitoring, recordkeeping, reporting, and other requirements in 40 CFR 60.113b through 40 CFR 60.116b to ensure compliance with the standards. Storage vessels with an EFR consist of an open-top cylindrical steel shell equipped with a deck that floats on the surface (commonly referred to as a floating "roof") of the stored liquid. Storage vessels with an IFR are fixed roof vessels[3] that also have a deck internal to the vessel that floats on the liquid surface (commonly referred to as an internal floating "roof") within the fixed roof vessel.

The standards set in NSPS subpart Kb for storage vessels with an EFR or IFR are a combination of design, equipment, work practice, and operational standards set pursuant to CAA section 111(h). These standards require, among other things, that a rim seal be installed continuously around the circumference of the vessel (between the inner wall of the vessel and the floating roof) to prevent VOC emissions from escaping to the atmosphere through gaps between the floating roof and the inner wall of the storage vessel. For IFRs, NSPS subpart Kb allows a single liquid-mounted or mechanical shoe primary seal (to be used with or without a secondary seal), or a vapor-mounted primary seal in combination with a secondary seal. For EFRs, NSPS subpart Kb allows either a liquid-mounted or mechanical shoe primary seal, both of which must be used with a secondary seal; vapor-mounted primary seals are not allowed for EFR.

NSPS subpart Kb also requires numerous deck fittings[4] on the floating roof to be equipped with a gasketed cover or lid that is kept in the closed position at all times (*i.e.*, no visible gap), except when the device (deck fitting) is in actual use, to prevent VOC emissions from escaping through the deck fittings. In addition, NSPS subpart Kb requires owners and operators to conduct visual inspections to check for defects in the floating roof, rim seals, and deck fittings (*e.g.*, holes, tears, or other openings in the rim seal, or covers and lids on deck fittings that no longer close properly) that could expose the liquid surface to the atmosphere and potentially result in VOC emission losses through rim seals and deck fittings.[5]

NSPS subpart Kb includes two primary alternative means of compliance. Owners or operators may either comply with the consolidated air rule provisions for storage vessels in 40 CFR part 65, subpart C, or comply with the national emission standards for hazardous air pollutants (NESHAP) for storage vessels in 40 CFR part 63, subpart WW. The substantive control requirements in these rules are the same as in NSPS subpart Kb although they may have slight differences in the details of the fitting and inspection requirements.

We estimate that there were approximately 9,100 storage vessels subject to NSPS subpart Kb in 2022, with an estimated 240 storage vessels becoming new affected facilities under the rule each year. Under the current NSPS subpart Kb requirements, it is generally difficult to become a modified storage vessel.

[1] On October 15, 2003 (68 FR 59329), the EPA finalized amendments to NSPS subpart Kb to exempt certain storage vessels by capacity and vapor pressure, exempt process tanks, and add a process tank definition. At the same time, the EPA also amended the rule to exempt storage vessels that are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Solvent Extraction of Vegetable Oil Production.

[2] All affected storage vessels storing organic liquids with a true vapor pressure of 76.6 kPa or more must use a closed vent system and a control device. See 40 CFR 60.112b(b).

[3] A fixed roof storage vessel consists of a cylindrical steel shell with a permanently affixed roof, which may vary in design from cone or dome-shaped to flat.

[4] Numerous fittings pass through or are attached to floating decks to accommodate structure support components or to allow for operational functions. Typical deck fittings include, but are not limited to access hatches, gauge floats, gauge-hatch/sample ports, rim vents, deck drains, deck legs, vacuum breakers, and guidepoles. IFR storage vessels may also have deck seams, fixed-roof support columns, ladders, and/or stub drains.

[5] For details about storage vessel emissions, refer to the Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, AP–42, Fifth Edition, Chapter 7: Liquid Storage Tanks, dated June 2020 which is available at: *https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors.*

*C. How does the EPA perform the NSPS review?*

As noted in section II.A of this preamble, CAA section 111 requires the EPA to, at least every 8 years, review and, if appropriate, revise the standards of performance applicable to new, modified, and reconstructed sources. If the EPA revises the standards of performance, those standards must reflect the degree of emission limitation achievable through the application of the BSER considering the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements. CAA section 111(a)(1).

In reviewing an NSPS to determine whether it is "appropriate" to revise the standards of performance, the EPA evaluates the statutory factors, which may include consideration of the following information:

- Expected growth for the source category, including how many new facilities, reconstructions, and modifications may trigger NSPS in the future.
- Pollution control measures, including advances in control technologies, process operations, design or efficiency improvements, or other systems of emission reduction, that are "adequately demonstrated" in the regulated industry.
- Available information from the implementation and enforcement of current requirements indicating that emission limitations and percent reductions beyond those required by the current standards are achieved in practice.
- Costs (including capital and annual costs) associated with implementation of the available pollution control measures.
- The amount of emission reductions achievable through application of such pollution control measures.
- Any non-air quality health and environmental impact and energy requirements associated with those control measures.

In evaluating whether the cost of a particular system of emission reduction is reasonable, the EPA considers various costs associated with the particular air pollution control measure or a level of control, including capital costs and operating costs, and the emission reductions that the control measure or particular level of control can achieve. The Agency considers these costs in the context of the industry's overall capital expenditures and revenues. The Agency also considers cost effectiveness analysis as a useful metric and a means of evaluating whether a given control achieves emission reduction at a reasonable cost. A cost effectiveness analysis allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost effectiveness is a measure of the outcomes produced by resources spent. In the context of air pollution control options, cost effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually.

After the EPA evaluates the statutory factors, the EPA compares the various systems of emission reductions and determines which system is "best," and therefore represents the BSER. The EPA then establishes a standard of performance that reflects the degree of emission limitation achievable through the implementation of the BSER. In performing this analysis, the EPA can determine whether subcategorization is appropriate based on classes, types, and sizes of sources, and may identify a different BSER and establish different performance standards for each subcategory. The result of the analysis and BSER determination leads to standards of performance that apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Because the new source performance standards reflect the best system of emission reduction under conditions of proper operation and maintenance, in doing its review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping, and reporting requirements needed to ensure compliance with the emission standards.

See section II.D of this preamble for information on the specific data sources that were reviewed as part of this action.

*D. What data and information were used to support this action?*

We reviewed recent federal, State, and local rulemakings associated with VOL storage vessels. We also reviewed vendor websites and contacted selected floating roof suppliers to collect information to support our review of the existing requirements for organic liquid storage vessels and our BSER assessments. We met with industry representatives that own and operate VOL storage vessels to discuss their experience with various control equipment.

We used the equations in Chapter 7 of AP–42*: Compilation of Air Emission Factors* to estimate emissions from different VOL storage vessels based on size, contents, and control configuration (*e.g.,* type of floating roof with different seal and fitting controls). We estimated emission reductions by comparing the controlled emissions with emissions from an uncontrolled fixed roof storage vessel.

Our cost estimates were based largely on vendor costs developed from previous rulemakings. For some control methods, we had limited recent data from vendors or State and local rulemakings. All costs were escalated to 2022 dollars using the Chemical Engineering Plant Cost Index for capital expenditures and Bureau of Labor Statistics data for labor rates.

## III. What actions are we proposing?

The EPA is proposing revisions to the NSPS for VOL storage vessels pursuant to the EPA's review of NSPS subpart Kb. The EPA is proposing to codify the NSPS revisions proposed in this action in a new subpart NSPS subpart Kc. The proposed NSPS subpart Kc would be applicable to sources that commence construction, reconstruction, or modification after October 4, 2023.

This section outlines the proposed actions for NSPS subpart Kc. The EPA is proposing new vapor pressure applicability thresholds for controls under NSPS subpart Kc. The EPA is also proposing new standards for VOL storage vessels subject to control requirements. Under NSPS subpart Kc we are proposing that the standard of performance reflecting the application of BSER for VOL storage vessels subject to control requirements and used to store liquids with maximum true vapor pressures below 11.1 psia (76.6 kPa) is an IFR. The updated standards are projected to increase the average control efficiency of IFR storage vessels to 98 percent. As an alternative compliance to the proposed IFR design standard, we are proposing to permit either the use of an EFR or the use of a closed vent system and a control device that meet an equivalent standard of control. For controlled storage vessels that store liquids with a maximum true vapor pressure equal to or greater than 11.1 psia (76.6 kPa), we are proposing to find that the BSER is a closed vent system and a control device. We are proposing that the standard of performance reflecting the emission limitation achievable is a 98 percent reduction in VOC emissions (increased from 95 percent in the NSPS subpart Kb). EPA is also including modification requirements under NSPS subpart Kc and discusses the relevant criteria for meeting modifications in this section. This section also details the proposed testing, monitoring and inspection requirements, degassing provisions,

provisions for SSM, and electronic reporting requirements. As described in this section, the revisions proposed in this action were determined to be cost-effective and to reflect the application of the best system of emission reduction (BSER) for VOL storage vessels.

*A. What vapor pressure applicability thresholds are we proposing and why?*

NSPS subpart Kb established control requirements, at 40 CFR 60.112b(a), for storage vessels based on vessel capacity and VOL vapor pressures. In our review of NSPS subpart Kb, we assessed the vapor applicability thresholds for affected facilities and for controls on affected storage vessels to determine whether these thresholds needed to be revised for purposes of NSPS subpart Kc. In NSPS subpart Kb there are two different sets of vapor pressure applicability thresholds: one for determining affected facilities and one for determining controls.

In NSPS subpart Kb, the vapor pressure applicability thresholds for defining affected facilities were slightly lower than those used for affected facilities for which controls were required. The EPA included the two separate applicability requirements sets in NSPS subpart Kb, one to identify storage vessels near the control applicability thresholds and another to establish limited monitoring procedures for vessels with variable components and vapor pressures. We are proposing to not include specific vapor pressure applicability thresholds in defining an affected facility under NSPS subpart Kc. As such, the proposed affected facility under NSPS subpart Kc is any storage vessel with a capacity of 20,000 gallons or more used to store a volatile organic liquid without exclusion for storage vessels under a set vapor pressure. This proposed change simplifies the applicability under NSPS subpart Kc and establishes a baseline for monitoring and recordkeeping in accordance with good air pollution control practices for storage vessels that do not meet the vapor pressure emission control threshold.

In our review of NSPS subpart Kb, in assessing the vapor applicability thresholds that require emission controls, we estimated the cost of including an IFR as part of a new fixed roof storage vessel installation for a variety of surrogate organic liquids covering a wide range of vapor pressures for both 20,000 gallon and 40,000 gallon capacity storage vessels. We used the AP–42 equations for liquid storage tanks to estimate emissions for fixed roof storage vessels and IFR storage vessels. Costs were estimated based on various vendor quotes, escalated to 2022$. For more detail regarding the analyses conducted, see memorandum *Control Options for Storage Vessels* included in Docket ID No. EPA–HQ–OAR–2023–0358.

For storage vessels of 20,000 gallon capacity or more but less than 40,000 gallon capacity, we evaluated the cost and cost effectiveness of different vapor pressure applicability thresholds, including:

- 4.0 psia based on NSPS subpart Kb value (27.6 kPa)
- 1.9 psia based on thresholds used in several NESHAP including 40 CFR part 63, subparts G and CC.
- 1.5 psia based on thresholds in South Coast Air Quality Management District (SCAQMD) Rule 463.
- 1.0 psia to evaluate an option beyond 1.5 psia.

We conducted this analysis using a model storage vessel of 20,000 gallon capacity. We assessed costs for two different levels of IFR: one meeting the basic requirements of NSPS subpart Kb and one with upgraded seal requirements (requiring a mechanical shoe seal or liquid-mounted primary seal with a rim-mounted secondary seal). Table 1 summarizes the results of our analysis for these small storage vessels.

TABLE 1—SUMMARY OF THRESHOLD ANALYSIS FOR STORAGE VESSELS WITH A CAPACITY BETWEEN 20,000 AND 40,000 GALLONS

| Threshold | VOC emissions reduction (tpy) | TCI [1] ($) | TAC [2] without product recovery ($/yr) | TAC [2] with product recovery ($/yr) | CE [3] ($/ton VOC) |
|---|---|---|---|---|---|
| **Costs for Meeting NSPS Subpart Kb Requirements for IFR** | | | | | |
| 4.0 psia | 2.04 | $48,877 | $6,035 | $4,257 | $2,100 |
| 1.9 psia | 0.97 | 48,877 | 6,035 | 5,190 | 5,300 |
| 1.5 psia | 0.77 | 48,877 | 6,035 | 5,368 | 7,000 |
| 1.0 psia | 0.51 | 48,877 | 6,035 | 5,590 | 10,900 |
| **Costs for IFR with Upgraded Seal Requirements ('Option 1')** | | | | | |
| 4.0 psia | 2.29 | 55,008 | 6,793 | 4,802 | 2,100 |
| 1.9 psia | 1.09 | 55,008 | 6,793 | 5,847 | 5,000 |
| 1.5 psia | 0.86 | 55,008 | 6,793 | 6,046 | 7,000 |
| 1.0 psia | 0.57 | 55,008 | 6,793 | 6,295 | 11,000 |

[1] Total Capital Investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.
[3] Cost effectiveness.

A similar analysis was conducted for storage vessels with a design capacity of 40,000 gallons or more. For this analysis, we used a model storage vessel with a 60,000 gallon capacity, which we consider representative of storage vessels at the smaller end of the range of storage vessels with a capacity of 40,000 gallons or more. We evaluated the cost and cost effectiveness of different vapor pressure applicability thresholds, including:

- 0.75 psia based on NSPS subpart Kb value (5.2 kPa).
- 0.50 based on thresholds in SCAQMD Rule 463.
- 0.35 psia to evaluate an option beyond 0.5 psia.

Table 2 summarizes the results of our analysis for storage vessels with a capacity of 40,000 gallons or more.

TABLE 2—SUMMARY OF THRESHOLD ANALYSIS FOR STORAGE VESSELS WITH A CAPACITY OF 40,000 GALLONS OR MORE

| Threshold | VOC emissions reduction (tpy) | TCI [1] ($) | TAC [2] without product recovery ($/yr) | TAC [2] with product recovery ($/yr) | CE [3] ($/ton VOC) |
|---|---|---|---|---|---|
| **Costs for Meeting NSPS Subpart Kb Requirements for IFR** | | | | | |
| 0.75 psia | 1.36 | $54,979 | $6,789 | $5,609 | $4,100 |
| 0.50 psia | 0.90 | 54,979 | 6,789 | 6,002 | 6,600 |
| 0.35 psia | 0.63 | 54,979 | 6,789 | 6,238 | 9,900 |
| **Costs for IFR with Upgraded Seal Requirements ('Option 1')** | | | | | |
| 0.75 psia | 1.42 | 62,914 | 7,769 | 6,532 | 4,600 |
| 0.50 psia | 0.95 | 62,914 | 7,769 | 6,944 | 7,300 |
| 0.35 psia | 0.66 | 62,914 | 7,769 | 7,192 | 10,800 |

[1] Total Capital Investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.
[3] Cost effectiveness.

Based on this analysis, we are proposing for NSPS subpart Kc to revise the vapor applicability thresholds that require emission controls. We are proposing to revise the maximum true vapor pressure threshold for small storage vessels (those with capacity of at least 20,000 gallons but less than 40,000 gallons) to 1.5 psia and for larger storage vessels (those with capacity of 40,000 gallons or more) to 0.5 psia. These thresholds yield emission reductions at a cost of approximately $6,000 and $7,000 per ton of VOC reduced respectively, which is within the range of what the EPA has considered cost-effective for the control of VOC emissions in other recent NSPS rulemakings. See, *e.g.,* 88 FR 29982 (May 9, 2023) (finding a value of $6,800/ton of VOC emissions reductions cost-effective for automobile and light duty truck surface coating operations (NSPS subpart MMa)). The cost effectiveness for VOLs with vapor pressures less than the proposed maximum true vapor pressure cutoffs are approximately $10,000 and $11,000 per ton of VOC reduced. This is not cost-effective because it is significantly higher than what the EPA has historically found to be cost-effective for VOC regulations. The EPA solicits comment on the proposed vapor pressure applicability described in this section.

*B. What other changes to applicability are we proposing and why?*

NSPS subpart Kb includes several provisions that exempt specific groups of VOL storage vessels from applicability under the standard. These exemptions are outlined in 40 CFR 60.110b (d) and include specific exemptions for storage vessels that operate at coke oven by-product plants, bulk gasoline plants, and gasoline service stations. The exemptions include pressure vessels operating in excess of 204.9 kPA, vessels attached to mobile vehicles, and vessels that store beverage alcohol. These exemptions are being carried over into the proposal for NSPS Kc as the justifications for their exemption remains unchanged from the original NSPS subpart Kb promulgation.

The EPA is also proposing to carry over the exemption requirements in 40 CFR 60.110b(d)(4), which covers storage vessels with capacities less than or equal to 1,589.874 $m^3$ (~420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer. The EPA previously explained the applicability of this exemption in the preamble to NSPS subpart Ka (45 FR 23377) stating, "this exemption applies to storage between the time that the petroleum liquid is removed from the ground and the time the custody of the petroleum liquid is transferred from the well or producing operations to the transportation operations. If it is determined in the future that VOC emissions from new production field vessels smaller than 1,589,873 liters (420,000 gallons) are significant, separate standards of performance will be developed." Since promulgation of NSPS subpart Ka, the EPA promulgated subparts OOOO and OOOOa for the oil and natural gas sector, which include standards of performance for these types of storage vessels. The EPA has also proposed revised standards for these sources in its latest review, as part of the proposed NSPS subpart OOOOb and the emission guideline for existing sources at proposed subpart OOOOc. See 87 FR 74702. As such, the EPA proposes to carry the language of this exemption into NSPS subpart Kc.

NSPS subpart Kb also includes an exemption for vessels subject to the NESHAP for solvent extraction for vegetable oil production outlined in 40 CFR 63 subpart GGGG. The EPA determined as part of its review, that the standards proposed in NSPS subpart Kc improve upon the existing NESHAP subpart GGGG standards. As such, the EPA proposes that vessels subject to NESHAP subpart GGGG, would not be exempted from NSPS subpart Kc applicability.

The EPA solicits comment on these proposed exemptions and changes to the applicability provisions.

*C. What are the proposed BSER and compliance alternatives for newly constructed, modified, and reconstructed storage vessels?*

The EPA is proposing standards of performance that reflect the BSER as well as alternative compliance standards for controlled storage vessels under NSPS subpart Kc. The proposed BSER analyses and proposed standards for NSPS subpart Kc are dependent on the maximum true vapor pressure of a stored VOL and follow the precedent established in NSPS subpart Kb. For storage vessels storing VOL with maximum true vapor pressures less than 11.1 psia, the EPA discusses the BSER analysis and proposes standards of performance for newly constructed and reconstructed IFRs in section III.D. The EPA also is proposing two alternative compliance options for storage vessels with maximum true vapor pressures less than 11.1 psia. These alternative compliance options are EFRs and closed vent system and control. Details regarding alternative compliance standards for newly constructed and reconstructed storage vessels are discussed in section III.E.

For storage vessels with maximum true vapor pressures greater than or equal to 11.1 psia, the EPA is proposing to determine that the BSER is closed vent system and control, and the standard of performance reflecting the BSER is a 98 percent reduction in VOC emissions. The BSER analysis and standard of performance for storage vessels with VOL maximum true vapor pressures greater than or equal to 11.1 psia are discussed in section III.F. Additionally, we are proposing requirements that are applicable to storage vessels that are controlled using a closed vent system and a control device to meet either proposed standard, and those proposed requirements are also discussed in section III.F.

In section III.G the EPA proposes what constitutes a modification for purposes of NSPS subpart Kc. Discussion regarding the BSER analysis, standards of performance for modified storage vessels and compliance alternatives are discussed in sections III.F and III.H.

*D. What is the BSER and standard of performance for new and reconstructed storage vessels with maximum true vapor pressures less than 11.1 psia?*

In our review of NSPS subpart Kb for storage vessels storing VOL with maximum true vapor pressures less than 11.1 psia, we focused on control options for IFR storage vessels because IFR storage vessels are more effective at controlling emissions and are technologically achievable. Therefore, IFR storage vessel control options were evaluated to determine BSER for VOL vapor pressures less than 11.1 psia. Because floating roof tanks are unsuitable for controlling VOL with vapor pressures greater than or equal 11.1 psia, the EPA conducted a separate analysis to determine the BSER and standard of performance for those storage vessels.

The control options we evaluated for IFR storage vessels included:

- *Baseline.* NSPS subpart Kb control requirements (with NSPS subpart Kc proposed lower vapor pressure thresholds detailed in section III.A)
- *Option IFR–1.* NSPS subpart Kb but primary seal must either be liquid-mounted or mechanical shoe seal and must have a rim-mounted secondary seal.
- *Option IFR–2.* Option 1 requirements + require fixed roof legs or cable suspended roof (cannot have adjustable roof legs that penetrate through the floating roof).
- *Option IFR–3.* Option 2 requirements + require welded seems and best guidepole fittings.

All three of the listed options above also include provisions for requiring gauge-hatches/sample ports to be gasketed. We determined that all of these IFR control options are in use in the industry and thus adequately demonstrated.

The cost effectiveness of these control options is dependent on the size and contents of the storage vessel. We estimated that approximately 240 new storage vessels become subject to the NSPS subpart Kb every year, such that 1,200 new storage vessels could become subject to NSPS subpart Kc over the next five years if no change in thresholds is adopted. We projected that with lower vapor pressure thresholds, approximately 20 percent more storage vessels could become subject to the NSPS subpart Kc standards each year. We assigned the estimated 1,440 new storage vessels across a range of storage vessel sizes and vapor pressures for the stored liquids to develop national impact estimates for each IFR control option. For more information on the nationwide cost analysis of IFR control options for new storage vessels, see memorandum *Control Options for Storage Vessels* in Docket ID No. EPA–HQ–OAR–2023–0358.

The national impacts projected for each IFR control option are presented in Table 3 of this preamble.

TABLE 3—SUMMARY OF NATIONAL IMPACTS FOR CONTROL OPTIONS FOR NEW AND RECONSTRUCTED IFR STORAGE VESSELS

| Control option | VOC emissions reduction [1] (tpy) | TCI [2] (million $) | TAC [3] without product recovery (million $/yr) | TAC [3] with product recovery (million $/yr) | Overall CE [1 4] ($/ton VOC) | CE [4] to Kb baseline ($/ton VOC) | ICE [5] ($/ton VOC) |
|---|---|---|---|---|---|---|---|
| Baseline—Kb | 41,886 | $127 | $15.7 | ($20.8) | ($496) | ..... | ..... |
| Option IFR–1 | 42,420 | 145 | 17.9 | (19.1) | (449) | 3,180 | 3,180 |
| Option IFR–2 | 42,684 | 173 | 21.3 | (15.8) | (370) | 6,250 | 12,272 |
| Option IFR–3 | 42,961 | 199 | 24.6 | (12.8) | (297) | 7,470 | 10,966 |

[1] Relative to uncontrolled fixed roof storage vessel.
[2] Total Capital Investment (TCI).
[3] Total annualized costs (TAC) considering annualized cost of capital.
[4] Cost effectiveness.
[5] Incremental cost effectiveness (compared to previous option).

Based on this analysis, we are proposing to determine that for new and reconstructed storage vessels with vapor pressures less than 11.1 psia, BSER is Option IFR–1. Specifically, we are proposing to require that the primary seal must either be liquid-mounted or a mechanical shoe seal and must have a rim-mounted secondary seal. While Table 3 displays numerous options that have favorable cost effectiveness values, incremental cost effectiveness was the determining factor in selecting the appropriate IFR control option. The EPA estimated that the incremental cost effectiveness of Option IFR–1 is projected to yield emission reductions at a cost of approximately $3,200 per ton of VOC reduced on average, which we determined is cost- effective and is well within the range of what the EPA has considered cost-effective for the control of VOC emissions. The other control options we evaluated for IFR storage vessels had incremental cost effectiveness of $11,000 or more per ton of VOC reduced, which is well above what we have determined to be cost-effective for the control of VOC emissions. IFRs are the most common emission control method for VOL storage vessels and thus are adequately demonstrated. Further, IFRs do not require power or addition of add-on controls; therefore, there are minimal non-air quality health and environmental impacts and energy requirements.

IFRs with a liquid-mounted or mechanical shoe primary seal and rim-mounted secondary seal (Option IFR–1) were selected as the most appropriate option for new and reconstructed storage vessels under the BSER determination. The EPA therefore

proposes an equipment standard pursuant to CAA section 111(h)(5) that would require that new storage vessels be constructed as IFR, that the primary seal must either be liquid-mounted or mechanical shoe seal and must have a rim-mounted secondary seal, that gauge-hatches/sample ports to be gasketed, and that the guidepole configurations incorporate the provisions outlined in the 2000 EPA Storage Tank Emissions Reduction Partnership Program (STERPP).

The EPA solicits comment on the proposal to determine that the BSER for storage vessels storing VOL with maximum true vapor pressures less than 11.1 psia is Option IFR–1, or whether one of the alternative options would be justified. The EPA also solicits comment on the proposed equipment standard.

*E. What compliance alternatives are available for new and reconstructed storage vessels with maximum true vapor pressures less than 11.1 psia?*

As discussed in section III.D of this preamble, we are proposing to determine that, for new and reconstructed storage vessels with a maximum true vapor pressure less than 11.1 psia, the BSER and equipment standard is IFR with enhanced rim seal requirements: specifically, the primary seal must either be liquid-mounted or mechanical shoe seal and must have a rim-mounted secondary seal. We are also proposing to revise the NSPS requirements for EFR storage vessels as an alternative compliance option to equipment standard for newly constructed and reconstructed storage vessels. The average control efficiency for the proposed Option IFR–1 was determined to be 98 percent. In reviewing the NSPS, we found that certain EFR storage vessels could achieve the same level of control as the proposed control option for IFR storage vessels (Option IFR–1). As such, we are proposing to permit the use of EFR storage vessels that we determined achieve equivalent performance as an IFR storage vessel across a range of different capacities. Based on AP–42 emission calculation methods, we found that an EFR storage vessel that has primary and secondary seals as specified in Option IFR–1, welded seams (typical construction for EFR), and that use an unslotted guidepole with gasketed sliding cover and pole wiper have emissions comparable to an IFR storage vessel under Option IFR–1. If a slotted guidepole is used, a liquid mounted primary seal must be used and the slotted guidepole must have a gasketed sliding cover, pole sleeve and pole wiper (with or without float). We recognize that other control combinations for the EFR storage vessel may achieve comparable emissions to an Option IFR–1 storage vessel depending on the size and content of the storage vessel, and the typical meteorological conditions. Although we are not attempting to identify every such combination in proposing to codify this compliance alternative, CAA section 111(h)(5) permits facilities to request an alternative means of emission limitation to assess equivalency of EFR controls to IFR controls under site-specific conditions.

We are also proposing to permit storage vessels with a maximum true vapor pressure less than 11.1 psia to use closed vent system and control devices as an alternative compliance to the equipment standard, so long as the storage vessel achieves a 98 percent reduction in VOC emissions to be equivalent to the proposed IFR standard. Such storage vessels would be required to meet the proposed requirements for closed vent systems and control devices described in section III.F.

The EPA solicits comment on these proposed compliance alternatives for storage vessels with a maximum true vapor pressure less than 11.1 psia.

*F. What is the BSER and standard of performance for new, modified, and reconstructed storage vessels with maximum true vapor pressures equal to or greater than 11.1 psia?*

As noted previously, the EPA is proposing that for newly constructed and reconstructed VOL storage vessels with a maximum true vapor pressure less than 11.1 psia, the BSER is IFR with enhanced rim seal requirements. Because floating roof tanks are unsuitable for controlling VOL with vapor pressures greater than or equal 11.1 psia, the EPA conducted a separate analysis to determine the BSER and standard of performance for those storage vessels that are new, modified, or reconstructed. In NSPS subpart Kb, closed vent systems and control devices are the BSER for storage vessels for organic liquids with maximum true vapor pressures of 11.1 psia or greater and have served as an alternative compliance option for storage vessels with lower vapor pressures. Therefore, in reviewing NSPS subpart Kb, the EPA also reviewed the control requirements associated with storage vessels that use closed vent systems and control devices. We assessed the cost and cost effectiveness of a closed vent system and control device for a range of storage vessels used to store liquids with high vapor pressures. We are proposing to continue to find the BSER to be closed vent systems and control devices for new, modified, or reconstructed storage vessels for organic liquids with maximum true vapor pressures of 11.1 psia or greater, and to set the standard of performance to require that these storage vessels must achieve a 98 percent reduction in VOC emissions.

For storage vessels used to store organic liquids with maximum true vapor pressures of 11.1 psia or greater, we estimated the cost of a flare dedicated to a single storage vessel. We estimated the costs separately for flares meeting the requirements in 40 CFR 60.18 (95 percent reduction) or using the flare requirements in 40 CFR 63.670 (98 percent reduction). We used two times the maximum filling rate to size the flares, we determined the time period needed at the maximum filling rate to achieve the modeled working losses, and we determined the average flow rate needed for the remaining time period to correspond to the modeled standing losses. Because of the high vapor pressure of the liquid contents, flares meeting the requirements in 40 CFR 63.670 are expected to be able to use the methods in 40 CFR 63.670(j)(6) to determine minimum net heating value of the gas stream. Depending on the assist-type of the flare, supplemental gas may be needed during periods of low flow, which is the vast majority of the time. We expect facilities would use a pressure valve in the closed vent system to prevent low flows and prevent back flow from the flare to the storage vessel when emptying the storage vessel. These pressure valves could be set to ensure gas flow to the flare is always sufficient to prevent over-assisting, but we assumed flares with low flows would use supplemental natural gas. For smaller storage vessels (20,000 to 60,000 gallons capacity), there were added costs associated with meeting the combustion zone operating limits in 40 CFR 63.670. For the larger storage vessels, routine flows from the storage vessels were sufficient to meet the combustion zone operating limits in 40 CFR 63.670. We estimate there would be 25 new storage vessels used for storing high vapor pressure liquids for which closed vent system and control device would be required, primarily in the 40,000 to 60,000 gallon capacity range. For more details regarding the nationwide of costs for closed vent systems and control devices, see memorandum *Control Options for Storage Vessels* in Docket ID No. EPA–HQ–OAR–2023–0358. The nationwide impacts projected for these two control options evaluated for purposes of NSPS

subpart Kc (95 percent and 98 percent control) are provided in Table 4 of this preamble.

TABLE 4—SUMMARY OF NATIONAL IMPACTS FOR CONTROL OPTIONS FOR CLOSED VENT SYSTEMS AND CONTROL DEVICE FOR HIGH VAPOR PRESSURE LIQUIDS

| Control option | VOC emissions reduction [1] (tpy) | TCI [2] (million $) | TAC [3] without product recovery (million $/yr) | CE [4] ($/ton VOC) | ICE [5] ($/ton VOC) |
|---|---|---|---|---|---|
| 95 percent control | 928 | $2.69 | $2.61 | $2,820 | $2,820 |
| 98 percent control | 957 | 2.69 | 2.71 | 2,830 | 3,360 |

[1] Relative to uncontrolled fixed roof storage vessel.
[2] Total Capital Investment (TCI).
[3] Total annualized costs (TAC) considering annualized cost of capital.
[4] Cost effectiveness.
[5] Incremental cost effectiveness.

Based on our analysis, we are proposing that the BSER for storage vessels operating with maximum true vapor pressures equal to or greater than 11.1 psia is the use of a closed vent system and control device meeting a 98 percent control efficiency. The EPA considers the cost-effectiveness of both control options to be within the range of what the EPA has considered cost-effective for the control of VOC emissions. While the incremental cost-effectiveness of 98 percent control is slightly higher than for 95 percent control, it is also well within the range of what the EPA has considered cost-effective. Although these control devices use power and result in additional combustion emissions, there is no significant difference between 95 and 98 percent control levels in as regards to the non-air quality health and environmental impacts, or energy requirements. Accordingly, the EPA proposes to find the use of a closed vent system and control device meeting a 98 percent control efficiency is the BSER and proposes to set a standard of performance for new, reconstructed, and modified storage vessels operating with vapor pressures equal to or greater than 11.1 psia as 98 percent control of VOC emissions.

The EPA is also proposing to establish requirements for closed vent systems and control devices to ensure that storage vessels using them to comply with the proposed standards actually achieve 98 percent control efficiency. In order for the closed vent system and control device to meet 98 percent control efficiency, the storage vessel must not vent to the atmosphere. Conservation vents and pressure relief devices are often used to vent emissions from storage vessels when the pressure within the storage vessel approaches the maximum design pressure of the storage vessel. Many atmospheric storage vessels have pressure ratings of 1 or 2 psig and would therefore vent often if the vapor pressure of the stored liquid is above 2 psi. Consequently, to ensure direct venting from the storage vessel does not occur, we are proposing to require storage vessels have a design operating gauge pressure no less than 1 psi greater than the maximum vapor pressure of the liquid being stored and any back pressure anticipated when the storage vessel is filled at its maximum rate. While vapor pressures are commonly reported in terms of absolute pressure, a storage vessel containing a liquid with a vapor pressure of 4 psia would generally have a headspace pressure of 4 psi above atmospheric pressure, or 4 psig. Storage vessel owners or operators would also have to evaluate the back pressure of the control system used and ensure that the closed vent system can handle the maximum filling rate of the storage vessel without increasing pressure in the storage vessel above this 5 psig value or else establish a higher design and operating pressure for the storage vessels. For example, if the back pressure of the closed vent system (or the pressure drop from the storage vessel to the control device) is 3 psi at the maximum filling rate, and the liquid stored has a maximum true vapor pressure of 4 psia, the minimum opening pressure of any pressure relief device on the storage vessel would have to be 8 psig (3+4+additional 1). We are also proposing to require that any vacuum breaking device have a close pressure no less than 0.1 psig vacuum to prevent losses from the vacuum breaker vent.

The EPA solicits comment on our proposed BSER determination and standard of performance for new, reconstructed, and modified storage vessels operating with vapor pressures equal to or greater than 11.1 psia, as well as the proposed requirements for closed vent systems and control devices.

*G. What actions constitute a modification for storage vessels and why?*

For purposes of CAA section 111, modifications are defined as "any physical change in, or change in the method of operation of," an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.[6] 40 CFR 60.2. NSPS Subpart A further provides provisions explaining how a modification is identified as well as defining certain exemptions to those general rules. In particular, 40 CFR 60.14(e)(4) states that the "[u]se of an alternative fuel or raw material" is not considered a modification if the existing facility was designed to accommodate that alternative use. In prior EPA actions making applicability determinations for purposes of NSPS Kb, the EPA has previously cited to this provision to assert that a change in the type of material stored in a storage vessel is not, by itself, a modification if the storage vessel is capable of accommodating the storage of the new materials.[7] However, the EPA has revisited the previous interpretation as discussed in the following paragraphs and now proposes, for purposes of NSPS Kc, that a change in the liquid stored in the storage vessel to an organic liquid with a higher maximum true vapor pressure does not constitute a "use of an alternative fuel or raw material," and would be considered a change in the method of operation of the storage vessel. Thus, the EPA proposes that a change in the liquid stored which results in increased

[6] *See* 42 U.S.C. 7411(a)(4).

[7] *See, e.g.*, U.S. EPA Applicability Determination Index, Control Number: 0400015, (referencing 40 CFR 60.14(e)(4)–(5)).

VOC emissions would be a modification under NSPS Kc. The EPA recognizes that the proposed approach to modifications for purposes of NSPS subpart Kc represents a change of the EPA's previous interpretation of the provision in 40 CFR 60.14(e)(4) that asserted that change in liquid alone did not trigger a modification. However, the EPA proposes to find that this change in interpretation for purposes of defining a modification for NSPS subpart Kc is appropriate, in particular, because as discussed below the changes in the organic liquid stored in a storage vessel do not constitute changes in "fuel or raw material," as the primary function of this affected facility is the storage of materials, and the materials stored are neither raw material nor fuel inputs to a process at the facility itself. *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515–16 (2009) (when the Agency acknowledges change in position, "it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the Agency believes it to be better, which the conscious change of course adequately indicates").

As noted earlier in this preamble, as the EPA has defined modification for purposes of CAA section 111, using a different fuel or raw material in the process that the facility was specifically designed for does not itself constitute a modification under the exemption identified in 40 CFR 60.14(e)(4). However, for storage vessels, the primary function of this affected facility is the storage of materials, and the materials stored are neither raw material nor fuel inputs to a process at the facility itself. Therefore, for purposes of NSPS Kc, the EPA now proposes to determine that the exemption outlined in 40 CFR 60.14(e)(4) does not apply, because the organic liquid stored in the vessels subject to this part does not constitute fuels or raw materials. Accordingly, the EPA proposes to consider the change in materials stored in a storage vessel to be an operational change under CAA section 111(a)(4). Thus, where an owner or operator changes the operation of the tank to store materials with higher vapor pressures, this change results in an increased emission potential. The EPA proposes to find that this change is an operation meeting the definition of "modification" under CAA section 111(a)(4) and 40 CFR 60.14(a). If the modified storage vessel meets the applicability criteria of NSPS subpart Kc, then it would be subject to the standards of performance and other requirements established in the final rule.

The EPA has identified no other exemption in 40 CFR 60.14(e) which applies to a change in the organic liquid stored in a storage vessel. The EPA further proposes to determine that a change in the organic liquid stored at a storage vessel constitutes a modification under the statutory definition because it is reasonable to consider a change in the organic liquid stored to a new liquid with a higher true vapor pressure to be a change in operation, especially because such a change is expected to increase VOC emissions. Thus, the EPA proposes that a change in the liquid stored which results in increased VOC emissions would be a modification under NSPS subpart Kc. If the previous content of the storage vessel was below the vapor pressure threshold, a change in the liquid stored in the vessel to one that is above the vapor pressure threshold would increase the amount of VOC emitted from the storage vessel and should be considered a modification of the storage vessel and trigger the NSPS subpart Kc control requirements.

The EPA solicits comment on the proposed change in interpretation of 40 CFR 60.14(e) as it applies to modifying storage vessels subject to NSPS subpart Kc.

*H. What are the BSER and standards of performance for modified storage vessels with maximum true vapor pressures less than 11.1 psia?*

The EPA evaluated BSER for modified storage vessels for NSPS subpart Kc with maximum true vapor pressures less than 11.1 psia. In most cases, the EPA expects that modified storage vessels will have existing fixed roofs, because IFRs were not previously required by NSPS subpart Kb. The costs of retrofitting a fixed roof storage vessel with an IFR are the same as the costs of adding an IFR to a new storage vessel. Some modified storage vessels that newly trigger into the NSPS, however, may already have IFRs, and upgrading only certain elements of the IFR can have significantly different costs than when installing a new IFR. Therefore, to assess BSER for modified storage vessels, we developed national cost estimates separately for modified storage vessels depending on whether or not the storage vessels had existing IFRs prior to modification.

We estimate a total of 30 storage vessels would become newly affected facilities due to modifications over the first 5 years after promulgation of NSPS subpart Kc. We estimate 10 percent of these storage vessels would have an existing IFR and that the existing IFR was compliant with the IFR requirements in NSPS subpart Kb. For more information on the nationwide cost analysis of IFR control options for modified storage vessels, see memorandum *Control Options for Storage Vessels* in Docket ID No. EPA–HQ–OAR–2023–0358.

Table 5 of this preamble summarizes the costs and cost effectiveness of the impacts of modified storage vessels without an IFR prior to the modification, under the baseline of the existing Kb requirements and all three IFR options. The incremental costs are somewhat higher than for new and reconstructed storage vessels because we projected that the vapor pressures of the organic liquids stored in the modified storage vessels would be near the vapor pressure applicability threshold. Thus, we projected that storage vessels that triggered into the NSPS subpart Kc because of a change in the liquid stored would generally have lower vapor pressure organic liquids, on average, than compared to new storage vessels. Based on this analysis, we are proposing for NSPS subpart Kc to find that Option IFR–1 (enhanced rim seal requirements) is cost-effective and represents BSER for modified fixed roof storage vessels. Like for new and reconstructed sources, the cost-effectiveness of all options is well within the range of what the EPA has considered to be cost-effective in past rulemakings. However, while the incremental cost effectiveness of Option IFR–1 is also reasonable, the incremental cost-effectiveness of Option IFR–2 and Option IFR–3 are significantly higher than what the EPA has previously found reasonable. Accordingly, while the cost-effectiveness of all options is quite reasonable, the high incremental cost-effectiveness is the determining factor in the EPA's consideration of costs. The EPA's consideration of non-air quality health and environmental impacts, as well as energy requirements, is also the same as for new and reconstructed storage vessels. Therefore, the EPA is proposing to determine that Option IFR–1 is the BSER for existing storage vessels with maximum true vapor pressures less than 11.1 psia that modify and do not have an existing floating roof. These proposed requirements are also applicable to new sources (sources constructed after the proposal date) that modify after the proposal date.

TABLE 5—SUMMARY OF NATIONAL IMPACTS FOR CONTROL OPTIONS FOR MODIFIED FIXED ROOF STORAGE VESSELS WITH MAXIMUM TRUE VAPOR PRESSURES LESS THAN 11.1 PSIA

| Control option | VOC emissions reduction [1] (tpy) | TCI [2] (million $) | TAC [3] without product recovery ($/yr) | TAC [3] with product recovery ($/yr) | CE [4] ($/ton VOC) | ICE [5] ($/ton VOC) |
|---|---|---|---|---|---|---|
| Existing Kb | 501 | $2.32 | $286,000 | ($150,000) | ($299) | ($299) |
| Option IFR–1 | 507 | 2.65 | 327,000 | (114,000) | (224) | 5,900 |
| Option IFR–2 | 510 | 3.18 | 392,000 | (51,200) | (100) | 21,100 |
| Option IFR–3 | 513 | 3.67 | 453,000 | 7,300 | 14 | 19,100 |

[1] Relative to uncontrolled fixed roof storage vessel.
[2] Total Capital Investment (TCI).
[3] Total annualized costs (TAC) considering annualized cost of capital.
[4] Cost effectiveness.
[5] Incremental cost effectiveness.

Table 6 of this preamble summarizes the costs and cost effectiveness of the impacts of modified storage vessels with maximum true vapor pressures less than 11.1 psia that already have an existing IFR prior to the modification. The costs per ton of VOC reduced when modifying controls on an existing IFR are much higher than when installing a new IFR on an existing fixed roof storage vessel. The cost effectiveness and incremental cost effectiveness of all three IFR options are well above what the EPA has found to be reasonable for the control of VOC emissions. Consequently, we are proposing for NSPS subpart Kc that, for modified storage vessels with maximum true vapor pressures less than 11.1 psia with an existing IFR, the NSPS subpart Kb control requirements without upgrading the rim seal requirements represent the application of BSER, and we propose to retain those standards for these sources in NSPS subpart Kc.

TABLE 6—SUMMARY OF NATIONAL IMPACTS FOR CONTROL OPTIONS FOR MODIFIED IFR STORAGE VESSELS

| Control option | VOC emissions reduction (tpy) | TCI [1] ($) | TAC [2] without product recovery ($/yr) | TAC [2] with product recovery ($/yr) | CE [3] ($/ton VOC) | ICE [4] ($/ton VOC) |
|---|---|---|---|---|---|---|
| Existing Kb | 0 | $0 | $0 | $0 | $0 | $0 |
| Option IFR–1 | 0.48 | 64,000 | 7,900 | 7,480 | 15,700 | 15,700 |
| Option IFR–2 | 0.73 | 169,100 | 20,900 | 20,300 | 27,800 | 50,700 |
| Option IFR–3 | 0.87 | 254,600 | 31,400 | 30,700 | 35,300 | 74,600 |

[1] Total Capital Investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.
[3] Cost effectiveness.
[4] Incremental cost effectiveness.

For existing EFR storage vessels, like existing IFR storage vessels, improvements to the floating roof and guidepole design would not result in significant additional emission reductions beyond those achieved by the use of the EFR itself. As a result, as for the IFR analysis just discussed, cost-effectiveness would be expected to be quite high such that the costs associated with the limited additional emission reductions would not be considered reasonable. Accordingly, we propose for NSPS subpart Kc, that if the modified tank has an existing EFR, the BSER and standard of performance is consistent with the EFR requirements as specified in NSPS subpart Kb.

In very rare cases, a fixed roof storage vessel may already be vented through a closed vent system to a control device at the time that it undergoes a modification. In NSPS subpart Kb, the control requirement for these control devices is 95 percent. As discussed in section III.F. of this preamble, we are proposing to require storage vessels with maximum true vapor pressures equal to or greater than 11.1 psia that are subject to NSPS subpart Kc to meet a 98 percent control efficiency based on a BSER identified as a closed vent system and control device. The primary difference between a flare, thermal oxidizer, or carbon adsorption system achieving 98 percent control efficiency rather than 95 percent control efficiency is largely in the operation of the control system rather than the design. Thus, we conclude that storage vessels that already vent through a closed vent system to a control device can technically achieve 98 percent control efficiency. As discussed in section III.F. of this preamble, we evaluated the incremental cost of operating a control system to achieve 98 percent control efficiency compared to 95 percent control efficiency and determined that it is cost-effective to meet a 98 percent control requirement. We consider that the analysis in section III.F. of this preamble to also be applicable to modified storage vessels because there are no meaningful differences in the costs of achieving 98 percent control efficiency as compared to new or reconstructed storage vessels. Therefore, for NSPS subpart Kc, we conclude that if a storage vessel with an existing closed vent system routed to a control device meets the qualifications for modification discussed in section III.G, the BSER is a closed vent system to a control device and standard of performance is 98 percent control of VOC emissions, the same as new or reconstructed storage vessels.

The EPA solicits comment on the proposed standards for modified storage vessels, including whether the EPA should finalize any of the alternative options.

*I. What control requirements are we proposing for IFR and EFR storage vessels emptying and degassing and why?*

Occasionally, floating roof storage vessels need to be taken out of service to clean, inspect, or repair the storage vessel or floating roof. For example, some floating roof seal components may wear out more quickly over time than the main structure of the floating roof. Depending on the seal type, this repair may require that the storage vessel be taken out of service. When the storage vessel is emptied, the floating roof will land on support legs or, if suspended by cables, reach a fixed height position. Commonly, the support legs or cable suspension will have two different fixed settings. One setting would be at a low height (for example, one foot) to maximize the working volume of the storage vessel when it is in service. The other setting would be a high "maintenance" height that allows maintenance crews to enter the storage vessel and walk under the roof once the floating roof is landed and the storage vessel is emptied. The vapor space can have significant volatile content due to volatilization of the organic liquid as the storage vessel is emptied or from liquid film that may cling to the wall and floor after the tank is emptied. The VOC emissions from the emptying and degassing process is dependent on the vapor pressure of the liquid stored, the dimensions of the storage vessel, and the height of the floating roof when landed (for maintenance), which impacts the size of the vapor space below the floating roof. The EPA evaluated different scenarios in which a control device could be utilized to achieve a 98 percent destruction efficiency until the vapor space concentration is within 10 percent of the lower explosive limit (LEL).

We evaluated the cost and VOC emissions for a wide variety of storage vessel sizes and VOL contents. We found that degassing controls were generally only cost-effective for larger storage vessels with vapor pressures greater than 1.5 psia. We evaluated the following options to determine the applicability threshold for control during degassing events:

- Baseline: Uncontrolled degassing.
- Degassing Option 1: Control degassing for storage vessels with a capacity of 1-million gallon or more storing organic liquids with a maximum true vapor pressure of 1.5 psia or more.
- Degassing Option 2a: Control degassing for storage vessels with a capacity of 300,000 gallon or more storing organic liquids with a maximum true vapor pressure of 1.5 psia or more.
- Degassing Option 2b: Control degassing for storage vessels with a capacity of 1-million gallon or more storing organic liquids with a maximum true vapor pressure of 0.5 psia or more.

Degassing Options 2a and 2b were both evaluated against Degassing Option 1 to evaluate whether lowering the size threshold or lowering the vapor pressure threshold could be cost-effective. Nationwide impacts were estimated based on our projected distribution of storage vessels. Furthermore, we estimated that storage vessels would be emptied and degassed once every 10 years. For more details regarding the nationwide estimated of degassing emissions and costs and emission reductions for degassing controls, see memorandum *Control Options for Storage Vessels* in Docket ID No. EPA–HQ–OAR–2023–0358. The nationwide impacts projected for the degassing control options are summarized in Table 7 of this preamble. We evaluated the cost effectiveness and incremental cost effectiveness of the three different options. While all three options were cost-effective, degassing option 1 was selected because the incremental cost effectiveness of the remaining options exceeded reasonable values established for the control of VOC emissions in prior rulemaking. Based on our analysis, we are proposing that, for degassing emissions, a control device utilized to achieve a 98 percent destruction efficiency is the BSER for storage vessels with a capacity of 1-million gallon or more storing organic liquids with a maximum true vapor pressure of 1.5 psia or more. The EPA's consideration of non-air quality health and environmental impacts as well as energy requirements is the same as considered for control devices in section III.F. Accordingly, the EPA proposes to establish a standard of performance of 98 percent control until the vapor space concentration is within 10 percent of the LEL for these storage vessels that applies during degassing events.

The EPA solicits comment on the proposed BSER and standard of performance for degassing events, including the applicability threshold for application of those standards.

TABLE 7—SUMMARY OF NATIONAL IMPACTS FOR DEGASSING CONTROLS

| Control option | VOC emissions (tpy) | VOC emissions reduction (tpy) | TAC [1] without product recovery (million $/yr) | CE [2] ($/ton VOC) | ICE [3] ($/ton VOC) |
|---|---|---|---|---|---|
| Baseline | 33.30 | ..... | ..... | ..... | ..... |
| Degassing Option 1 | 18.92 | 14.38 | $69,860 | $4,859 | ..... |
| Degassing Option 2a | 14.89 | 18.41 | 119,000 | 6,465 | $12,196 |
| Degassing Option 2b | 13.38 | 19.92 | 129,740 | 6,514 | 10,809 |

[1] Total annualized costs (TAC) considering annualized cost of capital.
[2] Cost effectiveness (CE).
[3] Incremental cost effectiveness (ICE). The ICE of Degassing Options 2a and 2b are calculated against Degassing Option 1.

*J. What requirements are we proposing for storage vessel testing, monitoring, and inspections and why?*

Because the NSPS reflects BSER under conditions of proper operation and maintenance, in doing our review, we also evaluate and determine the proper testing, monitoring, recordkeeping and reporting requirements needed to ensure compliance with the requirements of NSPS subpart Kc. This section includes our discussion on current testing and monitoring requirements of the NSPS subpart Kb and any revisions or additions we are proposing to include for NSPS subpart Kc.

We reviewed and compared monitoring and inspection requirements across several rules, including NSPS subpart Kb and the storage vessel requirements in 40 CFR part 63, subpart WW and 40 CFR part 65, subpart C. Generally, these requirements are similar to each other, and we strove to develop monitoring and inspection requirements consistent with these federal standards and that provide the best clarity for the specific requirements. However, we note that the

current NSPS subpart Kb includes provision for inspections every 5 years for IFRs that have a dual seal system. We are proposing to require dual seal IFRs for storage vessels with a maximum vapor pressure less than 11.1 psia, but as discussed later in this section, we are also proposing the use of lower explosive limit (LEL) monitoring within the headspace of the IFR as a means to enhance inspections and more readily identify malfunctioning internal floating roofs. Because a top-side inspection can be easily conducted in conjunction with the annual LEL monitoring, we are proposing to require annual LEL monitoring and floating roof inspections for all floating roofs, including IFRs with a dual seal system.

We are proposing to add annual monitoring of IFR storage vessels using a LEL monitor to identify floating roofs with poorly functioning seals or fitting controls. We identified at least two States or localities (New Jersey rule 7:27–16 and SCAQMD Rule 1178) that have LEL monitoring for IFR storage vessels. Our emission estimates from various storage vessel requirements assume that proper seals and other equipment are in-place and operating as required. If these controls are not operating as intended, the emissions from these storage vessels can be much higher. We found that the visual inspections are subjective and may, at times, not be performed well. For example, although a hired contractor for BP's Carson Refinery had reported no problems with the facility's 26 floating roof storage vessels from 1994 to 2002, a SCAQMD inspection "revealed that more than 80 percent of the storage vessels had numerous leaks, gaps, torn seals, and other defects that caused excess emissions." [8] Therefore, for purposes of NSPS subpart Kc, we sought a less subjective means to monitor and verify performance of the floating roofs. We concluded that periodic LEL monitoring could be used to ensure the floating roofs are performing as intended.

The New Jersey and SCAQMD rules set a maximum LEL that triggers an obligation for corrective action at the storage vessel, and we modeled our proposed NSPS subpart Kc provision following these State rules. For storage vessels installed after June 1, 1984, these rules set a maximum LEL of 30 percent. However, the National Fire Protection Association (NFPA) standard sets a maximum LEL of 25 percent for explosion prevention for IFR storage vessels. Per our review, we conclude that establishing a maximum LEL level for IFR storage vessels in NSPS subpart Kc that will trigger an obligation for the owner and operator to repair the IFR, discussed further in the next paragraph, which will ensure the emission reductions expected by the application of BSER are achieved. From the data we collected, there were very few measurements that exceeded 25 percent LEL that did not also exceed 50 percent LEL. Thus, when failures occurred, the LEL was often very high. Based on these observations and considering the more stringent NFPA standard, we propose for NSPS subpart Kc, for new, modified, and reconstructed storage vessels, the use of LEL monitor to identify floating roofs with poorly functioning seals or fitting controls and we propose that the appropriate LEL levels for IFR storage vessels is 25 percent.

We acknowledge that it is difficult to estimate the emission impacts of these LEL monitoring requirements because we do not have data on the number of poorly functioning floating roofs. NSPS subpart Kb already requires repair of floating roofs that fail inspection and failure of the proposed NSPS subpart Kc LEL monitoring would trigger the same repairs. As such, we consider that these repairs are already required in NSPS subpart Kb and the LEL requirement predominately makes the required inspections less subjective. In the worst-case scenario, a poorly operated IFR storage vessel can have emissions similar to those of a fixed roof storage vessel. In establishing the floating roof requirements, we already determined that installing a floating roof was cost-effective and that the costs of replacing a poorly functioning floating roof is not significantly different from the costs of retrofitting a fixed roof storage vessel. In our cost analysis, we projected floating roofs have a 15-year life, so our annualized costs account for IFR replacement every 15 years. We expect that most poorly performing floating roofs can be repaired, rather than replaced, but we expect that replacement will be necessary in some cases. We propose to require in NSPS subpart Kc that for new, modified, and reconstructed storage vessels whose IFRs have failed to the point that 25 percent LEL is exceeded, the owner or operator must repair the IFR and, if necessary, to replace the IFR when repairs are ineffective.

We are proposing in NSPS subpart Kc specific testing requirements when monitoring LEL for storage vessels with IFRs. We are proposing that LEL standard be assessed on a 5-minute rolling average basis and that LEL monitoring be conducted for a minimum of 20 minutes unless an exceedance is measured prior to completing 20 minutes of LEL monitoring. We are proposing that LEL be measured within the storage vessel no more than 3 feet above the IFR. We are proposing that LEL monitoring be conducted when the wind speed at the top of the tank is 5 miles per hour or less where practicable, but the testing will be invalid and must be reconducted at a later date (no later than 30 days from the previous attempted measurement) if the wind speed at the top of the tank is greater than the annual average wind speed at the site's location or 15 miles per hour, whichever is less.

The EPA solicits comment on the proposed testing, monitoring, and inspection requirements, including whether our selection of maximum 25 percent LEL is appropriate, or whether this number should be higher or lower.

There are a number of other monitoring and inspection requirements included as part of this proposal. The EPA is proposing equipping floating roof storage vessels with a visual or audible alarm system to monitor when the floating roof approaches specified landing heights. For closed vent systems, the EPA is proposing quarterly visual, audible, and olfactory inspections, annual EPA Method 21 instrument monitoring, and monitoring of bypasses. The EPA also proposes that storage vessels using closed vent systems and control devices must equip pressure relief devices with appropriate monitoring to identify releases.

The EPA is proposing specific requirements for flare and non-flare control devices to ensure they achieve the required control efficiency on an ongoing basis. Specifically, we are proposing initial testing of non-flare control devices and periodic testing every five years. During the performance test, the owner or operator would set an operating limit on the control device; continuous compliance with the operating limit would be demonstrated on a 3-hour rolling average basis. We propose that flares would be monitored consistent with the flare requirements in 40 CFR part 63 subpart CC.

Lastly the EPA is proposing applying the requirements in 40 CFR 60.116b(f) for waste mixtures to all mixtures with indeterminate or variable compositions.

### *K. Proposal of NSPS Subpart Kc Without Startup, Shutdown, and Malfunction Exemptions*

In its 2008 decision in *Sierra Club* v. *EPA*, 551 F.3d 1019 (D.C. Cir. 2008), the United States Court of Appeals for the District of Columbia Circuit (D.C.

[8] Mokhiber, Russell. Multinational Monitor; Washington Vol. 24, Iss. 4, (April 2003): 30.

Circuit) vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and (h)(1), holding that under section 302(k) of the CAA, emissions standards or limitations must be continuous in nature and that the SSM exemption violates the CAA's requirement that some section 112 standard apply continuously. The EPA has determined the reasoning in the Court's decision in *Sierra Club* applies equally to CAA section 111 because the definition of emission or standard in CAA section 302(k), and the embedded requirement for continuous standards, also applies to the NSPS.

Consistent with *Sierra Club* v. *EPA,* we are proposing standards in this rule that apply at all times. The NSPS general provisions in 40 CFR 60.11(c) currently exclude opacity requirements during periods of SSM and the provision in 40 CFR 60.8(c) contains an exemption from non-opacity standards. We are proposing in NSPS subpart Kc specific requirements at 40 CFR 60.112c(a)(1) that override the general provisions for SSM provisions. We are proposing a combination of design, equipment, work practice, and operational standards in NSPS subpart Kc that apply at all times.

The EPA has attempted to ensure that the general provisions we are proposing to override are inappropriate, unnecessary, or redundant in the absence of the SSM exemption. We are specifically seeking comment on whether we have successfully done so.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through "the application of the best system of emission reduction" that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting emissions standards, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a "normal or usual manner" and no statutory language compels EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting "achievable" standards under CAA section 112) has been upheld as reasonable by the D.C. Circuit in *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (2016).]

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, sudden, infrequent, not reasonably preventable, and was not instead caused, in part, by poor maintenance or careless operation. 40 CFR 60.2 (definition of "Malfunction").

If the EPA determines in a particular case that an enforcement action against a source for violation of an emission standard is warranted, the source can raise any and all defenses in that enforcement action and the Federal District Court will determine what, if any, relief is appropriate. The same is true for citizen enforcement actions. Similarly, the presiding officer in an administrative proceeding can consider any defense raised and determine whether administrative penalties are appropriate.

In summary, the EPA proposes that its interpretation of the CAA and, in particular, CAA section 111 is reasonable and encourages practices that will avoid malfunctions. Administrative and judicial procedures for addressing exceedances of the standards fully recognize that violations may occur despite good faith efforts to comply and can accommodate those situations. *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (2016).

### *L. Electronic Reporting*

The EPA is proposing that owners and operators of volatile organic liquid storage vessels (including petroleum liquid storage vessels) subject to NSPS subpart Kb and NSPS subpart Kc, submit electronic copies of certain required notifications and reports through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). A description of the electronic data submission process is provided in the memorandum *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* available in the docket for this action. Specifically, the proposed rule requires that for NSPS subpart Kb the reports specified in 40 CFR 60.115b(a)(1), 60.115b(a)(3), 60.115b(a)(4), 60.115b(b)(1), 60.115b(b)(2), 60.115b(b)(4), 60.115b(d)(1), 60.115b(d)(3), and 60.116b(d) be submitted as a portable document format upload in CEDRI, and for NSPS subpart Kc the rule requires that owners and operators use the appropriate spreadsheet templates to submit the initial notification specified in 40 CFR 60.116c(a) and semiannual reports specified in 40 CFR 60.116c(b) to CEDRI. Draft versions of the proposed templates for the NSPS subpart Kc initial notification and semiannual report are included in the docket for this action.[9] The EPA specifically requests comment on the content, layout, and overall design of the templates. We note that for NSPS subpart Kb, we are only proposing to change the format of the reporting requirements to require electronic reporting *(i.e.,* we are not proposing any new data elements).

Additionally, the EPA has identified two broad circumstances in which electronic reporting extensions may be provided. These circumstances are (1) outages of the EPA's CDX or CEDRI which preclude an owner or operator from accessing the system and submitting required reports and (2) *force majeure* events, which are defined as events that will be or have been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevent an owner or operator from complying with the requirement to submit a report electronically. Examples of *force majeure* events are acts of nature, acts of war or terrorism, or equipment failure or safety hazards beyond the control of the facility. The EPA is providing these potential extensions to protect owners and operators from noncompliance in

[9] See 40 CFR part_60_Subpart_Kc_60.116c(a)_Initial_Notification.xlsx and 40 CFR part_60_subpart_Kc_60.116c(b)_Semiannual_Report.xlsx, available in the docket for this action.

cases where they cannot successfully submit a report by the reporting deadline for reasons outside of their control. In both circumstances, the decision to accept the claim of needing additional time to report is within the discretion of the Administrator, and reporting should occur as soon as possible.

The electronic submittal of the reports addressed in this proposed rulemaking will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability and transparency, will further assist in the protection of public health and the environment, will improve compliance by facilitating the ability of regulated facilities to demonstrate compliance with requirements and by facilitating the ability of delegated State, local, Tribal, and territorial air agencies and the EPA to assess and determine compliance, and will ultimately reduce burden on regulated facilities, delegated air agencies, and the EPA. Electronic reporting also eliminates paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing data reporting errors, and providing data quickly and accurately to the affected facilities, air agencies, the EPA, and the public. Moreover, electronic reporting is consistent with the EPA's plan [10] to implement Executive Order 13563 and is in keeping with the EPA's agency-wide policy [11] developed in response to the White House's Digital Government Strategy.[12] For more information on the benefits of electronic reporting, see the memorandum *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* referenced earlier in this section.

### *M. Other Proposed Actions*

NSPS subpart Kb includes a number of technical methods which have been updated or replaced in the NSPS subpart Kc proposal. Two of these methods, American Society for Testing and Materials (ASTM) D2879 and American Petroleum Institute (API) Bulletin 2517, are used in determining vapor pressures including the maximum true vapor pressure.

We propose to replace ASTM D2879, "Standard Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope," with both ASTM D6378–22, "Standard Test Method for Determination of Vapor Pressure (VPX) of Petroleum Products, Hydrocarbons, and Hydrocarbon-Oxygenate Mixtures (Triple Expansion Method)," and ASTM D6377–20 "Standard Test Method for Determination of Vapor Pressure of Crude Oil: $VPCR_x$ (Expansion Method)." This change is consistent with the actions finalized in the 2020 amendments to the Organic Liquids Distribution (OLD) NESHAP (85 FR 40740). ASTM D2879 involves both an isoteniscope and heating the sample to a boil. The proposed replacement is an automated device method that produces more accurate vapor pressure measurements. ASTM D6378–22 is used for measuring vapor pressures between 7 kPa and 150 kPa. ASTM D6377–20 is used for measuring vapor pressures between 29 kPa and 180 kPa. For each analysis, you must use a 4:1 vapor to liquid ratio.

Additionally, we propose replacing the API Bulletin 2517, *Evaporative Loss from External Floating-Roof Tanks,* with information available in AP–42, Chapter 7. While API Bulletin 2517 does not prescribe methods for measuring liquid vapor pressure, it acts as a reference and includes a table of vapor pressures for pure substances at temperatures between 40 and 100 degrees Fahrenheit. API Bulletin 2517 also includes information for calculating Reid vapor pressures crude oil and refined petroleum stocks. AP–42, Chapter 7 includes comparable information and is publicly available. EPA is also proposing not to incorporate ASTM D323 into the proposed subpart. ASTM D323, "Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method)" is used for the determination of the Reid vapor pressure which can be used in conjunction with ASTM D2879 for determining vapor pressures. The inclusion of ASTM D6378 and ASTM D6377, makes the need for ASTM D323 unnecessary in the proposed standard.

### *N. Compliance Dates*

Pursuant to CAA section 111(b)(1)(B), the effective date of the final rule requirements in NSPS subpart Kc will be the promulgation date. Affected sources that commence construction, reconstruction, or modification after October 4, 2023 must comply with all requirements of NSPS subpart Kc, no later than the effective date of the final rule or upon startup, whichever is later. The EPA is proposing amendments to NSPS subpart Kb to include electronic submission requirements. Affected NSPS subpart Kb sources that commence construction, reconstruction or modification after July 23, 1984, and before October 4, 2023 must comply with the updated requirements to submit reports electronically no later than the effective date of the final rule.

## IV. Summary of Cost, Environmental, and Economic Impacts

### *A. What are the air quality impacts?*

The proposed revisions in NSPS subpart Kc reduce emissions of VOCs, some of which may also be hazardous air pollutants (HAPs). The EPA estimates that the updated standards would reduce VOC emissions by 1,085 tons per year, which includes the impacts from new, modified, and reconstructed storage vessels. More information regarding the air quality impacts and emission reductions are included in the memorandum *Control Options for Storage Vessels.*

### *B. What are the cost impacts?*

This final action will cost (in 2022 dollars) approximately $20.6 million in total capital cost and result in total annualized cost savings of $4.48 million per year (including product recovery) based on our analysis of the proposed actions in NSPS subpart Kc. More information about the estimated cost of the proposed actions can be found in the memorandum *Control Options for Storage Vessels.*

### *C. What are the economic impacts?*

For economic impact analyses of rules that directly affect a single or a few industries, the EPA often prepares a partial equilibrium analysis. In this type of economic analysis, the focus of the effort is on estimating impacts on a single affected industry or several affected industries, and all impacts of this rule on industries outside of those affected are assumed to be zero or so inconsequential to not be considered in the analysis. If the compliance costs, which are key inputs to an economic impact analysis, are quite insignificant, then the impact analysis could consist of a calculation of annual (or annualized) costs as a percentage of sales for affected companies. This latter type of analysis is called a screening analysis and is applied when a partial equilibrium or more complex economic impact analysis approach is deemed not

[10] EPA's Final Plan for Periodic Retrospective Reviews, August 2011. Available at: *https://www.regulations.gov/document?D=EPA-HQ-OA-2011-0156-0154.*

[11] E-Reporting Policy Statement for EPA Regulations, September 2013. Available at: *https://www.epa.gov/sites/default/files/2016-03/documents/epa-ereporting-policy-statement-2013-09-30.pdf.*

[12] Digital Government: Building a 21st Century Platform to Better Serve the American People, May 2012. Available at: *https://obamawhitehouse.archives.gov/sites/default/files/omb/egov/digital-government/digital-government.html.*

necessary given the expected size of the impacts.

The net present value of the estimated cost impacts of the proposed NSPS subpart Kc is $18.9 million, discounted at a 3 percent rate over a 5-year analytic time frame from 2024 to 2028 in 2022 dollars. Using a 7 percent discount rate, the net present value of the estimated cost impacts is $16.9 million. The equivalent annualized value in 2022 dollars is a cost of approximately $4.1 million using a discount rate of three and seven percent.

Storage vessels in NSPS subpart Kb are most closely associated with the petroleum and coal products industry (NAICS 324000), chemical products industry (NAICS 325000), and the petroleum bulk stations terminals industry (NAICS 424710). While we do not know the precise distribution of new and modified storage vessels across the affected sectors, we know that there are affected storage vessels in the sectors mentioned earlier in this preamble. These sectors contribute gross value added, ranging from $129 to $440 billion per sector, to the national economy. In comparison, the proposed requirements in NSPS subpart Kc have estimated total costs of $20.6 million. The total cost is the total incurred collectively amongst numerous sectors, and each of the sectors examined have sales of at least $129 billion. Thus, the compliance costs of this action are insignificant relative to the scale for the sectors affected, and it is appropriate to evaluate the economic impacts by conducting a screening analysis comparing the costs to entity-level sales.

Given the results of the analysis, these economic impacts are relatively low for affected industries and entities impacted by this proposed rule, and there will not be substantial impacts on the markets for affected products. The costs of the proposed rule are not expected to result in a significant market impact, regardless of whether they are passed on to the purchaser or absorbed by the firms. We also expect minimal impacts on employment.

*D. What are the benefits?*

These proposed revisions in NSPS subpart Kc would reduce emissions of VOCs, some of which may also be HAPs. Because VOCs react in the atmosphere to produce ozone, these standards would help to reduce atmospheric ozone concentrations and reduce health effects associated with high levels of ozone. Furthermore, the proposed requirements to submit reports and test results electronically would improve monitoring, compliance, and implementation of the rule.

*E. What analysis of environmental justice did we conduct?*

Executive Order 12898 directs the EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms, which are specifically minority populations (people of color), low-income populations, and Indigenous peoples (59 FR 7629, February 16, 1994). Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through Federal government actions (86 FR 7009, January 20, 2021). The EPA defines environmental justice (EJ) as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies." [13] The EPA further defines fair treatment to mean that "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies." In recognizing that people of color and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution. For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis," [14] which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) Create new disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; (2) exacerbate existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; or (3) present opportunities to address existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples through this action under development.

We are unable to quantitatively estimate the potential EJ impact of NSPS subparts Kb and Kc for the following reasons. Over the next 5 years, the EPA estimates that 1,440 new tanks and 27 modified tanks would be subject to NSPS subpart Kc. However, the locations of any new VOL storage vessels that would be subject to NSPS subpart Kc are unknown. Furthermore, there is insufficient data available regarding the locations of existing VOL storage vessels. We estimate that there are approximately more than 10,000 existing Volatile Organic Liquid Storage Vessels, but do not have a list of specific units and their locations. Therefore, we cannot perform a proximity demographic analysis of populations near existing units as a proxy for units that may be modified or reconstructed and become subject to NSPS subpart Kc. Finally, because we based the analysis of the impacts and emission reductions on model plants, we are not able to ascertain specifically how the potential benefits of this rule would be distributed across the population. Thus, we are limited in our ability to estimate the potential EJ impacts of this rule.

However, we anticipate the proposed requirements in NSPS subpart Kc would generally minimize future emissions in surrounding communities of new, modified, or reconstructed VOL storage vessels. The three most relevant industry NAICS industry segments affected under NSPS Kc include Petroleum and Coal Products Manufacturing (NAICS code 324000), Chemical Manufacturing (NAICS code 325000), and Petroleum and Bulk Stations and Terminals (NAICS code 422710). Specifically, the EPA determined that the standards should be revised to amend the vapor pressure applicability thresholds, require stricter seal requirements on IFR tanks, establish equivalent control requirements for external floating roofs, and strengthen the closed vent system standard to account for 98 percent destruction efficiency. The changes would have beneficial effects on air quality and public health for populations exposed to emissions from new, modified or reconstructed VOL storage vessels and would provide additional health protection for affected populations, including communities already overburdened by pollution, which are often people of color, low-income, and indigenous communities.

## V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be

[13] *https://www.epa.gov/environmentaljustice.*

[14] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

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September 17, 2025

Mr. Michael Rael
Air Quality Supervisor
Clark County DAQ
4701 West Russell Road
Suite 200
Las Vegas NV 89118-2231

**RE: 2025 RACT Requirements Review**
**Calnev Pipe Line, LLC – Las Vegas Terminal, Part 70 Permit Number 13**
**5049 North Sloan Lane, Las Vegas, NV 89115**

Dear Mr. Rael:

Please find enclosed the response to the September 8, 2025 letter regarding New Source Performance Standard (NSPS) Subpart Kc and Calnev Pipe Line, LLC Las Vegas Terminal's (Calnev) Reasonably Available Control Technology (RACT).

Per the September 8, 2025 letter, Air Quality Regulation (AQR) 120.5(c) requires RACT determinations submitted within the past 36 months to continue to be RACT because there are no changes to the available control technologies, technical feasibility, control effectiveness, cost-effectiveness, or environmental, energy, or other impacts since that determination was initially performed. The letter also notes that since NSPS Subpart Kc was updated after the October 2022 RACT determination, it should be included in the current RACT submittal. The letter also notes that NSPS Subpart Kc, does not apply to Calnev, since the facility has not commenced construction, reconstruction, or modification of any applicable volatile organic liquid storage vessel after October 4, 2023.

As part of the evaluation of NSPS Kc, Calnev conducted a review of the NSPS Subpart Kc rule text, including the preamble as located in 89 FR 83296, originally published October 15, 2024 and a memorandum from the United States Environmental Protection Agency (USEPA) titled "Control Options for Storage Vessels (Docket ID No. EPA-HQ-OAR-2023-0358-0002)."

In the preamble text of NSPS Subpart Kc, the USEPA finalized standards which reflect the best source of emission reduction (BSER), which is the equivalent of the best available control technology (BACT) and stated that the final standards are consistent with the determinations explained in the rulemaking proposal (88 FR 68540-47; October 4, 2023), and the analysis in the Control Options for Storage Vessels memo. Under NSPS Subpart Kc, USEPA proposed emission controls based on vapor pressure thresholds and vessel size with an emission reduction cost of

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approximately $6,000 and $7,000 dollars per ton of volatile organic compounds (VOCs) reduced respectively. To meet these thresholds, EPA proposed multiple different options with varying levels of control and cost. These options are described in detail below:

| **Detailed IFR Storage Vessel Parameters for each tank configuration.** | | | | |
|---|---|---|---|---|
| **Input Parameter** | **IFR-Kb** | **IFR-1** | **IFR-2** | **IFR-3** |
| **Tank Construction** | Welded | Welded | Welded | Welded |
| **Tank Surface Color** | Gray, Light | Gray, Light | Gray, Light | Gray, Light |
| **Tank Surface Condition** | Average | Average | Average | Average |
| **Shell Condition** | Light Rust | Light Rust | Light Rust | Light Rust |
| **Roof Support** | Self Supported | Self Supported | Self Supported | Self Supported |
| **Column Type** | N/A | N/A | N/A | N/A |
| **Seal Fit** | Average | Average | Average | Average |
| **Deck Type** | Bolted | Bolted | Bolted | *Welded* |
| **Deck Construction** | Panel - 5 x 7.5 ft rectangular | Panel - 5 x 7.5 ft rectangular | Panel - 5 x 7.5 ft rectangular | *N/A* |
| **Primary Seal** | Mechanical Shoe | Mechanical Shoe | Mechanical Shoe | Mechanical Shoe |

| | | | | |
|---|---|---|---|---|
| **Secondary Seal** | None | Rim mounted | Rim mounted | Rim mounted |
| **Access Hatch** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Guidepoles** | Slotted guidepole/sample well, gasketed sliding cover, with float and pole wiper | Slotted guidepole/sample well, gasketed sliding cover, with float and pole wiper | Slotted guidepole/sample well, gasketed sliding cover, with float and pole wiper | *Slotted guidepole/sample well, gasketed sliding cover, with pole sleeve and pole wiper* |
| **Gauge-float well** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Gauge-hatch/Sample Port** | Slit fabric seal, 10% open area | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Vacuum Breaker** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Deck Leg** | Adjustable | Adjustable | *Fixed* | Fixed |
| **Rim Vent** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |

Of the options listed above, it was determined that the IFR-Kb & IFR-1 options met the definition of BSER/BACT. As a base line, the USEPA evaluated additional IFR storage vessel configurations including the following for new or reconstructed storage vessels with a maximum true vapor pressure less than 11.1 psia:

- Baseline: NSPS Subpart Kb control requirements (with NSPS Subpart Kc proposed lower vapor pressure thresholds).

- Option IFR-1. NSPS Subpart Kb, but primary seal must be either liquid-mounted or mechanical shoe seal and must have a rim-mounted secondary seal.

- Option IFR-2. Option 1 requirements while requiring fixed roof legs or cable suspended roof (cannot have adjustable roof legs that penetrate through the floating roof)

- Option IFR-3. Option 2 requirements + requiring welded seams and best guidepole fittings.

All three of the listed options above also include provisions for requiring gauge-hatches/sample ports to be gasketed. It was determined that all of the IFR control options, BSER for vessels with a vapor pressure less than 11.1 psia is option IFR-1. Specifically, EPA proposed to require that the primary seal must either be liquid-mounted or mechanical shoe seal and must have a rim-mounted secondary seal, that gauge-hatches/sample ports to be gasketed, and that guide pole configurations incorporate the provisions outlined in the 2000 EPA Storage Tank Emission Reduction Partnership Program (STERPP) as the BSER.

For modified storage vessels, EPA assumed that modified storage vessels will have existing fixed roofs, because IFRs were not previously required by NSPS Subpart Kb. The costs of retrofitting a fixed roof storage vessel with an IFR are approximately the same as the cost of adding an IFR to a new storage vessel. Whereas some "modified" storage vessels that trigger into the NSPS, may already have an IFR, and upgrading only certain elements of the IFR can have significantly different costs than when installing a new IFR. Therefore, the BSER for modified storage vessels is separate depending on whether or not the vessel had existing IFRs prior to modification. Ultimately, it was determined that Option IFR-1 is the BSER for existing storage vessels with a maximum TVP less than 11.1 psia that modify and do not have an existing floating roof. However, for storage vessels with an existing IFR, the NSPS Subpart Kb control requirements without upgrading the rim seal requirements represent the application of BSER and EPA proposed to retain those standards for sources in NSPS Subpart Kc.

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For newly constructed/reconstructed external floating roof tanks, the US EPA proposed the following configurations:

| External Floating Roof vessel parameters for each tank configuration | | | | |
|---|---|---|---|---|
| **Input Parameter** | **EFR-Kb** | **EFR-1** | **EFR-2** | **EFR-3** |
| **Tank Surface Color** | Gray, Light | Gray, Light | Gray, Light | Gray, Light |
| **Tank Surface Condition** | Average | Average | Average | Average |
| **Internal Shell Condition** | Light Rust | Light Rust | Light Rust | Light Rust |
| **Roof Type** | Pontoon | Pontoon | Pontoon | Pontoon |
| **Tank Construction** | Welded | Welded | Welded | Welded |
| **Deck Construction** | Welded | Welded | Welded | Welded |
| **Seal Fit** | Average | Average | Average | Average |
| **Primary Seal** | Mechanical Shoe | Mechanical Shoe | *Liquid-mounted* | Liquid-mounted |
| **Secondary Seal** | Rim-Mounted | Rim-Mounted | Rim-Mounted | Rim-Mounted |

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| | | | | |
|---|---|---|---|---|
| **Access Hatch** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Guidepoles** | Slotted Guidepole/sample well, gasketed sliding cover, with float and pole wiper | *Unslotted guidepole and well, gasketed sliding cover w/ pole wiper* | *Slotted guidepole/sample well, gasketed sliding cover, with pole sleeve and pole wiper* | *Unslotted guidepole and well, gasketed sliding cover w/ pole wiper* |
| **Gauge-float well** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Gauge-hatch/sample port** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Vacuum Breaker** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Deck Leg (pontoon area of pontoon roofs)** | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed |
| **Deck Leg (double deck roofs and center area of pontoon roofs)** | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed |
| **Rim Vent** | Weighted mechanical | Weighted mechanical | Weighted mechanical | Weighted mechanical |

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| | | | | |
|---|---|---|---|---|
| | actuation, gasketed | actuation, gasketed | actuation, gasketed | actuation, gasketed |

For existing EFR storage vessels, like existing IFR storage vessels, improvements to the floating roof and guidepole design would not result in significant additional emission reductions beyond those achieved by the use of the EFR itself. As a result, for NSPS Subpart Kc, it was determined that if a modified tank has an existing EFR, the BSER and standard of performance is consistent with the EFR requirements in NSPS Subpart Kb.

Further information and analysis from the tables is provided in Attachments A & B.

The other control technology that is referenced in NSPS Subpart Kc is a closed vent system routed to a control device, fuel gas system, or process. Calnev does not utilize this method of control since this method generally applies to storage vessels storing an organic liquid with a true maximum vapor pressure of 11.1 psia or greater.

Based on this information, the US EPA is not proposing any new reasonably available control technologies in NSPS Subpart Kc, but is instead restating that for existing sources, the control requirements found in NSPS Subpart Kb are sufficient to meet BSER/BACT. In addition, it should be noted that there is currently an active petition for reconsideration and request for administrative stay of NSPS Subpart Kc (Case Nos.: 24-1377 and 24-1379). See Attachment C.

If you have any questions, please contact Seth Tate at (713) 420-6076 or via email at Seth_Tate@KinderMorgan.com.

In accordance with Section 120.5(c), I certify that based on information and belief formed after reasonable inquiry, the attached determination continues to represent the reasonably available control technology (RACT) requirements. There have been no changes to available control technologies, technical feasibility, control effectiveness, cost-effectiveness, or environmental, energy, and other impacts since the original determination.

Duncan Sinclair
Director of Operations
For Calnev Pipe Line, LLC

**FEDEX Tracking No.: 3932 7457 9136**

Cc: Troy Otramba, Jeremy Shenk, Nina McAfee, Seth Tate – Calnev Pipe Line LLC.

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Enclosures:

A. Relevant Portions of 88 Federal Register 68535 dated October 4, 2023 "Proposed Rules"
B. "Control Options for Storage Vessels" dated August 11, 2023
C. ILTA & ACC Petitions for Reconsideration (Case Nos.: 24-1377 & 24-1379)

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# Attachment A

Relevant Portions of 88 Federal Register 68535 dated October 4, 2023 "Proposed Rules"

## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Part 60

**[EPA–HQ–OAR–2023–0358; FRL–10655–01–OAR]**

**RIN 2060–AV93**

## New Source Performance Standards Review for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Proposed rule.

**SUMMARY:** The Environmental Protection Agency (EPA) is proposing amendments to the Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) as the preliminary results of the review of the New Source Performance Standards (NSPS) required by the Clean Air Act. The EPA is proposing revisions to the NSPS that are applicable to volatile organic liquid (VOL) storage vessels that commence construction, reconstruction, or modification after October 4, 2023 under a new NSPS subpart. In the new NSPS subpart, the EPA is proposing to reduce the vapor pressure applicability thresholds In addition, the EPA is proposing to revise the volatile organic compound (VOC) standards to reflect the best system of emissions reductions (BSER) for affected storage vessels. We are also proposing additional monitoring and operating requirements to ensure continuous compliance with the standard. In addition, the EPA is proposing degassing emission controls; clarification of startup, shutdown, and malfunction requirements; requirements for electronic reporting; and other technical improvements. The EPA is also proposing to amend NSPS subpart Kb to apply to VOL storage vessels that commence construction, reconstruction or modification after July 23, 1984 and on or before October 4, 2023 and to add electronic reporting requirements.

**DATES:**

*Comments.* Comments must be received on or before November 20, 2023. Comments on the information collection provisions submitted to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (PRA) are best assured of consideration by OMB if OMB receives a copy of your comments on or before November 3, 2023.

*Public Hearing.* If anyone contacts us requesting a public hearing on or before October 10, 2023, we will hold a virtual hearing. Please refer to the **SUPPLEMENTARY INFORMATION** for information on requesting and registering for a public hearing.

**ADDRESSES:** You may send comments, identified by Docket ID No. EPA–HQ–OAR–2023–0358, by any of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2023–0358 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2023–0358.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2023–0358, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal Holidays).

*Instructions:* All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov,* including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section of this document.

**FOR FURTHER INFORMATION CONTACT:** For questions about this proposed action, contact U.S. EPA, Attn: Michael Cantoni, Mail Drop: E143–01, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711; telephone number: (919) 541–5593; and email address: *Cantoni.Michael@epa.gov.*

**SUPPLEMENTARY INFORMATION:**

*Participation in virtual public hearing.* To request a virtual public hearing, contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.* If requested, the virtual hearing will be held on October 19, 2023. The hearing will convene at 11:00 a.m. Eastern Time (ET) and will conclude at 3:00 p.m. ET. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will announce further details at *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum.*

If a public hearing is requested, the EPA will begin pre-registering speakers for the hearing no later than 1 business day after the publication of this document in the **Federal Register**. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum* or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.* The last day to pre-register to speak at the hearing will be October 16, 2023. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers at: *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to submit a copy of their oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum.* While the EPA expects the hearing to go forward as described in this section, please monitor our website or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of a translator or a special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by October 11, 2023. The EPA may not be able to arrange accommodations without advanced notice.

*Docket.* The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2023–0358. All

documents in the docket are listed in the *Regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy.

*Written Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2023–0358, at *https://www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to EPA's docket at *https://www.regulations.gov* any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed in the *Submitting CBI* section of this document.

Multimedia submissions (audio, video, *etc.*) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the Web, cloud, or other file sharing system). Please visit *https://www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI or multimedia submissions; and general guidance on making effective comments.

The *https://www.regulations.gov* website allows you to submit your comment anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *https://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses.

*Submitting CBI.* Do not submit information containing CBI to the EPA through *https://www.regulations.gov.* Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, note the docket ID, mark the outside of the digital storage media as CBI, and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in the *Written Comments* section of this document. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the docket ID. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings and note the docket ID. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. If sending CBI information through the postal service, please send it to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404–02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711, Attention Docket ID No. EPA–HQ–OAR–2023–0358. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

*Preamble acronyms and abbreviations.* Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

API American Petroleum Institute
ASTM American Society for Testing and Materials
BSER best system of emission reduction
CAA Clean Air Act
CBI Confidential Business Information
CDX Central Data Exchange
CE cost effectiveness
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
EFR external floating roof
EIA economic impact analysis
EJ environmental justice
EPA Environmental Protection Agency
ET Eastern Time
FR Federal Register
HAP hazardous air pollutant(s)
ICE incremental cost effectiveness
ICR information collection request
IFR internal floating roof
kPa kilopascals
LEL lower explosive limit
$m^3$ cubic meters
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PRA Paperwork Reduction Act
psia pounds per square inch absolute
psig pounds per square inch gauge
RFA Regulatory Flexibility Act
RIN Regulatory Information Number
SCAQMD South Coast Air Quality Management District
SSM startup, shutdown, and malfunctions
TAC total annualized cost
TCI total capital investment
tpy tons per year
UMRA Unfunded Mandates Reform Act
U.S.C. United States Code
VOC volatile organic compound(s)
VOL volatile organic liquid(s)

*Organization of this document.* The information in this preamble is organized as follows:

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## I. General Information

### *A. Does this action apply to me?*

The source category that is the subject of this proposal is composed of VOL storage vessels regulated under Clean Air Act (CAA) section 111, New Source Performance Standards. The 2022 North American Industry Classification System (NAICS) codes for this source category are 325, 324, and 422710. The NAICS codes serve as a guide for readers outlining the entities that this proposed action is likely to affect. The proposed standards, once promulgated, will be directly applicable to affected facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Federal, State, local and Tribal government entities that own and/or operate storage vessels would be affected by this action.

### *B. Where can I get a copy of this document and other related information?*

In addition to being available in the docket, an electronic copy of this action is available on the internet at *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposal and key technical documents at this same website.

A memorandum showing the edits that would be necessary to incorporate the changes to 40 CFR part 60, subparts Kb and Kc proposed in this action is available in the docket (Docket ID No. EPA–HQ–OAR–2023–0358). Following signature by the EPA Administrator, the EPA also will post a copy of this document to *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum.*

## II. Background

### *A. What is the statutory authority for this action?*

The EPA's authority for this proposed rule is CAA section 111, which governs the establishment of standards of performance for stationary sources. Section 111(b)(1)(A) of the CAA requires the EPA Administrator to list categories of stationary sources that in the Administrator's judgment cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for new (and modified or reconstructed) sources in each source category pursuant to CAA section 111(b)(1)(B). These standards are referred to as new source performance standards, or NSPS. The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, set the emission level of the standards, and distinguish among classes, types, and sizes within categories in establishing the standards.

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years review and, if appropriate, revise" new source performance standards. However, the Administrator need not review any such standard if the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an existing performance standard, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." The term "standard of performance" in CAA section 111(a)(1) makes clear that the EPA is to determine both the best system of emission reduction (BSER) for the regulated sources in the source category and the degree of emission limitation achievable through application of the BSER. The EPA must then, under CAA section 111(b)(1)(B), promulgate standards of performance for new sources that reflect that level of stringency. CAA section 111(b)(5) generally precludes the EPA from prescribing a particular technological system that must be used to comply with a standard of performance. Rather, sources can select any measure or combination of measures that will achieve the standard. CAA section 111(h)(1) authorizes the Administrator to promulgate "a design, equipment, work practice, or operational standard, or combination thereof" if in his or her judgment, "it is not feasible to prescribe or enforce a standard of performance." CAA section 111(h)(2) provides the circumstances under which prescribing or enforcing a standard of performance is "not feasible," such as, when the pollutant

cannot be emitted through a conveyance designed to emit or capture the pollutant, or when there is no practicable measurement methodology for the particular class of sources.

Pursuant to the definition of new source in CAA section 111(a)(2), standards of performance apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Under CAA section 111(a)(4), "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Changes to an existing facility that do not result in an increase in emissions are not considered modifications. Under the provisions in 40 CFR 60.15, reconstruction means the replacement of components of an existing facility such that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

*B. What is this source category and what are the current NSPS requirements?*

The EPA promulgated NSPS subpart K, specific to storage vessels for petroleum liquids, in 1974 (39 FR 9317, March 8, 1974). These standards were amended several times before 1980, when EPA proposed to establish revised NSPS for storage vessels for petroleum liquids as NSPS subpart Ka (45 FR 23379, April 4, 1980). In 1982, the EPA published a list of priority sources for which additional NSPS should be established (47 FR 951, January 8, 1982), and VOL storage vessels at synthetic organic chemical manufacturers were included in the priority list. Pursuant to the EPA's authority under CAA section 111, the Agency proposed (49 FR 29698, July 23, 1984) and promulgated (52 FR 11420, April 8, 1987) NSPS for volatile organic liquid storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction, or modification commenced after July 23, 1984, as NSPS subpart Kb.[1] NSPS subpart Kb regulates storage vessels with a capacity of 75 cubic meters ($m^3$) (~20,000 gallons) or more that store VOLs with a true vapor pressure over 15.0 kilopascals (kPa) (~2.18 psia), and from storage vessels with a capacity of 151 $m^3$ (~40,000 gallons) or more that store organic liquids with a true vapor pressure over 3.5 kPa (~0.51 psia). VOC emissions controls are required on storage vessels with a capacity of 75 cubic meters ($m^3$) (~20,000 gallons) or more that store VOLs with a true vapor pressure over 27.6 KPa (~4.0 psia), and from storage vessels with a capacity of 151 $m^3$ (~40,000 gallons) or more that store organic liquids with a true vapor pressure over 5.2 kPa (~0.75 psia). NSPS subpart Kb emission controls include the use of either an external floating roof (EFR), an internal floating roof (IFR), or a closed vent system and a control device (see 40 CFR 60.110b(a) and 40 CFR 60.112b(a) and (b)). [2] NSPS subpart Kb also specifies testing, monitoring, recordkeeping, reporting, and other requirements in 40 CFR 60.113b through 40 CFR 60.116b to ensure compliance with the standards. Storage vessels with an EFR consist of an open-top cylindrical steel shell equipped with a deck that floats on the surface (commonly referred to as a floating "roof") of the stored liquid. Storage vessels with an IFR are fixed roof vessels [3] that also have a deck internal to the vessel that floats on the liquid surface (commonly referred to as an internal floating "roof") within the fixed roof vessel.

The standards set in NSPS subpart Kb for storage vessels with an EFR or IFR are a combination of design, equipment, work practice, and operational standards set pursuant to CAA section 111(h). These standards require, among other things, that a rim seal be installed continuously around the circumference of the vessel (between the inner wall of the vessel and the floating roof) to prevent VOC emissions from escaping to the atmosphere through gaps between the floating roof and the inner wall of the storage vessel. For IFRs, NSPS subpart Kb allows a single liquid-mounted or mechanical shoe primary seal (to be used with or without a secondary seal), or a vapor-mounted primary seal in combination with a secondary seal. For EFRs, NSPS subpart Kb allows either a liquid-mounted or mechanical shoe primary seal, both of which must be used with a secondary seal; vapor-mounted primary seals are not allowed for EFR.

NSPS subpart Kb also requires numerous deck fittings [4] on the floating roof to be equipped with a gasketed cover or lid that is kept in the closed position at all times (*i.e.,* no visible gap), except when the device (deck fitting) is in actual use, to prevent VOC emissions from escaping through the deck fittings. In addition, NSPS subpart Kb requires owners and operators to conduct visual inspections to check for defects in the floating roof, rim seals, and deck fittings (*e.g.,* holes, tears, or other openings in the rim seal, or covers and lids on deck fittings that no longer close properly) that could expose the liquid surface to the atmosphere and potentially result in VOC emission losses through rim seals and deck fittings.[5]

NSPS subpart Kb includes two primary alternative means of compliance. Owners or operators may either comply with the consolidated air rule provisions for storage vessels in 40 CFR part 65, subpart C, or comply with the national emission standards for hazardous air pollutants (NESHAP) for storage vessels in 40 CFR part 63, subpart WW. The substantive control requirements in these rules are the same as in NSPS subpart Kb although they may have slight differences in the details of the fitting and inspection requirements.

We estimate that there were approximately 9,100 storage vessels subject to NSPS subpart Kb in 2022, with an estimated 240 storage vessels becoming new affected facilities under the rule each year. Under the current NSPS subpart Kb requirements, it is generally difficult to become a modified storage vessel.

[1] On October 15, 2003 (68 FR 59329), the EPA finalized amendments to NSPS subpart Kb to exempt certain storage vessels by capacity and vapor pressure, exempt process tanks, and add a process tank definition. At the same time, the EPA also amended the rule to exempt storage vessels that are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Solvent Extraction of Vegetable Oil Production.

[2] All affected storage vessels storing organic liquids with a true vapor pressure of 76.6 kPa or more must use a closed vent system and a control device. See 40 CFR 60.112b(b).

[3] A fixed roof storage vessel consists of a cylindrical steel shell with a permanently affixed roof, which may vary in design from cone or dome-shaped to flat.

[4] Numerous fittings pass through or are attached to floating decks to accommodate structure support components or to allow for operational functions. Typical deck fittings include, but are not limited to access hatches, gauge floats, gauge-hatch/sample ports, rim vents, deck drains, deck legs, vacuum breakers, and guidepoles. IFR storage vessels may also have deck seams, fixed-roof support columns, ladders, and/or stub drains.

[5] For details about storage vessel emissions, refer to the Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, AP–42, Fifth Edition, Chapter 7: Liquid Storage Tanks, dated June 2020 which is available at: *https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors.*

*C. How does the EPA perform the NSPS review?*

As noted in section II.A of this preamble, CAA section 111 requires the EPA to, at least every 8 years, review and, if appropriate, revise the standards of performance applicable to new, modified, and reconstructed sources. If the EPA revises the standards of performance, those standards must reflect the degree of emission limitation achievable through the application of the BSER considering the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements. CAA section 111(a)(1).

In reviewing an NSPS to determine whether it is "appropriate" to revise the standards of performance, the EPA evaluates the statutory factors, which may include consideration of the following information:

- Expected growth for the source category, including how many new facilities, reconstructions, and modifications may trigger NSPS in the future.
- Pollution control measures, including advances in control technologies, process operations, design or efficiency improvements, or other systems of emission reduction, that are "adequately demonstrated" in the regulated industry.
- Available information from the implementation and enforcement of current requirements indicating that emission limitations and percent reductions beyond those required by the current standards are achieved in practice.
- Costs (including capital and annual costs) associated with implementation of the available pollution control measures.
- The amount of emission reductions achievable through application of such pollution control measures.
- Any non-air quality health and environmental impact and energy requirements associated with those control measures.

In evaluating whether the cost of a particular system of emission reduction is reasonable, the EPA considers various costs associated with the particular air pollution control measure or a level of control, including capital costs and operating costs, and the emission reductions that the control measure or particular level of control can achieve. The Agency considers these costs in the context of the industry's overall capital expenditures and revenues. The Agency also considers cost effectiveness analysis as a useful metric and a means of evaluating whether a given control achieves emission reduction at a reasonable cost. A cost effectiveness analysis allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost effectiveness is a measure of the outcomes produced by resources spent. In the context of air pollution control options, cost effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually.

After the EPA evaluates the statutory factors, the EPA compares the various systems of emission reductions and determines which system is "best," and therefore represents the BSER. The EPA then establishes a standard of performance that reflects the degree of emission limitation achievable through the implementation of the BSER. In performing this analysis, the EPA can determine whether subcategorization is appropriate based on classes, types, and sizes of sources, and may identify a different BSER and establish different performance standards for each subcategory. The result of the analysis and BSER determination leads to standards of performance that apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Because the new source performance standards reflect the best system of emission reduction under conditions of proper operation and maintenance, in doing its review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping, and reporting requirements needed to ensure compliance with the emission standards.

See section II.D of this preamble for information on the specific data sources that were reviewed as part of this action.

*D. What data and information were used to support this action?*

We reviewed recent federal, State, and local rulemakings associated with VOL storage vessels. We also reviewed vendor websites and contacted selected floating roof suppliers to collect information to support our review of the existing requirements for organic liquid storage vessels and our BSER assessments. We met with industry representatives that own and operate VOL storage vessels to discuss their experience with various control equipment.

We used the equations in Chapter 7 of AP–42: *Compilation of Air Emission Factors* to estimate emissions from different VOL storage vessels based on size, contents, and control configuration (*e.g.*, type of floating roof with different seal and fitting controls). We estimated emission reductions by comparing the controlled emissions with emissions from an uncontrolled fixed roof storage vessel.

Our cost estimates were based largely on vendor costs developed from previous rulemakings. For some control methods, we had limited recent data from vendors or State and local rulemakings. All costs were escalated to 2022 dollars using the Chemical Engineering Plant Cost Index for capital expenditures and Bureau of Labor Statistics data for labor rates.

## III. What actions are we proposing?

The EPA is proposing revisions to the NSPS for VOL storage vessels pursuant to the EPA's review of NSPS subpart Kb. The EPA is proposing to codify the NSPS revisions proposed in this action in a new subpart NSPS subpart Kc. The proposed NSPS subpart Kc would be applicable to sources that commence construction, reconstruction, or modification after October 4, 2023.

This section outlines the proposed actions for NSPS subpart Kc. The EPA is proposing new vapor pressure applicability thresholds for controls under NSPS subpart Kc. The EPA is also proposing new standards for VOL storage vessels subject to control requirements. Under NSPS subpart Kc we are proposing that the standard of performance reflecting the application of BSER for VOL storage vessels subject to control requirements and used to store liquids with maximum true vapor pressures below 11.1 psia (76.6 kPa) is an IFR. The updated standards are projected to increase the average control efficiency of IFR storage vessels to 98 percent. As an alternative compliance to the proposed IFR design standard, we are proposing to permit either the use of an EFR or the use of a closed vent system and a control device that meet an equivalent standard of control. For controlled storage vessels that store liquids with a maximum true vapor pressure equal to or greater than 11.1 psia (76.6 kPa), we are proposing to find that the BSER is a closed vent system and a control device. We are proposing that the standard of performance reflecting the emission limitation achievable is a 98 percent reduction in VOC emissions (increased from 95 percent in the NSPS subpart Kb). EPA is also including modification requirements under NSPS subpart Kc and discusses the relevant criteria for meeting modifications in this section. This section also details the proposed testing, monitoring and inspection requirements, degassing provisions,

provisions for SSM, and electronic reporting requirements. As described in this section, the revisions proposed in this action were determined to be cost-effective and to reflect the application of the best system of emission reduction (BSER) for VOL storage vessels.

*A. What vapor pressure applicability thresholds are we proposing and why?*

NSPS subpart Kb established control requirements, at 40 CFR 60.112b(a), for storage vessels based on vessel capacity and VOL vapor pressures. In our review of NSPS subpart Kb, we assessed the vapor applicability thresholds for affected facilities and for controls on affected storage vessels to determine whether these thresholds needed to be revised for purposes of NSPS subpart Kc. In NSPS subpart Kb there are two different sets of vapor pressure applicability thresholds: one for determining affected facilities and one for determining controls.

In NSPS subpart Kb, the vapor pressure applicability thresholds for defining affected facilities were slightly lower than those used for affected facilities for which controls were required. The EPA included the two separate applicability requirements sets in NSPS subpart Kb, one to identify storage vessels near the control applicability thresholds and another to establish limited monitoring procedures for vessels with variable components and vapor pressures. We are proposing to not include specific vapor pressure applicability thresholds in defining an affected facility under NSPS subpart Kc. As such, the proposed affected facility under NSPS subpart Kc is any storage vessel with a capacity of 20,000 gallons or more used to store a volatile organic liquid without exclusion for storage vessels under a set vapor pressure. This proposed change simplifies the applicability under NSPS subpart Kc and establishes a baseline for monitoring and recordkeeping in accordance with good air pollution control practices for storage vessels that do not meet the vapor pressure emission control threshold.

In our review of NSPS subpart Kb, in assessing the vapor applicability thresholds that require emission controls, we estimated the cost of including an IFR as part of a new fixed roof storage vessel installation for a variety of surrogate organic liquids covering a wide range of vapor pressures for both 20,000 gallon and 40,000 gallon capacity storage vessels. We used the AP–42 equations for liquid storage tanks to estimate emissions for fixed roof storage vessels and IFR storage vessels. Costs were estimated based on various vendor quotes, escalated to 2022$. For more detail regarding the analyses conducted, see memorandum *Control Options for Storage Vessels* included in Docket ID No. EPA–HQ–OAR–2023–0358.

For storage vessels of 20,000 gallon capacity or more but less than 40,000 gallon capacity, we evaluated the cost and cost effectiveness of different vapor pressure applicability thresholds, including:

- 4.0 psia based on NSPS subpart Kb value (27.6 kPa)
- 1.9 psia based on thresholds used in several NESHAP including 40 CFR part 63, subparts G and CC.
- 1.5 psia based on thresholds in South Coast Air Quality Management District (SCAQMD) Rule 463.
- 1.0 psia to evaluate an option beyond 1.5 psia.

We conducted this analysis using a model storage vessel of 20,000 gallon capacity. We assessed costs for two different levels of IFR: one meeting the basic requirements of NSPS subpart Kb and one with upgraded seal requirements (requiring a mechanical shoe seal or liquid-mounted primary seal with a rim-mounted secondary seal). Table 1 summarizes the results of our analysis for these small storage vessels.

TABLE 1—SUMMARY OF THRESHOLD ANALYSIS FOR STORAGE VESSELS WITH A CAPACITY BETWEEN 20,000 AND 40,000 GALLONS

| Threshold | VOC emissions reduction (tpy) | TCI [1] ($) | TAC [2] without product recovery ($/yr) | TAC [2] with product recovery ($/yr) | CE [3] ($/ton VOC) |
|---|---|---|---|---|---|
| **Costs for Meeting NSPS Subpart Kb Requirements for IFR** | | | | | |
| 4.0 psia | 2.04 | $48,877 | $6,035 | $4,257 | $2,100 |
| 1.9 psia | 0.97 | 48,877 | 6,035 | 5,190 | 5,300 |
| 1.5 psia | 0.77 | 48,877 | 6,035 | 5,368 | 7,000 |
| 1.0 psia | 0.51 | 48,877 | 6,035 | 5,590 | 10,900 |
| **Costs for IFR with Upgraded Seal Requirements ('Option 1')** | | | | | |
| 4.0 psia | 2.29 | 55,008 | 6,793 | 4,802 | 2,100 |
| 1.9 psia | 1.09 | 55,008 | 6,793 | 5,847 | 5,000 |
| 1.5 psia | 0.86 | 55,008 | 6,793 | 6,046 | 7,000 |
| 1.0 psia | 0.57 | 55,008 | 6,793 | 6,295 | 11,000 |

[1] Total Capital Investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.
[3] Cost effectiveness.

A similar analysis was conducted for storage vessels with a design capacity of 40,000 gallons or more. For this analysis, we used a model storage vessel with a 60,000 gallon capacity, which we consider representative of storage vessels at the smaller end of the range of storage vessels with a capacity of 40,000 gallons or more. We evaluated the cost and cost effectiveness of different vapor pressure applicability thresholds, including:

- 0.75 psia based on NSPS subpart Kb value (5.2 kPa).
- 0.50 based on thresholds in SCAQMD Rule 463.
- 0.35 psia to evaluate an option beyond 0.5 psia.

Table 2 summarizes the results of our analysis for storage vessels with a capacity of 40,000 gallons or more.

TABLE 2—SUMMARY OF THRESHOLD ANALYSIS FOR STORAGE VESSELS WITH A CAPACITY OF 40,000 GALLONS OR MORE

| Threshold | VOC emissions reduction (tpy) | TCI [1] ($) | TAC [2] without product recovery ($/yr) | TAC [2] with product recovery ($/yr) | CE [3] ($/ton VOC) |
|---|---|---|---|---|---|
| **Costs for Meeting NSPS Subpart Kb Requirements for IFR** | | | | | |
| 0.75 psia | 1.36 | $54,979 | $6,789 | $5,609 | $4,100 |
| 0.50 psia | 0.90 | 54,979 | 6,789 | 6,002 | 6,600 |
| 0.35 psia | 0.63 | 54,979 | 6,789 | 6,238 | 9,900 |
| **Costs for IFR with Upgraded Seal Requirements ('Option 1')** | | | | | |
| 0.75 psia | 1.42 | 62,914 | 7,769 | 6,532 | 4,600 |
| 0.50 psia | 0.95 | 62,914 | 7,769 | 6,944 | 7,300 |
| 0.35 psia | 0.66 | 62,914 | 7,769 | 7,192 | 10,800 |

[1] Total Capital Investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.
[3] Cost effectiveness.

Based on this analysis, we are proposing for NSPS subpart Kc to revise the vapor applicability thresholds that require emission controls. We are proposing to revise the maximum true vapor pressure threshold for small storage vessels (those with capacity of at least 20,000 gallons but less than 40,000 gallons) to 1.5 psia and for larger storage vessels (those with capacity of 40,000 gallons or more) to 0.5 psia. These thresholds yield emission reductions at a cost of approximately $6,000 and $7,000 per ton of VOC reduced respectively, which is within the range of what the EPA has considered cost-effective for the control of VOC emissions in other recent NSPS rulemakings. See, *e.g.*, 88 FR 29982 (May 9, 2023) (finding a value of $6,800/ton of VOC emissions reductions cost-effective for automobile and light duty truck surface coating operations (NSPS subpart MMa)). The cost effectiveness for VOLs with vapor pressures less than the proposed maximum true vapor pressure cutoffs are approximately $10,000 and $11,000 per ton of VOC reduced. This is not cost-effective because it is significantly higher than what the EPA has historically found to be cost-effective for VOC regulations. The EPA solicits comment on the proposed vapor pressure applicability described in this section.

*B. What other changes to applicability are we proposing and why?*

NSPS subpart Kb includes several provisions that exempt specific groups of VOL storage vessels from applicability under the standard. These exemptions are outlined in 40 CFR 60.110b (d) and include specific exemptions for storage vessels that operate at coke oven by-product plants, bulk gasoline plants, and gasoline service stations. The exemptions include pressure vessels operating in excess of 204.9 kPA, vessels attached to mobile vehicles, and vessels that store beverage alcohol. These exemptions are being carried over into the proposal for NSPS Kc as the justifications for their exemption remains unchanged from the original NSPS subpart Kb promulgation.

The EPA is also proposing to carry over the exemption requirements in 40 CFR 60.110b(d)(4), which covers storage vessels with capacities less than or equal to 1,589.874 $m^3$ (~420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer. The EPA previously explained the applicability of this exemption in the preamble to NSPS subpart Ka (45 FR 23377) stating, "this exemption applies to storage between the time that the petroleum liquid is removed from the ground and the time the custody of the petroleum liquid is transferred from the well or producing operations to the transportation operations. If it is determined in the future that VOC emissions from new production field vessels smaller than 1,589,873 liters (420,000 gallons) are significant, separate standards of performance will be developed." Since promulgation of NSPS subpart Ka, the EPA promulgated subparts OOOO and OOOOa for the oil and natural gas sector, which include standards of performance for these types of storage vessels. The EPA has also proposed revised standards for these sources in its latest review, as part of the proposed NSPS subpart OOOOb and the emission guideline for existing sources at proposed subpart OOOOc. See 87 FR 74702. As such, the EPA proposes to carry the language of this exemption into NSPS subpart Kc.

NSPS subpart Kb also includes an exemption for vessels subject to the NESHAP for solvent extraction for vegetable oil production outlined in 40 CFR 63 subpart GGGG. The EPA determined as part of its review, that the standards proposed in NSPS subpart Kc improve upon the existing NESHAP subpart GGGG standards. As such, the EPA proposes that vessels subject to NESHAP subpart GGGG, would not be exempted from NSPS subpart Kc applicability.

The EPA solicits comment on these proposed exemptions and changes to the applicability provisions.

*C. What are the proposed BSER and compliance alternatives for newly constructed, modified, and reconstructed storage vessels?*

The EPA is proposing standards of performance that reflect the BSER as well as alternative compliance standards for controlled storage vessels under NSPS subpart Kc. The proposed BSER analyses and proposed standards for NSPS subpart Kc are dependent on the maximum true vapor pressure of a stored VOL and follow the precedent established in NSPS subpart Kb. For storage vessels storing VOL with maximum true vapor pressures less than 11.1 psia, the EPA discusses the BSER analysis and proposes standards of performance for newly constructed and reconstructed IFRs in section III.D. The EPA also is proposing two alternative compliance options for storage vessels with maximum true vapor pressures less than 11.1 psia. These alternative compliance options are EFRs and closed vent system and control. Details regarding alternative compliance standards for newly constructed and reconstructed storage vessels are discussed in section III.E.

For storage vessels with maximum true vapor pressures greater than or equal to 11.1 psia, the EPA is proposing to determine that the BSER is closed vent system and control, and the standard of performance reflecting the BSER is a 98 percent reduction in VOC emissions. The BSER analysis and standard of performance for storage vessels with VOL maximum true vapor pressures greater than or equal to 11.1 psia are discussed in section III.F. Additionally, we are proposing requirements that are applicable to storage vessels that are controlled using a closed vent system and a control device to meet either proposed standard, and those proposed requirements are also discussed in section III.F.

In section III.G the EPA proposes what constitutes a modification for purposes of NSPS subpart Kc. Discussion regarding the BSER analysis, standards of performance for modified storage vessels and compliance alternatives are discussed in sections III.F and III.H.

*D. What is the BSER and standard of performance for new and reconstructed storage vessels with maximum true vapor pressures less than 11.1 psia?*

In our review of NSPS subpart Kb for storage vessels storing VOL with maximum true vapor pressures less than 11.1 psia, we focused on control options for IFR storage vessels because IFR storage vessels are more effective at controlling emissions and are technologically achievable. Therefore, IFR storage vessel control options were evaluated to determine BSER for VOL vapor pressures less than 11.1 psia. Because floating roof tanks are unsuitable for controlling VOL with vapor pressures greater than or equal 11.1 psia, the EPA conducted a separate analysis to determine the BSER and standard of performance for those storage vessels.

The control options we evaluated for IFR storage vessels included:

- *Baseline.* NSPS subpart Kb control requirements (with NSPS subpart Kc proposed lower vapor pressure thresholds detailed in section III.A)
- *Option IFR–1.* NSPS subpart Kb but primary seal must either be liquid-mounted or mechanical shoe seal and must have a rim-mounted secondary seal.
- *Option IFR–2.* Option 1 requirements + require fixed roof legs or cable suspended roof (cannot have adjustable roof legs that penetrate through the floating roof).
- *Option IFR–3.* Option 2 requirements + require welded seems and best guidepole fittings.

All three of the listed options above also include provisions for requiring gauge-hatches/sample ports to be gasketed. We determined that all of these IFR control options are in use in the industry and thus adequately demonstrated.

The cost effectiveness of these control options is dependent on the size and contents of the storage vessel. We estimated that approximately 240 new storage vessels become subject to the NSPS subpart Kb every year, such that 1,200 new storage vessels could become subject to NSPS subpart Kc over the next five years if no change in thresholds is adopted. We projected that with lower vapor pressure thresholds, approximately 20 percent more storage vessels could become subject to the NSPS subpart Kc standards each year. We assigned the estimated 1,440 new storage vessels across a range of storage vessel sizes and vapor pressures for the stored liquids to develop national impact estimates for each IFR control option. For more information on the nationwide cost analysis of IFR control options for new storage vessels, see memorandum *Control Options for Storage Vessels* in Docket ID No. EPA–HQ–OAR–2023–0358.

The national impacts projected for each IFR control option are presented in Table 3 of this preamble.

TABLE 3—SUMMARY OF NATIONAL IMPACTS FOR CONTROL OPTIONS FOR NEW AND RECONSTRUCTED IFR STORAGE VESSELS

| Control option | VOC emissions reduction [1] (tpy) | TCI [2] (million $) | TAC [3] without product recovery (million $/yr) | TAC [3] with product recovery (million $/yr) | Overall CE [1 4] ($/ton VOC) | CE [4] to Kb baseline ($/ton VOC) | ICE [5] ($/ton VOC) |
|---|---|---|---|---|---|---|---|
| Baseline—Kb | 41,886 | $127 | $15.7 | ($20.8) | ($496) | ..... | ..... |
| Option IFR–1 | 42,420 | 145 | 17.9 | (19.1) | (449) | 3,180 | 3,180 |
| Option IFR–2 | 42,684 | 173 | 21.3 | (15.8) | (370) | 6,250 | 12,272 |
| Option IFR–3 | 42,961 | 199 | 24.6 | (12.8) | (297) | 7,470 | 10,966 |

[1] Relative to uncontrolled fixed roof storage vessel.
[2] Total Capital Investment (TCI).
[3] Total annualized costs (TAC) considering annualized cost of capital.
[4] Cost effectiveness.
[5] Incremental cost effectiveness (compared to previous option).

Based on this analysis, we are proposing to determine that for new and reconstructed storage vessels with vapor pressures less than 11.1 psia, BSER is Option IFR–1. Specifically, we are proposing to require that the primary seal must either be liquid-mounted or a mechanical shoe seal and must have a rim-mounted secondary seal. While Table 3 displays numerous options that have favorable cost effectiveness values, incremental cost effectiveness was the determining factor in selecting the appropriate IFR control option. The EPA estimated that the incremental cost effectiveness of Option IFR–1 is projected to yield emission reductions at a cost of approximately $3,200 per ton of VOC reduced on average, which we determined is cost- effective and is well within the range of what the EPA has considered cost-effective for the control of VOC emissions. The other control options we evaluated for IFR storage vessels had incremental cost effectiveness of $11,000 or more per ton of VOC reduced, which is well above what we have determined to be cost-effective for the control of VOC emissions. IFRs are the most common emission control method for VOL storage vessels and thus are adequately demonstrated. Further, IFRs do not require power or addition of add-on controls; therefore, there are minimal non-air quality health and environmental impacts and energy requirements.

IFRs with a liquid-mounted or mechanical shoe primary seal and rim-mounted secondary seal (Option IFR–1) were selected as the most appropriate option for new and reconstructed storage vessels under the BSER determination. The EPA therefore

proposes an equipment standard pursuant to CAA section 111(h)(5) that would require that new storage vessels be constructed as IFR, that the primary seal must either be liquid-mounted or mechanical shoe seal and must have a rim-mounted secondary seal, that gauge-hatches/sample ports to be gasketed, and that the guidepole configurations incorporate the provisions outlined in the 2000 EPA Storage Tank Emissions Reduction Partnership Program (STERPP).

The EPA solicits comment on the proposal to determine that the BSER for storage vessels storing VOL with maximum true vapor pressures less than 11.1 psia is Option IFR–1, or whether one of the alternative options would be justified. The EPA also solicits comment on the proposed equipment standard.

*E. What compliance alternatives are available for new and reconstructed storage vessels with maximum true vapor pressures less than 11.1 psia?*

As discussed in section III.D of this preamble, we are proposing to determine that, for new and reconstructed storage vessels with a maximum true vapor pressure less than 11.1 psia, the BSER and equipment standard is IFR with enhanced rim seal requirements: specifically, the primary seal must either be liquid-mounted or mechanical shoe seal and must have a rim-mounted secondary seal. We are also proposing to revise the NSPS requirements for EFR storage vessels as an alternative compliance option to equipment standard for newly constructed and reconstructed storage vessels. The average control efficiency for the proposed Option IFR–1 was determined to be 98 percent. In reviewing the NSPS, we found that certain EFR storage vessels could achieve the same level of control as the proposed control option for IFR storage vessels (Option IFR–1). As such, we are proposing to permit the use of EFR storage vessels that we determined achieve equivalent performance as an IFR storage vessel across a range of different capacities. Based on AP–42 emission calculation methods, we found that an EFR storage vessel that has primary and secondary seals as specified in Option IFR–1, welded seams (typical construction for EFR), and that use an unslotted guidepole with gasketed sliding cover and pole wiper have emissions comparable to an IFR storage vessel under Option IFR–1. If a slotted guidepole is used, a liquid mounted primary seal must be used and the slotted guidepole must have a gasketed sliding cover, pole sleeve and pole wiper (with or without float). We recognize that other control combinations for the EFR storage vessel may achieve comparable emissions to an Option IFR–1 storage vessel depending on the size and content of the storage vessel, and the typical meteorological conditions. Although we are not attempting to identify every such combination in proposing to codify this compliance alternative, CAA section 111(h)(5) permits facilities to request an alternative means of emission limitation to assess equivalency of EFR controls to IFR controls under site-specific conditions.

We are also proposing to permit storage vessels with a maximum true vapor pressure less than 11.1 psia to use closed vent system and control devices as an alternative compliance to the equipment standard, so long as the storage vessel achieves a 98 percent reduction in VOC emissions to be equivalent to the proposed IFR standard. Such storage vessels would be required to meet the proposed requirements for closed vent systems and control devices described in section III.F.

The EPA solicits comment on these proposed compliance alternatives for storage vessels with a maximum true vapor pressure less than 11.1 psia.

*F. What is the BSER and standard of performance for new, modified, and reconstructed storage vessels with maximum true vapor pressures equal to or greater than 11.1 psia?*

As noted previously, the EPA is proposing that for newly constructed and reconstructed VOL storage vessels with a maximum true vapor pressure less than 11.1 psia, the BSER is IFR with enhanced rim seal requirements. Because floating roof tanks are unsuitable for controlling VOL with vapor pressures greater than or equal 11.1 psia, the EPA conducted a separate analysis to determine the BSER and standard of performance for those storage vessels that are new, modified, or reconstructed. In NSPS subpart Kb, closed vent systems and control devices are the BSER for storage vessels for organic liquids with maximum true vapor pressures of 11.1 psia or greater and have served as an alternative compliance option for storage vessels with lower vapor pressures. Therefore, in reviewing NSPS subpart Kb, the EPA also reviewed the control requirements associated with storage vessels that use closed vent systems and control devices. We assessed the cost and cost effectiveness of a closed vent system and control device for a range of storage vessels used to store liquids with high vapor pressures. We are proposing to continue to find the BSER to be closed vent systems and control devices for new, modified, or reconstructed storage vessels for organic liquids with maximum true vapor pressures of 11.1 psia or greater, and to set the standard of performance to require that these storage vessels must achieve a 98 percent reduction in VOC emissions.

For storage vessels used to store organic liquids with maximum true vapor pressures of 11.1 psia or greater, we estimated the cost of a flare dedicated to a single storage vessel. We estimated the costs separately for flares meeting the requirements in 40 CFR 60.18 (95 percent reduction) or using the flare requirements in 40 CFR 63.670 (98 percent reduction). We used two times the maximum filling rate to size the flares, we determined the time period needed at the maximum filling rate to achieve the modeled working losses, and we determined the average flow rate needed for the remaining time period to correspond to the modeled standing losses. Because of the high vapor pressure of the liquid contents, flares meeting the requirements in 40 CFR 63.670 are expected to be able to use the methods in 40 CFR 63.670(j)(6) to determine minimum net heating value of the gas stream. Depending on the assist-type of the flare, supplemental gas may be needed during periods of low flow, which is the vast majority of the time. We expect facilities would use a pressure valve in the closed vent system to prevent low flows and prevent back flow from the flare to the storage vessel when emptying the storage vessel. These pressure valves could be set to ensure gas flow to the flare is always sufficient to prevent over-assisting, but we assumed flares with low flows would use supplemental natural gas. For smaller storage vessels (20,000 to 60,000 gallons capacity), there were added costs associated with meeting the combustion zone operating limits in 40 CFR 63.670. For the larger storage vessels, routine flows from the storage vessels were sufficient to meet the combustion zone operating limits in 40 CFR 63.670. We estimate there would be 25 new storage vessels used for storing high vapor pressure liquids for which closed vent system and control device would be required, primarily in the 40,000 to 60,000 gallon capacity range. For more details regarding the nationwide of costs for closed vent systems and control devices, see memorandum *Control Options for Storage Vessels* in Docket ID No. EPA–HQ–OAR–2023–0358. The nationwide impacts projected for these two control options evaluated for purposes of NSPS

subpart Kc (95 percent and 98 percent control) are provided in Table 4 of this preamble.

TABLE 4—SUMMARY OF NATIONAL IMPACTS FOR CONTROL OPTIONS FOR CLOSED VENT SYSTEMS AND CONTROL DEVICE FOR HIGH VAPOR PRESSURE LIQUIDS

| Control option | VOC emissions reduction [1] (tpy) | TCI [2] (million $) | TAC [3] without product recovery (million $/yr) | CE [4] ($/ton VOC) | ICE [5] ($/ton VOC) |
|---|---|---|---|---|---|
| 95 percent control | 928 | $2.69 | $2.61 | $2,820 | $2,820 |
| 98 percent control | 957 | 2.69 | 2.71 | 2,830 | 3,360 |

[1] Relative to uncontrolled fixed roof storage vessel.
[2] Total Capital Investment (TCI).
[3] Total annualized costs (TAC) considering annualized cost of capital.
[4] Cost effectiveness.
[5] Incremental cost effectiveness.

Based on our analysis, we are proposing that the BSER for storage vessels operating with maximum true vapor pressures equal to or greater than 11.1 psia is the use of a closed vent system and control device meeting a 98 percent control efficiency. The EPA considers the cost-effectiveness of both control options to be within the range of what the EPA has considered cost-effective for the control of VOC emissions. While the incremental cost-effectiveness of 98 percent control is slightly higher than for 95 percent control, it is also well within the range of what the EPA has considered cost-effective. Although these control devices use power and result in additional combustion emissions, there is no significant difference between 95 and 98 percent control levels in as regards to the non-air quality health and environmental impacts, or energy requirements. Accordingly, the EPA proposes to find the use of a closed vent system and control device meeting a 98 percent control efficiency is the BSER and proposes to set a standard of performance for new, reconstructed, and modified storage vessels operating with vapor pressures equal to or greater than 11.1 psia as 98 percent control of VOC emissions.

The EPA is also proposing to establish requirements for closed vent systems and control devices to ensure that storage vessels using them to comply with the proposed standards actually achieve 98 percent control efficiency. In order for the closed vent system and control device to meet 98 percent control efficiency, the storage vessel must not vent to the atmosphere. Conservation vents and pressure relief devices are often used to vent emissions from storage vessels when the pressure within the storage vessel approaches the maximum design pressure of the storage vessel. Many atmospheric storage vessels have pressure ratings of 1 or 2 psig and would therefore vent often if the vapor pressure of the stored liquid is above 2 psi. Consequently, to ensure direct venting from the storage vessel does not occur, we are proposing to require storage vessels have a design operating gauge pressure no less than 1 psi greater than the maximum vapor pressure of the liquid being stored and any back pressure anticipated when the storage vessel is filled at its maximum rate. While vapor pressures are commonly reported in terms of absolute pressure, a storage vessel containing a liquid with a vapor pressure of 4 psia would generally have a headspace pressure of 4 psi above atmospheric pressure, or 4 psig. Storage vessel owners or operators would also have to evaluate the back pressure of the control system used and ensure that the closed vent system can handle the maximum filling rate of the storage vessel without increasing pressure in the storage vessel above this 5 psig value or else establish a higher design and operating pressure for the storage vessels. For example, if the back pressure of the closed vent system (or the pressure drop from the storage vessel to the control device) is 3 psi at the maximum filling rate, and the liquid stored has a maximum true vapor pressure of 4 psia, the minimum opening pressure of any pressure relief device on the storage vessel would have to be 8 psig (3+4+additional 1). We are also proposing to require that any vacuum breaking device have a close pressure no less than 0.1 psig vacuum to prevent losses from the vacuum breaker vent.

The EPA solicits comment on our proposed BSER determination and standard of performance for new, reconstructed, and modified storage vessels operating with vapor pressures equal to or greater than 11.1 psia, as well as the proposed requirements for closed vent systems and control devices.

*G. What actions constitute a modification for storage vessels and why?*

For purposes of CAA section 111, modifications are defined as "any physical change in, or change in the method of operation of," an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.[6] 40 CFR 60.2. NSPS Subpart A further provides provisions explaining how a modification is identified as well as defining certain exemptions to those general rules. In particular, 40 CFR 60.14(e)(4) states that the "[u]se of an alternative fuel or raw material" is not considered a modification if the existing facility was designed to accommodate that alternative use. In prior EPA actions making applicability determinations for purposes of NSPS Kb, the EPA has previously cited to this provision to assert that a change in the type of material stored in a storage vessel is not, by itself, a modification if the storage vessel is capable of accommodating the storage of the new materials.[7] However, the EPA has revisited the previous interpretation as discussed in the following paragraphs and now proposes, for purposes of NSPS Kc, that a change in the liquid stored in the storage vessel to an organic liquid with a higher maximum true vapor pressure does not constitute a "use of an alternative fuel or raw material," and would be considered a change in the method of operation of the storage vessel. Thus, the EPA proposes that a change in the liquid stored which results in increased

[6] *See* 42 U.S.C. 7411(a)(4).

[7] *See, e.g.*, U.S. EPA Applicability Determination Index, Control Number: 0400015, (referencing 40 CFR 60.14(e)(4)–(5)).

VOC emissions would be a modification under NSPS Kc. The EPA recognizes that the proposed approach to modifications for purposes of NSPS subpart Kc represents a change of the EPA's previous interpretation of the provision in 40 CFR 60.14(e)(4) that asserted that change in liquid alone did not trigger a modification. However, the EPA proposes to find that this change in interpretation for purposes of defining a modification for NSPS subpart Kc is appropriate, in particular, because as discussed below the changes in the organic liquid stored in a storage vessel do not constitute changes in "fuel or raw material," as the primary function of this affected facility is the storage of materials, and the materials stored are neither raw material nor fuel inputs to a process at the facility itself. *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515–16 (2009) (when the Agency acknowledges change in position, "it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the Agency believes it to be better, which the conscious change of course adequately indicates").

As noted earlier in this preamble, as the EPA has defined modification for purposes of CAA section 111, using a different fuel or raw material in the process that the facility was specifically designed for does not itself constitute a modification under the exemption identified in 40 CFR 60.14(e)(4). However, for storage vessels, the primary function of this affected facility is the storage of materials, and the materials stored are neither raw material nor fuel inputs to a process at the facility itself. Therefore, for purposes of NSPS Kc, the EPA now proposes to determine that the exemption outlined in 40 CFR 60.14(e)(4) does not apply, because the organic liquid stored in the vessels subject to this part does not constitute fuels or raw materials. Accordingly, the EPA proposes to consider the change in materials stored in a storage vessel to be an operational change under CAA section 111(a)(4). Thus, where an owner or operator changes the operation of the tank to store materials with higher vapor pressures, this change results in an increased emission potential. The EPA proposes to find that this change is an operation meeting the definition of "modification" under CAA section 111(a)(4) and 40 CFR 60.14(a). If the modified storage vessel meets the applicability criteria of NSPS subpart Kc, then it would be subject to the standards of performance and other requirements established in the final rule.

The EPA has identified no other exemption in 40 CFR 60.14(e) which applies to a change in the organic liquid stored in a storage vessel. The EPA further proposes to determine that a change in the organic liquid stored at a storage vessel constitutes a modification under the statutory definition because it is reasonable to consider a change in the organic liquid stored to a new liquid with a higher true vapor pressure to be a change in operation, especially because such a change is expected to increase VOC emissions. Thus, the EPA proposes that a change in the liquid stored which results in increased VOC emissions would be a modification under NSPS subpart Kc. If the previous content of the storage vessel was below the vapor pressure threshold, a change in the liquid stored in the vessel to one that is above the vapor pressure threshold would increase the amount of VOC emitted from the storage vessel and should be considered a modification of the storage vessel and trigger the NSPS subpart Kc control requirements.

The EPA solicits comment on the proposed change in interpretation of 40 CFR 60.14(e) as it applies to modifying storage vessels subject to NSPS subpart Kc.

*H. What are the BSER and standards of performance for modified storage vessels with maximum true vapor pressures less than 11.1 psia?*

The EPA evaluated BSER for modified storage vessels for NSPS subpart Kc with maximum true vapor pressures less than 11.1 psia. In most cases, the EPA expects that modified storage vessels will have existing fixed roofs, because IFRs were not previously required by NSPS subpart Kb. The costs of retrofitting a fixed roof storage vessel with an IFR are the same as the costs of adding an IFR to a new storage vessel. Some modified storage vessels that newly trigger into the NSPS, however, may already have IFRs, and upgrading only certain elements of the IFR can have significantly different costs than when installing a new IFR. Therefore, to assess BSER for modified storage vessels, we developed national cost estimates separately for modified storage vessels depending on whether or not the storage vessels had existing IFRs prior to modification.

We estimate a total of 30 storage vessels would become newly affected facilities due to modifications over the first 5 years after promulgation of NSPS subpart Kc. We estimate 10 percent of these storage vessels would have an existing IFR and that the existing IFR was compliant with the IFR requirements in NSPS subpart Kb. For more information on the nationwide cost analysis of IFR control options for modified storage vessels, see memorandum *Control Options for Storage Vessels* in Docket ID No. EPA–HQ–OAR–2023–0358.

Table 5 of this preamble summarizes the costs and cost effectiveness of the impacts of modified storage vessels without an IFR prior to the modification, under the baseline of the existing Kb requirements and all three IFR options. The incremental costs are somewhat higher than for new and reconstructed storage vessels because we projected that the vapor pressures of the organic liquids stored in the modified storage vessels would be near the vapor pressure applicability threshold. Thus, we projected that storage vessels that triggered into the NSPS subpart Kc because of a change in the liquid stored would generally have lower vapor pressure organic liquids, on average, than compared to new storage vessels. Based on this analysis, we are proposing for NSPS subpart Kc to find that Option IFR–1 (enhanced rim seal requirements) is cost-effective and represents BSER for modified fixed roof storage vessels. Like for new and reconstructed sources, the cost-effectiveness of all options is well within the range of what the EPA has considered to be cost-effective in past rulemakings. However, while the incremental cost effectiveness of Option IFR–1 is also reasonable, the incremental cost-effectiveness of Option IFR–2 and Option IFR–3 are significantly higher than what the EPA has previously found reasonable. Accordingly, while the cost-effectiveness of all options is quite reasonable, the high incremental cost-effectiveness is the determining factor in the EPA's consideration of costs. The EPA's consideration of non-air quality health and environmental impacts, as well as energy requirements, is also the same as for new and reconstructed storage vessels. Therefore, the EPA is proposing to determine that Option IFR–1 is the BSER for existing storage vessels with maximum true vapor pressures less than 11.1 psia that modify and do not have an existing floating roof. These proposed requirements are also applicable to new sources (sources constructed after the proposal date) that modify after the proposal date.

TABLE 5—SUMMARY OF NATIONAL IMPACTS FOR CONTROL OPTIONS FOR MODIFIED FIXED ROOF STORAGE VESSELS WITH MAXIMUM TRUE VAPOR PRESSURES LESS THAN 11.1 PSIA

| Control option | VOC emissions reduction [1] (tpy) | TCI [2] (million $) | TAC [3] without product recovery ($/yr) | TAC [3] with product recovery ($/yr) | CE [4] ($/ton VOC) | ICE [5] ($/ton VOC) |
|---|---|---|---|---|---|---|
| Existing Kb | 501 | $2.32 | $286,000 | ($150,000) | ($299) | ($299) |
| Option IFR–1 | 507 | 2.65 | 327,000 | (114,000) | (224) | 5,900 |
| Option IFR–2 | 510 | 3.18 | 392,000 | (51,200) | (100) | 21,100 |
| Option IFR–3 | 513 | 3.67 | 453,000 | 7,300 | 14 | 19,100 |

[1] Relative to uncontrolled fixed roof storage vessel.
[2] Total Capital Investment (TCI).
[3] Total annualized costs (TAC) considering annualized cost of capital.
[4] Cost effectiveness.
[5] Incremental cost effectiveness.

Table 6 of this preamble summarizes the costs and cost effectiveness of the impacts of modified storage vessels with maximum true vapor pressures less than 11.1 psia that already have an existing IFR prior to the modification. The costs per ton of VOC reduced when modifying controls on an existing IFR are much higher than when installing a new IFR on an existing fixed roof storage vessel. The cost effectiveness and incremental cost effectiveness of all three IFR options are well above what the EPA has found to be reasonable for the control of VOC emissions. Consequently, we are proposing for NSPS subpart Kc that, for modified storage vessels with maximum true vapor pressures less than 11.1 psia with an existing IFR, the NSPS subpart Kb control requirements without upgrading the rim seal requirements represent the application of BSER, and we propose to retain those standards for these sources in NSPS subpart Kc.

TABLE 6—SUMMARY OF NATIONAL IMPACTS FOR CONTROL OPTIONS FOR MODIFIED IFR STORAGE VESSELS

| Control option | VOC emissions reduction (tpy) | TCI [1] ($) | TAC [2] without product recovery ($/yr) | TAC [2] with product recovery ($/yr) | CE [3] ($/ton VOC) | ICE [4] ($/ton VOC) |
|---|---|---|---|---|---|---|
| Existing Kb | 0 | $0 | $0 | $0 | $0 | $0 |
| Option IFR–1 | 0.48 | 64,000 | 7,900 | 7,480 | 15,700 | 15,700 |
| Option IFR–2 | 0.73 | 169,100 | 20,900 | 20,300 | 27,800 | 50,700 |
| Option IFR–3 | 0.87 | 254,600 | 31,400 | 30,700 | 35,300 | 74,600 |

[1] Total Capital Investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.
[3] Cost effectiveness.
[4] Incremental cost effectiveness.

For existing EFR storage vessels, like existing IFR storage vessels, improvements to the floating roof and guidepole design would not result in significant additional emission reductions beyond those achieved by the use of the EFR itself. As a result, as for the IFR analysis just discussed, cost-effectiveness would be expected to be quite high such that the costs associated with the limited additional emission reductions would not be considered reasonable. Accordingly, we propose for NSPS subpart Kc, that if the modified tank has an existing EFR, the BSER and standard of performance is consistent with the EFR requirements as specified in NSPS subpart Kb.

In very rare cases, a fixed roof storage vessel may already be vented through a closed vent system to a control device at the time that it undergoes a modification. In NSPS subpart Kb, the control requirement for these control devices is 95 percent. As discussed in section III.F. of this preamble, we are proposing to require storage vessels with maximum true vapor pressures equal to or greater than 11.1 psia that are subject to NSPS subpart Kc to meet a 98 percent control efficiency based on a BSER identified as a closed vent system and control device. The primary difference between a flare, thermal oxidizer, or carbon adsorption system achieving 98 percent control efficiency rather than 95 percent control efficiency is largely in the operation of the control system rather than the design. Thus, we conclude that storage vessels that already vent through a closed vent system to a control device can technically achieve 98 percent control efficiency. As discussed in section III.F. of this preamble, we evaluated the incremental cost of operating a control system to achieve 98 percent control efficiency compared to 95 percent control efficiency and determined that it is cost-effective to meet a 98 percent control requirement. We consider that the analysis in section III.F. of this preamble to also be applicable to modified storage vessels because there are no meaningful differences in the costs of achieving 98 percent control efficiency as compared to new or reconstructed storage vessels. Therefore, for NSPS subpart Kc, we conclude that if a storage vessel with an existing closed vent system routed to a control device meets the qualifications for modification discussed in section III.G, the BSER is a closed vent system to a control device and standard of performance is 98 percent control of VOC emissions, the same as new or reconstructed storage vessels.

The EPA solicits comment on the proposed standards for modified storage vessels, including whether the EPA should finalize any of the alternative options.

*I. What control requirements are we proposing for IFR and EFR storage vessels emptying and degassing and why?*

Occasionally, floating roof storage vessels need to be taken out of service to clean, inspect, or repair the storage vessel or floating roof. For example, some floating roof seal components may wear out more quickly over time than the main structure of the floating roof. Depending on the seal type, this repair may require that the storage vessel be taken out of service. When the storage vessel is emptied, the floating roof will land on support legs or, if suspended by cables, reach a fixed height position. Commonly, the support legs or cable suspension will have two different fixed settings. One setting would be at a low height (for example, one foot) to maximize the working volume of the storage vessel when it is in service. The other setting would be a high "maintenance" height that allows maintenance crews to enter the storage vessel and walk under the roof once the floating roof is landed and the storage vessel is emptied. The vapor space can have significant volatile content due to volatilization of the organic liquid as the storage vessel is emptied or from liquid film that may cling to the wall and floor after the tank is emptied. The VOC emissions from the emptying and degassing process is dependent on the vapor pressure of the liquid stored, the dimensions of the storage vessel, and the height of the floating roof when landed (for maintenance), which impacts the size of the vapor space below the floating roof. The EPA evaluated different scenarios in which a control device could be utilized to achieve a 98 percent destruction efficiency until the vapor space concentration is within 10 percent of the lower explosive limit (LEL).

We evaluated the cost and VOC emissions for a wide variety of storage vessel sizes and VOL contents. We found that degassing controls were generally only cost-effective for larger storage vessels with vapor pressures greater than 1.5 psia. We evaluated the following options to determine the applicability threshold for control during degassing events:

- Baseline: Uncontrolled degassing.
- Degassing Option 1: Control degassing for storage vessels with a capacity of 1-million gallon or more storing organic liquids with a maximum true vapor pressure of 1.5 psia or more.
- Degassing Option 2a: Control degassing for storage vessels with a capacity of 300,000 gallon or more storing organic liquids with a maximum true vapor pressure of 1.5 psia or more.
- Degassing Option 2b: Control degassing for storage vessels with a capacity of 1-million gallon or more storing organic liquids with a maximum true vapor pressure of 0.5 psia or more.

Degassing Options 2a and 2b were both evaluated against Degassing Option 1 to evaluate whether lowering the size threshold or lowering the vapor pressure threshold could be cost-effective. Nationwide impacts were estimated based on our projected distribution of storage vessels. Furthermore, we estimated that storage vessels would be emptied and degassed once every 10 years. For more details regarding the nationwide estimated of degassing emissions and costs and emission reductions for degassing controls, see memorandum *Control Options for Storage Vessels* in Docket ID No. EPA–HQ–OAR–2023–0358. The nationwide impacts projected for the degassing control options are summarized in Table 7 of this preamble. We evaluated the cost effectiveness and incremental cost effectiveness of the three different options. While all three options were cost-effective, degassing option 1 was selected because the incremental cost effectiveness of the remaining options exceeded reasonable values established for the control of VOC emissions in prior rulemaking. Based on our analysis, we are proposing that, for degassing emissions, a control device utilized to achieve a 98 percent destruction efficiency is the BSER for storage vessels with a capacity of 1-million gallon or more storing organic liquids with a maximum true vapor pressure of 1.5 psia or more. The EPA's consideration of non-air quality health and environmental impacts as well as energy requirements is the same as considered for control devices in section III.F. Accordingly, the EPA proposes to establish a standard of performance of 98 percent control until the vapor space concentration is within 10 percent of the LEL for these storage vessels that applies during degassing events.

The EPA solicits comment on the proposed BSER and standard of performance for degassing events, including the applicability threshold for application of those standards.

TABLE 7—SUMMARY OF NATIONAL IMPACTS FOR DEGASSING CONTROLS

| Control option | VOC emissions (tpy) | VOC emissions reduction (tpy) | TAC [1] without product recovery (million $/yr) | CE [2] ($/ton VOC) | ICE [3] ($/ton VOC) |
|---|---|---|---|---|---|
| Baseline | 33.30 | ..... | ..... | ..... | ..... |
| Degassing Option 1 | 18.92 | 14.38 | $69,860 | $4,859 | ..... |
| Degassing Option 2a | 14.89 | 18.41 | 119,000 | 6,465 | $12,196 |
| Degassing Option 2b | 13.38 | 19.92 | 129,740 | 6,514 | 10,809 |

[1] Total annualized costs (TAC) considering annualized cost of capital.
[2] Cost effectiveness (CE).
[3] Incremental cost effectiveness (ICE). The ICE of Degassing Options 2a and 2b are calculated against Degassing Option 1.

*J. What requirements are we proposing for storage vessel testing, monitoring, and inspections and why?*

Because the NSPS reflects BSER under conditions of proper operation and maintenance, in doing our review, we also evaluate and determine the proper testing, monitoring, recordkeeping and reporting requirements needed to ensure compliance with the requirements of NSPS subpart Kc. This section includes our discussion on current testing and monitoring requirements of the NSPS subpart Kb and any revisions or additions we are proposing to include for NSPS subpart Kc.

We reviewed and compared monitoring and inspection requirements across several rules, including NSPS subpart Kb and the storage vessel requirements in 40 CFR part 63, subpart WW and 40 CFR part 65, subpart C. Generally, these requirements are similar to each other, and we strove to develop monitoring and inspection requirements consistent with these federal standards and that provide the best clarity for the specific requirements. However, we note that the

current NSPS subpart Kb includes provision for inspections every 5 years for IFRs that have a dual seal system. We are proposing to require dual seal IFRs for storage vessels with a maximum vapor pressure less than 11.1 psia, but as discussed later in this section, we are also proposing the use of lower explosive limit (LEL) monitoring within the headspace of the IFR as a means to enhance inspections and more readily identify malfunctioning internal floating roofs. Because a top-side inspection can be easily conducted in conjunction with the annual LEL monitoring, we are proposing to require annual LEL monitoring and floating roof inspections for all floating roofs, including IFRs with a dual seal system.

We are proposing to add annual monitoring of IFR storage vessels using a LEL monitor to identify floating roofs with poorly functioning seals or fitting controls. We identified at least two States or localities (New Jersey rule 7:27–16 and SCAQMD Rule 1178) that have LEL monitoring for IFR storage vessels. Our emission estimates from various storage vessel requirements assume that proper seals and other equipment are in-place and operating as required. If these controls are not operating as intended, the emissions from these storage vessels can be much higher. We found that the visual inspections are subjective and may, at times, not be performed well. For example, although a hired contractor for BP's Carson Refinery had reported no problems with the facility's 26 floating roof storage vessels from 1994 to 2002, a SCAQMD inspection "revealed that more than 80 percent of the storage vessels had numerous leaks, gaps, torn seals, and other defects that caused excess emissions." [8] Therefore, for purposes of NSPS subpart Kc, we sought a less subjective means to monitor and verify performance of the floating roofs. We concluded that periodic LEL monitoring could be used to ensure the floating roofs are performing as intended.

The New Jersey and SCAQMD rules set a maximum LEL that triggers an obligation for corrective action at the storage vessel, and we modeled our proposed NSPS subpart Kc provision following these State rules. For storage vessels installed after June 1, 1984, these rules set a maximum LEL of 30 percent. However, the National Fire Protection Association (NFPA) standard sets a maximum LEL of 25 percent for explosion prevention for IFR storage vessels. Per our review, we conclude that establishing a maximum LEL level for IFR storage vessels in NSPS subpart Kc that will trigger an obligation for the owner and operator to repair the IFR, discussed further in the next paragraph, which will ensure the emission reductions expected by the application of BSER are achieved. From the data we collected, there were very few measurements that exceeded 25 percent LEL that did not also exceed 50 percent LEL. Thus, when failures occurred, the LEL was often very high. Based on these observations and considering the more stringent NFPA standard, we propose for NSPS subpart Kc, for new, modified, and reconstructed storage vessels, the use of LEL monitor to identify floating roofs with poorly functioning seals or fitting controls and we propose that the appropriate LEL levels for IFR storage vessels is 25 percent.

We acknowledge that it is difficult to estimate the emission impacts of these LEL monitoring requirements because we do not have data on the number of poorly functioning floating roofs. NSPS subpart Kb already requires repair of floating roofs that fail inspection and failure of the proposed NSPS subpart Kc LEL monitoring would trigger the same repairs. As such, we consider that these repairs are already required in NSPS subpart Kb and the LEL requirement predominately makes the required inspections less subjective. In the worst-case scenario, a poorly operated IFR storage vessel can have emissions similar to those of a fixed roof storage vessel. In establishing the floating roof requirements, we already determined that installing a floating roof was cost-effective and that the costs of replacing a poorly functioning floating roof is not significantly different from the costs of retrofitting a fixed roof storage vessel. In our cost analysis, we projected floating roofs have a 15-year life, so our annualized costs account for IFR replacement every 15 years. We expect that most poorly performing floating roofs can be repaired, rather than replaced, but we expect that replacement will be necessary in some cases. We propose to require in NSPS subpart Kc that for new, modified, and reconstructed storage vessels whose IFRs have failed to the point that 25 percent LEL is exceeded, the owner or operator must repair the IFR and, if necessary, to replace the IFR when repairs are ineffective.

We are proposing in NSPS subpart Kc specific testing requirements when monitoring LEL for storage vessels with IFRs. We are proposing that LEL standard be assessed on a 5-minute rolling average basis and that LEL monitoring be conducted for a minimum of 20 minutes unless an exceedance is measured prior to completing 20 minutes of LEL monitoring. We are proposing that LEL be measured within the storage vessel no more than 3 feet above the IFR. We are proposing that LEL monitoring be conducted when the wind speed at the top of the tank is 5 miles per hour or less where practicable, but the testing will be invalid and must be reconducted at a later date (no later than 30 days from the previous attempted measurement) if the wind speed at the top of the tank is greater than the annual average wind speed at the site's location or 15 miles per hour, whichever is less.

The EPA solicits comment on the proposed testing, monitoring, and inspection requirements, including whether our selection of maximum 25 percent LEL is appropriate, or whether this number should be higher or lower.

There are a number of other monitoring and inspection requirements included as part of this proposal. The EPA is proposing equipping floating roof storage vessels with a visual or audible alarm system to monitor when the floating roof approaches specified landing heights. For closed vent systems, the EPA is proposing quarterly visual, audible, and olfactory inspections, annual EPA Method 21 instrument monitoring, and monitoring of bypasses. The EPA also proposes that storage vessels using closed vent systems and control devices must equip pressure relief devices with appropriate monitoring to identify releases.

The EPA is proposing specific requirements for flare and non-flare control devices to ensure they achieve the required control efficiency on an ongoing basis. Specifically, we are proposing initial testing of non-flare control devices and periodic testing every five years. During the performance test, the owner or operator would set an operating limit on the control device; continuous compliance with the operating limit would be demonstrated on a 3-hour rolling average basis. We propose that flares would be monitored consistent with the flare requirements in 40 CFR part 63 subpart CC.

Lastly the EPA is proposing applying the requirements in 40 CFR 60.116b(f) for waste mixtures to all mixtures with indeterminate or variable compositions.

### *K. Proposal of NSPS Subpart Kc Without Startup, Shutdown, and Malfunction Exemptions*

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the United States Court of Appeals for the District of Columbia Circuit (D.C.

[8] Mokhiber, Russell. Multinational Monitor; Washington Vol. 24, Iss. 4, (April 2003): 30.

Circuit) vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and (h)(1), holding that under section 302(k) of the CAA, emissions standards or limitations must be continuous in nature and that the SSM exemption violates the CAA's requirement that some section 112 standard apply continuously. The EPA has determined the reasoning in the Court's decision in *Sierra Club* applies equally to CAA section 111 because the definition of emission or standard in CAA section 302(k), and the embedded requirement for continuous standards, also applies to the NSPS.

Consistent with *Sierra Club* v. *EPA,* we are proposing standards in this rule that apply at all times. The NSPS general provisions in 40 CFR 60.11(c) currently exclude opacity requirements during periods of SSM and the provision in 40 CFR 60.8(c) contains an exemption from non-opacity standards. We are proposing in NSPS subpart Kc specific requirements at 40 CFR 60.112c(a)(1) that override the general provisions for SSM provisions. We are proposing a combination of design, equipment, work practice, and operational standards in NSPS subpart Kc that apply at all times.

The EPA has attempted to ensure that the general provisions we are proposing to override are inappropriate, unnecessary, or redundant in the absence of the SSM exemption. We are specifically seeking comment on whether we have successfully done so.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through "the application of the best system of emission reduction" that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting emissions standards, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a "normal or usual manner" and no statutory language compels EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting "achievable" standards under CAA section 112) has been upheld as reasonable by the D.C. Circuit in *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (2016).]

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, sudden, infrequent, not reasonably preventable, and was not instead caused, in part, by poor maintenance or careless operation. 40 CFR 60.2 (definition of "Malfunction").

If the EPA determines in a particular case that an enforcement action against a source for violation of an emission standard is warranted, the source can raise any and all defenses in that enforcement action and the Federal District Court will determine what, if any, relief is appropriate. The same is true for citizen enforcement actions. Similarly, the presiding officer in an administrative proceeding can consider any defense raised and determine whether administrative penalties are appropriate.

In summary, the EPA proposes that its interpretation of the CAA and, in particular, CAA section 111 is reasonable and encourages practices that will avoid malfunctions. Administrative and judicial procedures for addressing exceedances of the standards fully recognize that violations may occur despite good faith efforts to comply and can accommodate those situations. *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (2016).

### *L. Electronic Reporting*

The EPA is proposing that owners and operators of volatile organic liquid storage vessels (including petroleum liquid storage vessels) subject to NSPS subpart Kb and NSPS subpart Kc, submit electronic copies of certain required notifications and reports through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). A description of the electronic data submission process is provided in the memorandum *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* available in the docket for this action. Specifically, the proposed rule requires that for NSPS subpart Kb the reports specified in 40 CFR 60.115b(a)(1), 60.115b(a)(3), 60.115b(a)(4), 60.115b(b)(1), 60.115b(b)(2), 60.115b(b)(4), 60.115b(d)(1), 60.115b(d)(3), and 60.116b(d) be submitted as a portable document format upload in CEDRI, and for NSPS subpart Kc the rule requires that owners and operators use the appropriate spreadsheet templates to submit the initial notification specified in 40 CFR 60.116c(a) and semiannual reports specified in 40 CFR 60.116c(b) to CEDRI. Draft versions of the proposed templates for the NSPS subpart Kc initial notification and semiannual report are included in the docket for this action.[9] The EPA specifically requests comment on the content, layout, and overall design of the templates. We note that for NSPS subpart Kb, we are only proposing to change the format of the reporting requirements to require electronic reporting *(i.e.,* we are not proposing any new data elements).

Additionally, the EPA has identified two broad circumstances in which electronic reporting extensions may be provided. These circumstances are (1) outages of the EPA's CDX or CEDRI which preclude an owner or operator from accessing the system and submitting required reports and (2) *force majeure* events, which are defined as events that will be or have been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevent an owner or operator from complying with the requirement to submit a report electronically. Examples of *force majeure* events are acts of nature, acts of war or terrorism, or equipment failure or safety hazards beyond the control of the facility. The EPA is providing these potential extensions to protect owners and operators from noncompliance in

[9] See 40 CFR part_60_Subpart_Kc_60.116c(a)_Initial_Notification.xlsx and 40 CFR part_60_subpart_Kc_60.116c(b)_Semiannual_Report.xlsx, available in the docket for this action.

cases where they cannot successfully submit a report by the reporting deadline for reasons outside of their control. In both circumstances, the decision to accept the claim of needing additional time to report is within the discretion of the Administrator, and reporting should occur as soon as possible.

The electronic submittal of the reports addressed in this proposed rulemaking will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability and transparency, will further assist in the protection of public health and the environment, will improve compliance by facilitating the ability of regulated facilities to demonstrate compliance with requirements and by facilitating the ability of delegated State, local, Tribal, and territorial air agencies and the EPA to assess and determine compliance, and will ultimately reduce burden on regulated facilities, delegated air agencies, and the EPA. Electronic reporting also eliminates paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing data reporting errors, and providing data quickly and accurately to the affected facilities, air agencies, the EPA, and the public. Moreover, electronic reporting is consistent with the EPA's plan [10] to implement Executive Order 13563 and is in keeping with the EPA's agency-wide policy [11] developed in response to the White House's Digital Government Strategy.[12] For more information on the benefits of electronic reporting, see the memorandum *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* referenced earlier in this section.

### *M. Other Proposed Actions*

NSPS subpart Kb includes a number of technical methods which have been updated or replaced in the NSPS subpart Kc proposal. Two of these methods, American Society for Testing and Materials (ASTM) D2879 and American Petroleum Institute (API) Bulletin 2517, are used in determining vapor pressures including the maximum true vapor pressure.

We propose to replace ASTM D2879, "Standard Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope," with both ASTM D6378–22, "Standard Test Method for Determination of Vapor Pressure (VPX) of Petroleum Products, Hydrocarbons, and Hydrocarbon-Oxygenate Mixtures (Triple Expansion Method)," and ASTM D6377–20 "Standard Test Method for Determination of Vapor Pressure of Crude Oil: $VPCR_x$ (Expansion Method)." This change is consistent with the actions finalized in the 2020 amendments to the Organic Liquids Distribution (OLD) NESHAP (85 FR 40740). ASTM D2879 involves both an isoteniscope and heating the sample to a boil. The proposed replacement is an automated device method that produces more accurate vapor pressure measurements. ASTM D6378–22 is used for measuring vapor pressures between 7 kPa and 150 kPa. ASTM D6377–20 is used for measuring vapor pressures between 29 kPa and 180 kPa. For each analysis, you must use a 4:1 vapor to liquid ratio.

Additionally, we propose replacing the API Bulletin 2517, *Evaporative Loss from External Floating-Roof Tanks,* with information available in AP–42, Chapter 7. While API Bulletin 2517 does not prescribe methods for measuring liquid vapor pressure, it acts as a reference and includes a table of vapor pressures for pure substances at temperatures between 40 and 100 degrees Fahrenheit. API Bulletin 2517 also includes information for calculating Reid vapor pressures crude oil and refined petroleum stocks. AP–42, Chapter 7 includes comparable information and is publicly available. EPA is also proposing not to incorporate ASTM D323 into the proposed subpart. ASTM D323, "Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method)" is used for the determination of the Reid vapor pressure which can be used in conjunction with ASTM D2879 for determining vapor pressures. The inclusion of ASTM D6378 and ASTM D6377, makes the need for ASTM D323 unnecessary in the proposed standard.

### *N. Compliance Dates*

Pursuant to CAA section 111(b)(1)(B), the effective date of the final rule requirements in NSPS subpart Kc will be the promulgation date. Affected sources that commence construction, reconstruction, or modification after October 4, 2023 must comply with all requirements of NSPS subpart Kc, no later than the effective date of the final rule or upon startup, whichever is later. The EPA is proposing amendments to NSPS subpart Kb to include electronic submission requirements. Affected NSPS subpart Kb sources that commence construction, reconstruction or modification after July 23, 1984, and before October 4, 2023 must comply with the updated requirements to submit reports electronically no later than the effective date of the final rule.

## IV. Summary of Cost, Environmental, and Economic Impacts

### *A. What are the air quality impacts?*

The proposed revisions in NSPS subpart Kc reduce emissions of VOCs, some of which may also be hazardous air pollutants (HAPs). The EPA estimates that the updated standards would reduce VOC emissions by 1,085 tons per year, which includes the impacts from new, modified, and reconstructed storage vessels. More information regarding the air quality impacts and emission reductions are included in the memorandum *Control Options for Storage Vessels.*

### *B. What are the cost impacts?*

This final action will cost (in 2022 dollars) approximately $20.6 million in total capital cost and result in total annualized cost savings of $4.48 million per year (including product recovery) based on our analysis of the proposed actions in NSPS subpart Kc. More information about the estimated cost of the proposed actions can be found in the memorandum *Control Options for Storage Vessels.*

### *C. What are the economic impacts?*

For economic impact analyses of rules that directly affect a single or a few industries, the EPA often prepares a partial equilibrium analysis. In this type of economic analysis, the focus of the effort is on estimating impacts on a single affected industry or several affected industries, and all impacts of this rule on industries outside of those affected are assumed to be zero or so inconsequential to not be considered in the analysis. If the compliance costs, which are key inputs to an economic impact analysis, are quite insignificant, then the impact analysis could consist of a calculation of annual (or annualized) costs as a percentage of sales for affected companies. This latter type of analysis is called a screening analysis and is applied when a partial equilibrium or more complex economic impact analysis approach is deemed not

[10] EPA's Final Plan for Periodic Retrospective Reviews, August 2011. Available at: *https://www.regulations.gov/document?D=EPA-HQ-OA-2011-0156-0154.*

[11] E-Reporting Policy Statement for EPA Regulations, September 2013. Available at: *https://www.epa.gov/sites/default/files/2016-03/documents/epa-ereporting-policy-statement-2013-09-30.pdf.*

[12] Digital Government: Building a 21st Century Platform to Better Serve the American People, May 2012. Available at: *https://obamawhitehouse.archives.gov/sites/default/files/omb/egov/digital-government/digital-government.html.*

necessary given the expected size of the impacts.

The net present value of the estimated cost impacts of the proposed NSPS subpart Kc is $18.9 million, discounted at a 3 percent rate over a 5-year analytic time frame from 2024 to 2028 in 2022 dollars. Using a 7 percent discount rate, the net present value of the estimated cost impacts is $16.9 million. The equivalent annualized value in 2022 dollars is a cost of approximately $4.1 million using a discount rate of three and seven percent.

Storage vessels in NSPS subpart Kb are most closely associated with the petroleum and coal products industry (NAICS 324000), chemical products industry (NAICS 325000), and the petroleum bulk stations terminals industry (NAICS 424710). While we do not know the precise distribution of new and modified storage vessels across the affected sectors, we know that there are affected storage vessels in the sectors mentioned earlier in this preamble. These sectors contribute gross value added, ranging from $129 to $440 billion per sector, to the national economy. In comparison, the proposed requirements in NSPS subpart Kc have estimated total costs of $20.6 million. The total cost is the total incurred collectively amongst numerous sectors, and each of the sectors examined have sales of at least $129 billion. Thus, the compliance costs of this action are insignificant relative to the scale for the sectors affected, and it is appropriate to evaluate the economic impacts by conducting a screening analysis comparing the costs to entity-level sales.

Given the results of the analysis, these economic impacts are relatively low for affected industries and entities impacted by this proposed rule, and there will not be substantial impacts on the markets for affected products. The costs of the proposed rule are not expected to result in a significant market impact, regardless of whether they are passed on to the purchaser or absorbed by the firms. We also expect minimal impacts on employment.

*D. What are the benefits?*

These proposed revisions in NSPS subpart Kc would reduce emissions of VOCs, some of which may also be HAPs. Because VOCs react in the atmosphere to produce ozone, these standards would help to reduce atmospheric ozone concentrations and reduce health effects associated with high levels of ozone. Furthermore, the proposed requirements to submit reports and test results electronically would improve monitoring, compliance, and implementation of the rule.

*E. What analysis of environmental justice did we conduct?*

Executive Order 12898 directs the EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms, which are specifically minority populations (people of color), low-income populations, and Indigenous peoples (59 FR 7629, February 16, 1994). Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through Federal government actions (86 FR 7009, January 20, 2021). The EPA defines environmental justice (EJ) as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies." [13] The EPA further defines fair treatment to mean that "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies." In recognizing that people of color and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution. For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis," [14] which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) Create new disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; (2) exacerbate existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; or (3) present opportunities to address existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples through this action under development.

We are unable to quantitatively estimate the potential EJ impact of NSPS subparts Kb and Kc for the following reasons. Over the next 5 years, the EPA estimates that 1,440 new tanks and 27 modified tanks would be subject to NSPS subpart Kc. However, the locations of any new VOL storage vessels that would be subject to NSPS subpart Kc are unknown. Furthermore, there is insufficient data available regarding the locations of existing VOL storage vessels. We estimate that there are approximately more than 10,000 existing Volatile Organic Liquid Storage Vessels, but do not have a list of specific units and their locations. Therefore, we cannot perform a proximity demographic analysis of populations near existing units as a proxy for units that may be modified or reconstructed and become subject to NSPS subpart Kc. Finally, because we based the analysis of the impacts and emission reductions on model plants, we are not able to ascertain specifically how the potential benefits of this rule would be distributed across the population. Thus, we are limited in our ability to estimate the potential EJ impacts of this rule.

However, we anticipate the proposed requirements in NSPS subpart Kc would generally minimize future emissions in surrounding communities of new, modified, or reconstructed VOL storage vessels. The three most relevant industry NAICS industry segments affected under NSPS Kc include Petroleum and Coal Products Manufacturing (NAICS code 324000), Chemical Manufacturing (NAICS code 325000), and Petroleum and Bulk Stations and Terminals (NAICS code 422710). Specifically, the EPA determined that the standards should be revised to amend the vapor pressure applicability thresholds, require stricter seal requirements on IFR tanks, establish equivalent control requirements for external floating roofs, and strengthen the closed vent system standard to account for 98 percent destruction efficiency. The changes would have beneficial effects on air quality and public health for populations exposed to emissions from new, modified or reconstructed VOL storage vessels and would provide additional health protection for affected populations, including communities already overburdened by pollution, which are often people of color, low-income, and indigenous communities.

## V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be

[13] *https://www.epa.gov/environmentaljustice.*

[14] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

*A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094 Modernizing Regulatory Review*

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

*B. Paperwork Reduction Act (PRA)*

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2791.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The EPA is proposing requirements for storage vessels including periodic inspections based on the type of storage vessel. This information will be collected to assure compliance with NSPS subpart Kc.

*Respondents/affected entities:* Owners or operators of VOL storage vessels.

*Respondent's obligation to respond:* Mandatory (40 CFR part 60, subpart Kc).

*Estimated number of respondents:* 588.

*Frequency of response:* Initially and Semiannually.

*Total estimated burden:* 16,394 hours (per year). Burden is defined at 5 CFR 1320.3(b).

*Total estimated cost:* $2,009,357 (per year), includes $528,240 in annualized capital and no operation or maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *OIRA_submission@omb.eop.gov,* Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than November 3, 2023. The EPA will respond to any ICR-related comments in the final rule.

*C. Regulatory Flexibility Act (RFA)*

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses and small governmental jurisdictions. The Agency has determined that small entities may experience an impact of likely below 1 percent relative to sales for any affected small entity, and an even larger margin before it would approach a 1 percent impact for a substantial number of small entities. Details of this analysis are presented in the memorandum *Economic Impact Analysis for the Proposed New Source Performance Standards (NSPS) for the Volatile Organic Liquid Storage Vessels (Tanks)* included in the docket.

*D. Unfunded Mandates Reform Act (UMRA)*

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any State, local, or Tribal governments or the private sector.

*E. Executive Order 13132: Federalism*

This action does not have federalism implications. It would not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

*F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments*

This proposed action does have Tribal implications as specified in Executive Order 13175. NSPS subpart Kb includes provisions for storage vessels that already have impacts on Tribal Governments that have tanks in excess of 20,000 gallons that meet the vapor pressure cutoffs for general rule applicability or control applicability. The NSPS subpart Kc proposal includes some updates to the VOC standards and monitoring requirements for storage vessels that meet the revised vapor pressure cutoffs for control. Additionally, basic requirements for recordkeeping and good air pollution control practices are being proposed for all storage vessels greater than 20,000. These changes would only impact storage vessels that are constructed, modified, or reconstructed after the proposal date. Consistent with the *EPA Policy on Consultation and Coordination with Indian Tribes,* the EPA will offer government-to-government consultation with tribes and will conduct additional outreach to inform them of the content of the proposed rule.

*G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks*

Executive Order 13045 (62 FR 19885, April 23, 1997) directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. These proposed revisions would reduce emissions of VOCs, some of which may also be hazardous air pollutants (HAPs). These standards would help to reduce atmospheric ozone concentrations and reduce health effects associated with high levels of ozone.

However, EPA's *Policy on Children's Health* applies to this action. Information on how the Policy was applied is available under "Children's Environmental Health" in the **SUPPLEMENTARY INFORMATION** section of this preamble.

*H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use*

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

*I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51*

This action for Kb and Kc involves technical standards. Therefore, the EPA conducted a search to identify potentially applicable voluntary consensus standards. However, the Agency identified no such standards. Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 18, 21, 22, and 25A of 40 CFR part 60, appendix A. The EPA has decided to use EPA Methods 21, 22, and 25A. Additional information

for the voluntary consensus standard search and determinations can be found in the memorandum titled, *Voluntary Consensus Standard Results for Review of Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels).* All potential standards were reviewed to determine the practicality of the voluntary consensus standards (VCS) for this rule. Although there were no applicable voluntary consensus standards identified, we are amending 40 CFR 60.17 to incorporate by reference two ASTM methods as discussed in section III.M. These include the following:

- ASTM D6377–20, "Standard Test Method for Determination of Vapor Pressure of Crude Oil: $VPCR_x$ (Expansion Method). The method is an automated device method for measuring vapor pressures for crude oils samples between 29 kPa and 180 kPa at 37.8 °C. The method is suitable for testing with a 4:1 vapor-liquid ratio.
- ASTM D6378–22, "Standard Test Method for Determination of Vapor Pressure (VPX) of Petroleum Products, Hydrocarbons, and Hydrocarbon-Oxygenate Mixtures (Triple Expansion Method). The method is an automated device method for measuring vapor pressures between 7 kPa and 150 kPa at 37.8 °C for tested samples with boiling points at 0 °C. The method is suitable for volatile organic liquids, hydrocarbons and liquid petroleum products sampled at a 4:1 vapor-liquid ratio.

The ASTM standards are available from the American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959. See *https://www.astm.org.*

*J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing our Nation's Commitment to Environmental Justice for All*

The EPA believes that it is not practicable to assess whether the human health or environmental conditions that exist prior to this action result in disproportionate and adverse effects on communities with EJ concerns. Over the next 5 years, the EPA estimates that 1,440 new tanks and 27 modified tanks will be subject to NSPS subpart Kc. However, the locations of any new VOL storage vessels that would be subject to NSPS subpart Kc are not known. Furthermore, there is insufficient data available regarding the locations of existing VOL storage vessels is also not known. The EPA estimates that there are approximately more than 10,000 existing vessels subject to NSPS subpart Kb, but do not have a list of specific units and their locations. Therefore, we cannot perform a proximity demographic analysis of populations near existing units as a proxy for units that may be modified or reconstructed and become subject to NSPS subpart Kc. Finally, because we based the analysis of the impacts and emission reductions on model plants, we are not able to ascertain specifically how the potential benefits of this rule would be distributed across the population. Thus, we are limited in our ability to estimate the potential EJ impacts of this rule.

The information supporting this Executive Order review is contained in in section IV.E. All pertinent supporting documents such as the technical memo, "Control Options for Storage Vessels" which discusses the costs and environmental impacts of the regulatory options considered have been placed in the docket.

**Michael S. Regan,**

*Administrator.*

[FR Doc. 2023–21976 Filed 10–3–23; 8:45 am]

**BILLING CODE 6560–50–P**

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### 42 CFR Part 52i

**[Docket No. NIH–2022–0001]**

**RIN 0925–AA70**

## National Institute on Minority Health and Health Disparities Research Endowment Programs

**AGENCY:** National Institutes of Health, HHS.

**ACTION:** Notice of proposed rulemaking.

**SUMMARY:** The Department of Health and Human Services (HHS or Department), through the National Institutes of Health (NIH), is proposing to amend the regulation governing the National Institute on Minority Health and Health Disparities (NIMHD) Research Endowment Programs (REP) to update the heading of the regulation to reflect the new name of the program, the eligibility requirements for the program to indicate the new expanded eligibility for research endowment awards that is mandated by statute, the heading of one section of the regulation, and certain references to regulations and policies cited in the regulation that apply to program grant awards.

**DATES:** Comments must be received on or before December 4, 2023.

**ADDRESSES:** You may send comments, identified by Docket Number NIH 2022–0001 and/or RIN 0925–AA70, by any of the following methods:

*Electronic Submissions*

You may send comments electronically in the following way:

- *Federal eRulemaking Portal: www.regulations.gov.* Follow the instructions for sending comments.

*Written Submissions*

You may send written comments in the following ways:

Please allow enough time for mailed comments to be received before the close of the comment period.

- *Mail (for paper or CD–ROM submissions):* Daniel Hernandez, NIH Regulations Officer, National Institutes of Health, Office of Management Assessment, Rockledge 1, 6705 Rockledge Drive, Suite 601, Room 601–T, MSC 7901, Bethesda, Maryland 20892–7901.
- *Hand Delivery/Courier (for paper or CD–ROM submissions):* Daniel Hernandez, Rockledge 1, 6705 Rockledge Drive, Suite 601, Room 601–T, MSC 7901, Bethesda, Maryland 20892–7901.

*Instructions:* All submissions received must include the agency name and docket number or Regulatory Information Number (RIN) for this rulemaking. All comments will be posted without change to *www.regulations.gov,* including any personal information provided.

*Docket:* For access to the docket to read background documents or comments received, go to the eRulemaking Portal at *www.regulations.gov* and insert the docket number provided in brackets in the heading on page one of this document into the: "Search" box and follow the prompts.

**FOR FURTHER INFORMATION CONTACT:** Daniel Hernandez, NIH Regulations Officer, Office of Management Assessment, NIH, Rockledge 1, 6705 Rockledge Drive, Suite 601, Room 601–T, Bethesda, MD 20817, MSC 7901, by email at *dhernandez@mail.nih.gov,* or by telephone at 301–435–3343 (not a toll-free number). For program information contact: Dr. Nathan Stinson, Director, Division of Community Health and Population Sciences, NIMHD, by email *stinsonn@nih.gov,* or telephone 301–594–8704. Information concerning the requirements, application deadline dates, and an on-line application for NIMHD REP awards may be obtained from the NIMHD via *https://www.nimhd.nih.gov/programs/extramural/research-endowment.html.*

# Attachment B

"Control Options for Storage Vessels" dated August 11, 2023

RTI INTERNATIONAL | Memorandum

**FROM:** Fallon Clemens, Jeff Coburn, Marissa DeLang, and David Randall – RTI International

**TO:** Michael Cantoni, Jennifer Caparoso, and Brenda Shine, EPA/OAQPS

**FOR:** EPA Docket No. EPA-HQ-OAR-2023-0358

**DATE:** August 11, 2023

**SUBJECT:** Control Options for Storage Vessels

## 1. Purpose

This memorandum documents the costs and environmental impacts for several regulatory options considered as part of the new source performance standard (NSPS) review for storage vessels.

## 2. Background

Sections 111(b)(1)(B) of the Clean Air Act (CAA) direct the U.S. Environmental Protection Agency (EPA) to develop NSPS. Section 111(b)(1)(B) also requires the EPA to review NSPS for a given source category every 8 years, and, if appropriate, revise such standards. The federal standards currently being reviewed are found at 40 CFR part 60, subpart Kb, Standards of Performance for Volatile Organic Liquids Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.

NSPS subpart Kb is applicable to large storage vessels containing organic liquids that can emit volatile organic compounds (VOC) across a wide range of industries, such as petroleum refineries, chemical plants, and portions of the oil and gas industry. The three most relevant industry sectors by North American Industry Classification System (NAICS) codes are Petroleum and Coal Products Manufacturing (NAICS code 324000), Chemical Manufacturing (NAICS code 325000), and Petroleum Bulk Stations and Terminals (NAICS code 422710).

NSPS subpart Kb includes control requirements for internal floating roof (IFR) and external floating roof (EFR) storage vessels and storage vessels with closed vent systems for control.

The IFR and EFR requirements in NSPS subpart Kb apply to storage vessels based on the vapor pressure of the stored liquid and the size of the storage vessel. **Table 1** outlines the current NSPS subpart Kb thresholds for floating roof storage vessel requirements established under 40 CFR 60.112b(a).

**Table 1. NSPS subpart Kb floating roof storage vessel control requirement thresholds.[1]**

| Storage Vessel Capacity ($m^3$) | Minimum Vapor Pressure (kPa) | Minimum Vapor Pressure (psi) |
|---|---|---|
| ≥ 75 | 27.6 | 4.0 |
| ≥ 151 | 5.2 | 0.75 |

[1] NSPS subpart Kb requires applicable storage vessels with fluid maximum true vapor pressures greater than or equal to 76.6 kPa (11.1 psi) to utilize a closed vent system and control under NSPS subpart Kb.

Under NSPS subpart Kb, storage vessels with a design capacity greater than or equal to 75 $m^3$ (20,000 gallons) containing a volatile organic liquid with a maximum true vapor pressure greater than or equal to 76.6 kPa (11.1 psia) must be equipped with a closed vent system and control device that reduces inlet VOC emissions by 95 percent or greater.

## 3. Model Analysis Approach

As part of this NSPS review, we reviewed other federal and local regulations for storage vessels and compared these requirements to NSPS subpart Kb. In terms of other federal regulations with requirements for IFR and EFR storage vessels, we reviewed the Consolidated Federal Air Rule for storage vessels at 40 CFR Part 65 Subpart C and the national emissions standards for hazardous air pollutants (NESHAP) for storage vessels located at 40 CFR part 63, subpart WW. We also reviewed the South Coast Air Quality Management District (SCAQMD) regulations for Organic Liquid Storage and Further Reductions of VOC Emissions from Storage Tanks at Petroleum Facilities under Rule 643 and Rule 1178, respectively.

In order to estimate the cost and emission impacts of various storage vessel control options, we first defined model storage vessels and surrogate chemicals to represent the population of storage vessels affected by NSPS subpart Kb as summarized in this section. We then developed potential control options for IFR storage vessels, EFR storage vessels, closed vent systems, and degassing to compare to the current requirements in NSPS subpart Kb (see Sections 4 through 7). We modeled emissions primarily using the equations in Chapter 7 of AP-42 (U.S. EPA, 2020) to estimate emissions from model storage vessels based on the size, contents, and tank configuration of the storage vessel. All storage vessels were modeled as being located in Houston, TX for the meteorological input parameters. We developed cost estimates for each tank configuration, estimated the number of tanks affected by each requirement, and calculated nationwide impacts. Control options were evaluated based on the best system of emissions reductions and the cost effectiveness of each control option in comparison to NSPS subpart Kb.

In order to evaluate control options for storage vessels, we established the model storage vessel set as shown in **Table 2**.

**Table 2. Model storage vessel parameters.**

| Matrix/Model | Model Parameter/Value | | | |
|---|---|---|---|---|
| Storage Vessel Designation | Diameter (ft) | Height (ft) | Capacity (Gallons) | Throughput (Gallons per year)[1] |
| Model 1 | 9.3 | 16 | 8,000 | 208,000 |
| Model 2 | 14 | 18 | 20,000 | 520,000 |
| Model 3 | 18 | 21.5 | 40,000 | 1,040,000 |
| Model 4 | 20 | 25.8 | 60,000 | 1,560,000 |
| Model 5 | 30.3 | 30 | 160,000 | 4,160,000 |
| Model 6 | 48 | 30 | 400,000 | 10,400,000 |
| Model 7 | 93 | 40 | 2,000,000 | 52,000,000 |
| Model 8 | 200 | 44 | 10,000,000 | 260,000,000 |

[1]Assumed 26 turnovers per year.

All model storage vessels were first modeled with fixed roofs to establish an emissions baseline for which subsequent control options could be evaluated. In addition to the size parameters listed above, additional parameters for fixed roof storage vessels are shown in **Table 3**. Since NSPS subpart Kb can apply to storage vessels across a variety of industries, we modeled multiple chemicals across a range of vapor pressures. **Table 4** displays the chemicals modeled in this NSPS review.

**Table 3. Fixed roof storage vessel input parameters.**

| Input Parameter | Fixed Roof |
|---|---|
| **Tank Surface Color** | Gray, Light |
| **Tank Surface Condition** | Average |

**Table 4. Chemicals Modeled**

| Chemical Name | Vapor Pressure (psia) |
|---|---|
| o-Xylene | 0.12 |
| Methyl isobutyl ketone (MIK) | 0.35 |
| Toluene | 0.51 |
| Heptane | 0.825 |
| Ethanol | 1.055 |
| Methacrylonitrile | 1.295 |
| Benzene | 1.73 |
| Vinyl Acetate | 2.08 |
| Hexane | 2.76 |
| Diethylamine | 4.08 |
| Gasoline (RVP7) | 4.65 |

| Chemical Name | Vapor Pressure (psia) |
|---|---|
| Gasoline (RVP13) | 9.05 |
| Isopentane[1] | 12.68 |

[1] Modeled with a closed vent system

The equations in AP-42 output VOC emissions, so the emissions, emission reductions, and cost-effectiveness of control options were evaluated in terms of VOC. ***Appendix A*** provides the emissions for each model storage vessel size and chemical stored for fixed roof storage vessels and for each control option evaluated as described in Section 4 and 5.

## 4. Impact Estimates for IFR Storage Vessels

### *4.1 IFR Model Storage Vessels*

Based on our review of technologies applicable for internal floating roofs as well and the requirements the Consolidated Federal Air Rule for storage vessels at 40 CFR Part 65 subpart C, the NESHAP for storage vessels located at 40 CFR part 63 subpart WW, and the SCAQMD regulations (Rule 643 and Rule 1178), we identified the following potential tank configurations:

- IFR-Kb. NSPS subpart Kb for internal floating roofs considering controls for guidepoles as provided in the Storage Tank Emission Reduction Partnership Program (STERPP) as provided in 65 FR 19891 (April 13, 2000).
- IFR-1. NSPS subpart Kb but primary seal must either be liquid-mounted or mechanical shoe seal and must have rim-mounted secondary seal and gauge-hatch/sampling port using a gasketed cover with weighted mechanical actuation.
- IFR-2. Option IFR-1 with fixed roof legs or a cable suspended roof (cannot have adjustable roof legs that penetrate through the floating roof).
- IFR-3. Option IFR-2 with welded seems and best guidepole fittings.

We estimated the emissions from an IFR storage vessel for each of the tank configurations (*i.e.*, set of storage vessel parameters) shown in **Table 5**.

**Table 5. Detailed IFR storage vessel parameters for each tank configuration[1].**

| Input Parameter | IFR-Kb | IFR-1 | IFR-2 | IFR-3 |
|---|---|---|---|---|
| **Tank Construction** | Welded | Welded | Welded | Welded |
| **Tank Surface Color** | Gray, Light | Gray, Light | Gray, Light | Gray, Light |
| **Tank Surface Condition** | Average | Average | Average | Average |
| **Shell Condition** | Light Rust | Light Rust | Light Rust | Light Rust |
| **Roof Support** | Self Supported | Self Supported | Self Supported | Self Supported |
| **Column Type** | N/A | N/A | N/A | N/A |
| **Seal Fit** | Average | Average | Average | Average |
| **Deck Type** | Bolted | Bolted | Bolted | *Welded* |

| Input Parameter | IFR-Kb | IFR-1 | IFR-2 | IFR-3 |
|---|---|---|---|---|
| **Deck Construction** | Panel - 5 x 7.5 ft rectangular | Panel - 5 x 7.5 ft rectangular | Panel - 5 x 7.5 ft rectangular | N/A |
| **Primary Seal** | Mechanical shoe | Mechanical shoe | Mechanical shoe | Mechanical shoe |
| **Secondary Seal** | None | *Rim mounted* | Rim mounted | Rim mounted |
| **Access Hatch** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Guidepoles** | Slotted guidepole/sample well, gasketed sliding cover, with float and pole wiper | Slotted guidepole/sample well, gasketed sliding cover, with float and pole wiper | Slotted guidepole/sample well, gasketed sliding cover, with float and pole wiper | *Slotted guidepole/sample well, gasketed sliding cover, with pole sleeve and pole wiper* |
| **Gauge-float well** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Gauge-hatch/sample port** | Slit fabric seal, 10% open area | *Weighted mechanical actuation, gasketed* | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Vacuum Breaker** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Deck Leg** | Adjustable | Adjustable | *Fixed* | Fixed |
| **Rim Vent** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |

[1] Storage vessel parameters that changed from the previous tank configuration in the table are italicized.

### *4.2 IFR Storage Vessel Emissions*

Emissions reductions for each model storage vessel and tank configuration combination are dependent on the chemical stored. **Table 6** displays the emissions reductions for Model 4 (60,000-gallon storage vessel) for each of the chemicals modeled. Emissions for all model storage vessel sizes and chemical combinations that were modeled for each tank configuration are presented in ***Appendix A***.

**Table 6. Model 4 emissions for IFR tank configurations and various chemicals.**

| Tank Configuration | VOC Emissions (lb/year) | VOC Emissions Reductions (lb/year) |
|---|---|---|
| **o-xylene** | | |
| Fixed Roof | 630.5 | -- |
| IFR-Kb | 71.2 | 559.3 |
| IFR-1 | 46.4 | 584.0 |
| IFR-2 | 32.9 | 597.6 |
| IFR-3 | 26.2 | 604.3 |
| **MIK** | | |
| Fixed Roof | 1,768 | -- |
| IFR-Kb | 164.8 | 1,603 |
| IFR-1 | 94.5 | 1673 |
| IFR-2 | 55.9 | 1712 |

| Tank Configuration | VOC Emissions (lb/year) | VOC Emissions Reductions (lb/year) |
|---|---|---|
| IFR-3 | 37.0 | 1731 |
| **Toluene** | | |
| Fixed Roof | 2,348 | -- |
| IFR-Kb | 217.4 | 2,131 |
| IFR-1 | 122.7 | 2,226 |
| IFR-2 | 70.9 | 2,277 |
| IFR-3 | 45.3 | 2,303 |
| **Heptane** | | |
| Fixed Roof | 4,086 | -- |
| IFR-Kb | 366.1 | 3,720 |
| IFR-1 | 198.5 | 3,888 |
| IFR-2 | 106.8 | 3,979 |
| IFR-3 | 61.5 | 4,025 |
| **Ethanol** | | |
| Fixed Roof | 2,446 | -- |
| IFR-Kb | 225.6 | 2,221 |
| IFR-1 | 126.2 | 2,320 |
| IFR-2 | 71.8 | 2,374 |
| IFR-3 | 44.9 | 2,401 |
| **Methacrylonitrile** | | |
| Fixed Roof | 4,237 | -- |
| IFR-Kb | 393.1 | 3,844 |
| IFR-1 | 213.8 | 4,023 |
| IFR-2 | 115.7 | 4,121 |
| IFR-3 | 67.3 | 4,169 |
| **Benzene** | | |
| Fixed Roof | 6,606 | -- |
| IFR-Kb | 612.4 | 5,994 |
| IFR-1 | 329.2 | 6,277 |
| IFR-2 | 174.3 | 6,432 |
| IFR-3 | 97.9 | 6,508 |
| **Vinyl acetate** | | |
| Fixed Roof | 8,788 | -- |
| IFR-Kb | 816.2 | 7,972 |
| IFR-1 | 436.3 | 8,352 |
| IFR-2 | 228.5 | 8,560 |
| IFR-3 | 125.9 | 8,662 |
| **Hexane** | | |
| Fixed Roof | 11,590 | -- |
| IFR-Kb | 1,101 | 10,489 |
| IFR-1 | 582.0 | 11,008 |
| IFR-2 | 298.3 | 11,291 |
| IFR-3 | 158.4 | 11,431 |
| **Diethylamine** | | |
| Fixed Roof | 15,087 | -- |

| Tank Configuration | VOC Emissions (lb/year) | VOC Emissions Reductions (lb/year) |
|---|---|---|
| IFR-Kb | 1,455 | 13,633 |
| IFR-1 | 767.7 | 14,320 |
| IFR-2 | 391.8 | 14,696 |
| IFR-3 | 206.3 | 14,881 |
| **Gasoline (RVP7)** | | |
| Fixed Roof | 15,119 | -- |
| IFR-Kb | 1,579 | 13,540 |
| IFR-1 | 832.2 | 14,286 |
| IFR-2 | 423.6 | 14,695 |
| IFR-3 | 222.1 | 14,897 |
| **Gasoline (RVP13)** | | |
| Fixed Roof | 29,888 | -- |
| IFR-Kb | 3,552 | 26,437 |
| IFR-1 | 1,863 | 28,125 |
| IFR-2 | 939.3 | 29,049 |
| IFR-3 | 483.6 | 29,505 |
| **Isopentane** | | |
| Fixed Roof | 82,777 | -- |
| IFR-Kb | 8,114 | 74,663 |
| IFR-1 | 4,247 | 78,530 |
| IFR-2 | 2,131 | 80,646 |
| IFR-3 | 1,087 | 81,690 |

### *4.3 IFR Control Costs*

The unit costs and factors used to estimate costs for a typical IFR are shown in **Table 7**. These costs were provided in 2008$. We escalated the total capital and annual costs to 2022$ using the Chemical Engineering Plant Cost Index (CEPCI) as shown at the bottom of **Table 7**.

**Table 7. IFR cost calculation parameters.**

| Costing Element | Unit Cost or Costing Factor | Basis[1] |
|---|---|---|
| **Capital Costs** | | |
| Internal floating roof | E = (29.207 x Diameter^0.1796)/100 x (6.3825 x Diameter^2 + 374.27 x Diameter + 19017) | (Randall, 2012) |
| Fittings cost | F = see Table 6. | |
| Mobilization | MO=$2,000 | (Randall, 2012) |
| Taxes and Freight | TF=0.08 x E | EPA Control Cost Manual (U.S. EPA, 2002) |
| Installation | I = (1 – (29.207 x Diameter^0.1796)/100) x (6.3825 x Diameter^2 + 374.27 x Diameter + 19017) | (Randall, 2012) |

| | | |
|---|---|---|
| Total capital investment | TCI = E + F + MO + TF + I | |
| **Annual Costs** | | |
| Capital recovery | CR = 0.115 x TCI | Capital recovery factor calculated using equation in OAQPS Control Cost Manual (U.S. EPA, 2002); assumed IFR life of 15 years and used 7.75% interest rate |
| Maintenance | MA = 0.05 x TCI | From other EPA analyses (U.S. EPA, 1994) |
| Property taxes, insurance, administration | P = 0.04 x TCI | EPA Control Cost Manual (U.S. EPA, 2002) |
| Total annual cost | TAC = CR + MA + P | |
| **Annual Costs with Product Recovery** | | |
| Product recovery credit[2] | R = $870/ton | Based on the projected bulk sale gasoline price of $2.72 per gallon in 2022$ and a density of gasoline of 6.25 pounds/gallon |
| Total annual cost with product recovery | TAC with product recovery = TAC + R | |
| **2008$ to 2022$ Escalation Factor** | | |
| Cost escalation | CE = 816/575.4 = 1.42 | Chemical Engineering Plant Cost Index, 2008 CEPCI = 575.4; 2022 CEPCI = 816 |

[1] Many of these costs are from a previous RTI uniform standards storage tank review, where vendors were contacted to obtain cost estimates. It was assumed that this analysis was in 2008$, which were converted to 2022$ using the ratio of the CEPCI in 2022 to 2008 as a cost escalation factor (1.42).
[2] The VOC recovery credit was calculated based on the bulk sale gasoline price in 2021 ($2.07 from https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=ema_epm0_pbr_nus_dpg&f=m) and the gasoline retail price in 2021 and 2022 ($3.01 and $3.95, respectively, from https://www.eia.gov/dnav/pet/pet_pri_gnd_dcus_nus_w.htm). The bulk sale gasoline price in 2022 was not published at the time of this memo. The ratio of the bulk sales price to the retail price in 2021 (0.688) was applied to the retail price in 2022 to obtain a projected bulk sales price in 2022 of $2.72. Using a density of gasoline of 6.25 lb/gallon, we estimated the value of gasoline recovered to be $2.72/gallon * (1 gallon/6.25 lbs) * (2,000 lbs/ton) = $870/ton.

Costs specific to seals or fittings relevant for each tank configuration for a new IFR storage vessel are shown in **Table 8.**

**Table 8. IFR fittings and equipment costs for a new storage vessels.**

| Costing Element | Unit Cost (2008$) | Basis | Cost Multiplier for a New Storage Vessel | | | |
|---|---|---|---|---|---|---|
| | | | IFR-Kb | IFR-1 | IFR-2 | IFR-3 |
| Secondary Seal | π x Diameter x $383.47×(Diameter^-0.262)/2 | Assumed EFRT seal costs from Randall (2012) | -- | 1 | 1 | 1 |
| Welded Seams | π x Diameter x $383.47×(Diameter^-0.262)/2 | Assumed welded seam costs would be similar to a secondary seal. | -- | -- | -- | 1 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Column Well Covers | $550 | (Randall, 2012) | 1 | 1 | 1 | 1 |
| Access Hatch, Gasketed | $400 | (Randall, 2012) | 1 | 1 | 1 | 1 |
| Gauge Hatch, Slit Fabric Cover | $300 | Assumed 75% of a gasketed gauge hatch and included in IFR equipment cost | -- | -1 | -1 | -1 |
| Gauge Hatch, Gasketed | $400 | Assumed same cost as a gasketed access hatch | -- | 1 | 1 | 1 |
| Float Well, Gasketed | $400 | (Randall, 2012) | 1 | 1 | 1 | 1 |
| Ladder Cover, Gasketed | $400 | (Randall, 2012) | 1 | 1 | 1 | 1 |
| Guide Pole Cover and Wiper | $950 | (Randall, 2012) | 1 | 1 | 1 | -- |
| Guide Pole Flexible Fabric Enclosure | $2,400 | (Randall, 2012) | -- | -- | -- | 1 |
| Cable system | $9,323[1] | (SCAQMD, 2022) | -- | -- | 1 | 1 |

[1]49,000 in 2022$ (70% of retrofit costs) minus costs for adjustable leg column well covers.

In addition to analyzing the costs for constructing a new IFR storage vessel with various tank configurations, we also calculated the costs of upgrading an existing IFR, with a secondary seal or improved fittings. For the installation of a new IFR, the installation costs were based on installing the primary roof and the fitting controls costs were part of the roof cost and did not add to the installation cost. For the installation of fittings on an existing IFR, the installation costs were based on the cost of the fittings using a similar correlation to estimate the relative cost of equipment (in this case fitting controls) and installation based on the storage vessel diameter correlation used for new IFR storage vessels. The IFR upgrade costs are shown in **Table 9**. Again, these costs were provided in 2008$. We escalated the total capital and annual cost estimates for the IFR upgrades to 2022$ using the CEPCI as shown in **Table 7**.

**Table 9. IFR fittings and equipment costs for a modified storage vessel.**

| Costing Element | Unit Cost (2008$) | Basis | Cost Multiplier for Storage Vessel Upgrade | | |
|---|---|---|---|---|---|
| | | | IFR-1 | IFR-2 | IFR-3 |
| Mobilization | $2,000 | (Randall, 2012) | 1 | 1 | 1 |
| Installation | I = F× (1/(0.29207 x Diameter^0.1796) -1) | Assumed installation costs proportional to fitting cost and vessel diameter function for IFR | 1 | 1 | 1 |
| Taxes and Freight | TF = 8%F | (Randall, 2012) | 1 | 1 | 1 |
| Secondary Seal | π x Diameter x $383.47×(Diameter^-0.262)/2 | (Randall, 2012) | 1 | 1 | 1 |

| Costing Element | Unit Cost (2008$) | Basis | Cost Multiplier for Storage Vessel Upgrade | | |
|---|---|---|---|---|---|
| | | | IFR-1 | IFR-2 | IFR-3 |
| Welded Seams | π x Diameter x $383.47×(Diameter^-0.262)/2 | Assumed welded seam costs would be similar to a secondary seal. | -- | -- | 1 |
| Column Well Covers | $550 | (Randall, 2012) | 1 | 1 | 1 |
| Access Hatch, Gasketed | $400 | (Randall, 2012) | 1 | 1 | 1 |
| Gauge Hatch, Gasketed | $400 | Assumed same cost as a gasketed access hatch | 1 | 1 | 1 |
| Float Well, Gasketed | $400 | (Randall, 2012) | 1 | 1 | 1 |
| Ladder Cover, Gasketed | $400 | (Randall, 2012) | 1 | 1 | 1 |
| Guide Pole Cover and Wiper | $950 | (Randall, 2012) | 1 | 1 | 1 |
| Guide Pole Flexible Fabric Enclosure | $150/foot vessel height | (Randall, 2012) | -- | -- | 1 |
| Cable system | $9,323[1] | (SCAQMD, 2022) | -- | 1 | 1 |

[1]49,000 in 2022$ (70% of retrofit costs) minus costs for adjustable leg column well covers.

The cost for each tank configuration and each storage vessel size for new IFR installations are shown in **Table 10.** Costs are presented as total capital investment (TCI) and total annual costs (TAC).

**Table 10. Cost (in 2022$) by tank configuration for each storage vessel size for new and modified IFRs.**

| Tank Configuration | New IFR Storage Vessel | | Modified IFR Storage Vessel | |
|---|---|---|---|---|
| | TCI[1] ($) | TAC[2] ($/year) | TCI[1] ($) | TAC[2] ($/year) |
| **Model 1 (8,000 gallons)** | | | | |
| IFR-Kb | $45,173 | $5,578 | -- | -- |
| IFR-1 | $49,744 | $6,143 | $14,697 | $1,815 |
| IFR-2 | $62,965 | $7,775 | $46,083 | $5,690 |
| IFR-3 | $70,798 | $8,742 | $64,677 | $7,987 |
| **Model 2 (20,000 gallons)** | | | | |
| IFR-Kb | $48,877 | $6,035 | -- | -- |
| IFR-1 | $55,008 | $6,035 | $17,337 | $2,141 |
| IFR-2 | $69,955 | $6,793 | $50,391 | $6,222 |
| IFR-3 | $79,774 | $8,638 | $72,105 | $8,904 |

| Tank Configuration | New IFR Storage Vessel | | Modified IFR Storage Vessel | |
|---|---|---|---|---|
| | TCI[1] ($) | TAC[2] ($/year) | TCI[1] ($) | TAC[2] ($/year) |
| **Model 3 (40,000 gallons)** | | | | |
| IFR-Kb | $53,130 | $6,561 | -- | -- |
| IFR-1 | $60,482 | $7,469 | $19,304 | $2,384 |
| IFR-2 | $76,601 | $9,459 | $53,433 | $6,598 |
| IFR-3 | $88,385 | $10,914 | $78,384 | $9,679 |
| **Model 4 (60,000 gallons)** | | | | |
| IFR-Kb | $54,979 | $6,789 | -- | -- |
| IFR-1 | $62,914 | $7,769 | $20,220 | $2,497 |
| IFR-2 | $79,550 | $9,823 | $54,809 | $6,768 |
| IFR-3 | $92,832 | $11,463 | $82,424 | $10,178 |
| **Model 5 (160,000 gallons)** | | | | |
| IFR-Kb | $67,261 | $8,306 | -- | -- |
| IFR-1 | $77,992 | $9,631 | $24,430 | $3,017 |
| IFR-2 | $96,836 | $11,958 | $60,901 | $7,520 |
| IFR-3 | $113,807 | $14,053 | $93,748 | $11,576 |
| **Model 6 (400,000 gallons)** | | | | |
| IFR-Kb | $93,538 | $11,550 | -- | -- |
| IFR-1 | $108,550 | $13,404 | $30,444 | $3,759 |
| IFR-2 | $130,182 | $16,075 | $69,129 | $8,536 |
| IFR-3 | $151,435 | $18,700 | $107,134 | $13,229 |
| **Model 7 (2,000,000 gallons)** | | | | |
| IFR-Kb | $191,274 | $23,619 | -- | -- |
| IFR-1 | $215,643 | $26,628 | $42,433 | $5,240 |
| IFR-2 | $242,024 | $29,886 | $84,561 | $10,442 |
| IFR-3 | $274,760 | $33,928 | $136,840 | $16,897 |
| **Model 8 (10,000,000 gallons)** | | | | |
| IFR-Kb | $602,782 | $74,433 | -- | -- |
| IFR-1 | $645,556 | $79,715 | $63,403 | $7,829 |
| IFR-2 | $678,749 | $83,814 | $109,942 | $13,576 |
| IFR-3 | $730,740 | $90,234 | $182,836 | $22,577 |

[1] Total capital investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.

### *4.4 Impacts for Revising the Vapor Pressure Thresholds for Controlled Storage Vessels*

The results of the individual model storage vessels, specifically Model 1 (8,000-gallon capacity), supported historical assessments that adding an IFR for small storage vessels is not cost effective. However, in our review of NSPS subpart Kb and other federal and state rules requiring the control of emissions from storage vessels, we identified several rules with lower

vapor pressure applicability limits than NSPS subpart Kb for storage vessels with a capacity of 20,000 gallons or more.

The following potential vapor pressure applicability thresholds for storage vessels with a capacity of 20,000 gallons or more but less than 40,000 gallons were evaluated:

- 4.0 psia based on NSPS subpart Kb value (27.6 kPa).
- 1.9 psia based on thresholds used in several NESHAP including 40 CFR part 63, subparts G and CC.
- 1.5 psia based on thresholds in SCAQMD Rule 463.
- 1.0 psia to evaluate an option beyond 1.5 psia.

For storage vessels with a design capacity of 40,000 gallons or more, we identified and evaluated the following vapor pressure applicability thresholds:

- 0.75 psia based on NSPS subpart Kb value (5.2 kPa).
- 0.50 psia based on thresholds in SCAQMD Rule 463.
- 0.35 psia to evaluate an option beyond 0.5 psia.

Initially, we sought to evaluate the impacts for chemicals that were right at the vapor pressure thresholds. However, the mass emission rate is a function of both vapor pressure and molecular weight of the chemical selected. To better represent the average mass emission as a function of vapor pressure, we plotted the emissions of the surrogate compounds as a function of vapor pressure for tank configurations IFR-Kb and IFR-1. In assessing the vapor pressure applicability thresholds for storage vessels with a capacity of 20,000 gallons or more but less than 40,000 gallons, we used the Model 2 (20,000 gallon) storage vessel to represent the storage vessels in this range and we used all surrogate compounds with a vapor pressure under 5 psi. **Figures 1 and 2** show the plot of emission reductions as a function of vapor pressure for the Model 2 storage vessel with tank configurations of IFR-Kb and IFR-1.

In assessing the vapor pressure applicability thresholds for storage vessels with a capacity of 40,000 gallons or more, we used the Model 4 (60,000 gallon) storage vessel to represent the storage vessels in the lower end of this wide range. Because the thresholds considered for storage vessels with a capacity of 40,000 gallons or more are lower than those considered for the smaller storage vessels, we used all surrogate compounds with a vapor pressure under 3 psi to develop the emissions to vapor pressure correlation for the larger storage vessels with a capacity of 40,000 gallons or more. **Figures 3 and 4** present the plot of emission reductions as a function of vapor pressure for the Model 4 storage vessel with tank configurations of IFR-Kb and IFR-1.

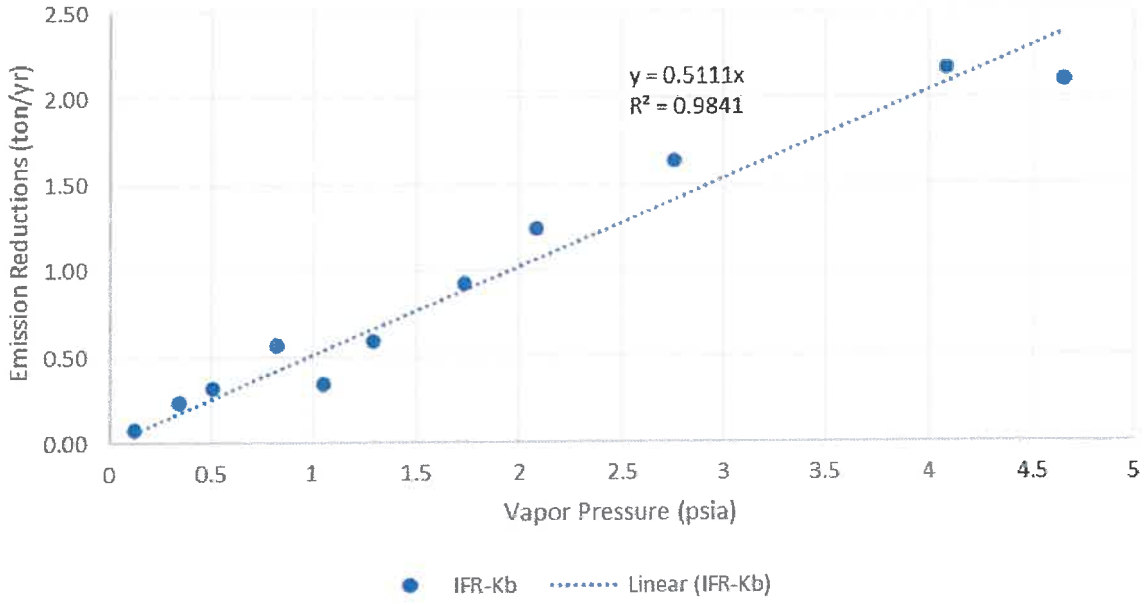



**Figure 1. Emission reduction as a function of surrogate compound vapor pressure for Model 2 storage vessel with a tank configuration of IFR-Kb.**

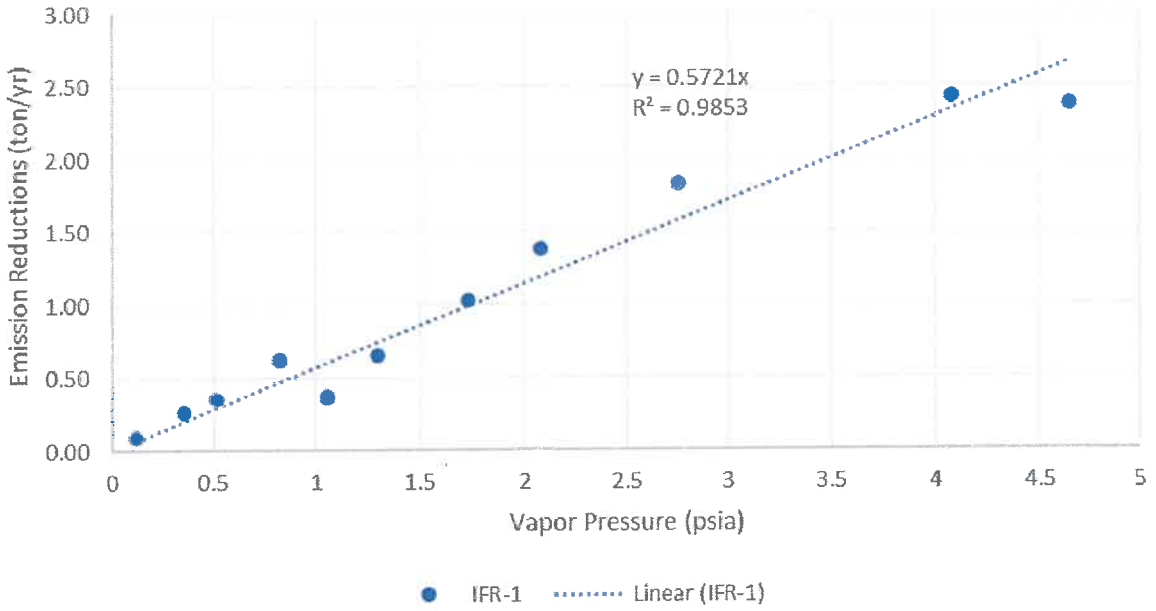



**Figure 2. Emission reduction as a function of surrogate compound vapor pressure for Model 2 storage vessel with a tank configuration of IFR-1.**

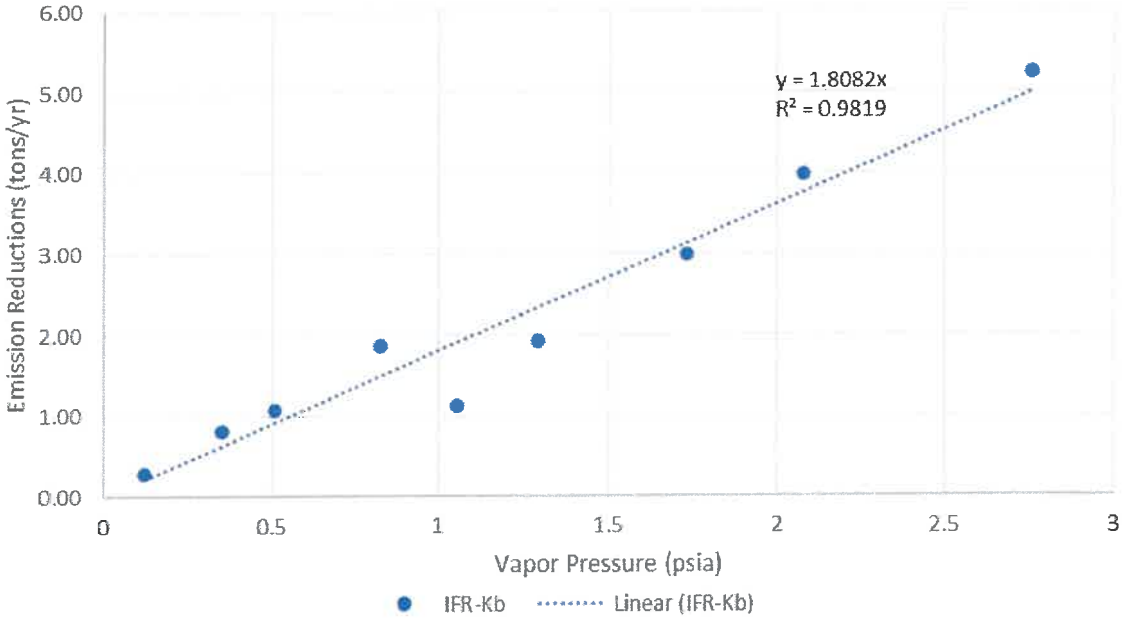



**Figure 3. Emission reduction as a function of surrogate compound vapor pressure for Model 4 storage vessel with a tank configuration of IFR-Kb.**

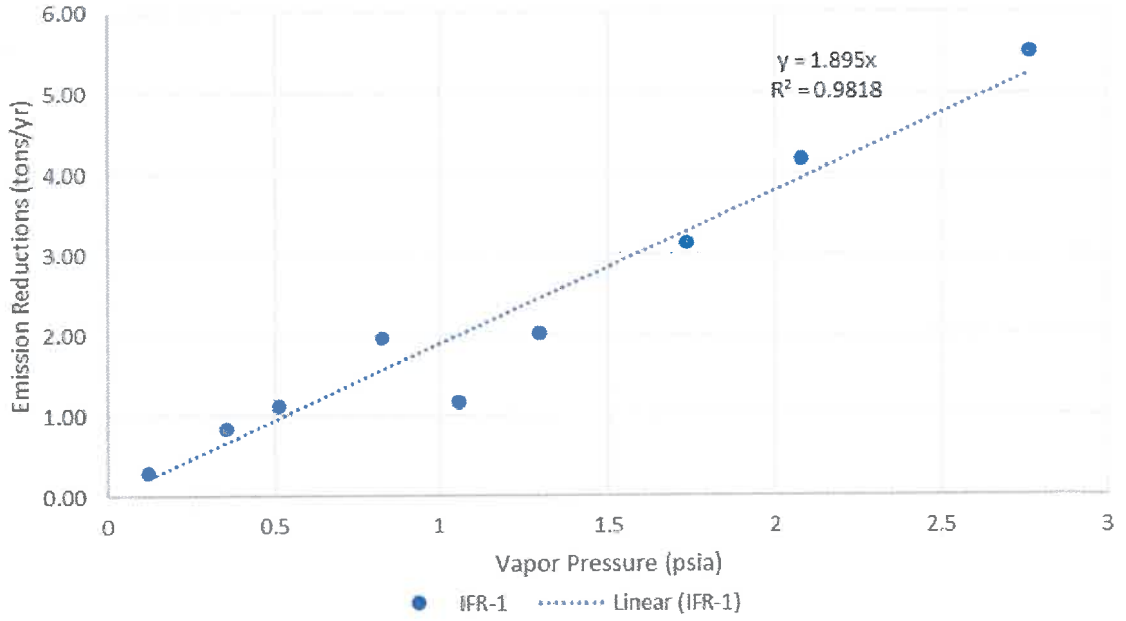



**Figure 4. Emission reduction as a function of surrogate compound vapor pressure for Model 4 storage vessel with a tank configuration of IFR-1.**

We used the correlation equation specific to each model storage vessel and storage vessel configuration combination to estimate the average emission reductions that would be achieved at a given vapor pressure applicability threshold. The control costs are only a function of storage vessel size and IFR tank configuration. **Table 11** summarizes the results of our analysis for assessing vapor pressure applicability thresholds.

**Table 11. Summary of vapor pressure applicability threshold analysis.**

| Threshold | VOC Emissions Reduction (tpy) | TCI[1] ($) | TAC[2] without Product Recovery ($/yr) | TAC[2] with Product Recovery ($/yr) | CE[3] ($/ton VOC) |
|---|---|---|---|---|---|
| **Costs for Model 2 Storage Vessel with IFR-Kb Configuration** | | | | | |
| 4.0 psia | 2.04 | $48,877 | $6,035 | $4,257 | $2,100 |
| 1.9 psia | 0.97 | $48,877 | $6,035 | $5,190 | $5,300 |
| 1.5 psia | 0.77 | $48,877 | $6,035 | $5,368 | $7,000 |
| 1.0 psia | 0.51 | $48,877 | $6,035 | $5,590 | $10,900 |
| **Costs for Model 2 Storage Vessel with IFR-1 Configuration** | | | | | |
| 4.0 psia | 2.29 | $55,008 | $6,793 | $4,802 | $2,100 |
| 1.9 psia | 1.09 | $55,008 | $6,793 | $5,847 | $5,000 |
| 1.5 psia | 0.86 | $55,008 | $6,793 | $6,046 | $7,000 |
| 1.0 psia | 0.57 | $55,008 | $6,793 | $6,295 | $11,000 |
| **Costs for Model 4 Storage Vessel with IFR-Kb Configuration** | | | | | |
| 0.75 psia | 1.36 | $54,979 | $6,789 | $5,609 | $4,100 |
| 0.50 psia | 0.90 | $54,979 | $6,789 | $6,002 | $6,600 |
| 0.35 psia | 0.63 | $54,979 | $6,789 | $6,238 | $9,900 |
| **Costs for Model 4 Storage Vessel with IFR-1 Configuration** | | | | | |
| 0.75 psia | 1.42 | $62,914 | $7,769 | $6,532 | $4,600 |
| 0.50 psia | 0.95 | $62,914 | $7,769 | $6,944 | $7,300 |
| 0.35 psia | 0.66 | $62,914 | $7,769 | $7,192 | $10,800 |

[1] Total capital investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.
[3] Cost effectiveness (CE).

### *4.5 Nationwide Impacts for New IFR Storage Vessels*

We estimated the number of new storage vessels that would be impacted by new standards, as shown in **Table 12**. If the current applicability thresholds in NSPS subpart Kb, as described in **Table 1**, are maintained, we estimated that there would be 1,200 new IFR storage vessels during the first five years of the proposed rule. If the current applicability thresholds are expanded to the proposed lower vapor thresholds described in section III.A of the preamble (1.5 and 0.50 psi for small and larger storage vessels, respectively), we estimated that there would be 1,440 new IFR storage vessels.

**Table 12. Estimated new IFR storage vessels subject to new standards.[1]**

| Chemical Stored | Vapor Pressure (psia) | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 | Model 7 |
|---|---|---|---|---|---|---|---|
| Toluene | 0.51 | 0 | 40 | 40 | 40 | 40 | 40 |
| Heptane | 0.825 | 0 | 40 | 40 | 40 | 40 | 40 |
| Ethanol | 1.055 | 0 | 40 | 40 | 40 | 40 | 40 |
| Benzene | 1.73 | 20 | 40 | 40 | 40 | 40 | 40 |
| Hexane | 2.76 | 20 | 40 | 40 | 40 | 40 | 40 |
| Gasoline (RVP7) | 4.65 | 20 | 40 | 60 | 60 | 60 | 60 |
| Gasoline (RVP13) | 9.05 | 20 | 40 | 40 | 0 | 0 | 0 |

[1]Shaded cells indicate storage vessels that are below current NSPS subpart Kb thresholds.

Based on the emissions and costs developed for various IFR tank configurations and the number of tanks at each size and surrogate chemical stored, we developed nationwide impacts for new IFR storage vessels for four different control options. A description of each of the control options is provided below:

- Baseline. NSPS subpart Kb control requirements (tank configuration IFR-Kb) with proposed lower vapor thresholds described in section III.A of the preamble (1.5 and 0.50 psi for small and larger storage vessels, respectively).
- Option IFR-1. NSPS subpart Kb but primary seal must either be liquid-mounted or mechanical shoe seal and must have rim-mounted secondary seal (tank configuration IFR-1).
- Option IFR-2. Option IFR-1 with fixed roof legs or a cable suspended roof, meaning the storage vessel cannot have adjustable roof legs that penetrate through the floating roof (tank configuration IFR-2).
- Option IFR-3. Option IFR-2 with welded seems and best guidepole fittings (tank configuration IFR-3).

Given the projected distribution of new storage vessels, the nationwide impacts estimated for the control options are provided in **Table 13**.

**Table 13. New IFR storage vessel nationwide impacts.**

| Control Option | VOC Emissions (tpy) | VOC Emissions Reduction (tpy) | TCI[1] ($) | TAC[2] without Product Recovery ($/year) | TAC with Product Recovery ($/year) | CE[3] ($/ton VOC) | ICE[4] ($/ton VOC) |
|---|---|---|---|---|---|---|---|
| Baseline | 1218.2 | -- | -- | -- | -- | -- | -- |
| Option IFR-1 | 683.7 | 534.4 | $17,959,194 | $2,217,657 | $1,752,714 | $3,280 | $3,280 |
| Option IFR-2 | 419.9 | 798.3 | $46,041,875 | $5,685,393 | $4,990,886 | $6,252 | $12,272 |
| Option IFR-3 | 143.2 | 1075.0 | $72,560,985 | $8,960,054 | $8,024,845 | $7,465 | $10,966 |

[1] Total capital investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.
[3] Cost effectiveness (CE) compared to baseline.
[4] Incremental cost effectiveness (ICE) compared to the previous option in the table.

### *4.6 Nationwide Impacts for Modified Storage Vessels*

We estimated the number of modified storage vessels that would be impacted by new standards, as shown in **Table 14**. We estimated that there would be 27 modified fixed roof storage vessels and 3 modified IFR storage vessels.

**Table 14. Estimated modified storage vessels subject to new standards.**

| Chemical Stored | Vapor Pressure (psia) | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 | Model 7 |
|---|---|---|---|---|---|---|---|
| **Modified Fixed Roof Storage Vessel** | | | | | | | |
| Heptane | 0.825 | 0 | 0 | 3 | 3 | 3 | 2 |
| Benzene | 1.73 | 0 | 3 | 3 | 3 | 3 | 2 |
| Gasoline (RVP7) | 4.65 | 2 | 0 | 0 | 0 | 0 | 0 |
| **Modified IFR Storage Vessel** | | | | | | | |
| Benzene | 1.73 | 0 | 1 | 1 | 1 | 0 | 0 |

Given the projected distribution of modified storage vessels, the nationwide impacts estimated for the control options are provided in **Table 15**.

**Table 15. Modified storage vessel nationwide impacts.**

| Control Option | VOC Emissions (tpy) | VOC Emissions Reduction (tpy) | TCI[1] ($) | TAC[2] without Product Recovery ($/year) | TAC with Product Recovery ($/year) | CE[3] ($/ton) | ICE[4] ($/ton) |
|---|---|---|---|---|---|---|---|
| **Modified Fixed Roof Storage Vessels** | | | | | | | |
| Fixed Roof | 514.68 | -- | -- | -- | -- | -- | -- |
| Baseline | 13.93 | 500.75 | $2,316,899 | $286,098 | -$149,558 | -$299 | -$299 |
| Option IFR-1 | 7.87 | 506.81 | $2,650,771 | $327,325 | -$113,601 | -$224 | $5,935 |
| Option IFR-2 | 4.90 | 509.78 | $3,177,220 | $392,333 | -$51,172 | -$100 | $21,066 |
| Option IFR-3 | 1.85 | 512.83 | $3,672,187 | $453,453 | $7,291 | $14 | $19,145 |
| **Modified IFR Storage Vessels** | | | | | | | |
| Baseline | 14.20 | -- | -- | -- | -- | -- | -- |
| Option IFR-1 | 1.03 | 0.48 | $63,954 | $7,897 | $7,482 | $15,663 | $15,663 |
| Option IFR-2 | 0.55 | 0.73 | $169,144 | $20,886 | $20,252 | $27,765 | $50,728 |
| Option IFR-3 | 0.30 | 0.87 | $254,556 | $31,433 | $30,677 | $35,298 | $74,641 |

[1] Total capital investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.
[3] Cost effectiveness (CE) compared to baseline.
[4] Incremental cost effectiveness (ICE) compared to the previous option in the table.

## 5. Impact Estimates for EFR Storage Vessels

### *5.1 EFR Model Storage Vessels*

We estimated the emissions from an EFR storage vessel under four tank configurations described below:

- EFR-Kb. NSPS subpart Kb for external floating roofs considering controls for guidepoles as provided in the Storage Tank Emission Reduction Partnership Program (STERPP) as provided in 65 FR 19891 (April 13, 2000).
- EFR-1. Current subpart Kb requirements with an unslotted guidepole with gasketed sliding cover with pole wiper.
- EFR-2. Current subpart Kb requirements with a liquid mounted primary seal and a slotted guidepole with gasketed sliding cover with pole sleeve and pole wiper.
- EFR-3. Current subpart Kb requirements with a liquid mounted primary seal and an unslotted guidepole with gasketed sliding cover with pole wiper.

Specific EFR storage vessel parameters for each tank configuration are shown in **Table 16**.

**Table 16. Detailed EFR storage vessel parameters for each tank configuration[1].**

| Input Parameter | EFR-Kb | EFR-1 | EFR-2 | EFR-3 |
|---|---|---|---|---|
| **Tank Surface Color** | Gray, Light | Gray, Light | Gray, Light | Gray, Light |
| **Tank Surface Condition** | Average | Average | Average | Average |
| **Internal Shell Condition** | Light Rust | Light Rust | Light Rust | Light Rust |
| **Roof Type** | Pontoon | Pontoon | Pontoon | Pontoon |
| **Tank Construction** | Welded | Welded | Welded | Welded |
| **Deck Construction** | Welded | Welded | Welded | Welded |
| **Seal Fit** | Average | Average | Average | Average |
| **Primary Seal** | Mechanical Shoe | Mechanical Shoe | *Liquid-mounted* | Liquid-mounted |
| **Secondary Seal** | Rim-mounted | Rim-mounted | Rim-mounted | Rim-mounted |
| **Access Hatch** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Guidepoles** | Slotted guidepole/sample well, gasketed sliding cover, with float and pole wiper | *Unslotted guidepole and well, gasketed sliding cover w/ pole wiper* | *Slotted guidepole/sample well, gasketed sliding cover, with pole sleeve and pole wiper* | *Unslotted guidepole and well, gasketed sliding cover w/ pole wiper* |
| **Gauge-float well** | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed | Bolted cover, gasketed |
| **Gauge-hatch/sample port** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Vacuum Breaker** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |
| **Deck Leg (pontoon area of pontoon roofs)** | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed |
| **Deck Leg (double deck roofs and center area of pontoon roofs)** | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed | Adjustable - gasketed |
| **Rim Vent** | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed | Weighted mechanical actuation, gasketed |

[1] Storage vessel parameters that changed from the previous tank configuration in the table are italicized.

### *5.2 EFR Storage Vessel Emissions*

Emissions reductions for each model storage vessel are dependent on the chemical stored. **Table 17** displays the emissions reductions for Model 4. Emissions for all model sizes are presented in ***Appendix A***.

**Table 17. Emissions from Model 4 for EFR tank configurations and various chemicals.**

| Tank Configuration | VOC Emissions (lb/year) | VOC Emissions Reductions (lb/year) |
|---|---|---|
| **o-xylene** | | |
| Fixed Roof | 630.5 | -- |
| EFR-Kb | 83.9 | 546.6 |
| EFR-1 | 49 | 581.5 |
| EFR-2 | 48.7 | 581.8 |
| EFR-3 | 38.6 | 591.9 |
| **MIK** | | |
| Fixed Roof | 1,768 | -- |
| EFR-Kb | 199.9 | 1,568 |
| EFR-1 | 101.2 | 1,666 |
| EFR-2 | 100.4 | 1,667 |
| EFR-3 | 72 | 1,696 |
| **Toluene** | | |
| Fixed Roof | 2,348 | -- |
| EFR-Kb | 262.8 | 2,086 |
| EFR-1 | 130.9 | 2,217 |
| EFR-2 | 129.8 | 2,219 |
| EFR-3 | 91.8 | 2,257 |
| **Heptane** | | |
| Fixed Roof | 4,086 | -- |
| EFR-Kb | 445.5 | 3,641 |
| EFR-1 | 212.6 | 3,874 |
| EFR-2 | 210.7 | 3,876 |
| EFR-3 | 143.6 | 3,943 |
| **Ethanol** | | |
| Fixed Roof | 2,446 | -- |
| EFR-Kb | 276.8 | 2,169 |
| EFR-1 | 136.4 | 2,310 |
| EFR-2 | 135.2 | 2,311 |
| EFR-3 | 94.8 | 2,351 |
| **Methacrylonitrile** | | |
| Fixed Roof | 4,237 | -- |
| EFR-Kb | 474.5 | 3,762 |
| EFR-1 | 227.3 | 4,009 |
| EFR-2 | 225.2 | 4,012 |
| EFR-3 | 154 | 4,083 |
| **Benzene** | | |
| Fixed Roof | 6,606 | -- |
| EFR-Kb | 743.7 | 5,862 |
| EFR-1 | 351.8 | 6,254 |
| EFR-2 | 348.5 | 6,257 |
| EFR-3 | 235.6 | 6,370 |

| Tank Configuration | VOC Emissions (lb/year) | VOC Emissions Reductions (lb/year) |
|---|---|---|
| **Vinyl acetate** | | |
| Fixed Roof | 8,788 | -- |
| EFR-Kb | 995.4 | 7,793 |
| EFR-1 | 468 | 8,320 |
| EFR-2 | 463.5 | 8,325 |
| EFR-3 | 311.6 | 8,477 |
| **Hexane** | | |
| Fixed Roof | 11590 | -- |
| EFR-Kb | 1,339 | 10,251 |
| EFR-1 | 622.3 | 10,967 |
| EFR-2 | 616.3 | 10,973 |
| EFR-3 | 410 | 11,180 |
| **Diethylamine** | | |
| Fixed Roof | 15,087 | -- |
| EFR-Kb | 1,795 | 13,292 |
| EFR-1 | 832.5 | 14,255 |
| EFR-2 | 824.4 | 14,263 |
| EFR-3 | 547.1 | 14,540 |
| **Gasoline (RVP7)** | | |
| Fixed Roof | 15,119 | -- |
| EFR-Kb | 1,900 | 13,219 |
| EFR-1 | 879.9 | 14,239 |
| EFR-2 | 871.4 | 14,247 |
| EFR-3 | 577.7 | 14,541 |
| **Gasoline (RVP13)** | | |
| Fixed Roof | 29,888 | -- |
| EFR-Kb | 4,357 | 25,631 |
| EFR-1 | 2,008 | 27,980 |
| EFR-2 | 1,988 | 28,000 |
| EFR-3 | 1,312 | 28,677 |
| **Isopentane** | | |
| Fixed Roof | 82,777 | -- |
| EFR-Kb | 11,049 | 71,728 |
| EFR-1 | 5,079 | 77,698 |
| EFR-2 | 5,029 | 77,748 |
| EFR-3 | 3,310 | 79,467 |

### *5.3 EFR Equivalency to IFR Storage Vessels*

We compared the emissions from each EFR tank configuration to the same sized IFR storage vessel under Option IFR-1 controls. In general, we assumed most new storage vessels would use IFR, but that EFR storage vessels may be used for large capacity storage. **Table 18** shows the emissions for each EFR tank configuration in comparison to an IFR-1 tank configuration.

**Table 18. IFR and EFR emissions comparison.**

| Tank Configuration | VOC Emissions (lb/year) | | | | | Percent of IFR-1 Emissions | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Model 4 | Model 5 | Model 6 | Model 7 | Model 8 | Model 4 | Model 5 | Model 6 | Model 7 | Model 8 |
| **Toluene** | | | | | | | | | | |
| IFR-1 | 122.7 | 174.8 | 281.2 | 724.3 | 2,552.9 | -- | -- | -- | -- | -- |
| EFR-1 | 130.9 | 178.5 | 259.8 | 505.3 | 1,083.2 | 107% | 102% | 92% | 70% | 42% |
| EFR-2 | 129.8 | 157.2 | 204.0 | 361.5 | 730.3 | 106% | 90% | 73% | 50% | 29% |
| EFR-3 | 91.8 | 119.2 | 166.0 | 323.5 | 692.3 | 75% | 68% | 59% | 45% | 27% |
| **Heptane** | | | | | | | | | | |
| IFR-1 | 198.5 | 276.5 | 446.0 | 1,148.3 | 4,207.7 | -- | -- | -- | -- | -- |
| EFR-1 | 212.6 | 282.4 | 407.2 | 759.1 | 1,603.1 | 107% | 102% | 91% | 66% | 38% |
| EFR-2 | 210.7 | 244.9 | 308.6 | 505.2 | 980.0 | 106% | 89% | 69% | 44% | 23% |
| EFR-3 | 143.6 | 177.9 | 241.6 | 438.1 | 912.9 | 72% | 64% | 54% | 38% | 22% |
| **Ethanol** | | | | | | | | | | |
| IFR-1 | 126.2 | 178.8 | 287.9 | 741.5 | 2,636.3 | -- | -- | -- | -- | -- |
| EFR-1 | 136.4 | 184.8 | 268.4 | 516.7 | 1,103.9 | 108% | 103% | 93% | 70% | 42% |
| EFR-2 | 135.2 | 162.2 | 209.0 | 363.7 | 728.4 | 107% | 91% | 73% | 49% | 28% |
| EFR-3 | 94.8 | 121.7 | 168.5 | 323.3 | 688.0 | 75% | 68% | 59% | 44% | 26% |
| **Benzene** | | | | | | | | | | |
| IFR-1 | 329.2 | 456.4 | 736.4 | 1,896.0 | 7,006.3 | -- | -- | -- | -- | -- |
| EFR-1 | 351.8 | 464.7 | 668.5 | 1,234.2 | 2,597.4 | 107% | 102% | 91% | 65% | 37% |
| EFR-2 | 348.5 | 401.6 | 502.6 | 807.0 | 1,548.8 | 106% | 88% | 68% | 43% | 22% |
| EFR-3 | 235.6 | 288.7 | 389.8 | 694.2 | 1,435.9 | 72% | 63% | 53% | 37% | 20% |
| **Hexane** | | | | | | | | | | |
| IFR-1 | 582.0 | 799.1 | 1,290.7 | 3,322.8 | 12,483.6 | -- | -- | -- | -- | -- |
| EFR-1 | 622.3 | 813.0 | 1,164.5 | 2,107.5 | 4,402.4 | 107% | 102% | 90% | 63% | 35% |
| EFR-2 | 616.3 | 697.6 | 861.2 | 1,326.5 | 2,485.2 | 106% | 87% | 67% | 40% | 20% |
| EFR-3 | 410.0 | 491.3 | 654.9 | 1,120.1 | 2,278.9 | 70% | 61% | 51% | 34% | 18% |
| **Gasoline (RVP7)** | | | | | | | | | | |
| IFR-1 | 832.2 | 1,140.1 | 1,841.9 | 4,741.9 | 17,876.4 | -- | -- | -- | -- | -- |
| EFR-1 | 879.9 | 1,146.8 | 1,641.3 | 2,958.1 | 6,169.3 | 106% | 101% | 89% | 62% | 35% |
| EFR-2 | 871.4 | 982.7 | 1,209.7 | 1,846.6 | 3,441.1 | 105% | 86% | 66% | 39% | 19% |
| EFR-3 | 577.7 | 689.0 | 916.0 | 1,552.9 | 3,147.4 | 69% | 60% | 50% | 33% | 18% |

## 6. Impact Estimates for High Vapor Pressure Storage Vessels

### *6.1 High Vapor Pressure Model Storage Vessels*

We evaluated the current NSPS subpart Kb requirement that storage vessels storing an organic liquid with a true maximum vapor pressure of 11.1 psia or greater must be equipped with a closed vent system control device to reduce inlet VOC emissions by 95 percent or greater. For several model storage vessel sizes, we estimated the cost and control of closed vent systems. We used isopentane as a surrogate for chemicals in this vapor pressure range due to its vapor pressure of 12.68 psia. We modeled each storage vessel at a 95% and a 98% control level in comparison to a fixed roof storage vessel.

For each model storage vessel, the design parameters used to estimate control costs are shown in **Table 19**.

**Table 19. High vapor pressure model storage vessel parameters.**

| Design Parameter | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 |
|---|---|---|---|---|---|
| Maximum Fill Rate (gpm) | 40 | 50 | 50 | 80 | 100 |
| Design Flow Rate[1] (scfm) | 13.4 | 16.7 | 16.7 | 26.7 | 33.4 |
| Annual Fill Time[2] (hr/yr) | 217 | 346.7 | 520 | 866.7 | 1733 |
| Standing Time[3] (hr/yr) | 8,533 | 8,403 | 8,230 | 7,883 | 7, 017 |
| Maximum Working Loss Emissions[4] (lb/yr) | 15,330 | 29,470 | 43,210 | 113,100 | 278,800 |
| Vapor Space Percent Saturation[5] | 73% | 76% | 77% | 79% | 80% |
| Standing Flow Rate[6] (scfm) | 0.3 | 0.5 | 0.7 | 1.6 | 4.3 |
| Vapor Net Heaving Value[7] (Btu/scf) | 2,661 | 2,768 | 2,832 | 2,885 | 2,926 |

[1] Assuming the design flow rate is the maximum fill rate multiplied by a safety factor of 2.5.
[2] Assuming that all loading occurs at the maximum fill rate and there are 26 turnovers per year.
[3] Assuming the storage vessel is in operation 8,760 hours per year, the design flow time is 10 hours per year, and the standing time is the operation time minus the design flow time.
[4] Calculated as: [(design flow rate) * (design flow time) + (maximum fill rate) * (annual flow time)] * 60 minutes/hour * (molecular weight) / (molar volume conversion factor), where the molecular weight of isopentane is 76.15 lb/mol and the molar volume conversion factor is 385 $ft^3$/lb-mol.
[5] Calculated as the ratio of working losses emissions to the maximum working loss emissions.
[6] Calculated as the standing losses converted to a flow rate using the percent saturation, standing time, molecular weight and molar volume conversion factor: [(standing losses) * (molar volume conversion factor)] / [(molecular weight) * (percent saturation) * (standing time) * 60 minutes/hour], where the molecular weight of isopentane is 76.15 lb/mol and the molar volume conversion factor is 385 $ft^3$/lb-mol.
[7] Calculated as the vapor space percent saturation multiplied by the isopentane net heating value of 3,655 Btu/scf.

### *6.2 High Vapor Pressure Storage Vessel Emissions and Costs*

For the 95% control level, emissions were estimated as 0.05 times the fixed roof storage vessel emissions. For the 98% control, emissions were estimated as 0.02 times the fixed roof storage vessel emissions. Emissions are shown in **Table 20**.

We used EPA's Control Cost Manual (EPA, 2002) costing algorithms (updated elevated flares spreadsheet April 2019) to estimate costs associate with a flare meeting a 95% and a 98% control level. The total capital investment for a flare was estimated to be $107,450 for Models 2

through 6. The total annual costs varied by model storage vessel, as shown in **Table 21**. There are no VOC recovery credits for flare control systems.

**Table 20. Cost and control options of closed vent systems.**

| Control Option | VOC Emissions (tpy) | VOC Emissions Reduction (tpy) | TCI[1] ($) | TAC[2] ($/year) | CE[3] ($/ton VOC) |
|---|---|---|---|---|---|
| **Model 2 (20,000 gallons)** | | | | | |
| Fixed Roof | 17.15 | -- | -- | -- | -- |
| 95% control | 0.86 | 16.29 | 107,450 | 104,327 | $6,403 |
| 98% control | 0.34 | 16.81 | 107,450 | 112,036 | $6,665 |
| **Model 3 (40,000 gallons)** | | | | | |
| Fixed roof | 30.73 | -- | -- | -- | -- |
| 95% control | 1.54 | 29.20 | $107,450 | $104,346 | $3,574 |
| 98% control | 0.61 | 30.12 | $107,450 | $109,113 | $3,623 |
| **Model 4 (60,000 gallons)** | | | | | |
| Fixed roof | 41.39 | -- | -- | -- | -- |
| 95% control | 2.07 | 39.32 | $107,450 | $104,357 | $2,654 |
| 98% control | 0.83 | 40.56 | $107,450 | $107,123 | $2,641 |
| **Model 5 (160,000 gallons)** | | | | | |
| Fixed roof | 102.05 | -- | -- | -- | -- |
| 95% control | 5.10 | 96.95 | $107,450 | $104,562 | $1,079 |
| 98% control | 2.04 | 100.01 | $107,450 | $104,562 | $1,046 |
| **Model 6 (400,000 gallons)** | | | | | |
| Fixed roof | 255.82 | -- | -- | -- | -- |
| 95% control | 12.79 | 243.03 | $107,450 | $105,041 | $432 |
| 98% control | 5.12 | 250.70 | $107,450 | $105,041 | $419 |

[1] Total capital investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.
[3] Cost effectiveness (CE) compared to baseline.

### *6.3 Nationwide Impacts for High Vapor Pressure Storage Vessels*

To estimate the nationwide impacts of closed vent systems used for high vapor pressure storage vessels, we first estimated the number of new storage vessels storing high vapor pressure liquids to be 25. **Table 21** displays the number of projected storage vessels by size.

**Table 21. Number of new storage vessels storing high vapor pressure liquids.**

| Model | Capacity (gallons) | Number of Storage Vessels |
|---|---|---|
| Model 2 | 20,000 | 3 |
| Model 3 | 40,000 | 10 |
| Model 4 | 60,000 | 10 |
| Model 5 | 160,000 | 2 |
| Model 6 | 400,000 | 0 |

The nationwide impacts projected for the two control options, either 95% control or 98% control, are provided in **Table 22.**

**Table 22. Nationwide impacts for high vapor pressure storage vessels.**

| Control Option | VOC Emissions (tpy) | VOC Emissions Reduction (tpy) | TCI[1] ($) | TAC[2] ($/year) | CE[3] ($/ton VOC) | ICE[4] ($/ton VOC) |
|---|---|---|---|---|---|---|
| Fixed Roof | 976.8 | -- | -- | -- | -- | -- |
| 95% control | 48.8 | 927.9 | $2,686,000 | $2,609,000 | $2,812 | $2,812 |
| 98% control | 19.5 | 957.2 | $2,686,000 | $2,708,000 | $2,829 | $3,360 |

[1] Total capital investment (TCI).
[2] Total annualized costs (TAC) considering annualized cost of capital.
[3] Cost effectiveness (CE) compared to baseline.
[4] Incremental cost effectiveness (ICE) compared to the previous option in the table.

## 7. Impact Estimates for Degassing

### *7.1 Degassing Control Option Review*

As part of this NSPS review, we identified federal and state regulations with controlled degassing requirements. The Texas Commission on Environmental Quality (TCEQ) developed standards for Controlling VOC Emissions from Degassing Storage Tanks, Transport Vessels, and Marine Vessels at 30 TAC Chapter 115, Part 1, Subchapter F, Division 3. In the recent reconsideration of the Ethylene Production, Miscellaneous Organic Chemical Manufacturing, Organic Liquids Distribution (Non-Gasoline), and Petroleum Refineries NESHAP final rules, degassing requirements were proposed. A summary of the degassing requirements is found in **Table 23.**

**Table 23. Degassing requirements.**

| Requirement | TCEQ[1] | Proposed NESHAP subpart YY[2] | Proposed NESHAP subpart FFFF[3] | Proposed NESHAP subpart EEEE[4] |
|---|---|---|---|---|
| Percent Control | 90% | 98% | 95% | 95% |
| Applicable Tanks Size | Any size | ≥5,000 gallons | ≥5,000 gallons | ≥5,000 gallons |
| Vapor Pressure (psia) | ≥0.5 | ≥0.5 and <11.1 | ≥2.5 | ≥4.0 and <11.1 |
| Concentration Threshold to Perform Controlled Degassing Until | Less than 34,000 parts per million by volume expressed as methane or 50 percent of the lower explosive limit | Less than 10 percent of the lower explosive limit | Less than 10 percent of the lower explosive limit | Less than 10 percent of the lower explosive limit |

[1] 30 Texas Administrative Code (TAC) Chapter 115, Part 1, Subpart F, Division 3, Degassing of Storage Tanks, Transport Vessels, and Marine Vessels
[2] Proposed 40 CFR part 63 subpart YY, Ethylene Production, EPA-HQ-OAR-2022-0787-0014
[3] Proposed 40 CFR part 63 subpart FFFF, Miscellaneous Organic Chemical Manufacturing, EPA-HQ-OAR-2022-0787-0026
[4] Proposed 40 CFR part 63, subpart EEEE, Organic Liquids Distribution (Non-Gasoline), EPA-HQ-OAR-2022-0787-0020

### *7.2 Degassing Model Storage Vessels*

We estimated the emissions from degassing an IFR storage vessel under two control options. A description of each of the control options is provided below:

- Uncontrolled Degassing. Uncontrolled degassing to 0 psia.
- Controlled Degassing. Degassing controlled with 98% efficiency to 0.15 psia as a surrogate for less than 10 percent of the lower explosive limit (LEL).

For each chemical modeled in the degassing analysis, relevant chemical characteristics are shown in **Table 24**.

**Table 24. Chemical characteristics.**

| Chemical | Vapor Molecular Weight (g/mol) | Reid Vapor Pressure (psi) | Vapor Pressure at 68°F (psi) | Liquid Density (lb/gal) |
|---|---|---|---|---|
| Toluene | 92.14 | 1.03 | 0.50 | 7.24 |
| Heptane | 100.16 | 1.62 | 0.83 | 5.71 |
| Ethanol | 46.1 | 2.3 | 1.21 | 6.59 |
| Benzene | 78.11 | 3.22 | 1.75 | 7.32 |
| Hexane | 86.18 | 4.94 | 2.79 | 5.47 |
| Gasoline (RVP7) | 68 | 7 | 4.09 | 5.6 |
| Gasoline (RVP 13) | 62 | 13 | 8.05 | 5.6 |

The volume degassed for each model storage vessel during a degassing event is shown in **Table 25**. The volume degassed was calculated as the volume of space under the landed roof at a height of 6 feet.

**Table 25. Volume degassed.**

| Model | Capacity (gallons) | Volume Degassed ($ft^3$) | Emptying Time (hours) | Degassing Time (hours) |
|---|---|---|---|---|
| Model 2 | 20,000 | 900 | 2.24 | 0.30 |
| Model 3 | 40,000 | 1,500 | 3.74 | 0.50 |
| Model 4 | 60,000 | 1,900 | 4.74 | 0.63 |
| Model 5 | 160,000 | 4,300 | 7.15 | 1.19 |
| Model 6 | 400,000 | 10,900 | 13.59 | 2.27 |
| Model 7 | 2,000,000 | 40,800 | 25.43 | 6.80 |

### *7.3 Degassing Emissions*

Total emissions from a degassing event were calculated as the sum of vapor and clingage emissions. We assumed a clingage factor of 0.25, a 100% saturation rate in the vapor space, and an ambient temperature of 68°F. Degassing emissions are shown in **Table 26**.

**Table 26. Degassing emissions.**

| Control Option | Model 2 | | Model 3 | | Model 4 | | Model 5 | | Model 6 | | Model 7 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Emiss.[1] | Emiss. Red.[2] | Emiss.[1] | Emiss. Red.[2] | Emiss.[1] | Emiss. Red.[2] | Emiss.[1] | Emiss. Red.[2] | Emiss.[1] | Emiss. Red.[2] | Emiss.[1] | Emiss. Red.[2] |
| **Toluene** | | | | | | | | | | | | |
| Uncontrolled Degassing | 39.1 | -- | 57.4 | -- | 68.1 | -- | 133.4 | -- | 295 | -- | 983 | -- |
| Controlled Degassing | 2.9 | 36.2 | 4.7 | 52.7 | 5.9 | 62.2 | 12.9 | 120.4 | 32.0 | 263.5 | 117.2 | 866.1 |
| **Heptane** | | | | | | | | | | | | |
| Uncontrolled Degassing | 38.2 | -- | 57.5 | -- | 69.2 | -- | 140.2 | -- | 322 | -- | 1,108 | -- |
| Controlled Degassing | 3.1 | 35.1 | 5.0 | 52.4 | 6.3 | 62.8 | 14.0 | 126.2 | 34.8 | 287.0 | 128.2 | 979.4 |
| **Ethanol** | | | | | | | | | | | | |
| Uncontrolled Degassing | 37.8 | -- | 55.9 | -- | 66.5 | -- | 131.8 | -- | 295 | -- | 993 | -- |
| Controlled Degassing | 1.8 | 35.9 | 2.9 | 53.0 | 3.6 | 62.9 | 7.8 | 124.0 | 18.9 | 276.3 | 68.7 | 924.6 |
| **Benzene** | | | | | | | | | | | | |
| Uncontrolled Degassing | 53.8 | -- | 81.8 | -- | 98.9 | -- | 203 | -- | 471 | -- | 1,641 | -- |
| Controlled Degassing | 2.9 | 50.9 | 4.7 | 77.1 | 5.8 | 93.1 | 12.8 | 190.2 | 31.5 | 440.0 | 115.5 | 1,525 |
| **Hexane** | | | | | | | | | | | | |
| Uncontrolled Degassing | 62.2 | -- | 97.8 | -- | 120.4 | -- | 256.9 | -- | 619 | -- | 2,225 | -- |
| Controlled Degassing | 3.3 | 59.0 | 5.3 | 92.5 | 6.7 | 113.8 | 14.8 | 242.2 | 36.8 | 582.3 | 135.7 | 2,089 |
| **Gasoline (RVP7)** | | | | | | | | | | | | |
| Uncontrolled Degassing | 68.8 | -- | 108.5 | -- | 133.9 | -- | 287.1 | -- | 695 | -- | 2,505 | -- |
| Controlled Degassing | 3.0 | 65.8 | 4.8 | 103.7 | 6.0 | 127.9 | 13.3 | 273.7 | 33.1 | 661.6 | 122.1 | 2,383 |
| **Gasoline (RVP13)** | | | | | | | | | | | | |
| Uncontrolled Degassing | 103.9 | -- | 167.1 | -- | 208 | -- | 454.8 | -- | 1,120 | -- | 4,097 | -- |
| Controlled Degassing | 3.5 | 100.3 | 5.8 | 161.3 | 7.2 | 200.8 | 16.0 | 438.8 | 39.9 | 1,080 | 147.6 | 3,949 |

[1] VOC Emissions (lb/event)
[2] VOC Emissions Reduction (lb/event)

*7.4 Degassing Costs*

To estimate degassing costs, we first estimated the labor costs associated with a degassing event using labor rates as published by the Bureau of Labor and Statistics (BLS). The BLS labor rates for NAICS code 325000 Chemical Manufacturing (BLS, 2023a) and NAICS code 324000 Petroleum and Coal Products Manufacturing (BLS, 2023b) are summarized in **Table 27.**

**Table 27. Summary of 2022 national labor rates.**

| Occupational Code | Labor Title | Mean Hourly Wage ($/hour) |
|---|---|---|
| **NAICS code 325000: Chemical Manufacturing** | | |
| 11-0000 | Management Occupations | $76.74 |
| 17-2081 | Environmental Engineers | $59.21 |
| 43-0000 | Office and Administrative Support Occupations | $25.55 |
| 49-9000 | Other Installation, Maintenance, and Repair Occupations | $33.37 |
| **NAICS code 324000: Petroleum and Coal Products Manufacturing** | | |
| 11-0000 | Management Occupations | $76.87 |
| 17-2081 | Environmental Engineers | $61.84 |
| 43-0000 | Office and Administrative Support Occupations | $28.95 |
| 49-9000 | Other Installation, Maintenance, and Repair Occupations | $43.64 |

To represent the industries with storage vessels affected by this rule, we used an average of the mean hourly wages for NAICS code 325000 and NAICS code 324000. Additionally, we assumed that overhead expenses are 110 percent of the base hourly rates. The fully loaded labor rates are shown in **Table 28.**

**Table 28. Summary of 2022 fully loaded labor rates.**

| Labor Title | Mean Hourly Wage ($/hour) | Burden (110%) | Burdened Rate ($/hour) |
|---|---|---|---|
| Management Occupations | $76.81 | $84.49 | $161.30 |
| Environmental Engineers | $60.53 | $66.58 | $127.11 |
| Office and Administrative Support Occupations | $27.25 | $29.98 | $57.23 |
| Other Installation, Maintenance, and Repair Occupations | $38.51 | $42.36 | $80.87 |

We assumed each hour of emptying would require 0.25 hours of operator time and 0.05 hours of engineer time and each hour of degassing would require 2 hours of operator time and 0.5 hours of engineer time. Additionally, for each hour of engineer time, there would be 0.1 hours of manager time and 0.1 hours of administrative support. Given these assumptions, the total labor time for emptying and degassing is shown in **Table 29.**

**Table 29. Emptying and degassing labor time.**

| Labor Title | Labor Time (hours) | | | | | |
|---|---|---|---|---|---|---|
| | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 | Model 7 |
| Management Occupations | 0.03 | 0.04 | 0.06 | 0.1 | 0.18 | 0.47 |
| Environmental Engineers | 0.3 | 0.4 | 0.6 | 1 | 1.8 | 4.7 |
| Office and Administrative Support Occupations | 0.03 | 0.04 | 0.06 | 0.1 | 0.18 | 0.47 |
| Other Installation, Maintenance, and Repair Occupations | 1.2 | 1.9 | 2.5 | 4.2 | 7.9 | 20 |

In addition to labor costs, controlled degassing also requires control equipment rental costs. The control equipment rental cost is a flat fee of $1,600 plus an hourly fee of $250/hour, in 2010 dollars (Randall, 2012). Using the ratio of the 2022 CEPCI (816) to the 2010 CEPCI (550.8), we escalated these costs to be $2,400 plus $370/hour in 2022 dollars.

The total cost of each degassing event, including labor and equipment costs, is shown in **Table 30**.

**Table 30. Cost per degassing event by model storage vessel.**

| Model | Degassing Event Cost ($/event) | |
|---|---|---|
| | Uncontrolled Degassing | Controlled Degassing |
| Model 2 | $141.73 | $2,911.73 |
| Model 3 | $213.24 | $2,983.24 |
| Model 4 | $291.56 | $3,061.56 |
| Model 5 | $488.62 | $3,628.62 |
| Model 6 | $907.02 | $4,417.02 |
| Model 7 | $2,317.56 | $7,307.56 |

### *7.5 Nationwide Impacts for Degassing*

To estimate the nationwide impacts of degassing control options, we first estimated the number of storage vessels expected to have a degassing event each. It was assumed that 10% of storage vessels have a degassing event each year. **Table 31** displays the number of storage vessels degassed by size and chemical.

**Table 31. Number of storage vessels degassed per year by model storage vessel.**

| Chemical Stored | Vapor Pressure (psia) | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 | Model 7 |
|---|---|---|---|---|---|---|---|
| Toluene | 0.51 | 0 | 4 | 4 | 4 | 4 | 4 |
| Heptane | 0.825 | 0 | 4 | 4 | 4 | 4 | 4 |
| Ethanol | 1.055 | 0 | 4 | 4 | 4 | 4 | 4 |
| Benzene | 1.73 | 2 | 4 | 4 | 4 | 4 | 4 |
| Hexane | 2.76 | 2 | 4 | 4 | 4 | 4 | 4 |
| Gasoline (RVP7) | 4.65 | 2 | 4 | 6 | 6 | 6 | 6 |
| Gasoline (RVP13) | 9.05 | 2 | 4 | 4 | 0 | 0 | 0 |

We evaluated the nationwide impacts of requiring controlled degassing by varying the applicability size threshold and calculating the cost effectiveness. We first evaluated the nationwide impacts for degassing all storage vessels storing a chemical with a vapor pressure greater than or equal to 0.5 psia in **Table 32**.

**Table 32. Nationwide controlled degassing impacts by size threshold for storage vessels with a vapor pressure greater than 0.5 psia**

| Cut-off Threshold Capacity (gallons) | VOC Emission Reductions[1] (tpy) | Added Cost[2] ($/yr) | CE[3] ($/ton) | ICE[4] ($/ton) |
|---|---|---|---|---|
| >= 1-million gallons | 19.92 | $129,740 | $6,514 | -- |
| >= 300,000 gallons | 25.60 | $221,000 | $8,632 | $16,059 |
| >= 125,000 gallons | 28.03 | $302,640 | $10,798 | $33,632 |
| >= 60,000 gallons | 29.60 | $385,740 | $13,030 | $52,764 |
| >= 40,000 gallons | 30.79 | $463,300 | $15,048 | $65,423 |
| >= 20,000 gallons | 31.07 | $485,460 | $15,627 | $80,283 |

[1] Emissions reductions compared to uncontrolled degassing.
[2] Added cost is the cost of controlled degassing minus the cost of uncontrolled degassing for that storage vessel size.
[3] Cost effectiveness (CE) compared to uncontrolled degassing.
[4] Incremental cost effectiveness (ICE) compared to the previous cut-off threshold in the table.

Alternatively, if controlled degassing was only required for storage vessels storing a chemical with a vapor pressure greater than 1.5 psia, the nationwide impacts are shown in **Table 33**.

**Table 33. Nationwide controlled degassing impacts by size threshold for storage vessels with a vapor pressure greater than 1.5 psia**

| Cut-off Threshold Capacity (gallons) | VOC Emission Reductions[1] (tpy) | Added Cost[2] ($/yr) | CE[3] ($/ton) | ICE[4] ($/ton) |
|---|---|---|---|---|
| >= 1-million gallons | 14.38 | $69,860 | $4,859 | -- |
| >= 300,000 gallons | 18.41 | $119,000 | $6,465 | $12,200 |
| >= 125,000 gallons | 20.09 | $162,960 | $8,110 | $26,100 |
| >= 60,000 gallons | 21.29 | $212,820 | $9,995 | $41,600 |
| >= 40,000 gallons | 22.16 | $257,140 | $11,603 | $51,000 |
| >= 20,000 gallons | 22.44 | $279,300 | $12,447 | $80,300 |

[1] Emissions reductions compared to uncontrolled degassing.
[2] Added cost is the cost of controlled degassing minus the cost of uncontrolled degassing for that storage vessel size.
[3] Cost effectiveness (CE) compared to uncontrolled degassing.
[4] Incremental cost effectiveness (ICE) compared to the previous cut-off threshold in the table.

## 8. Monitoring, Recordkeeping, and Reporting Costs

### *8.1 Technical Hour Cost*

In our analysis, we assumed the technical labor would be 20 percent environmental engineer and 80 percent plant operator and maintenance personnel. Therefore, using the labor rates provided in **Table 28** above, the blended technical hourly rate is $42.91 ($60.53×0.2+$38.51×0.8). We assumed management time would be 5 percent of the technical hours and administrative support would be 10 percent of the technical hours. Additionally, we assumed that overhead expenses are 110 percent of the base hourly rates. The fully loaded labor rates for technical, management, and administrative support are shown in **Table 34**.

**Table 34. Summary of 2022 fully loaded labor rates.**

| Labor Type | Mean Hourly Wage ($/hour) | Burden (110%) | Burdened Rate ($/hour) | Hour per Technical Hour ($/hour) | Cost per Technical Hour ($/hour) |
|---|---|---|---|---|---|
| Technical | $42.91 | $47.20 | $90.11 | 1 | $90.11 |
| Management | $76.81 | $84.49 | $161.29 | 0.05 | $8.06 |
| Administrative | $27.25 | $29.98 | $57.23 | 0.10 | $5.72 |
| Total Cost | -- | -- | -- | -- | $103.90 |

### *8.2 Nationwide Storage Vessels*

In our analysis of the nationwide impacts of control options for new IFR storage vessels in Section 4.4 of this memorandum, we assumed there would be 1,440 new IFR storage vessels

by the fifth year of the proposed rule. We did not previously estimate the number of new EFR storage vessels since we assumed any of the IFR storage vessels could instead be EFR storage vessels if the emission reductions are equivalent. To estimate the monitoring, recordkeeping, and reporting costs for IFR and EFR storage vessels, we assumed five percent of the 1,440 estimated IFR storage vessels would instead be EFR storage vessels. We estimated that there would be three modified IFR storage vessels and 27 modified fixed roof storage vessels by the fifth year. We assumed the number of new and modified tanks each year would be uniform across the first five years. The distribution of storage vessels in the fifth year is shown in **Table 35.**

**Table 35. Nationwide storage vessels in the fifth year.**

| Tank Type | New | Modified | Previously Subject | Total |
|---|---|---|---|---|
| Internal Floating Roof | 273.6 | 0.6 | 1,096.8 | 1,371 |
| External Floating Roof | 14.4 | 0 | 57.6 | 72 |
| Fixed Roof | 0 | 5.4 | 21.6 | 27 |

The proposed inspection requirements differ based on the type of storage vessel and when the storage vessel became subject to the rule. New floating roof storage vessels must complete an initial inspection. After the initial inspection, there are annual external inspection and LEL monitoring requirements for IFR storage vessels in addition to an internal inspection at least once every 10 years. For EFR storage vessels, gap measurement inspections are required at least every 5 years in addition to an internal inspection every time the storage vessel is emptied and degassed. The number of inspections by inspection type in the fifth year is shown in **Table 36.**

**Table 36. Nationwide inspections in the fifth year.**

| Inspection Type | Number of inspections |
|---|---|
| Initial IFR Inspection | 274.2 |
| Annual External IFR Inspection | 987.12 |
| Internal IFR Inspection | 109.68 |
| Initial EFR Gap Measurement Inspection | 14.4 |
| EFR Gap Measurement Inspection | 11.52 |
| Internal EFR Inspection | 1.15 |

### *8.3 Nationwide Reporting Impacts*

First, we estimated the reporting costs associated with notifications. We assumed that completing notifications of construction, startup, gap measurement inspection, and filling or refilling would each take two technical hours to complete. For notification of delay of repair or emptying, we assumed the notification would take four technical hours.

Second, we estimated the reporting costs associated with completing the semiannual reports. We first estimated the time to compile the semiannual report, which was estimated to be four technical hours. We also estimated the time to complete each section of the report. We estimated that including a report of failure, either for an IFR or an EFR storage vessel, in the semiannual report would take an additional two technical hours for each storage vessel. Including EFR 1st and 2nd gap measurements in the semiannual report was estimated to take four and two technical hours, respectively. It was estimated that two technical hours would be required to report a deviation in the operation of closed vent systems or a tank landing event.

We assumed ten percent of IFR storage vessels would fail the external inspection and ten percent of EFR storage vessels would fail the gap measurement inspection. Of the failed storage vessels, we assumed ten percent would be delayed in repair or emptying.

The reporting costs by occurrence and nationwide are shown in **Table 37**.

**Table 37. Reporting nationwide impacts in the fifth year.**

| Reporting Activity | Number of Technical Hours per Occurrence | Total Cost ($/occurrence) | Number of Occurrences per Year | Number of Applicable Storage Vessels | Nationwide Cost ($/year) |
|---|---|---|---|---|---|
| Familiarize with regulatory requirements | 1 | $104 | 1 | 294.0 | $30,546 |
| Notification of construction | 2 | $208 | 1 | 288.0 | $59,845 |
| Notification of actual startup | 2 | $208 | 1 | 288.0 | $59,845 |
| Notification of gap measurement inspection | 2 | $208 | 1 | 25.9 | $5,386 |
| Notification of IFR delay or repair/emptying | 4 | $416 | 1 | 11.0 | $4,558 |
| Notification of EFR delay or repair/emptying | 4 | $416 | 1 | 0.1 | $48 |
| Notification of filling or refilling | 2 | $208 | 1 | 503.5 | $104,634 |
| Compile semiannual report | 4 | $416 | 2 | 1,470.0 | $1,221,840 |
| Report of IFR failure | 2 | $208 | 1 | 109.7 | $22,791 |
| Report of EFR failure | 2 | $208 | 1 | 1.2 | $239 |
| EFR 1st seal gap measurement | 4 | $416 | 1 | 14.4 | $5,985 |
| EFR 2nd seal gap measurement | 2 | $208 | 1 | 14.4 | $2,992 |
| CVS CPMS deviation | 2 | $208 | 10 | 13.5 | $28,052 |
| CVS flare deviation | 2 | $208 | 10 | 13.5 | $28,052 |
| Tank landing event | 2 | $208 | 1 | 21.0 | $43,542 |

### *8.4 Nationwide Recordkeeping Impacts*

We estimated the costs associated with recordkeeping for the proposed rule. We assumed that for each new storage vessel, one hour of technical time would be spent reading the recordkeeping instructions. For each subject storage vessel, we assumed it would take one

technical hour per storage vessel to update records on the vessel volume, stored liquid vapor pressure, and flare parameters, if applicable. We assumed an internal IFR inspection would take 12 technical hours, an external IFR inspection would take four technical hours, an EFR gap measurement would take 12 technical hours, and an EFR internal inspection would take 12 technical hours. For the lower explosive level (LEL) monitoring requirements, we assumed all IFR storage vessels, including newly subject and previously subject IFR storage vessels, would perform LEL monitoring that would take 0.75 technical hours per storage vessel.

For storage vessels equipped with a closed vent system, it was assumed that newly subject storage vessels would require ten technical hours to develop a record system. We assumed recordkeeping of bypass lines and backpressure regulators would take one technical hour each. For new non-flare control devices, we assumed completing an operating plan would take four technical hours and an initial performance test would take eight technical hours. For flares, documenting a visible emissions event was assumed to take two technical hours. For non-flare control devices with parametric monitoring, weekly parameter records would take approximately one technical hour per week per storage vessel. For flares, monitoring of flare operations was assumed to take one technical hour per week.

To determine the amount of time necessary to inspect a closed vent system for leaks, we assumed a closed vent system component count of 30 components. Using a monitoring rate of 300 components per hour for audio, visual, olfactory inspections and 75 components per hour for Method 21 inspections (DeLang and Coburn, 2021), we estimated that each audio, visual, olfactory inspection would take 0.1 technical hours and each Method 21 inspection would take 0.4 technical hours.

For any storage vessels that are emptied and degassed, we assumed two technical hours would be required to document the degassing event.

The recordkeeping costs by occurrence and nationwide are shown in **Table 38**.

**Table 38. Recordkeeping nationwide impacts in the fifth year.**

| Recordkeeping Activity | Number of Technical Hours per Occurrence | Total Cost ($/occurrence) | Number of Occurrences per Year | Number of Applicable Storage Vessels | Nationwide Cost ($/year) |
|---|---|---|---|---|---|
| Read instructions | 1 | $104 | 1 | 294.0 | $30,546 |
| Vessel volumes, liquids vapor pressures, and flares | 1 | $104 | 1 | 1,470.0 | $152,730 |
| IFR internal inspection | 12 | $1,247 | 1 | 383.9 | $478,612 |
| IFR external inspection | 4 | $416 | 1 | 987.1 | $410,239 |
| EFR gap measurement | 12 | $1,247 | 1 | 25.9 | $32,316 |
| EFR internal inspection | 12 | $416 | 1 | 1.2 | $1,436 |
| IFR LEL monitoring | 0.75 | $78 | 1 | 1,371.0 | $106,833 |
| CVS backpressure regulator | 1 | $104 | 1 | 27.0 | $2,805 |
| CVS audio, visual, olfactory monitoring | 0.1 | $10 | 4 | 27.0 | $1,122 |
| CVS Method 21 monitoring | 0.4 | $42 | 1 | 27.0 | $1,122 |

| | | | | | |
|---|---|---|---|---|---|
| CVS bypass line | 1 | $104 | 1 | 27.0 | $2,805 |
| CVS non-flare operating plan | 4 | $416 | 1 | 2.7 | $1,122 |
| CVS non-flare performance test | 8 | $832 | 1 | 2.7 | $2,244 |
| CVS flare visible emissions events | 2 | $208 | 1 | 13.5 | $2,805 |
| Degassing events | 2 | $208 | 1 | 209.5 | $43,542 |
| Develop record system | 10 | $1,039 | 1 | 5.4 | $5,610 |
| CVS non-flare parameter records | 1 | $104 | 52 | 13.5 | $72,936 |
| CVS flare monitoring | 1 | $104 | 52 | 13.5 | $72,936 |

In addition to the labor costs associated with recordkeeping activities, we estimated the capital costs associated with the recordkeeping requirements. We assumed each facility would already own an LEL monitor and Method 21 equipment. For all new floating roof vessels, we estimated that new roof landing alarm system would cost $1,500 per tank[1] (SCAQMD, 2022). For vessels with a closed vent system, we estimated that flow indicators on the bypass line and pressure relief valve would cost $8,827 each[2] (Coburn, 2015).

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[1] Average of proximity switch cost of $1,000-$2,000 for switch, transmitter, receiver, and power

[2] $7,500 x $N^{0.6}$ where N is the number of pressure relief devices needing to be monitored, in 2007$. Escalated to 2022$ using Chemical Engineering Plant Cost Index, 2007 CEPCI = 525.4; 2022 CEPCI = 816

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## Appendix A: Model Storage Vessel Emissions

| Chemical | Tank Configuration | Emissions (lb/year) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Model 1 | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 | Model 7 | Model 8 |
| o-xylene | Fixed Roof | -- | 213 | 423.3 | 630.5 | 1,678 | -- | -- | -- |
| | Baseline EFR | -- | -- | -- | 83.9 | 107.3 | -- | -- | -- |
| | EFR-1 | -- | -- | -- | 49 | 72.4 | -- | -- | -- |
| | EFR-2 | -- | -- | -- | 48.7 | 66.8 | -- | -- | -- |
| | EFR-3 | -- | -- | -- | 38.6 | 56.7 | -- | -- | -- |
| | Baseline IFR | -- | 49.9 | 62.9 | 71.2 | 107.2 | -- | -- | -- |
| | IFR-1 | -- | 31.8 | 40.4 | 46.4 | 71 | -- | -- | -- |
| | IFR-2 | -- | 20.0 | 26.9 | 32.9 | 54 | -- | -- | -- |
| | IFR-3 | -- | 15.3 | 20.9 | 26.2 | 42.1 | -- | -- | -- |
| MIK | Fixed Roof | -- | 603.5 | 1,194 | 1,768 | 4,680 | -- | -- | -- |
| | Baseline EFR | -- | -- | -- | 199.9 | 238 | -- | -- | -- |
| | EFR-1 | -- | -- | -- | 101.2 | 139.3 | -- | -- | - |
| | EFR-2 | -- | -- | -- | 100.4 | 123.4 | -- | -- | -- |
| | EFR-3 | -- | -- | -- | 72 | 94.9 | -- | -- | --- |
| | Baseline IFR | -- | 123.9 | 151.1 | 164.8 | 238.6 | -- | -- | -- |
| | IFR-1 | -- | 72.6 | 87.1 | 94.5 | 135.7 | -- | -- | -- |

| Chemical | Tank Configuration | Emissions (lb/year) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Model 1 | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 | Model 7 | Model 8 |
| | IFR-2 | -- | 38.9 | 48.6 | 56 | 87.6 | -- | -- | -- |
| | IFR-3 | -- | 25.7 | 31.7 | 37 | 54 | -- | -- | -- |
| Toluene | Fixed Roof | 322.5 | 806.3 | 1,590 | 2,348 | 6,201 | 15,551 | 76,134 | 381,355 |
| | Baseline EFR | -- | -- | -- | 262.8 | 310.3 | 391.7 | 637.3 | 1,215 |
| | EFR-1 | -- | -- | -- | 130.9 | 178.5 | 259.8 | 505.3 | 1083 |
| | EFR-2 | -- | -- | -- | 129.8 | 157.2 | 204 | 361.5 | 730.3 |
| | EFR-3 | -- | -- | -- | 91.8 | 119.2 | 166 | 323.5 | 692.3 |
| | Baseline IFR | 134.6 | 164.7 | 200.1 | 217.4 | 313.4 | 495.3 | 1,130 | 3,415 |
| | IFR-1 | 85.5 | 95.6 | 113.9 | 122.7 | 174.8 | 281.2 | 724.3 | 2,553 |
| | IFR-2 | 40.2 | 50.2 | 62.1 | 70.99 | 110 | 190.6 | 536.5 | 1,957 |
| | IFR-3 | 26.5 | 32.4 | 39.4 | 45.3 | 64.8 | 92.9 | 198.5 | 431.8 |
| Heptane | Fixed Roof | 568 | 1,416 | 2,780 | 4,086 | 10,748 | 26,943 | 130,960 | 653,514 |
| | Baseline EFR | -- | -- | -- | 445.5 | 515.4 | 640.1 | 992 | 1,836 |
| | EFR-1 | -- | -- | -- | 212.6 | 282.4 | 407.2 | 759.1 | 1,603 |
| | EFR-2 | -- | -- | -- | 210.7 | 245 | 308.6 | 505.2 | 980 |
| | EFR-3 | -- | -- | -- | 143.6 | 177.9 | 241.6 | 438.1 | 912.9 |
| | Baseline IFR | 232.9 | 282.6 | 340.3 | 366.1 | 521.9 | 824.9 | 1,867 | 5,734 |

| Chemical | Tank Configuration | Emissions (lb/year) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Model 1 | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 | Model 7 | Model 8 |
| | IFR-1 | 146 | 160.3 | 187.8 | 198.5 | 276.5 | 446 | 1,148 | 4,208 |
| | IFR-2 | 65.8 | 80 | 96.1 | 106.8 | 161.9 | 285.5 | 815.9 | 3,153 |
| | IFR-3 | 41.5 | 48.5 | 55.9 | 61.5 | 81.9 | 112.6 | 217.6 | 453.3 |
| Ethanol | Fixed Roof | 343.4 | 854.3 | 1,671 | 2,446 | 6,415 | 16,080 | 77,738 | 387,147 |
| | Baseline EFR | -- | -- | -- | 276.8 | 325.1 | 408.7 | 657.1 | 1244 |
| | EFR-1 | -- | -- | -- | 136.4 | 184.8 | 268.4 | 516.7 | 1104 |
| | EFR-2 | -- | -- | -- | 135.2 | 162.2 | 209 | 363.7 | 728.4 |
| | EFR-3 | -- | -- | -- | 94.8 | 121.7 | 168.5 | 323.3 | 689 |
| | Baseline IFR | 140.6 | 171.7 | 208.1 | 225.6 | 324.4 | 512.7 | 1,168 | 3,541 |
| | IFR-1 | 89 | 99.1 | 117.6 | 126.2 | 178.8 | 287.9 | 741.5 | 2,636 |
| | IFR-2 | 41.4 | 51.5 | 63.2 | 71.8 | 110.8 | 192.7 | 544.3 | 2,011 |
| | IFR-3 | 27 | 32.8 | 39.4 | 44.9 | 63.4 | 90.2 | 189.4 | 409.1 |
| Methacrylonitrile | Fixed Roof | -- | 1,482 | 2,895 | 4,237 | 11,104 | -- | -- | -- |
| | Baseline EFR | -- | -- | -- | 474.5 | 549.8 | -- | -- | -- |
| | EFR-1 | -- | -- | -- | 227.3 | 302.6 | -- | -- | -- |
| | EFR-2 | -- | -- | -- | 225.2 | 262.8 | -- | -- | -- |
| | EFR-3 | -- | -- | -- | 154 | 191.6 | -- | -- | -- |

| Chemical | Tank Configuration | Emissions (lb/year) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Model 1 | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 | Model 7 | Model 8 |
| | Baseline IFR | -- | 303 | 365.1 | 393.1 | 560.8 | -- | -- | -- |
| | IFR-1 | -- | 172.1 | 201.9 | 213.8 | 298.4 | -- | -- | -- |
| | IFR-2 | -- | 86.3 | 103.9 | 115.7 | 175.8 | -- | -- | -- |
| | IFR-3 | -- | 52.5 | 60.9 | 67.3 | 90.3 | -- | -- | -- |
| Benzene | Fixed Roof | 939.7 | 2,328 | 4,531 | 6,606 | 17,266 | 43,254 | 208,131 | 1,033,651 |
| | Baseline EFR | -- | -- | -- | 743.7 | 856.6 | 1,060 | 1,626 | 2,989 |
| | EFR-1 | -- | -- | -- | 351.8 | 464.7 | 668.5 | 1,234 | 2,597 |
| | EFR-2 | -- | -- | -- | 348.5 | 401.6 | 502.6 | 807 | 1,549 |
| | EFR-3 | -- | -- | -- | 235.6 | 288.7 | 389.8 | 694.2 | 1,436 |
| | Baseline IFR | 391.7 | 474.6 | 570.4 | 612.4 | 870.8 | 1,376 | 3,110 | 9,584 |
| | IFR-1 | 244.9 | 267.8 | 312.7 | 329.2 | 456.4 | 736.4 | 1,896 | 7,006 |
| | IFR-2 | 109.3 | 132.3 | 157.8 | 174.3 | 262.7 | 465.3 | 1,334 | 5,225 |
| | IFR-3 | 68.4 | 79 | 89.9 | 97.9 | 127.6 | 173.2 | 323.8 | 663.8 |
| | Fixed Roof | -- | 3,115 | 6,043 | 8,788 | 22,926 | -- | -- | -- |
| | Baseline EFR | -- | -- | -- | 995.4 | 1143 | -- | -- | -- |
| | EFR-1 | -- | -- | -- | 468 | 615.8 | -- | -- | -- |
| | EFR-2 | -- | -- | -- | 463.5 | 530.9 | -- | -- | -- |

| Chemical | Tank Configuration | Emissions (lb/year) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Model 1 | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 | Model 7 | Model 8 |
| Vinyl acetate | EFR-3 | -- | -- | -- | 311.6 | 379 | -- | -- | -- |
| | Baseline IFR | -- | 634.1 | 761.2 | 816.2 | 1,159 | -- | -- | -- |
| | IFR-1 | -- | 356.8 | 415.5 | 436.3 | 602.8 | -- | -- | -- |
| | IFR-2 | -- | 174.9 | 207.7 | 228.5 | 343 | -- | -- | -- |
| | IFR-3 | -- | 103.4 | 116.7 | 125.9 | 161.8 | -- | -- | -- |
| Hexane | Fixed Roof | 1,676 | 4,133 | 7,991 | 11,590 | 30,178 | 75,574 | 361,731 | 1,792,640 |
| | Baseline EFR | -- | -- | -- | 1,339 | 1,530 | 1,881 | 2,824 | 5,119 |
| | EFR-1 | -- | -- | -- | 622.3 | 813 | 1,165 | 2,108 | 4,402 |
| | EFR-2 | -- | -- | -- | 616.3 | 697.6 | 861.2 | 1,326 | 2,485 |
| | EFR-3 | -- | -- | -- | 410 | 491.3 | 654.9 | 1,120 | 2,279 |
| | Baseline IFR | 711.3 | 859.1 | 1,029 | 1,101 | 1,558 | 2,463 | 5,545 | 17,204 |
| | IFR-1 | 442.5 | 480.6 | 557.2 | 582 | 799.1 | 1,291 | 3,323 | 12,484 |
| | IFR-2 | 194.3 | 232.3 | 273.5 | 298.3 | 444.5 | 794.2 | 2294 | 9221 |
| | IFR-3 | 119.3 | 134.7 | 149.3 | 158.4 | 197 | 259.3 | 443.6 | 868.3 |
| Diethylamine | Fixed Roof | -- | 5,474 | 10,488 | 15,087 | 39,062 | -- | -- | -- |
| | Baseline EFR | -- | -- | -- | 1,795 | 2,049 | -- | -- | -- |
| | EFR-1 | -- | -- | -- | 832.5 | 1,086 | -- | -- | -- |

| Chemical | Tank Configuration | Emissions (lb/year) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Model 1 | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 | Model 7 | Model 8 |
| | EFR-2 | -- | -- | -- | 824.4 | 930.7 | -- | -- | -- |
| | EFR-3 | -- | -- | -- | 547.1 | 653.4 | -- | -- | -- |
| | Baseline IFR | -- | 1,137 | 1,361 | 1,455 | 2,058 | -- | -- | -- |
| | IFR-1 | -- | 635.1 | 735.6 | 767.7 | 1,053 | -- | -- | -- |
| | IFR-2 | -- | 306.2 | 359.7 | 391.8 | 582.6 | -- | -- | -- |
| | IFR-3 | -- | 176.8 | 195.1 | 206.3 | 254.8 | -- | -- | -- |
| Gasoline (RVP7) | Fixed Roof | 2,214 | 5,437 | 10,462 | 15,119 | 39,278 | 98,328 | 469,606 | 2,324,602 |
| | Baseline EFR | -- | -- | -- | 1,900 | 2,167 | 2,661 | 3,978 | 7,189 |
| | EFR-1 | -- | -- | -- | 879.9 | 1,147 | 1,641 | 2,958 | 6,169 |
| | EFR-2 | -- | -- | -- | 871.4 | 982.7 | 1,210 | 1,847 | 3,441 |
| | EFR-3 | -- | -- | -- | 577.7 | 689 | 916 | 1,553 | 3,147 |
| | Baseline IFR | 1,023 | 1,234 | 1477 | 1,579 | 2,233 | 3,530 | 7,942 | 24,673 |
| | IFR-1 | 635.5 | 689.2 | 797.9 | 832.2 | 1,140 | 1,842 | 4,742 | 17,876 |
| | IFR-2 | 278 | 331.7 | 389.4 | 423.6 | 629.5 | 1,127 | 3,261 | 13,178 |
| | IFR-3 | 170.1 | 191.1 | 210.5 | 222.1 | 273.2 | 356.8 | 596 | 1,151 |
| Gasoline (RVP13) | Fixed Roof | 4,626 | 11,225 | 21,151 | 29,988 | -- | -- | -- | -- |
| | Baseline EFR | -- | -- | -- | 4,357 | -- | -- | -- | -- |

| Chemical | Tank Configuration | Emissions (lb/year) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Model 1 | Model 2 | Model 3 | Model 4 | Model 5 | Model 6 | Model 7 | Model 8 |
| | EFR-1 | -- | -- | -- | 2,008 | -- | -- | -- | -- |
| | EFR-2 | -- | -- | -- | 1,988 | -- | -- | -- | -- |
| | EFR-3 | -- | -- | -- | 1,312 | -- | -- | -- | -- |
| | Baseline IFR | 2,307 | 2,782 | 3,327 | 3,552 | -- | -- | -- | -- |
| | IFR-1 | 1,431 | 1,549 | 1,790 | 1,863 | -- | -- | -- | -- |
| | IFR-2 | 623.3 | 741.2 | 866.6 | 939.3 | -- | -- | -- | -- |
| | IFR-3 | 379.3 | 423.3 | 462.2 | 483.6 | -- | -- | -- | -- |
| Isopentane | Fixed Roof | -- | 34,304 | 61,467 | 82,777 | 204,096 | 511,639 | -- | -- |
| | Baseline EFR | -- | -- | -- | 11,049 | 12,557 | 15,378 | -- | -- |
| | EFR-1 | -- | -- | -- | 5,079 | 6,586 | 9,407 | -- | -- |
| | EFR-2 | -- | -- | -- | 5,029 | 5,625 | 6,881 | -- | -- |
| | EFR-3 | -- | -- | -- | 3,310 | 3,906 | 5,161 | -- | -- |
| | Baseline IFR | -- | 6,362 | 7,605 | 8,114 | 11,454 | 18,105 | -- | -- |
| | IFR-1 | -- | 3,539 | 4,085 | 4,247 | 5,794 | 9,364 | -- | -- |
| | IFR-2 | -- | 1,688 | 1,970 | 2,131 | 3,150 | 5,662 | -- | -- |
| | IFR-3 | -- | 959.8 | 1,044 | 1,087 | 1,305 | 1,674 | -- | -- |

# Attachment C

ILTA & ACC Petitions for Reconsideration (Case Nos.: 24-1377 & 24-1379)

**IN THE UNITED STATES COURT OF APPEALS**
**FOR THE DISTRICT OF COLUMBIA CIRCUIT**

| | |
|---|---|
| INTERNATIONAL LIQUID TERMINALS ASSOCIATION,<br><br>Petitioner,<br><br>v.<br><br>U.S. ENVIRONMENTAL PROTECTION AGENCY, and MICHAEL S. REGAN, ADMINISTRATOR, U.S. ENVIRONMENTAL PROTECTION AGENCY,<br><br>Respondents. | Case No: 24-1377 |

**PETITION FOR REVIEW**

Pursuant to Section 307 of the Clean Air Act, 42 U.S.C. § 7607, 5 U.S.C. § 701-706, and Rule 15 of the Federal Rules of Appellate Procedure, Petitioner International Liquid Terminals Association ("ILTA") hereby petitions the Court for review of the United States Environmental Protection Agency's final rule entitled "New Source Performance Standards Review for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)," published in the Federal Register at 89 Fed. Reg. 83,296 (October 15, 2024). A copy of the final rule is attached as Exhibit A.

This Court has jurisdiction and is the proper venue for this action pursuant to 42 U.S.C. § 7607(b)(1).

Dated: December 16, 2024

Respectfully submitted,

*/s/ Svend Brandt-Erichsen*
Svend Brandt-Erichsen
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Facsimile: 206.257.0780

*Attorneys for International Liquid Terminals Association*

# EXHIBIT A

**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Part 60**

**[EPA–HQ–OAR–2023–0358; FRL–10655–02–OAR]**

**RIN 2060–AV93**

## New Source Performance Standards Review for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** The Environmental Protection Agency (EPA) is finalizing amendments to the new source performance standards (NSPS) for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) pursuant to the review required by the Clean Air Act (CAA). The EPA is finalizing revisions to the NSPS that are applicable to volatile organic liquid (VOL) storage vessels that commence construction, reconstruction, or modification after October 4, 2023, under a new NSPS subpart, as well as amendments to an existing subpart. In the new NSPS subpart Kc, the EPA is finalizing requirements to reduce the vapor pressure applicability thresholds and revise the volatile organic compound (VOC) standards to reflect the best system of emission reduction (BSER) for affected storage vessels. In addition, the EPA is finalizing degassing emission controls; clarification of startup, shutdown, and malfunction (SSM) requirements; additional monitoring requirements; and other technical improvements

**DATES:** This final rule is effective on October 15, 2024. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of October 15, 2024.

**ADDRESSES:** The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2023–0358. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only as portable document format (PDF) versions that can only be accessed on the EPA computers in the docket office reading room. Certain databases and physical items cannot be downloaded from the docket but may be requested by contacting the Public Reading Room at (202) 566–1744. The docket office has up to 10 business days to respond to these requests. With the exception of such material, publicly available docket materials are available electronically in *Regulations.gov* or on the EPA computers in the Public Reading Room at the EPA Docket Center, WJC West Building, Room Number 3334, 1301 Constitution Ave. NW, Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

**FOR FURTHER INFORMATION CONTACT:** Mr. Michael Cantoni III, Sector Policies and Programs Division (E143–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5593; and email address: *cantoni.michael@epa.gov.*

**SUPPLEMENTARY INFORMATION:**

*Preamble acronyms and abbreviations.* Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

AMEL alternative means of emissions limitation
API American Petroleum Institute
ASTM American Society for Testing and Materials
AVO audible, visual, and olfactory
BSER best system of emission reduction
CAA Clean Air Act
CBI Confidential Business Information
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
EFR external floating roof
EIA economic impact analysis
EJ environmental justice
EPA Environmental Protection Agency
FR Federal Register
gal gallons
HAP hazardous air pollutant(s)
IBR incorporate by reference
ICR information collection request
IFR internal floating roof
kg/hr kilograms per hour
kPa kilopascals
LEL lower explosive limit
m3 cubic meters
MON Miscellaneous Organic Chemical Manufacturing NESHAP
MTVP maximum true vapor pressure
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NSPS new source performance standards
NTAA National Tribal Air Association
NTTAA National Technology Transfer and Advancement Act
OMB Office of Management and Budget
PDF portable document format
PRA Paperwork Reduction Act
PRD pressure relief device
ppmv parts per million by volume
psia pounds per square inch absolute
psig pounds per square inch gauge
RFA Regulatory Flexibility Act
RIN Regulatory Information Number
SCAQMD South Coast Air Quality Management District
SSM startup, shutdown, and malfunction
STERPP 2000 U.S. EPA Storage Tank Emission Reduction Partnership Program
UMRA Unfunded Mandates Reform Act
VCU vapor combustion unit
VOC volatile organic compound(s)
VOL volatile organic liquid

*Organization of this document.* The information in this preamble is organized as follows:

I. General Information
A. Does this action apply to me?
B. Where can I get a copy of this document and other related information?
C. Judicial Review and Administrative Review
II. Background
A. What is the statutory authority for this action?
B. How does the EPA perform the NSPS review?
C. What is the source category regulated in this final action?
D. What outreach and engagement did the EPA conduct?
III. What changes did we propose for the VOL Storage Vessel NSPS?
IV. What actions are we finalizing and what is our rationale for such decisions?
A. Revised NSPS for VOL Storage Vessels That Commenced Construction, Reconstruction, or Modification After July 23, 1984, and on or Before October 4, 2023
B. Revised NSPS for VOL Storage Vessels That Commenced Construction, Reconstruction, or Modification After October 4, 2023
C. NSPS Subpart Kc Without Startup, Shutdown, and Malfunction Exemptions
D. Testing, Monitoring, and Inspection Requirements
E. Recordkeeping and Electronic Reporting
F. Other Final Amendments
G. Effective Date and Compliance Dates
V. Summary of Cost, Environmental, and Economic Impacts
A. What are the air quality impacts?
B. What are the cost impacts?
C. What are the economic impacts?
D. What are the benefits?
E. What analysis of environmental justice did we conduct?
VI. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive

Order 14094: Modernizing Regulatory Review
B. Paperwork Reduction Act (PRA)
C. Regulatory Flexibility Act (RFA)
D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All
K. Congressional Review Act (CRA)

## I. General Information

### *A. Does this action apply to me?*

The source category that is the subject of this final action is composed of VOL storage vessels (including petroleum liquid storage vessels) regulated under CAA section 111, NSPS. The 2022 North American Industry Classification System (NAICS) codes for the source category are 325, 324, and 422710. The NAICS codes serve as a guide for readers outlining the type of entities that this final action is likely to affect. The NSPS codified in 40 CFR part 60, subpart Kc, are directly applicable to affected facilities that begin construction, reconstruction, or modification after October 4, 2023. Final amendments to 40 CFR part 60, subpart Kb, are applicable to affected facilities that begin construction, reconstruction, or modification after July 23, 1984, and before October 4, 2023. Federal, State, local, and Tribal government entities that own and/or operate VOL storage vessels are affected by this action. If you have any questions regarding the applicability of this action to a particular entity, you should carefully examine the applicability criteria found in 40 CFR part 60, subparts Kb and Kc, and consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this preamble, your State air pollution control agency with delegated authority for NSPS, or your EPA Regional Office.

### *B. Where can I get a copy of this document and other related information?*

In addition to being available in the docket, an electronic copy of this final action is available on the internet at *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rule and key technical documents at this same website.

### *C. Judicial Review and Administrative Review*

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the court) by December 16, 2024. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC West Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

## II. Background

### *A. What is the statutory authority for this action?*

The EPA's authority for this final rule is CAA section 111, which governs the establishment of standards of performance for stationary sources. Section 111(b)(1)(A) of the CAA requires the EPA Administrator to list categories of stationary sources that in the Administrator's judgment cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for new (and modified or reconstructed) sources in each source category pursuant to CAA section 111(b)(1)(B). These standards are referred to as new source performance standards, or NSPS. The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, set the emission level of the standards, and distinguish among classes, types, and sizes within categories in establishing the standards.

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years review and, if appropriate, revise" new source performance standards. However, the Administrator need not review any such standard if the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an existing performance standard, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." The term "standard of performance" in CAA section 111(a)(1) makes clear that the EPA is to determine both the best system of emission reduction for the regulated sources in the source category and the degree of emission limitation achievable through application of the BSER. The EPA must then, under CAA section 111(b)(1)(B), promulgate standards of performance for new sources that reflect that level of stringency. CAA section 111(b)(5) generally precludes the EPA from prescribing a particular technological system that must be used to comply with a standard of performance. Rather, sources can select any measure or combination of measures that will achieve the standard. CAA section 111(h)(1) authorizes the Administrator to promulgate "a design, equipment, work practice, or operational standard, or combination thereof" if in his or her judgment, "it is not feasible to prescribe

or enforce a standard of performance." CAA section 111(h)(2) provides the circumstances under which prescribing or enforcing a standard of performance is "not feasible," such as when the pollutant cannot be emitted through a conveyance designed to emit or capture the pollutant or when there is no practicable measurement methodology for the particular class of sources.

Pursuant to the definition of new source in CAA section 111(a)(2), standards of performance apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Under CAA section 111(a)(4), "modification" means any physical change in, or change in the method of operation of, a stationary source that increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Changes to an existing facility that do not result in an increase in emissions are not considered modifications. Under the provisions in 40 CFR 60.15, "reconstruction" means the replacement of components of an existing facility such that: (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

*B. How does the EPA perform the NSPS review?*

As noted in section II.A. of this preamble, CAA section 111 requires the EPA to, at least every 8 years, review and, if appropriate, revise the standards of performance applicable to new, modified, and reconstructed sources. If the EPA revises the standards of performance, the standards must reflect the degree of emission limitation achievable through the application of the BSER considering the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements. CAA section 111(a)(1).

In reviewing an NSPS to determine whether it is "appropriate" to revise the standards of performance, the EPA evaluates the statutory factors, which may include consideration of the following information:

- Expected growth for the source category, including how many new facilities, reconstructions, and modifications may trigger NSPS in the future.
- Pollution control measures, including advances in control technologies, process operations, design or efficiency improvements, or other systems of emission reduction, that are "adequately demonstrated" in the regulated industry.
- Available information from the implementation and enforcement of current requirements that indicates that emission limitations and percent reductions beyond those required by the current standards are achieved in practice.
- Costs (including capital and annual costs) associated with implementation of the available pollution control measures.
- The amount of emission reductions achievable through application of such pollution control measures.
- Any non-air quality health and environmental impact and energy requirements associated with those control measures.

In evaluating whether the cost of a particular system of emission reduction is reasonable, the EPA considers various costs associated with the particular air pollution control measure or a level of control, including capital costs and operating costs, and the emission reductions that the control measure or particular level of control can achieve. The Agency considers these costs in the context of the industry's overall capital expenditures and revenues. The Agency also considers cost effectiveness analysis as a useful metric and as a means of evaluating whether a given control achieves emission reduction at a reasonable cost. A cost effectiveness analysis allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost effectiveness is a measure of the outcomes produced by resources spent. In the context of air pollution control options, cost effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually.

After the EPA evaluates the statutory factors, the EPA compares the various systems of emission reductions and determines which system is "best" and therefore represents the BSER. The EPA then establishes a standard of performance that reflects the degree of emission limitation achievable through the implementation of the BSER. In performing this analysis, the EPA can determine whether subcategorization is appropriate based on classes, types, and sizes of sources, and may identify a different BSER and establish different performance standards for each subcategory. The result of the analysis and the BSER determination leads to standards of performance that apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Because the NSPS reflect the BSER under conditions of proper operation and maintenance, in doing its review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping, and reporting requirements needed to ensure compliance with the emission standards.

*C. What is the source category regulated in this final action?*

The EPA first promulgated NSPS for petroleum liquid storage vessels on March 8, 1974 (39 FR 9317). These standards of performance are codified in 40 CFR part 60, subpart K, and are applicable to sources that commence construction, modification, or reconstruction after June 11, 1973, and prior to May 19, 1978. These standards were amended several times before 1980, when the EPA proposed to establish revised NSPS for petroleum liquid storage vessels as NSPS subpart Ka (45 FR 23379; April 4, 1980). In 1982, the EPA published a list of priority sources for which additional NSPS should be established (47 FR 951; January 8, 1982), and VOL storage vessels at synthetic organic chemical manufacturers were included in the priority list.

Pursuant to the EPA's authority under CAA section 111, the Agency proposed (49 FR 29698; July 23, 1984) and promulgated (52 FR 11420; April 8, 1987) NSPS for VOL storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction, or modification commenced after July 23, 1984, as NSPS subpart Kb.[1] NSPS subpart Kb regulates storage vessels with a capacity of 75 cubic meters ($m^3$) (~20,000 gallons) or more that store VOLs with a maximum true vapor pressure (MTVP) greater than or equal to 15.0 kilopascals (kPa) (~2.18 pounds per square inch absolute (psia)) and from storage vessels with a capacity of 151 $m^3$ (~40,000 gallons) or more that store organic liquids with an MTVP

[1] On October 15, 2003 (68 FR 59328), the EPA finalized amendments to NSPS subpart Kb to exempt certain storage vessels by capacity and vapor pressure, exempt process tanks, and add a process tank definition. At the same time, the EPA also amended the rule to exempt storage vessels that are subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Solvent Extraction of Vegetable Oil Production.

greater than or equal to 3.5 kPa (~0.51 psia). VOC emissions controls are required on storage vessels with a capacity of 75 $m^3$ (~20,000 gallons) or more that store VOLs with an MTVP greater than or equal to 27.6 kPa (~4.0 psia) and from storage vessels with a capacity of 151 $m^3$ (~40,000 gallons) or more that store organic liquids with an MTVP greater than or equal to 5.2 kPa (~0.75 psia). NSPS subpart Kb emission controls include the use of an external floating roof (EFR), an internal floating roof (IFR), or a closed vent system and a control device (see 40 CFR 60.110b(a) and 40 CFR 60.112b(a) and (b)).[2] [3] NSPS subpart Kb also specifies testing, monitoring, recordkeeping, reporting, and other requirements in 40 CFR 60.113b through 40 CFR 60.116b to ensure compliance with the standards. Storage vessels with an EFR consist of an open-top cylindrical steel shell equipped with a deck that floats on the surface (commonly referred to as a floating "roof") of the stored liquid. Storage vessels with an IFR are fixed roof vessels [4] that also have a deck internal to the vessel that floats on the liquid surface (commonly referred to as an internal floating "roof") within the fixed roof vessel.

The standards set in NSPS subpart Kb for storage vessels with an EFR or IFR are a combination of design, equipment, work practice, and operational standards set pursuant to CAA section 111(h). These standards require, among other things, that a rim seal be installed continuously around the circumference of the vessel (between the inner wall of the vessel and the floating roof) to prevent VOC emissions from escaping to the atmosphere through gaps between the floating roof and the inner wall of the storage vessel. For IFRs, NSPS subpart Kb allows a single liquid-mounted or mechanical shoe primary seal (to be used with or without a secondary seal), or a vapor-mounted primary seal in combination with a secondary seal. For EFRs, NSPS subpart Kb allows either a liquid-mounted or mechanical shoe primary seal, both of which must be used with a secondary seal; vapor-mounted primary seals are not allowed for EFRs. NSPS subpart Kb also requires numerous deck fittings [5] on the floating roof to be equipped with a gasketed cover or lid that is kept in the closed position at all times (*i.e.,* no visible gap), except when the device (deck fitting) is in actual use, to prevent VOC emissions from escaping through the deck fittings. In addition, NSPS subpart Kb requires owners and operators to conduct visual inspections to check for defects in the floating roof, rim seals, and deck fittings (*e.g.,* holes, tears, or other openings in the rim seal, or covers and lids on deck fittings that no longer close properly) that could expose the liquid surface to the atmosphere and potentially result in VOC emission losses through rim seals and deck fittings.[6]

NSPS subpart Kb includes two primary alternative means of compliance. Owners or operators may either comply with the consolidated air rule provisions for storage vessels in 40 CFR part 65, subpart C, or comply with the national emission standards for hazardous air pollutants (NESHAP) for storage vessels in 40 CFR part 63, subpart WW (NESHAP subpart WW). The substantive control requirements in these rules are the same as in NSPS subpart Kb although they may have slight differences in the details of the fitting and inspection requirements.

The EPA proposed the current review of the VOL storage vessels (including petroleum liquid storage vessels) NSPS subpart Kb on October 4, 2023. We received 29 comments from industry, environmental groups, State environmental agencies, and others during the comment period. After the conclusion of the comment period, we received one additional comment in February 2024. A summary of the more significant comments we received regarding the proposed rule and our responses are provided in this preamble. A summary of all other public comments on the proposal and the EPA's responses to those comments is available in *New Source Performance Standards for Volatile Organic Liquid Storage Vessels, Background Information for Final Amendments, Summary of Public Comments and Responses,* Docket ID No. EPA–HQ–OAR–2023–0358. In this action, the EPA is finalizing decisions and revisions pursuant to CAA section 111(b)(1)(B) review for VOL storage vessels after our considerations of all the comments received.

### *D. What outreach and engagement did the EPA conduct?*

As part of this rulemaking, the EPA engaged and consulted with the public, including communities with environmental justice (EJ) concerns, through interactions such as providing a webinar, offering information on the website for this rule, and informing the public of the proposed action by sending notifications with summaries of the action and information on how to comment. These opportunities allowed the EPA to hear directly from the public, especially communities potentially impacted by this final action. The webinar slides can be found in the docket for this rule (Docket ID No. EPA–HQ–OAR–2023–0358).

Prior to proposal publication, the EPA conducted outreach by providing background on the source category and the existing requirements of NSPS subpart Kb on the September 19, 2023, EJ National Community Engagement call and on the August 31, 2023, National Tribal Air Association (NTAA) call. After publication, the EPA conducted a community outreach webinar on October 24, 2023, which was focused on discussing the details of the proposed rulemaking and how to provide comment on the proposed rule. Additionally, the EPA discussed the contents of the proposed rule on an October 26, 2023, NTAA call and encouraged interested parties to submit comments. The EPA received a request from one Tribe for consultation. On November 8, 2023, the EPA met with that Tribe for the purposes of discussing NSPS subpart Kc and other issues but was unable to conduct consultation on this specific rulemaking.

## III. What changes did we propose for the VOL Storage Vessel NSPS?

On October 4, 2023, the EPA proposed the current review of the VOL Storage Vessel NSPS. In that action, we proposed the following actions under NSPS subpart Kc:

[2] All affected storage vessels storing organic liquids with a true vapor pressure of 76.6 kPa or more must use a closed vent system and a control device. See 40 CFR 60.112b(b).

[3] As part of NSPS subpart Kb, the EPA proposed (49 FR 29703; July 23, 1984) and finalized (52 FR 11421; April 8, 1987) that the best demonstrated technology for vessels storing VOL liquids with vapor pressures less than 76.6 kPa (≅11.1 psia) consists of an IFR with a liquid-mounted or mechanical shoe primary seal and controlled fittings or an EFR with a liquid-mounted or mechanical shoe primary seal and gasketed fittings. For vessels with greater vapor pressures, the EPA determined the best demonstrated technology to be a closed vent system and control device.

[4] A fixed roof storage vessel consists of a cylindrical steel shell with a permanently affixed roof, which may vary in design from cone or dome-shaped to flat.

[5] Numerous fittings pass through or are attached to floating decks to accommodate structure support components or to allow for operational functions. Typical deck fittings include, but are not limited to access hatches, gauge floats, gauge hatch/sample wells, rim vents, deck drains, deck legs, vacuum breakers, pontoon covers and guidepoles. IFR storage vessels may also have deck seams, fixed roof support columns, ladders, and/or stub drains.

[6] For details about storage vessel emissions, refer to the *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, AP–42, Fifth Edition, Chapter 7: Liquid Storage Tanks,* dated June 2020 which is available at: *https://www.epa.gov/air-emissions-factors-andquantification/ap-42-compilation-air-emissions-factors.*

- General applicability thresholds that include VOL storage vessels greater than or equal to 20,000 gallons (gal).
- Vapor pressure thresholds for controlled VOL storage vessels greater than or equal to 40,000 gal (151 $m^3$) with MTVPs greater than or equal to 0.5 psia (3.4 kPa).
- Vapor pressure thresholds for controlled VOL storage vessels greater than or equal to 20,000 gal (75.7 $m^3$) and less than 40,000 gal (151 $m^3$) with MTVPs greater than or equal to 1.5 psia (10.3 kPa).
- Improved standards of performance for vessels that have IFRs, EFRs, and closed vent systems routed to a control device, fuel gas system, or process designed to achieve an average 98 percent control efficiency.
- Updated standards of performance for IFR storage vessels that include improved seal system requirements, guidepole configurations reflective of the 2000 U.S. EPA Storage Tank Emission Reduction Partnership Program (STERPP), and annual lower explosive limit (LEL) monitoring.
- Updated standards of performance for EFR storage vessels that include requirements for welded deck seams, and improved guidepole requirements.
- Updated standards for closed vent systems that are routed to a control device, fuel gas system, or process and include requirements for preventing emissions venting to atmosphere, annual EPA Method 21 monitoring, and quarterly audible, visual, and olfactory (AVO) inspections.
- Degassing standards of performance for VOL storage vessels greater than or equal to 1 million gal (3,790 $m^3$) with MTVPs greater than or equal to 1.5 psia (10.3 kPa).
- Modification provisions dependent upon an increase of the MTVP from the VOLs previously stored.
- Improved testing, monitoring, and inspection requirements.
- Provisions establishing that emission limitations apply at all times, including during periods of SSM.
- Improved recordkeeping and reporting requirements, which include the implementation of electronic reporting.

Additionally, we proposed to add electronic reporting requirements to the existing subpart, NSPS subpart Kb.

## IV. What actions are we finalizing and what is our rationale for such decisions?

The EPA is finalizing revisions to the NSPS for VOL storage vessels pursuant to CAA section 111(b)(1)(B) review. The EPA is promulgating the NSPS revisions in a new subpart, 40 CFR part 60, subpart Kc. The new NSPS subpart is applicable to affected sources constructed, modified, or reconstructed after October 4, 2023.

Under NSPS subpart Kc, we are finalizing standards that reflect the BSER for affected storage vessels. The rulemaking proposal included different criteria thresholds for general applicability versus for storage vessel control. Under the finalized general applicability provisions, the EPA has included a new exemption for storage vessels that only store VOL with an MTVP less than 0.25 psia (1.7 kPa) in response to comments we received asking to eliminate recordkeeping requirements for storage vessels with vapor pressures well below the thresholds for which controls are required. We are finalizing the capacity and vapor pressure thresholds for which controls are required as proposed. Specifically, we are finalizing control requirements for: (1) VOL storage vessels greater than or equal to 40,000 gal (151 $m^3$) with MTVPs greater than or equal to 0.5 psia (3.4 kPa); and (2) VOL storage vessels greater than or equal to 20,000 gal (75.7 $m^3$) and less than 40,000 gal (151 $m^3$) with MTVPs greater than or equal to 1.5 psia (10.3 kPa). We are also finalizing modification provisions similar to those proposed, but we are clarifying that a modification occurs when a ". . . storage vessel is used to store VOL that has a greater maximum true vapor pressure than *all VOL historically stored or permitted*."

In addition to updates involving applicability and modification, we are finalizing the proposed standards for storage vessels with IFRs, EFRs, and closed vent systems routed to a control device, fuel gas system, or process, with minor adjustments based on feedback. Regarding degassing controls, we are finalizing the provisions with minor revisions to require controls on nonflammable liquid degassing until reaching 5,000 parts per million by volume (ppmv) as methane vapor space concentration rather than the 10 percent LEL.

We are finalizing testing, monitoring, and inspection requirements as proposed, with some minor revisions that involve matters such as the timelines and frequency for completing inspections, LEL monitoring calibration procedures, inspection requirements, and the MTVP determinations. Similarly, we are finalizing the recordkeeping and reporting requirements with minor revisions from the proposal involving matters such as pressure releases, closed vent system monitoring, and reporting deadlines.

This action also finalizes standards of performance in NSPS subpart Kc that apply at all times including during periods of SSM and other changes such as electronic reporting, as proposed. This action also finalizes revisions in NSPS subpart Kb to require electronic reporting as proposed.

### *A. Revised NSPS for VOL Storage Vessels That Commenced Construction, Reconstruction, or Modification After July 23, 1984, and on or Before October 4, 2023*

We proposed revisions to NSPS subpart Kb to add electronic reporting requirements. We are finalizing those revisions as proposed. Our response to major comments received on the proposed NSPS subpart Kb revisions are provided in this section. Additional public comments received and our responses to those comments are include in the *Summary of Public Comments and Responses* document included in Docket ID No. EPA–HQ–OAR–2023–0358.

*Comment:* One commenter stated that the EPA has no lawful or rational basis for not reviewing the flare standards from existing NSPS subpart Kb to consider whether to revise NSPS subpart Kb itself. The commenter stated that since the EPA has declined to revise the general provisions to include specific monitoring requirements to ensure compliance, the EPA must revise the NSPS subpart Kb provisions to do so, as expressly required by 40 CFR 60.18(d). The commenter stated that the EPA's failure to consider whether to revise the NSPS subpart Kb standards also violates a consent decree that the EPA entered into to resolve environmental groups' lawsuit regarding the EPA's failure to comply with its 8-year review obligations under CAA section 111(b)(1)(B) for the flare provisions from NSPS subpart Kb and other NSPS subparts, as well as its 8-year review obligations for certain NESHAP subparts.

*Response:* The EPA disagrees with this comment. We reviewed NSPS subpart Kb and proposed new standards of performance, including new design, operating, and monitoring requirements for flares, in the new NSPS subpart Kc under CAA section 111(b)(1)(B), which requires that the EPA ". . . review and, if appropriate, revise such standards following the same procedures required by this subsection for promulgating such standards."

CAA section 111(b)(1)(B) does not require retroactive revisions to the existing NSPS subpart (*i.e.*, NSPS subpart Kb). Rather, any revision to an NSPS must follow the same procedures

for promulgating such standards under CAA section 111(b)(1)(B). CAA section 111 establishes a bifurcated approach to regulating sources. Under CAA section 111(b)(1)(B), the EPA is required to promulgate standards of performance for new sources, which CAA section 111(a)(2) defines as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source." Existing sources are defined at CAA section 111(a)(6) to mean "any stationary source other than a new source" and are regulated via a State planning process pursuant to CAA section 111(d). Accordingly, the revisions, which are being finalized in a new NSPS subpart Kc, apply to sources that have commenced construction, reconstruction, or modification after October 4, 2023, the proposal date for this action. Sources presently subject to NSPS subpart Kb are not, by definition under this statutory provision, new sources that could be subjected to the revised standards finalized in NSPS subpart Kc. Rather, they are treated as existing sources relative to the revised standards finalized in NSPS subpart Kc. Revision of the flare provisions in NSPS subpart Kb consistent with the changes being finalized with respect to NSPS subpart Kc would be akin to directly applying a new standard of performance to *existing* sources, which would be inconsistent with the statutory structure that subjects regulation of new and existing sources to separate processes. Further, NSPS subpart Kc includes standards prescribed in accordance with CAA section 111(h)(1), for flares and other closed vent systems routed to a control device designed to achieve a 98 percent reduction in VOC emissions. Because CAA section 111(b)(1)(B) does not require revisions to the existing NSPS subpart (*i.e.,* NSPS subpart Kb), which continues to require 95 percent reduction in VOC emissions when using a flare, the EPA did not propose in this rulemaking to reopen NSPS subpart Kb to include the new operating and monitoring requirements for flares that are needed to assure 98 percent VOC reduction when using a flare.

Moreover, because regulated sources subject to NSPS subpart Kb were not given notice of any such potential change, altering the flare requirements in NSPS subpart Kb in the final rule would unfairly put sources that have been using flares to comply with NSPS subpart Kb in violation of such requirements upon the effective date of this final rule. Thus, the EPA is not amending NSPS subpart Kb to reflect the new operating and monitoring flare requirements that are included in the new NSPS subpart Kc. The EPA notes, however, that as existing sources trigger modification, they will become subject to NSPS subpart Kc and the new flare requirements in the rule.

We disagree with the commenter's assertion that our review findings violate the consent decree. In that consent decree, the EPA agreed to review and, if necessary, revise NSPS subpart Kb. In this case, the EPA proposed these revisions as a new subpart to prevent application of "new source" standards to sources that are "existing" at the time of proposal. Thus, our proposal of NSPS subpart Kc reflects our review of NSPS subpart Kb and the revisions to that standard appropriate for new sources.

*Comment:* One commenter stated that the EPA unlawfully and arbitrarily failed to revise existing NSPS subpart Kb to specify that the SSM exemptions from the [40 CFR part 60] general provisions do not apply. The commenter stated that the EPA has acted outside its statutory authority in promulgating the unlawful SSM exemptions from the general provisions, and therefore the Agency must revise NSPS subpart Kb to make clear that the general provisions' exemptions do not apply. The commenter noted that although CAA section 111(b)(1)(B) allows the EPA to avoid revising standards when "review is not appropriate in light of readily available information on the efficacy of such standard," the EPA could not lawfully or rationally invoke that exception, since the application of the general provisions' exemptions to NSPS subpart Kb is plainly unlawful.

*Response:* As noted in the previous comment response, we reviewed the current subpart Kb standards, determined a series of appropriate revisions, and concluded that these revisions should be completed as a separate subpart. We disagree with the commenter that additional revision to NSPS subpart Kb is necessary to remove SSM exemptions in the 40 CFR part 60 general provisions. First, we note that the performance testing requirements in 40 CFR 60.113b(c) clearly indicate that the provisions in 40 CFR 60.8 do not apply. As such, objectionable language regarding performance test results obtained during SSM events is not applicable under NSPS subpart Kb. Second, the SSM exemption in 40 CFR 60.11(c) is also not applicable to NSPS subpart Kb because NSPS subpart Kb does not contain opacity limits. Because the sections in the 40 CFR part 60 general provisions that contain potentially unlawful SSM exemptions are not applicable under NSPS subpart Kb, we found no need to further revise NSPS subpart Kb at this time.

### *B. Revised NSPS for VOL Storage Vessels That Commenced Construction, Reconstruction, or Modification After October 4, 2023*

This section describes the key technical standards that were proposed, the major comments received on the proposed requirements, our responses to those comments, and our rationale for the final requirements. Additional public comments received on the technical standards and our responses to those comments are included in the *Summary of Public Comments and Responses* document included in Docket ID No. EPA–HQ–OAR–2023–0358.

The EPA is finalizing standards of performance that reflect the BSER as well as alternative compliance standards for controlled storage vessels. The final standards are consistent with the determinations explained in the rulemaking proposal (88 FR 68540–47; October 4, 2023) and the analysis detailed in the memorandum *Control Options for Storage Vessels* in Docket ID No. EPA–HQ–OAR–2023–0358. While the EPA has made minor adjustments to these standards based on public comment, the BSER determination remains unchanged. The adjustments incorporated based on public comment are detailed in sections IV.B.4. and 5. of this document.

In summary, the finalized BSER analyses for NSPS subpart Kc are dependent on the MTVP of a stored VOL and follow the precedent established in NSPS subparts Kb, Ka, and K. In the NSPS subpart K proposal, the EPA detailed its justification for the use of equipment specification (or work practice) standards. As part of the original rulemaking proposal, the EPA explained that equipment specifications are the most practical method of regulating storage vessel emissions. Direct emission measurements for storage vessels are often impractical, and storage vessel emissions are often modeled and dependent on many distinguishing factors and variables. The EPA believes that equipment specification standards are less burdensome for the storage vessel operation and enforcement (38 FR 15406; May 4, 1973). For VOL storage vessels with an MTVP less than 11.1 psia, the EPA is finalizing the following BSER as proposed (88 FR 68542;

October 4, 2023): a fixed roof in conjunction with an internal floating roof equipped with a liquid-mounted or mechanical shoe primary seal and a continuous rim mounted secondary seal, either a flexible fabric sleeve or gasketed sliding cover on pipe columns (if any), specific STERPP compliant guidepole configurations, and gasketed covers.

The EPA is also finalizing two alternative compliance options for VOL storage vessels with MTVPs less than 11.1 psia as proposed:

(1) An external floating roof equipped with a liquid-mounted or mechanical shoe primary seal and a continuous rim-mounted secondary seal, with welded deck seams and both seals meeting certain gap requirements, specific guidepole configurations, and gasketed covers; or

(2) A closed vent system routed to a 98 percent effective control device, fuel gas system, or process.

For VOL storage vessels with MTVPs greater than or equal to 11.1 psia, the EPA is finalizing, as proposed, the BSER as a closed vent system routed to a 98 percent effective control device, fuel gas system, or process.

1. Vapor Pressure Applicability Thresholds

NSPS subpart Kb established control requirements, at 40 CFR 60.112b(a), for storage vessels based on vessel capacity and VOL vapor pressures. In our review of NSPS subpart Kb, we assessed the vapor applicability thresholds for affected facilities and for controls on affected storage vessels to determine whether these thresholds needed to be revised for purposes of NSPS subpart Kc. In NSPS subpart Kb there are two different sets of vapor pressure applicability thresholds: one for determining affected facilities and one for determining controls.

We proposed to not include specific vapor pressure applicability thresholds in defining an affected facility under NSPS subpart Kc. As such, the proposed affected facility under NSPS subpart Kc is any storage vessel with a capacity of 20,000 gallons or more used to store a VOL without exclusion for storage vessels under a set vapor pressure. Based on comments received, we are adding an exemption at 40 CFR 60.110c(b)(8) for storage vessels that only store VOL with an MTVP of less than 0.25 psia. This revision from proposal helps to limit burden for storage vessels that only store VOL with very low vapor pressures, but it does not otherwise impact the control standards proposed for NSPS subpart Kc.

Based on the BSER analysis, we proposed to revise the vapor applicability thresholds that require emission controls under NSPS subpart Kc. Specifically, we proposed to revise the MTVP threshold for smaller storage vessels (those with capacity of at least 20,000 gallons but less than 40,000 gallons) to 1.5 psia and for larger storage vessels (those with capacity of 40,000 gallons or more) to 0.5 psia. We determined that applying controls for VOL at or above these thresholds yielded cost-effective emission reductions. We are finalizing these thresholds as proposed.

2. Other Applicability Provisions

NSPS subpart Kb includes several provisions that exempt specific groups of VOL storage vessels from applicability under the standard. We proposed to carry over several of these exemptions, such as exemptions for: storage vessels that operate at coke oven by-product plants; bulk gasoline plants; gasoline service stations; pressure vessels; vessels attached to mobile vehicles; certain vessels at oil and gas production sites prior to custody transfer; and vessels that store beverage alcohol. We proposed to remove exemptions under NSPS subpart Kc for vessels subject to the NESHAP for solvent extraction for vegetable oil production outlined in 40 CFR part 63, subpart GGGG, because the standards proposed in NSPS subpart Kc are more stringent than the existing NESHAP subpart GGGG standards. We are finalizing these applicability provisions as proposed.

We are adding overlap provisions, based on comments received, to allow storage vessels subject to NSPS subparts K, Ka, or Kb, or NESHAP subpart WW to comply with the provisions in NSPS subpart Kc because the final provisions in NSPS subpart Kc are at least as stringent as those in NSPS subparts Kb, Ka, and K, and NESHAP subpart WW. These overlap provisions, which were not proposed, allow facilities the operational flexibility of simply complying with NSPS subpart Kc if they operate storage vessels covered under the specified existing storage vessel rules.

*Comment:* One commenter stated that the EPA should add an alternative compliance option that complying with NSPS subpart Kc demonstrates compliance with the floating roof requirements in NESHAP subpart WW. Another commenter suggested that the EPA should address overlaps between NSPS subpart Kc and other rules consistent with the overlap provisions in NSPS subpart Kb.

*Response:* There are not overlap provisions in NSPS subpart Kb beyond the alternative means of compliance in 40 CFR 60.110b(e). The requirements in the rules listed in 40 CFR 60.110b(e) are not equivalent to the requirements in NSPS subpart Kc, so we removed these alternative means of compliance from NSPS subpart Kc. We agree with commenters that including provisions in NSPS subpart Kc to allow compliance with the provision in NSPS subpart Kc to be considered compliance with the provisions in NSPS subpart Kb or NESHAP subpart WW is appropriate because the final requirements in NSPS subpart Kc are at least as stringent as those in NSPS subpart Kb and NESHAP subpart WW. As such, we have added provisions under 40 CFR 60.110c(h) and 40 CFR 60.110c(i) that allow owners and operators with storage vessels subject to the standards of NSPS subparts K, Ka, and Kb, and NESHAP subpart WW to choose to comply with the provisions of NSPS subpart Kc to demonstrate compliance. This will allow facilities that may be subject to a NESHAP that references NSPS subpart Kb or NESHAP subpart WW but also subject to NSPS subpart Kc to consolidate their recordkeeping and reporting requirements and comply only with NSPS subpart Kc.

3. Modification Provisions

For purposes of CAA section 111, modifications are defined as ". . . any physical change in, or change in the method of operation of," an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted. NSPS subpart A further provides provisions explaining how a modification is identified, as well as defining certain exemptions to those general rules. In particular, 40 CFR 60.14(e)(4) states that the "[u]se of an alternative fuel or raw material" is not considered a modification if the existing facility was designed to accommodate that alternative use. The EPA proposed, for purposes of NSPS subpart Kc, that a change in the liquid stored in the storage vessel to a VOL with a higher MTVP does not constitute a "use of an alternative fuel or raw material" and would be considered a modification under NSPS subpart Kc. Specifically, the EPA proposed that a modification occurs when a "storage vessel is used to store VOL that has a greater maximum true vapor pressure than the VOL previously stored."

We are finalizing modification provisions similar to those proposed, but we are clarifying that a modification occurs when a ". . . storage vessel is used to store VOL that has a greater maximum true vapor pressure than *all VOL historically stored or permitted*." Commenters were concerned that our proposed language, which referred to VOL "*previously* stored," was ambiguous and potentially limited the modification assessment to the most recently stored VOL. We revised the text to ". . . historically stored or permitted . . . ," in order to clarify our intent that a modification occurs when a new VOL is stored that has a higher MTVP than any of the previously stored or permitted VOL (and not just the most recently stored VOL). Finally, we are also clearly stating, consistent with our discussion in section III.G. of the proposal preamble, that the alternative fuel or raw material exemption in 40 CFR 60.14(e)(4) does not apply to storage vessels under NSPS subpart Kc.

*Comment:* Several commenters stated that the language "the VOL previously stored" in 40 CFR 60.110c(e) is unclear as to whether any VOL the storage vessel has previously stored is included, or just the VOL stored immediately prior to the change. The proposed 40 CFR 60.110c(e) language does not clarify which liquids are different, or not different, from "the VOL previously stored." Without clarity on these points, the rule language is subject to a significant range of interpretations, from any stored organic liquid being the same VOL, to any de minimis change in liquid properties being a different VOL. Another commenter stated that the phrase "the VOL previously stored" should be removed from 40 CFR 60.110c(e).

Several commenters requested that storing a VOL with a higher MTVP than the liquid previously stored only be considered a modification if storing such a liquid would require modification of a facility's operating permit. One commenter further stated that using a facility's operating permit to determine modification would place an unreasonable burden of proof on facility owners or operators. Another commenter stated that storage vessels are permitted to handle multiple materials, typically using a worst-case scenario, and changing the liquid stored in the storage vessel to one above the permitted vapor pressure threshold would not necessarily increase emissions since emissions are based on other parameters and conditions, such as changing the hourly pumping rate, annual throughput, or storage temperature.

Two commenters noted that storage vessels routinely switch between storing materials with lower and higher vapor pressures at certain facilities, such as batch chemical plants, refineries, and gasoline terminals (for example, annual transitions between summer and winter gasoline). According to the commenters, such routine and other operational transitions between products do not rise to the level of a "modification" triggering performance standards for new sources under the CAA.

*Response:* We agree with the commenters that the proposed language ("the VOL previously stored") could be misinterpreted to refer only to the VOL stored immediately prior to the change, and that was not our intent. For example, if a storage vessel has been used to store both summer and winter grades of gasoline, we did not intend that the next switch from summer to winter gasoline would trigger a modification of the storage vessel. We also agree that owners and operators should not trigger modification for introducing VOLs that do not exceed the MTVP of all VOLs that may also exist in a permit. We are clarifying the regulatory language to match our intent at proposal and reduce burden by replacing the phrase "the VOL previously stored" with the phrase "all VOL historically stored or permitted." In discussions with industry representatives and the EPA permit specialists, we found that specific VOLs are not always listed in permits. Therefore, we are not including revisions suggested by some commenters to limit modification to only those actions that would require modification of a facility's operating permit.

We disagree with the commenters who suggested that changing the volatility of the liquids stored does not increase emissions from the storage vessel. We note that the emission rate for modification is expressed in kilograms per hour (kg/hr) and that it is not evaluated on an annual basis. Even if the facility intends to lower the fill rate to limit increases in annual emissions, the storage vessel will still have higher emissions (in kg/hr) during periods when the storage vessel is not being filled.

*Comment:* Several commenters disagreed with the EPA's proposal that a change in the liquid stored in the storage vessel to a VOL with a higher MTVP does not constitute a "use of an alternative fuel or raw material" and thus would instead be considered a change in the method of operation of a source. According to the commenters, the stored materials are fuels or raw materials for some customer or downstream user, and there is no requirement for a material to be used at the facility where it is being stored for it to be considered a raw material or a fuel. According to one commenter, the EPA had determined that changing a liquid, regardless of volatility, is not an operational change, and another commenter stated that storage vessel service changes are the kind of event that the EPA intended to address in 40 CFR 60.14(e)(4). Other commenters recommended that the EPA retain its long-held interpretation that a change of liquids in an existing VOL storage vessel does not constitute a "modification" triggering applicability of NSPS subpart Kc. Commenters also noted that the proposed interpretation would arbitrarily apply NSPS subpart Kc to some storage vessels, and not to other identical vessels, based on their historic use rather than their design capabilities.

One commenter stated that changing a liquid in a storage vessel is not a modification if the material could have been previously accommodated without a physical change or a capital expenditure. Some commenters requested that the EPA revise proposed 40 CFR 60.110c(e) to clearly state that changing the material stored is not a modification if the storage vessel could accommodate the new material without a physical change or significant capital expenditure. Commenters requested that the EPA review historical documents related to NSPS subpart Kb and reconfirm these long-held policies regarding modification of storage vessels.

One commenter stated that the EPA's reference to *FCC* v. *Fox Television Stations, Inc.* for the proposition that it need only articulate a "good reason" for its "change in policy" is misplaced. According to the commenter, the EPA is not proposing to amend any of its existing regulations setting forth its policy for NSPS triggering "modifications." Rather, the proposal reflects a reversal of the EPA's longstanding interpretation of the CAA and its regulations in 40 CFR 60.2 and 60.14. Unlike a change in policy, the commenter contends, "an agency's interpretation of a statute or regulation that conflicts with a prior interpretation is entitled to considerably less deference than a consistently held agency view." *Advanced Energy United, Inc.* v. *FERC* (82 F.4th 1095, 1114 (D.C. Cir. 2023) (quoting *Thomas Jefferson University* v. *Shalala,* 512 U.S. 504 (1994)). Accordingly, it is the EPA's long-held interpretation of "modifications"—for nearly 40 years—that is entitled to deference. The commenter asserts that

this is particularly true where, as here, the EPA has not provided a justification for the conflicting interpretation or articulated the scope of changes in volatility of stored liquids that would actually trigger a "modification."

*Response:* The EPA disagrees with these comments. First, the EPA's reliance on *FCC* v. *Fox,* 556 U.S. 502 (2009), the controlling case on changes in agency policy, is appropriate here. The quote that commenters cite above, asserting that an agency's statutory interpretation which conflicts with a prior interpretation is "entitled to considerably less deference than a consistently held view," is from *Thomas Jefferson University* v. *Shalala,* 512 U.S. 504 (1994), a 1994 Supreme Court case whose precedent on changes in agency policy was displaced by *FCC* v. *Fox,* in 2009, 556 U.S. 502. Under *FCC* v. *Fox,* "it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency believes it to be better, which the conscious change of course adequately indicates." *Id.* at 515.

According to the commenters, anything stored in a storage vessel should be considered an alternative fuel or raw material and therefore any change in the liquid stored should be exempt from being considered a modification. We find in this final rule that this interpretation of the alternative fuel or raw material exemption as applied to storage vessels is inappropriate and often excludes changes in the stored VOL that increase emissions and that therefore should trigger additional control requirements. The EPA explained its rationale for including additional modification provisions in section III.G. of the proposal preamble (88 FR 68543; October 4, 2023). The EPA explained that for purposes of NSPS subpart Kc, a change in the liquid stored in the storage vessel to an organic liquid with a greater MTVP does not constitute a "use of an alternative fuel or raw material" and would be considered a change in the method of operation of the storage vessel. The primary function of this affected facility is the storage of materials. The VOLs stored in the storage vessel are neither raw material nor fuel inputs to a process at the affected facility itself. Furthermore, even had the EPA not revisited its interpretation regarding the application of 40 CFR 60.14(e)(4), we maintain that changing the VOL stored to one with a higher MTVP is a modification (a change in the method of operation that results in an increase in the emissions rate). The NSPS subpart Kc modification provisions result in meaningful emission reductions. For these reasons, the final rulemaking appropriately supersedes the general provisions. As such, the EPA is finalizing modification provisions such that a change in the liquid stored, which results in increased VOC emissions, would be a modification under NSPS subpart Kc and is clarifying in 40 CFR 60.110c(e) that, for the purposes of this source category, the exemption at 40 CFR 60.14(e)(4) does not apply.

The precedent of MTVP dependent standards of performance for VOL storage vessels was established as part of NSPS subpart K and has informed the establishment of standards for subsequent rulemakings under NSPS subparts Ka and Kb. Under these standards, a VOL's MTVP (along with a vessel's capacity) has served as a primary mechanism for determining suitable standards for control. The amended modification provisions will provide meaningful emission reductions from storage vessels that would otherwise go unregulated despite satisfying the statutory criteria for a modification under CAA section 111(a)(4), as explained in this section and at III.G. of the proposal preamble (88 FR 68543; October 4, 2023). The modification provision, as amended, effectively curtails a previously existing loophole which had allowed owners and operators to circumvent the standards in NSPS subpart Kb. For example, prior to this rulemaking, an uncontrolled fixed roof vessel could be constructed and be exempt from NSPS subpart Kb standards because it was storing a low vapor pressure VOL. The vessel could then change operation to introduce a new material with a higher vapor pressure that would otherwise be subject to the NSPS had it been stored in the tank at the time of construction, but the owner or operator could continue to operate without meeting the floating roof or closed vent system and control device standards even if the vessel was constructed after the Kb applicability date. Similarly, if an owner or operator built floating roof tanks for VOLs with less than 11.1 psia and later replaced the liquid stored with a liquid with a vapor pressure greater than 11.1 psia, they could thereby circumvent the closed vent system and control device requirements under 40 CFR 60.112b which are directly dependent on the MTVP of the stored VOL and which would otherwise apply. As such, the prior NSPS provided significant leeway for owners and operators to circumvent the regulations intended to control storage vessel emissions. To address this concern, the EPA is finalizing modification provisions such that the MTVP can be used as an indicator to determine that a change in the liquid stored, which results in increased VOC emissions, would be a modification under NSPS subpart Kc.

The EPA's decision to consider a change in the liquid historically stored or permitted to one with a higher vapor pressure to be a modification is consistent with both the statutory and regulatory definitions of those terms. CAA section 111(a) defines modification to mean, "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." Similarly, the General Provisions to 40 CFR part 60 define modification at 40 CFR 60.2 to mean, "any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted." And 40 CFR 60.14 provides a more detailed framework for evaluating modifications, which similarly states at paragraph (a) that: "Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act." Thus, the CAA and general provisions for 40 CFR part 60 all rely on the same basic two-step process: (1) a physical change in, *or* change in the method of operation of, a stationary source; and (2) a resulting increase in emissions. Notably, it is not necessary for there to be a physical change at the source in the first step if there is a change in the method of operation. One or the other will suffice. We address each of these criteria in turn.

First, as proposed, the EPA has determined that a change in the liquid stored in a storage vessel constitutes a change in the method of operation of a storage vessel. The primary function of this affected facility is the storage of materials, and so the only logical "change in the method of operation" that a storage vessel would undergo is a change in the material stored. In other words, whenever a storage vessel changes the VOL that is stored, that is a change in that facility's method of operation. The EPA's interpretation

regarding what constitutes a change in the "method of operation" for storage vessels has not changed with this rulemaking. In explaining the applicability of modification under the CAA, in the NSPS subpart Kb preamble, the EPA affirmed, "Few, if any, changes in the physical configuration of the storage vessels that would increase emissions are anticipated. An operational change that would increase emissions is a changing of the stored liquid from a VOC non-emitting liquid to a VOC emitting liquid" (49 FR 29707; July 23, 1984). Thus, the EPA has long considered the changing of the stored liquid to meet the statutory requirements for an operational change. Second, the changing of the stored liquid can lead to an increase of emissions whenever the MTVP of the new liquid is greater than the previously stored liquid. Thus, both statutory criteria for identifying a modification are met.

The EPA agrees that we have historically applied the regulatory exemption under 60.14(e) for "use of an alternative fuel or raw material" to storage vessels. In making our decision regarding modifications, we reviewed several documents[7] and questioned both industry and enforcement personnel to better understand what changes are currently considered modifications. In the NSPS subpart Kb preamble, the EPA explained, "Section 60.14(e) of the General Provisions to Part 60 lists several changes that are not considered modifications. Among these is the use of raw material, if prior to the date of proposal of the standard, the existing facility was designed to accommodate that alternative use" (49 FR 29707; July 23, 1984). However, the EPA did not provide any further explanation at that time as to why the Agency believed this exemption applied to this affected facility, and the Agency has reconsidered the application of that exemption for purposes of NSPS subpart Kc. As explained in section III.G. of the proposal preamble, when the affected source is a storage vessel and not a process unit, we no longer consider a change in the liquid stored in the storage vessel (to an organic liquid with a higher MTVP) to qualify as a "use of an alternative fuel or raw material." As discussed above, the primary function of an affected facility in this source category is the storage of materials, and the VOL stored in the vessel are neither raw material nor alternative fuel inputs to a process at the facility itself. While the storage vessel may store liquids that are used as an alternative fuel or raw material used for inputs to a process for *another* facility, it is not reasonable to extend application of the exemption to mere storage of the alternative fuel or raw material. Accordingly, we no longer believe that the exemption should be applied to these factual circumstances by the terms of the regulation.

The EPA notes that, the fact that 40 CFR 60.14(e) is framed as *exempting* certain activities from the definition of modification indicates that, absent these exemptions, the EPA would consider the exempted activity to meet the statutory definition of modification in CAA section 111(a)(4). In other words, the EPA created a specific provision exempting the "use of an alternative fuel or raw material" from the regulatory definition of modification because this activity would, as the EPA proposed, typically be considered an operational change,[8] a consideration reinforced by the EPA's discussion on modification in the NSPS subpart Kb preamble. In this rulemaking, the EPA confirms that it does not consider a change in the liquid stored to one with a higher MTVP to qualify under this exemption. Moreover, irrespective of this determination, the EPA is also finalizing in this rulemaking that the exemption in 40 CFR 60.14(e)(4) regarding alternative fuel or raw material does not apply to storage vessels.

While we have determined for purposes of NSPS subpart Kc that a change in the liquid stored to a liquid with a higher vapor pressure does not constitute the "use of an alternative fuel or raw material," we note that even if this exemption would otherwise apply by its terms, this rulemaking supersedes the exemption pursuant to 40 CFR 60.14(f), because, as explained earlier, we have concluded that it is the better policy and consistent with the statutory definition of modification based on the facts of how this affected facility operates. The EPA has always maintained that there are some sources for which the basic exemptions from the standard definition of a modification may not be appropriate, and 40 CFR 60.14(f) was included in the general provisions to afford the EPA the ability to supersede the general modification regulations, the exemption provisions in 40 CFR 60.14(e), for those sources for which these provisions should not reasonably be applied. The EPA has previously applied specialized interpretations of modification for other source categories. For example, in NSPS subpart Ja, we included special provisions for the modification of flares at petroleum refineries because the basic considerations under 40 CFR 60.14(e), were generally developed considering process unit emission sources. The intermittent operation of a flare makes it difficult to use the criteria of 40 CFR 60.14(e) to determine when a flare is modified (73 FR 35843; June 24, 2008). In our review of NSPS subpart Kb, we identified similar short-comings regarding the "process unit-oriented" modification exemptions as previously applied to storage vessels. The specialized modification provision for storage vessels is consistent with the CAA statutory requirements, the general definition of modification outlined in 40 CFR 60.2 and 60.14, and previous determinations that source-specific modification provisions are justified for certain source categories. Accordingly, in this rulemaking, the EPA confirms that it does not consider a change in the liquid stored to one with a higher MTVP to qualify under the exemption in 40 CFR 60.14(e)(4), and, as a matter of clarity, irrespective of this determination, this rulemaking is superseding the exemption.

With respect to the comment that the proposed definition of modification would arbitrarily apply differently for identical vessels based on their historic use rather than their design capabilities, we disagree. As stated above, the modification provisions are directly dependent on the MTVP of the stored VOL. The precedent of MTVP dependent standards of performance for VOL storage vessels was established as part of NSPS subpart K and has informed the establishment of standards for subsequent rulemakings under NSPS subparts Ka and Kb. We are finalizing that storing a VOL with a greater MTVP than historically stored or permitted is a modification. We determined the BSER and set standards of performance considering existing emission controls of modified storage vessels.

The EPA also disagrees with the comment advocating a requirement for capital expenditure to determine whether there is a modification and that a capital expenditure clause should be added to the language proposed at 40 CFR 110c(e). First, we note that the

[7] See, *e.g.*, U.S. EPA Applicability Determination Index, Control Number: 0400015, (referencing 40 CFR 60.14(e)(4)–(5)) and NSPS subpart Kb Background Information Document (Docket ID No. EPA–HQ–OAR–2023–0358–0012).

[8] This is bolstered when considering the other exemptions in 40 CFR 60.14(e): a "replacement" referred to in (e)(1) and the addition of a system or device referred to in (e)(5) *is* a physical change to a facility, and an increase in production rate or an increase in hours of operation referred to in (e)(2) or (3) *is* a change in the facility's operation. However, the EPA had a rational basis for exempting these particular physical or operational changes, as a general matter, from the broader definition of modification under the regulations.

statute at CAA section 111(a)(4) contains no such requirement and the general provisions at 40 CFR 60.14(e)(2) only consider whether a capital expenditure is needed when considering an exemption from the definition of modification tied to increase in production at the facility. Critically, neither the statute nor the general provisions provide that the determination of whether a modification has occurred must be based on a capital expenditure. Thus, the commenters seek to impose an additional requirement that is not plainly necessary under the statute nor anticipated, either by Congress or by the EPA, without an explanation as to why that would be justified for this source category. In many cases, a capital expenditure is not needed to change the liquid stored in a fixed roof tank. Under the commenter's proposed capital expenditure paradigm, an operator of a fixed roof tank used to store a low volatility fluid could change to a higher vapor pressure fluid and argue that no modification occurred even though the storage vessel has changed its method of operation. This would permit the resulting emissions increases without the requisite control that the statute would otherwise anticipate under such circumstances. It is more consistent with the statutory standard to consider the change in the liquid stored or permitted as a change in the method of operation and then assess whether an increase in the vapor pressure of the liquid stored triggers the need for controls (which would require a capital expenditure). We found the controls required under proposed NSPS subpart Kc are cost effective and meet the BSER criteria, and we see no reason to allow uncontrolled modified storage vessels or less stringent controls simply because the tank was initially permitted for or stored a less volatile liquid.

4. Control Standards for IFRs and EFRs

The EPA proposed standards of performance that reflect the BSER for IFRs as well as alternative compliance standards for controlled storage vessel EFRs. The EPA proposed a work practice standard that would require new IFR storage vessels be constructed with either a liquid-mounted or a mechanical shoe primary seal, a rim-mounted secondary seal, and fittings on the floating roof that meet certain control requirements (*e.g.*, gasketed covers, specific guidepole control configurations) mostly consistent with the requirements of fitting controls in NSPS subpart Kb. The EPA also proposed that new EFR storage vessels be constructed with either a liquid-mounted or a mechanical shoe primary seal, a rim-mounted secondary seal, welded deck seams, and fittings on the floating roof that meet certain control requirements (*e.g.*, gasketed covers, specific guidepole control configurations). Except for the guidepole controls, the fitting controls are mostly consistent with the requirements of fitting controls in NSPS subpart Kb.

We are finalizing the control requirements for IFRs and EFRs as proposed with minor editorial revisions (such as replacing "roof leg supports" with "roof supports," replacing "bolted" with "bolted or otherwise mechanically secured," and using consistent language regarding requirements for vacuum breaker/automatic bleeder vents). For EFRs, we are also adding provisions for emergency roof drains to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening. As noted by commenters, this provision is included in NSPS subpart Kb and the IFR drain requirements were inadvertently copied for EFRs in the proposed rule for NSPS subpart Kc.

*Comment:* One commenter stated the proposed NSPS subpart Kc language refers to the floating roof being supported by legs when the floating roof is landed, but a common design for IFRs involves suspending the IFR from the fixed roof of the tank via cables. The commenter stated that proposed language at 40 CFR 60.112c(b)(1) and (4) should be revised to accommodate the cable-suspended design alternative. Similarly, a commenter recommended the EPA revise the definition of the term "Vacuum breaker/Automatic bleeder vent" to avoid restricting vacuum breakers to the leg-actuated type. Another commenter noted that since leg operated vacuum breakers must contact the floor prior to the roof support legs, the EPA should consider setting a maximum opening distance or clarify that the roof is considered landed when the vacuum breaker leg lands. One commenter noted that 40 CFR 60.112c(b)(1) reads ". . . and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled" whereas 40 CFR 60.112c(c)(1) reads: ". . . and when the storage vessel is completely emptied and subsequently refilled." The commenter suggested that the requirements for EFRs in 40 CFR 60.112c(c)(1) be revised to be consistent with 40 CFR 60.112c(b)(1).

*Response:* We agree with the commenters that the language regarding roof legs and vacuum breaker/automatic bleeder vents should be generalized to allow roof supports other than roof legs and vacuum actuations other than leg actuated devices and that consistent language should be used for EFRs. While we understand cable suspended roofs are specific to IFRs, we generalized the language for EFRs in the event different supports are developed for EFRs and to make the language consistent between 40 CFR 60.112c(b) and (c). We also revised the use of the term "vacuum breaker" by replacing it with "vacuum breaker/automatic bleeder vent" because that is the defined term for these devices on a floating roof and to distinguish these from vacuum breaking devices on a fixed roof. We are also adding a sentence to the roof landing monitoring requirements at 40 CFR 60.113c(a)(5) and (b)(8) to clarify that the roof is considered landed when the floating roof first rests on supports or when the vacuum breaker/automatic bleeder vent begins to open, whichever is first. This clarifies that the landing alarm must be set at the height the leg-actuated vacuum breaker/automatic bleeder vent begins to open the vent, which will be prior to the floating roof resting on the roof supports.

*Comment:* One commenter stated that the proposed NSPS subpart Kc does not address the emergency roof drains that are utilized with certain EFRs. The commenter noted that NSPS subpart Kc specifies that "stub drains" are not required to be covered at all, which could be understood as exempting EFR emergency roof drains from control. The commenter recommended that the EPA clarify, consistent with NSPS subpart Kb at 40 CFR 60.112(b)(2)(ii), that each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

*Response:* We agree with the commenter that we inadvertently used the language allowing uncontrolled stub drains for IFRs in the proposed EFR requirements. We had intended to maintain consistency with the EFR drain requirements in NSPS subpart Kb. We agree with the commenter that the reference to stub drains for EFRs is not appropriate as stub drains are not used for EFRs. In the final rule, we are including the requirements to use a slotted membrane fabric cover that covers at least 90 percent of the area of the opening at 40 CFR 60.112c(c)(2)(viii) consistent with the requirements for EFR drains in NSPS subpart Kb, as suggested by the commenter.

5. Control Standards for Closed Vent Systems Routed to a Control Device, Fuel Gas System, or Process

For storage vessels with closed vent systems routed to a control device, fuel gas system, or process, the EPA proposed certain design requirements for the storage vessel to prevent pressure releases from the storage vessel and proposed that control devices must meet 98 percent or greater emission reduction efficiency. The EPA proposed that non-flare thermal combustion devices must conduct performance tests initially and at least once every 60 months, in which they establish a temperature operating limit to which they must comply at all times. For flares, the EPA proposed that flares must meet the operating and monitoring requirements consistent with the requirements in the Refinery NESHAP (40 CFR 63.670 and 63.671). We are finalizing requirements for closed vent systems routed to a control device, fuel gas system, or process with some revisions from proposal for reasons noted in the following comments and responses.

First, we are revising the vacuum pressure at which vacuum breaking devices must close from −0.1 pounds per square inch gauge (psig) to −0.1 inches of water (−0.0036 psig) to better reflect common storage vessel design requirements. We are also clarifying the language since a higher vacuum setting would be a lower absolute pressure and the proposed language was potentially ambiguous. The revised provision clarifies that any vacuum breaking device on the storage vessel must close while the storage vessel is still under vacuum of at least −0.1 inches of water (−0.0036 psig or −0.025 kPa gauge). We proposed that storage vessels that are vented to a closed vent system must be designed to operate at elevated pressures (1 psig above MTVP plus any back pressure from the control device) without venting to the atmosphere. We are retaining this as an option but are adding an option to design and operate the recovery system to prevent venting from the storage vessel. In either case, we are retaining requirements consistent with those proposed that monitoring systems must be installed to detect pressure releases from each pressure relief device (PRD) or vacuum breaking device on a storage vessel and each PRD on the closed vent system. For owner and operators electing to design the storage vessel and closed vent system to operate at elevated pressures, we are including provisions that allow the control device to be taken out of service for maintenance provided that the storage vessels are operated with no emissions to the atmosphere.

We are retaining requirements for control devices to meet 98 percent control efficiencies as proposed. We allow enclosed combustion devices to demonstrate on-going compliance with the 98 percent control efficiency using temperature operating limit, as proposed. However, we are also finalizing an alternative for enclosed combustion devices, if elected, to comply with the flare operating limits, consistent with recent provisions provided for gasoline distribution facilities (40 CFR part 60, subpart XXa and 40 CFR part 63, subparts R and BBBBBB). Lastly, we are amending the requirements for open-ended lines to align with provisions more closely under the Miscellaneous Organic Chemical Manufacturing NESHAP (MON).

*Comment:* Two commenters suggested that the pressure constraints on design operating pressure and vacuum breaking devices are not technically feasible and could result in significant damage or failures of the storage vessels, stating that a gauge pressure higher than the designed pressure of the storage vessel or a vacuum greater than the design requirements could result in catastrophic failure of the storage vessel. The commenters noted that the proposed requirements conflict with American Petroleum Institute (API) Codes 650 and 2000. The commenters recommended the EPA delete the specific pressure requirements proposed and replace with general language that atmospheric vents should be designed to remain closed during normal operation.

*Response:* In the proposal, we intended to require the use of low-pressure storage vessels rather than atmospheric storage vessels so that the storage vessels would be built to withstand higher pressures. However, we recognize that this may be a more significant retrofit for modified storage vessels with gas collection systems designed to operate at lower pressures such that the pressure in the storage vessels can remain near atmospheric pressure. However, if the vapor recovery compressor or fan fails or is shut down for any reason, then the storage vessel would vent rather than being able to withstand the buildup of pressure as the headspace in the storage vessel reaches saturation without venting to the atmosphere like a low-pressure storage vessel would. We are maintaining the positive pressure requirements as one compliance option, but we are also finalizing an option for facilities to design and operate a vapor recovery system in a manner to prevent atmospheric releases from the storage vessel. As proposed, any pressure release from the storage vessel is a deviation of the storage vessel and closed vent system requirements. We are finalizing monitoring system requirements for the pressure relief devices and vacuum breaking devices to identify these deviations.

With respect to the vacuum requirements, we reviewed the API 650 standards applicable to low-pressure storage vessels and found in section 5.10.5.2 that these storage vessels ". . . may be safely subjected to a partial vacuum in the gas or vapor space not exceeding 1 ounce per square inch with the operating liquid level in the tank at any stage from full to empty." One ounce per square inch is equivalent to 0.0625 psi or 2 inches of water, so we agree that the vacuum requirement proposed is beyond standard design requirements for low-pressure storage vessels. We also confirmed that the API 650 standard indicates that the maximum vacuum for atmospheric storage vessels (without needing additional design considerations) is −0.25 kPa (or −1 inch of water or −0.036 psig). In our proposal, we wanted to ensure that the vacuum vent is closed while there is still a slight vacuum in the storage vessel, to prevent venting to the atmosphere from the vacuum breaking device as the pressure in the storage vessel increases. In reviewing the storage vessel specifications, we determined that the value we proposed was higher than needed to achieve this objective. The vacuum breaking devices must open before the maximum vacuum pressure is reached, so typical opening pressures are 0.5 inches of water pressure. Therefore, we are finalizing that the vacuum breaking device must close while the storage vessel is still under vacuum of at least −0.1 inches of water (−0.0036 psig or −0.025 kPa gauge) and are finalizing that a pressure release (deviation) occurs when the vessel reaches atmospheric pressure and the vacuum breaking device remains open. We are providing separate paragraphs for the monitoring requirements for PRDs between storage vessels and closed vent systems and adding monitoring requirements for the vacuum breaking devices on the storage vessels. Otherwise, the separate pressure release monitoring requirements we are finalizing in 40 CFR 60.112c(d)(1)(iii) and (d)(2)(iii) are the same as proposed for "each pressure relief device on a storage vessel or in a closed vent system," in 40 CFR 60.112c(d)(2)(iii).

*Comment:* One commenter recommended that the EPA add a 240-hour planned routine maintenance provision for storage vessels equipped with a closed vent system routed to a control device to NSPS subparts Kb and Kc similar to the language in the part 63 NESHAP regulations such as the MON and Organic Liquids Distribution (non-gasoline) NESHAP. According to the commenter, if the EPA decides to retain the language in 40 CFR 60.110c(g) removing the SSM provisions, it is reasonable for the EPA to include a separate 240-hour planned routine maintenance provision for control devices in NSPS subpart Kc similar to the language in the MON (40 CFR 63.2470(d)) and the associated recordkeeping and reporting requirement similar to the language in 40 CFR 63.998(d)(2) and 63.999(c)(4).

*Response:* We disagree that we should provide 240 hours for uncontrolled emissions when using an add-on control device. Similar provisions are not needed or appropriate for IFRs, which were determined to be the BSER for storage vessels storing VOLs with an MTVP less than 11.1 psia. We maintain that a 98 percent control requirement at all times is necessary for add-on control devices to achieve emission reductions equivalent to those for IFRs. Even for storage vessels storing VOLs with an MTVP of 11.1 psia or higher, we maintain that a 98 percent control requirement is the BSER, and that level of control cannot be achieved if we allow 240 hours of uncontrolled emissions. Nonetheless, if the storage vessel is designed to be able to operate at pressures above the MTVP consistent with the storage vessel design pressure requirements proposed (and being finalized as one compliance option), then the control device can be isolated from the storage vessel, and the closed vent system and the storage vessel can remain in service without venting to the atmosphere provided that the storage vessel is not filled to the extent that the pressure limits of the pressure relief valves on the storage vessel and closed vent system are exceeded and there is a pressure release. If there is no pressure release from the storage vessel during the planned maintenance activity, we agree that planned maintenance can be allowed. Therefore, we are including provisions at 40 CFR 60.112c(d)(7) to allow owners or operators to conduct planned maintenance on control devices while storage vessel affected facilities are still storing VOL under specific circumstances. Specifically, the storage vessel(s) storing VOL must be designed to operate above the MTVP of the stored VOL according to the requirements in 40 CFR 60.112c(d)(1)(i) and must comply with the pressure release monitoring, recordkeeping, and reporting requirements. Eliminating pressure releases during the maintenance periods may require operators to limit VOL addition to the storage vessel (such as only adding VOL when there is also corresponding withdrawal of VOL from the storage vessel), but the operator is expected to operate the storage vessel without a pressure release or atmospheric venting during the maintenance period.

*Comment:* One commenter stated that the EPA should define "vapor combustion unit" separately from "incinerator" and apply appropriate monitoring provisions to vapor combustion units (VCUs) to avoid subjecting VCUs to inappropriate requirements. The commenter stated that the EPA should allow VCUs to elect to meet the proposed flare provisions, as was provided in the Gasoline Distribution rules.

*Response:* In general, we agree with the commenter. We note that we had proposed specific requirements for "enclosed combustion devices" so we elected to define that term. We recognize that some enclosed combustion devices may operate more like a flare than like an incinerator (no direct combustion chamber and no means to control the amount of air entering the device). In similar situations in other rules (gasoline distribution rules at 40 CFR part 60, subpart XXa, and 40 CFR part 63, subparts R and BBBBBB, and the oil and gas rule at 40 CFR part 60, subparts OOOOb and OOOOc), we have allowed the enclosed combustion devices to comply with the flare operating limits rather than with the temperature operating limit. As such, we agree with the commenter's suggestion to allow enclosed combustion devices to comply with the flare operating limits. We have added a definition of both "enclosed combustion device" and "flare" to help distinguish between these devices (enclosed combustion devices emit pollutants through a conveyance suitable to conduct a performance test, and flares have open or shrouded flames and do not emit pollutants through a conveyance suitable to conduct a performance test). We note that the implementation of this provision led to revision of several paragraphs related to control device operating limits and monitoring, recordkeeping, and reporting requirements to allow "enclosed combustion devices electing to comply with § 60.112c(d)(5)" to be treated differently than other non-flare combustion devices. We are retaining the requirement for enclosed combustion devices to conduct a performance test to demonstrate that the enclosed combustion device is achieving a 98 percent VOC emission reduction regardless of whether the enclosed combustion device is complying with the flare operating limits in 40 CFR 60.112c(d)(5) or the temperature operating limits in 40 CFR 60.113c(c)(1)(ii)(E).

*Comment:* One commenter stated that the EPA should clarify in the final NSPS subpart Kc rule, in the closed vent system and bypass line provisions, that open-ended valves or lines that use a cap, blind flange, plug, or second valve are not considered to be bypass lines. According to the commenter, the EPA should add the text that is in 40 CFR 63.2450(e)(6)(v)(B) of the MON rule to 40 CFR 60.112c(d)(2)(ii) to clearly exempt these open-ended valves or lines from the bypass requirements.

*Response:* We agree with the recommendations to align NSPS subpart Kc more closely with the provisions in the MON regarding open-ended valves or lines that use a cap, blind flange, plug, or second valve, and have revised to 40 CFR 60.112c(d)(2)(ii) accordingly.

6. Control Standards for Degassing

Based on the analysis presented at proposal, the EPA proposed emptying and degassing standards in accordance with the BSER applicable to: (1) storage vessels equipped with a closed vent system routed to a control device, fuel gas system, or process; and (2) IFR and EFR storage vessels that have a capacity of greater than or equal to 1 million gallons storing a VOL with an MTVP greater than or equal to 1.5 psia. These vessels must meet certain requirements while the vapors in the storage vessel are at or above 10 percent of the LEL. The proposed standards of performance for degassing emissions reflect a 98 percent VOC reduction efficiency.

Regarding degassing controls, we are finalizing these provisions with minor revisions to what was proposed. We are finalizing standards for storage vessels subject to controlling degassing emissions as proposed. We are finalizing a requirement that controls must be used until the vapor space concentration is less than 10 percent of the LEL, as proposed, but we are also finalizing provisions for nonflammable liquids to comply with a 5,000 ppmv as methane concentration level based on comments received, because 5,000 ppmv is equal to 10 percent LEL if the vapors were methane. We are finalizing that the degassing emissions that must be controlled must be vented to control

device that achieves a 98 weight percent VOC reduction or greater as proposed. We are finalizing additional provisions to check LEL instrument calibration and instrumental offset response each day the instrument is used and prior to discontinuing controlled degassing consistent with LEL measurement requirements for IFR monitoring to ensure the accuracy of the instrument readings. We are also finalizing provisions that allow the introduction of chemicals or diluents for the purpose of reducing vapor concentration before or during active degassing, after considering comments received.

*Comment:* Two commenters stated that the EPA should incorporate a concentration limit for the storage vessel degassing emissions in 40 CFR 60.112c(e) since nonflammable chemicals do not exhibit an LEL. The commenter requested that the EPA include a concentration limit of less than 5,000 ppmv as methane as an alternative to the LEL requirement, consistent with the National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry proposal.

*Response:* We expect that most VOLs with an MTVP above 1.5 psia will have some flammability, but we agree that a concentration limit of 5,000 ppmv as methane for nonflammable liquids is appropriate because 5,000 ppmv is the 10 percent LEL of methane and it generally provides a concentration value that is similar to or lower than the 10 percent LEL level for heavier organics. For example, 10 percent LEL of butane is as stringent as or more stringent than 1,900 ppmv as butane or about 7,600 ppmv as methane.

*Comment:* One commenter noted that some companies flood the bottom of the tank with a low vapor pressure material to facilitate removal of residual sludges and/or to reduce the concentration of vapors in the vapor space of the tank prior to or during active degassing. According to the commenter, while the proposed rule language does not prohibit bottom flushing, this practice should be expressly accommodated in the rule language.

*Response:* We agree that flooding the bottom of the tank with a low vapor pressure material is a reasonable control measure for degassing. As such, we are revising 40 CFR 60.112c(e)(1) to expressly allow the addition of chemical or a diluent for the purpose of reducing vapor concentration before or during active degassing.

7. Alternative Means of Emission Limitation

We are finalizing the alternative means of emissions limitation (AMEL) provisions as proposed except for the addition of two clarifications. First, at 40 CFR 60.114c(a), we are replacing "any" with "the applicable" when referencing requirements in 40 CFR 60.112c, to clarify that the equivalency must be made for the same type of control system (IFR, EFR, or closed vent system routed to a control device, fuel gas system, or process). This clarification prevents operators that are using an IFR from reducing the fitting control requirements finalized for an IFR because, for that size of storage vessel and stored VOL, the required IFR controls achieve greater than a 98 percent reduction or greater reduction than an EFR meeting the final EFR requirements. Second, we are clarifying that the written application to the Administrator in 40 CFR 60.114c(c) may include either actual emissions test results or an engineering evaluation that the Administrator determines to be accurate, but it does not necessarily have to include both.

*Comment:* One commenter noted the proposed NSPS subpart Kc provides for requesting an AMEL at 40 CFR 60.114c and this section specifies that a request for approval of an alternative must include an actual emissions test; however, there are numerous alternative control measures that have already been tested and for which the EPA has published emission factors in AP–42. The commenter stated that the EPA should not arbitrarily require repeated testing for those control measures that have already been tested and for which the results have already been accepted by the EPA. The commenter stated that the language in 40 CFR 60.114c should be replaced with the language in NESHAP subpart WW at 40 CFR 63.1064.

*Response:* We have revised 40 CFR 60.114c(c) such that an AMEL written application must include either an actual emissions test (that covers the appropriate range of meteorological conditions) or an engineering evaluation, which may include use of emission factors as published in the EPA Report No. AP–42, *Compilation of Air Pollutant Emission Factors.* We reviewed the AMEL provision in NESHAP subpart WW. The NESHAP subpart WW provisions include a listing of test methods but do not limit the testing to those methods. As such, we are determining that the language that is included in the final rule is equivalent to the provisions in NESHAP subpart WW. We also note that the provisions in 40 CFR 63.1064(c) allow the use of different combinations of rim and deck fitting controls ". . . if the alternate emits no more than the combination specified in the § 63.1063." We interpret this provision to allow comparisons of fitting controls for IFRs to those required specifically for IFRs. While we consider that the three control options we provided are equivalent, we acknowledge that, depending on the size of tank, volatility of the VOL, and prevailing meteorological conditions, one of the control configurations (IFR, EFR, or closed vent system routed to a control device, fuel gas system, or process) will perform better and one configuration will perform worse than the other options allowed. We did not intend to allow changes to the specified control provisions to only require the lowest control efficiency for a given combination of tank size, VOL stored, and meteorological conditions. Therefore, we are also clarifying, consistent with our interpretation of the NESHAP subpart WW provisions, that the AMEL must compare with the "applicable" requirement. That is, for storage vessels with IFRs, you may request an AMEL for a different set of fittings, but you must show equivalency with the IFR requirements specified in 40 CFR 60.112c(b). For storage vessels with EFRs, the AMEL must show equivalency with the EFR requirements specified in 40 CFR 60.112c(c). For storage vessels with a closed vent system routed to a control device, fuel gas system, or process, the AMEL must show equivalency with the control requirements specified in 40 CFR 60.112c(d). With these revisions, we determine that the final AMEL provisions in NSPS subpart Kc are consistent with the AMEL provisions in NESHAP subpart WW.

Since control measures that were determined to be equivalent to NSPS subpart Kb may not be equivalent to controls required under NSPS subpart Kc, a new AMEL application must be submitted following 40 CFR 60.114c(c) in order to demonstrate that an AMEL is equivalent to the requirements in NSPS subpart Kc.

### *C. NSPS Subpart Kc Without Startup, Shutdown, and Malfunction Exemptions*

Consistent with *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the EPA has established standards in this rule that apply at all times. We are finalizing in NSPS subpart Kc specific requirements at 40 CFR 60.110c(g) that override the general provisions for SSM requirements. In finalizing the standards in this rule, the EPA has considered

startup and shutdown periods and, for the reasons explained in this section of the preamble, has not finalized alternate standards for those periods. The EPA has determined that the reasoning in the court's decision in *Sierra Club* applies equally to CAA section 111 because the definition of "emission standard" in CAA section 302(k), and the embedded requirement for continuous standards, also applies to the NSPS.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in caselaw requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through "the application of the best system of emission reduction" that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting emissions standards, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a "normal or usual manner," and no statutory language compels the EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting "achievable" standards under CAA section 112) has been upheld as reasonable by the D.C. Circuit in *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (2016).

### *D. Testing, Monitoring, and Inspection Requirements*

Because the NSPS reflect the BSER under conditions of proper operation and maintenance, we also, in performing our review, evaluate and determine the proper testing, monitoring, inspection, recordkeeping, and reporting requirements needed to ensure compliance with the emission standards. This section of the preamble includes our discussion of the proposed revisions to testing, monitoring, and inspection requirements, a summary of the significant comments received, our responses to the comments, and our final determinations regarding testing, monitoring, and inspection requirements. Changes to recordkeeping and reporting requirements are included in the section for recordkeeping and electronic reporting.

Generally, we proposed testing, monitoring, and inspection requirements consistent with those in NSPS subpart Kb and other Federal standards that would provide the best clarity for the specific requirements along with the following enhancements. The EPA proposed annual LEL monitoring as an enhancement to the monitoring and inspection requirements for storage vessels with IFRs. The EPA also proposed equipping floating roof storage vessels with a visual or audible alarm system to monitor when the floating roof approaches specified landing heights. For closed vent systems, the EPA proposed quarterly AVO inspections, annual EPA Method 21 instrument monitoring, and monitoring of bypasses. The EPA also proposed that storage vessels using closed vent systems routed to control devices, fuel gas systems, or processes must equip pressure relief devices with appropriate monitoring to identify releases. For storage vessels with closed vent systems routed to a control device, the EPA proposed that performance tests must be conducted at least once every 60 months rather than rely on a single initial performance test. Finally, the EPA proposed enhanced monitoring requirements for flares consistent with the Refinery NESHAP (40 CFR 63.671).

We are finalizing testing, monitoring, and inspection requirements as proposed except for the revisions outlined here.

- We revised the specification of the timing of these requirements to be "calendar months" rather than just "months," to clarify the timing and allow limited flexibility when scheduling the required testing or inspections.
- For IFRs, we are amending the requirements to conduct internal inspections of the floating roof at least once every 120 calendar months. We are retaining this inspection requirement each time the vessel is emptied and degassed, but we are not requiring storage vessels to be taken out of service specifically to conduct this inspection.
- We are making minor revisions to the LEL monitoring calibration procedures. We proposed language used from the gasoline distribution rule (40 CFR part 63, subpart R), which would require the correction factor to be based on "gasoline vapor." Because NSPS subpart Kc is applicable to a much broader range of chemicals, we are revising references to "gasoline vapors" to "vapors of the stored VOL." We are retaining the use of butane as the surrogate if correction factors are not available for the vapors of the VOL stored.
- We are adding specific requirements that fittings on EFR must be visually inspected during annual seal gap measurement inspections to ensure that covers are closed and gasketed with no visible gaps and that there are no tears in sleeves, wipers, or similar controls used for a given fitting during annual seal gap measurement inspections. Visual fitting inspections were proposed at 40 CFR 60.113c(b)(7) for inspections conducted when the storage vessel is emptied and degassed but did not specify fitting conditions that would result in an inspection failure, and we are adding these details to clarify the fitting inspection requirements based on comments received.
- For closed vent systems, we are including an additional reference at 40 CFR 60.113c(c)(2) for the quarterly AVO monitoring as required under both the proposed and final requirements at 40 CFR 60.112c(d)(2)(i). We are also revising the provision of 40 CFR 60.113c(c)(3) to clarify that emissions detected using visible, audible, and olfactory methods are leaks triggering corrective action.
- Regarding MTVP test methods, we are clarifying that owners and operators must determine the MTVP of the VOL prior to refilling the storage vessel with a new VOL. The proposed language only referenced "initial filling" and may allow facilities to change VOL without reassessing the MTVP. However, we considered that, when a new VOL is stored, that would be an initial filling of that VOL. The rephrasing of that provision helps to clarify this requirement. Additionally, we are adding a requirement to use a vapor-to-liquid ratio of 4:1 when using American Society for Testing and Materials (ASTM) D6378–22. We proposed this requirement when using ASTM D6377–20 but consider that the same provision should apply to both of the MTVP test methods. The EPA's intention to use a vapor-to-liquid ratio of 4:1 when using ASTM D6378–22 was detailed in the proposal preamble but was erroneously omitted from the proposed rule text.
- Additionally, as noted in section IV.B.5. of this preamble, we are allowing enclosed combustion devices to comply with the monitoring provisions for flares as an alternative to the temperature monitoring requirement.

*Comment:* One commenter stated that the EPA's proposed monitoring and inspection requirements for floating roof tanks are inadequate and must be strengthened to make it more likely that the tanks can reduce 98 percent of VOCs. According to the commenter, at a minimum, the EPA must require monitoring and inspection in keeping with the current requirements from South Coast Air Quality Management District (SCAQMD) Rule 1178. In addition, the commenter stated that the EPA must make it explicit that, for IFR visual inspections, the entire perimeter of the floating roof seal must be visually evaluated, even if that requires opening multiple manways. The commenter stated that the EPA must also require quarterly forward-looking infrared measurements from tank decks.

*Response:* In general, we considered that we had incorporated much from the SCAQMD Rule 1178 monitoring provisions in our proposal. We included LEL monitoring provisions for IFR storage vessels and PRD monitoring provisions for storage vessels with closed vent systems routed to a control device, fuel gas system, or process that are reasonably consistent with the monitoring requirements in SCAQMD Rule 1178. However, upon further review of SCAQMD Rule 1178 and our proposed inspection requirements, we noted that the inspection requirements we proposed for EFR storage vessels only covered inspections of the primary and secondary seals. Visual fitting inspections were proposed for IFR inspections and mentioned in the proposed inspections at 40 CFR 60.113c(b)(7) when the storage vessel is emptied and degassed. However, no requirement for fitting inspections were proposed during annual gap measurements, and the inspections proposed at 40 CFR 60.113c(b)(7) did not specify fitting conditions that would result in an inspection failure. After our review of SCAQMD Rule 1178 monitoring and inspection requirements based on this comment, we are adding specific requirements that fittings on EFR must be visually inspected during annual seal gap measurement inspections to ensure that covers are closed and gasketed with no visible gaps and that there are no tears in sleeves, wipers, or similar controls used for a given fitting. We are also adding the conditions under which an inspection failure occurs for the inspections conducted when the EFR storage vessel is emptied and degassed.

We considered optical gas imaging requirements in previous reviews of storage vessels, which we reviewed again for NSPS subpart Kc, and concluded that these requirements were not cost-effective. Regarding manways, we agree with the commenter's assertion that while performing IFR visual inspections, the entire perimeter of the floating roof seal must be visually evaluated, even if that requires opening multiple manways. We have elected not to add specific rule language, because we believe that having visual access to the entire primary seal, is already a necessary component of annual IFR inspections both in the rule language of NSPS subpart Kc and in the existing rule language of NSPS subpart Kb. As such, except for the specifications for fitting inspections for EFR storage vessels, we are not adding additional monitoring requirements to NSPS subpart Kc.

*Comment:* Numerous commenters requested that the EPA allow in-service inspections of IFRs either by providing additional language in 40 CFR 60.113c(a)(2) allowing for top-side inspections when there is visual access to all deck components or by incorporating an alternate means of compliance option to comply with NESHAP subpart WW [40 CFR 63.1063(d)(1) and (2)]. The commenters noted that in-service inspections were allowed in NSPS subpart Kb to avoid the costs and emissions associated with emptying and degassing vessels for inspection. If in-service inspections are provided, the commenters noted, rule revisions may also be needed in the notification requirements at 40 CFR 60.116c(b)(1) and the reporting requirements at 40 CFR 60.116c(c)(2)(ii).

*Response:* We had proposed language consistent with NSPS subpart Kb at 40 CFR 60.113b(a)(4) to require more detailed "out of service" inspections at least once every 10 years. The EPA agrees with the commenter's request to allow for in-service inspections to be performed entirely from the top side of the floating roof. The EPA is incorporating language into 40 CFR 60.113c(a)(2)(ii) to allow for in-service inspections to be performed entirely from the top side of the floating roof, as long as there is visual access to all deck fittings and rim seal systems specified in 40 CFR 60.112c(b). We are also adding repair timelines in 40 CFR 60.112c(b), similar to those already established for the annual visual inspection. We are also specifying that a 30-day notification must be provided for inspections in 40 CFR 60.116c(b)(1). Also, we are deleting the phrase "emptied and degassed and" from 40 CFR 60.116c(c)(2)(iii) to account for the reporting of these in-service inspections.

*Comment:* One commenter stated that the calibration requirements for the LEL meter in 40 CFR 60.113c(a)(3)(ii) and (iv) that are specified for demonstrating compliance with the 25 percent LEL limit for IFR storage vessels are burdensome and should be simplified to be consistent with the calibration requirements for the LEL meter within the storage vessel degassing requirements in 40 CFR 60.112c(e). The commenter stated that following the procedures for "calibration and maintenance according to manufacturer's specifications" should be adequate for both sections of the rule. The commenter recommended that the EPA simplify the language in 40 CFR 60.113c(a)(3)(ii) and (iv) consistent with the LEL calibration requirements in the storage vessel degassing section. Another commenter noted that the language at 40 CFR 60.113c(a)(3)(iv) references gasoline vapors and should be generalized to accommodate other stored VOLs.

*Response:* We disagree that the LEL calibration requirements in 40 CFR 60.113c(a)(3)(ii) and (iv) are burdensome. These paragraphs allow the use of manufacturers' calibration methods, and they primarily specify when calibration checks must be made and specify the LEL span response. Upon review of the two LEL monitoring requirements, we are adding more specific calibration requirements for the LEL monitoring instrument used to monitor degassing. Specifically, we are requiring calibration and zero offset checks each day and at the end of the degassing event prior to completion to confirm that the final readings are accurate before controlled degassing can be discontinued.

With respect to the comment regarding the reference to gasoline vapors in the calibration requirements at 40 CFR 60.113c(a)(3)(iv), we agree that the proposed language needed to be generalized. We used calibration language from the gasoline distribution rule (40 CFR part 63, subpart R), which requires the correction factor to be based on "gasoline vapor." Because NSPS subpart Kc is applicable to a much broader range of chemicals, we are revising references to "gasoline vapors" to "vapors of the stored VOL." We are, however, retaining the use of butane as the surrogate if correction factors are not available for the vapors of the VOL stored, because a surrogate is needed when no published correction factor is available for the VOL, and butane is considered a reasonable surrogate for any VOL that does not have a published correction factor.

*Comment:* Two commenters stated that EPA Method 21 testing is laborious, costly, and time-consuming for

facilities. One commenter believes that the sensory monitoring provisions as proposed would place undue burdens on operators and would result in redundancy in monitoring and compliance measures. Both commenters stated that when coupled with the quarterly sensory testing, the requirement for annual EPA Method 21 testing is unnecessary. One commenter submitted a 1997 rule interpretation memorandum written by the Texas Natural Resource Conservation Commission, which explained that the EPA Method 21 test under NSPS subpart Kb is not considered a performance test under 40 CFR 60.8 since the EPA Method 21 is considered a screening measurement rather than a performance test, subject to the recordkeeping requirements in the General Provisions of 40 CFR 60.7(f) and not required to be reported by either NSPS subpart A or Kb. The commenter requested that the EPA discuss whether the EPA agrees or disagrees with this guidance and whether the interpretation also applies to NSPS subpart Kc.

*Response:* We disagree that quarterly AVO monitoring is burdensome. If a leak is found via AVO monitoring, it triggers corrective action. Additionally, we disagree that annual EPA Method 21 monitoring is unnecessary, because EPA Method 21 will detect small emissions sources that are above 500 ppm but that would remain undetected by AVO monitoring. The closed vent system is to be operated "with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, § 60.485(b)." In the case of NSPS subpart Kb, 40 CFR 60.113b(c) states: "The owner or operator of each source that is equipped with a closed vent system and control device as required in § 60.112b (a)(3) or (b)(2) (other than a flare) is exempt from § 60.8 of the General Provisions and shall meet the following requirements." As such, the language in NSPS subpart Kb indicates that 40 CFR 60.8 does not apply.

For NSPS subpart Kc, we used language that the closed vent system must operate ". . . with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background . . ." (see 40 CFR 60.112c(d)(2)), but there is no clear exemption from 40 CFR 60.8 in 40 CFR 60.113c(c)(2). Nonetheless, we agree that the requirements in 40 CFR 60.8 do not apply to EPA Method 21 instrument monitoring under NSPS subpart Kb. Unlike in NSPS subpart Kb, we proposed and are finalizing reporting requirements in NSPS subpart Kc for EPA Method 21 instrument monitoring events. In reviewing the proposed NSPS subpart Kc provisions related to EPA Method 21 and AVO monitoring, we recognized that we focused on the instrument monitoring requirements when using EPA Method 21 and inadvertently neglected to mention the AVO inspection requirements. Therefore, we are adding reference to the monthly AVO monitoring requirement in 40 CFR 60.113c(c)(2) consistent with the requirement under the proposed and final requirements at 40 CFR 60.112c(d)(2)(i), and we are revising the provision of 40 CFR 60.113c(c)(3) to clarify that emissions detected using AVO methods are "leaks" triggering corrective action. This latter revision also clarifies that leaks identified from AVO monitoring do not trigger the need to conduct EPA Method 21 monitoring of an AVO-identified leak. In our review, we also identified a lack of reporting requirements related to AVO-identified leaks. Therefore, we have also revised what we proposed for recordkeeping requirements at 40 CFR 60.115c(d)(3)(v) and reporting requirements at 40 CFR 60.116c(f)(8)(ii) to indicate the type of monitoring conducted and to report information regarding all leaks identified, not just those identified during EPA Method 21 instrument monitoring.

*Comment:* Several commenters requested revisions to the vapor pressure testing requirements for mixtures of indeterminate or variable composition to define the term "variable" and to not require the initial and repeat physical testing for liquids whose upper and lower bounds of vapor pressure are known or are readily calculated using standard reference texts and good engineering judgment.

*Response:* We agree with the commenters that the concept of "variable compositions" of stored liquid mixtures for which the proposed rule would require initial and repeat physical testing to determine MTVP could be applied more broadly than intended. Thus, in 40 CFR 60.113c(d)(1) of the final rule, we are clarifying that for mixtures of variable composition, if the range of concentrations for each constituent is known such that the MTVP can be determined from data and procedures in standard reference texts, then physical testing is not required. Similarly, under the final rule, physical testing is not required for crude oils and refined petroleum products for which Reid vapor pressure is known and MTVP can be determined from nomographs and other procedures described in reference texts such as AP–42. Additionally, in 40 CFR 60.113c(d)(2) we have clarified that the provisions apply to affected storage vessels storing a mixture of indeterminate composition or a mixture of unknown variable composition.

*E. Recordkeeping and Electronic Reporting*

The EPA is finalizing a requirement that owners and operators of new, modified, or reconstructed VOL storage vessels subject to NSPS subpart Kc maintain records of the results of required testing, monitoring, and inspections. The EPA is finalizing a requirement that owners and operators of VOL storage vessels subject to the current and new NSPS at 40 CFR part 60, subparts Kb and Kc, submit electronic copies of required performance test reports and the semiannual excess emissions and continuous monitoring system performance and summary reports, through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI).

We are finalizing the recordkeeping and reporting requirements similar to those proposed except that some of the revisions made to the standards, testing, and monitoring provisions required revision of the recordkeeping and reporting requirements for the final rule. The revisions to the proposed recordkeeping and reporting requirements and our rationale for making the revisions are summarized in this section.

- As noted in section IV.D. of this preamble, we are revising the recordkeeping and reporting requirements in 40 CFR 60.115c(d)(3)(v) and 60.116c(c)(8)(ii) to include the type of monitoring conducted and to report information regarding all leaks identified, including leaks identified using AVO methods.
- As noted in section IV.B.5. of this preamble, we separated PRD monitoring requirements to separately address devices on storage vessels and devices on the closed vent system and included provisions to monitor vacuum breaking devices on storage vessels. In reviewing recordkeeping and reporting requirements related to these provisions, we noted that we had proposed reporting requirements for PRDs, but we failed to include recordkeeping requirements for PRDs. Therefore, we are adding recordkeeping requirements at 40 CFR 60.115c(d)(3)(vii) for PRDs or vacuum breaking devices on a storage vessel or closed vent system that include: the device type; the monitoring device or system used for the device; data from

the device or system indicating whether a pressure release occurred; and the date, time, and duration of each pressure release, if applicable. We are also adding reporting requirements at 40 CFR 60.116c(c)(12) for each pressure release that occurred as a result of a vacuum breaking device that failed to close prior to the storage vessel reaching atmospheric pressure. The added reporting requirements include: identification of the vacuum breaking device; start date, start time, and duration (in minutes) of the pressure release; and an estimate of the mass quantity in pounds of VOL released. These requirements mimic the pressure release reporting requirements proposed (and being finalized) for PRDs, and these similar reporting requirements are needed to document compliance with or deviations from the requirements for vacuum breaking devices used for storage vessels using a closed vent system routed to a control device.

- As noted in section IV.B.5. of this preamble, we are including alternative provisions that allow enclosed combustion devices to comply with the flare operating and monitoring requirements. We include minor revisions to the proposed recordkeeping and reporting requirements commensurate with the provided alternative, to specify which recordkeeping and reporting requirements apply to control systems "other than flares or enclosed combustion devices electing to comply with § 60.112c(d)(5)" and which recordkeeping and reporting requirements apply to "flares or enclosed combustion devices electing to comply with § 60.112c(d)(5)." We are also adding a reporting requirement for the initial notification at 40 CFR 60.116c(a)(6) that includes a requirement to specify the type of control device used and the compliance option selected, which, if an enclosed combustion device is used, include whether the device is complying with a temperature operating limit or is instead electing to comply with the flare requirements in 40 CFR 60.112c(d)(5). This initial notification requirement will be useful for EPA permitting and enforcement personnel to clearly understand the compliance option being elected for the enclosed combustion device.
- For EFRs, as discussed in section IV.D. of this preamble, we added requirements to visually inspect the roof fittings (such as access hatches, gauge floats, gauge hatch/sample wells, rim vents, deck drains, deck legs, vacuum breakers, pontoon covers, and guidepoles) when gap measurements are conducted. We are adding to the list at 40 CFR 60.116c(c)(5)(vi)(A) to include reference to deviations of the fitting controls outlined in 40 CFR 60.113c(b)(4)(iii)(A) through (D) to allow reporting of fitting deviations identified during the gap measurement inspections.
- As discussed in the comment and response included in this section of the preamble, we are revising what we proposed for the timing of semiannual compliance reports to either cover fixed time periods (from January 1 to June 30 or July 1 to December 31) or align with established reporting dates based on 40 CFR parts 70 or 71 permit requirements. The proposed schedule for semiannual reports appeared to require separate semiannual reports for different affected storage vessels at a facility depending on when the storage vessel became affected under NSPS subpart Kc. Because facilities may have several affected storage vessels under NSPS subpart Kc, having fixed reporting periods simplifies the reporting requirements for these facilities.

*Comment:* Numerous commenters requested that the EPA revise NSPS subpart Kc so that reporting requirements are consistent with other reporting obligations and establish the same semiannual reporting deadline for all VOL storage vessels. The commenters noted that, as proposed, it appeared that each affected VOL storage vessel could have a separate reporting schedule depending on when the sources became affected sources under NSPS subpart Kc. The commenters recommended that the EPA require the annual reports to cover activities in set time periods (January 1 through June 30 or July 1 through December 31, as applicable). One commenter also recommended that the EPA include an alternative that would allow each affected facility subject to permitting regulations pursuant to 40 CFR parts 70 or 71 to align the semiannual reports with established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A).

*Response:* First, we never intended to have different semiannual compliance report schedules for different storage vessels at a given facility. We note that the reporting form template was designed to allow reporting of all storage vessels at the facility in one semiannual report. However, we agree that, because the affected facility is each VOL storage vessel, the proposed requirements at 40 CFR 60.116c(d) could be interpreted to impose different reporting schedules for different storage vessels if they become affected facilities in different months. Several commenters suggested that the semiannual reports cover fixed timeframes, specifically January through June and July through December. This appears reasonable. One commenter also suggested including reference to semiannual reports under 40 CFR parts 70 or 71 in the event that the current semiannual reporting period is different from January through June and July through December. This also appears reasonable. Therefore, we are providing a fixed timeframe for the semiannual reports (January through June and July through December) and providing an alternative timeframe to harmonize with other semiannual reports as scheduled under 40 CFR parts 70 or 71, if different from the fixed timeframe being finalized. We clarify that the first semiannual compliance report is triggered by the date on which the first storage vessel at the facility becomes an affected facility subject to NSPS subpart Kc and would cover, for example, April 15 through June 30 if the source becomes an affected facility on April 15. As new storage vessels become affected facilities under NSPS subpart Kc, the information for those storage vessels will be added to the semiannual report. These semiannual reporting requirements simplify the reporting requirements compared to the timing proposed and allow alignment of the semiannual reports provided for NSPS subpart Kc with other reporting requirements that may apply for the facility.

### *F. Other Final Amendments*

#### 1. Editorial Corrections

We received a number of comments regarding editorial, typographical, and cross-reference corrections that we agree with and are finalizing. Additionally, we received comments recommending clarification of requirement language to reduce misinterpretation. After reviewing these comments, we are revising some language in the final rule. We are revising references of "a control" to "a control device." Beyond these changes, the EPA made several revisions throughout NSPS subpart Kc to improve clarity.

One commenter recommended that the EPA clarify in 40 CFR 60.113c(d)(1) that the requirement to determine MTVP is not a one-time requirement, as implied by the word "initial," but also applies to non-anticipated tank service changes. We agree that if the VOL stored in the storage vessel changes, the MTVP should be reassessed. We are revising 40 CFR 60.113c(d)(1) to require that this determination be made prior to the

initial filling of the storage vessel or to the refilling of the storage vessel with a new VOL.

One commenter recommended that in 40 CFR 60.115c(d)(5)(i) and 40 CFR 60.116c(c)(10)(i)(A) the EPA should add "or flare flame" to any occurrence of "pilot flame" consistent with the provisions in 40 CFR 60.112c(d)(5)(iv) and 40 CFR 60.113c(c)(1)(iv)(B). We are revising 40 CFR 60.115c(d)(5)(i) and 40 CFR 60.116c(c)(10)(i)(A) accordingly.

2. Definitions

We received several comments recommending the inclusion of definitions that were not included in the proposal. Additionally, we received comments recommending definition revisions. This section of the preamble summarizes major comments received concerning definitions and provides our responses to those comments.

*Comment:* Several commenters recommended that the EPA define the term "pressure relief device" in NSPS subpart Kc and provided a suggested definition:

> *Pressure relief device* means a valve, rupture disk, or similar device used only to release an unplanned, nonroutine discharge of gas from process equipment in order to avoid safety hazards or equipment damage. A pressure relief device discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause. Such devices include conventional, spring-actuated relief valves, balanced bellows relief valves, pilot-operated relief valves, rupture disks, and breaking, buckling, or shearing pin devices. Devices that are actuated either by a pressure of less than or equal to 2.5 pounds per square inch gauge or by a vacuum are not pressure relief devices.

*Response:* We agree with the commenters and are including a definition of "pressure relief device" in NSPS subpart Kc similar to the commenters' suggestion. For storage vessels, we consider "conservation vents" to be PRDs. These conservation vents typically have actuation pressure less than 2.5 psig. As such, the last sentence in our final definition reflects a change from the last sentence in our proposed definition to only exclude vacuum breaking devices from the definition of "pressure relief devices." We are also clarifying that, if a device has both a pressure relief function and a vacuum breaking function, such as a conservation vent, the portion of the conservation vent that acts to relieve pressure is considered a PRD and the portion of the conservation vent that acts to relieve vacuum is a vacuum breaking device and not a PRD. We are also adding a definition of "vacuum breaking device," which is specific to the fixed roof portion of the storage vessel and a vacuum breaker which is a component of a floating roof.

*Comment:* One commenter recommended that the EPA define the term "pressure release."

*Response:* We are adding a definition of "pressure release" to 40 CFR 60.111c. We are including in the definition of "pressure release" emissions of materials resulting from a vacuum breaking device failing to close prior to the system reaching atmospheric pressure.

*Comment:* One commenter recommended that the EPA define the terms "vapor balancing system," "fuel gas," "fuel gas system," and "routed to a process or route to a process."

*Response:* We determined that vapor balancing is not appropriate or equivalent to the BSER identified for VOL storage vessels. As such, we are not including a definition of "vapor balancing system" in NSPS subpart Kc. We disagree with the commenter's request to define "fuel gas" because the "fuel gas system" definition is sufficient. We are finalizing definitions for "fuel gas system" and "routed to a process or route to a process" in NSPS subpart Kc.

*Comment:* One commenter recommended that the EPA define "degassing" with language consistent with the Texas Commission on Environmental Quality's (TCEQ) definition.

*Response:* The EPA agrees with the commenter to define "degassing"; however, the TCEQ definition is insufficient as there may be other reasons to empty and degas a storage vessel other than cleaning. While we agree that cleaning may be a step in the process, we expect degassing to occur for other reasons. We are finalizing a definition for "degassing" in NSPS subpart Kc to clarify this point.

### *G. Effective Date and Compliance Dates*

Pursuant to CAA section 111(b)(1)(B), the effective date of the final rule requirements in subpart Kc will be the promulgation date. Affected sources that commence construction, reconstruction, or modification after October 4, 2023, must comply with all requirements of subpart Kc no later than the effective date of the final rule or upon startup, whichever is later. The EPA is finalizing amendments to NSPS subpart Kb to include electronic submission requirements. Affected NSPS subpart Kb sources that commence construction, reconstruction, or modification after July 23, 1984, and before October 4, 2023, must comply with the updated requirements to submit reports electronically no later than the effective date of the final rule.

## V. Summary of Cost, Environmental, and Economic Impacts

### *A. What are the air quality impacts?*

The final provisions in NSPS subpart Kc reduce emissions of VOCs, some of which may also be hazardous air pollutants (HAPs). The EPA estimates that the final standards will reduce VOC emissions by 1,085 tons per year, which includes the impacts from new, modified, and reconstructed storage vessels. More information regarding the air quality impacts and emission reductions are included in the memorandum *Control Options for Storage Vessels* (Docket ID No. EPA–HQ–OAR–2023–0358–0002).

### *B. What are the cost impacts?*

This final action will cost (in 2022 dollars) approximately $21.1 million in total capital cost and result in a total annualized cost of $5.38 million per year (including product recovery) based on our analysis of the final actions in NSPS subpart Kc. More information about the estimated cost of the final actions can be found in the memorandum *Control Options for Storage Vessels* (Docket ID No. EPA–HQ–OAR–2023–0358–0002).

### *C. What are the economic impacts?*

For economic impact analyses (EIA) of rules that directly affect a single industry or a few industries, the EPA often prepares a partial equilibrium analysis. In this type of economic analysis, the focus of the effort is on estimating impacts on a single affected industry or several affected industries, and all impacts of this rule on industries outside of those affected are assumed to be zero or so inconsequential as to not be considered in the analysis. If the compliance costs, which are key inputs to an EIA, are quite insignificant, then the impact analysis could consist of a calculation of annual (or annualized) costs as a percentage of sales for affected companies. This latter type of analysis is called a screening analysis and is applied when a partial equilibrium or more complex EIA approach is deemed not necessary given the expected size of the impacts.

The net present value of the estimated cost impacts of NSPS subpart Kc is $19.4 million, discounted at a 3 percent rate over a 5-year analytic timeframe from 2024 to 2028 in 2022 dollars. Using a 7 percent discount rate, the net present value of the estimated cost impacts is $17.3 million. The equivalent annualized value in 2022 dollars is a

cost of approximately $4.1 million using a discount rate of either 3 or 7 percent.

Storage vessels in NSPS subpart Kb are most closely associated with the petroleum and coal products industry (NAICS 324000), the chemical products industry (NAICS 325000), and the petroleum bulk stations and terminals industry (NAICS 424710). While we do not know the precise distribution of new and modified storage vessels across the affected sectors, we know that there are affected storage vessels in the sectors mentioned earlier in this preamble. These sectors contribute gross value added, ranging from $200 to $501 billion per sector, to the national economy. In comparison, the requirements in NSPS subpart Kc have estimated total costs of $21 million. The total cost is the total incurred collectively amongst numerous sectors, and each of the sectors examined has sales of at least $200 billion. Thus, the compliance costs of this action are insignificant relative to the scale for the sectors affected, and it is appropriate to evaluate the economic impacts by conducting a screening analysis comparing the costs to entity-level sales.

Given the results of the analysis, these economic impacts are relatively low for affected industries and entities impacted by this final rule, and there will not be substantial impacts on the markets for affected products. The costs of the final rule are not expected to result in a significant market impact, regardless of whether they are passed on to the purchaser or absorbed by the firms. We also expect minimal impacts on employment.

*D. What are the benefits?*

The final provisions in NSPS subpart Kc would reduce emissions of VOCs, some of which may also be HAPs. Because VOCs react in the atmosphere to produce ozone, these standards would help to reduce atmospheric ozone concentrations and reduce health effects associated with high levels of ozone. Furthermore, the final requirements to submit reports and test results electronically would improve monitoring, compliance, and implementation of the rule.

*E. What analysis of environmental justice did we conduct?*

For purposes of analyzing regulatory impacts, under Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, the EPA relies upon its June 2016 "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis," which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts on communities with EJ concerns; (2) exacerbate existing disproportionate impacts on communities with EJ concerns; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development.

The EPA's EJ technical guidance states that "[t]he analysis of potential EJ concerns for regulatory actions should address three questions: (A) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline? (B) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration? (C) For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?" [9]

Because this action finalizes standards of performance for new, modified, and reconstructed sources that commence construction after October 4, 2023, the locations of the construction of new VOL storage vessels are not known. In addition, it is not known which of the existing facilities will be modified or reconstructed in the future. Therefore, we are unable to quantitatively estimate the potential environmental justice impact of NSPS subpart Kc. Over the next 5 years, the EPA estimates that 1,440 new tanks and 30 modified tanks would be subject to NSPS subpart Kc. We estimate that there are more than 10,000 existing VOL storage vessels, but we do not have a list of specific storage vessels and their locations. Therefore, we cannot perform a proximity demographic analysis of populations near existing units as a proxy for units that may be modified or reconstructed and become subject to NSPS subpart Kc. Finally, because we based the analysis of the impacts and emission reductions on model plants, we cannot ascertain specifically how the potential benefits of this rule would be distributed across the population. Thus, we are limited in our ability to estimate the potential EJ impacts of this rule.

The EPA expects that NSPS subpart Kc will ensure compliance via revised vapor pressure applicability thresholds, stricter seal requirements on IFR tanks, equivalent control requirements for EFRs, and strengthened closed vent system standards for vessels routed to a control device, fuel gas system, or process. This action finalizes standards of performance that apply at all times (including periods of SSM) and achieve an average 98 percent control efficiency. The rule will also increase data transparency through electronic reporting. Therefore, effects of emissions on populations in proximity to any future affected sources, including in communities potentially overburdened by pollution, which are often communities with EJ concerns, will be minimized due to the compliance with the standards of performance being finalized in this action.

## VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

*A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review*

This action is not a significant regulatory action as defined in Executive Order 12866, as amended by Executive Order 14094, and was therefore not subject to a requirement for Executive Order 12866 review.

*B. Paperwork Reduction Act (PRA)*

The information collection activities in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2791.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until the Office of Management and Budget (OMB) approves them.

The EPA is finalizing requirements for storage vessels, including periodic inspections based on the type of storage vessel. This information will be collected to assure compliance with NSPS subpart Kc.

[9] *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis*, U.S. EPA, June 2016. Quote is from Section 3—Key Analytic Considerations, page 11. *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

*Respondents/affected entities:* Owners or operators of VOL storage vessels.

*Respondent's obligation to respond:* Mandatory (40 CFR part 60, subpart Kc).

*Estimated number of respondents:* 588.

*Frequency of response:* Initially and semiannually.

*Total estimated burden:* 16,394 hours (per year). Burden is defined at 5 CFR 1320.3(b).

*Total estimated cost:* $2,009,357 (per year), includes $528,240 in annualized capital and no operation or maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

*C. Regulatory Flexibility Act (RFA)*

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses and small governmental jurisdictions that own or operate VOL storage vessels. The Agency has determined that small entities may experience an impact of likely below 1 percent relative to sales for any affected small entity, and an even larger margin before it would approach a 1 percent impact for a substantial number of small entities. Details of this analysis are presented in the memorandum *Economic Impact Analysis for the New Source Performance Standards (NSPS) for the Volatile Organic Liquid Storage Vessels (Tanks)* included in the docket.

*D. Unfunded Mandates Reform Act (UMRA)*

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any State, local, or Tribal governments or the private sector.

*E. Executive Order 13132: Federalism*

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

*F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments*

This action does have Tribal implications as specified in Executive Order 13175. NSPS subpart Kb includes provisions for storage vessels that already have impacts on Tribal governments that have storage vessels with at least 20,000 gallons of capacity and that meet the vapor pressure thresholds for general rule applicability or control applicability. NSPS subpart Kc includes updates to the VOC standards and monitoring requirements for storage vessels that meet the revised vapor pressure thresholds for control. Additionally, basic requirements for determining a VOL's MTVP, recordkeeping, and good air pollution control practices are being finalized for all storage vessels greater than 20,000 gallons that only store VOLs with an MTVP greater than or equal to 0.25 psia. These changes will only impact storage vessels that are constructed, modified, or reconstructed after the proposal date.

Consistent with the *EPA Policy on Consultation and Coordination with Indian Tribes,* the EPA offered government-to-government consultation with Tribes by sending a letter dated October 3, 2023, inviting all federally recognized Tribes to request a consultation. The EPA received one request for consultation. On November 8, 2023, the EPA met with the Tribe for the purposes of discussing NSPS subpart Kc and other issues but were unable to conduct consultation on this specific rulemaking.

*G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks*

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866 and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. The final rule will reduce emissions of VOCs, some of which may also be HAPs. These standards will help to reduce atmospheric ozone concentrations and reduce health effects associated with high levels of ozone and are projected to improve overall health, including that of children.

*H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use*

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

*I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51*

This action for NSPS subparts Kb and Kc involves technical standards. Therefore, the EPA conducted a search to identify potentially applicable voluntary consensus standards. However, the Agency identified no such standards. Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 18, 21, 22, and 25A of 40 CFR part 60, appendix A. The EPA has decided to use EPA Methods 21, 22, and 25A. Additional information for the voluntary consensus standard search and determinations can be found in the memorandum titled, *Voluntary Consensus Standard Results for Review of Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels).* All potential standards were reviewed to determine the practicality of the voluntary consensus standards for this rule. Although there were no applicable voluntary consensus standards identified, we are finalizing the proposal to amend 40 CFR 60.17 to incorporate by reference two ASTM methods as discussed in section III.M. of the proposal preamble (88 FR 68550; October 4, 2023). These include the following:

- ASTM D6377–20, *Standard Test Method for Determination of Vapor Pressure of Crude Oil: VPCR$_x$ (Expansion Method).* The method is an automated device method for measuring vapor pressures for crude oils samples between 29 kPa and 180 kPa at 37.8 °C. The method is suitable for testing with a 4:1 vapor-liquid ratio.
- ASTM D6378–22, *Standard Test Method for Determination of Vapor Pressure (VPX) of Petroleum Products, Hydrocarbons, and Hydrocarbon-Oxygenate Mixtures (Triple Expansion Method).* The method is an automated device method for measuring vapor pressures between 7 kPa and 150 kPa at 37.8 °C for tested samples with boiling points at 0 °C. The method is suitable for volatile organic liquids,

hydrocarbons and liquid petroleum products sampled at a 4:1 vapor-liquid ratio.

The ASTM standards are available from ASTM, International, 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959. See *https://www.astm.org.*

*J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All*

The EPA believes that it is not practicable to assess whether the human health or environmental conditions that exist prior to this action result in disproportionate and adverse effects on communities with EJ concerns. Over the next 5 years, the EPA estimates that 1,440 new tanks and 30 modified tanks will be subject to NSPS subpart Kc. However, the locations of any new VOL storage vessels that would be subject to NSPS subpart Kc are not known. Furthermore, there is insufficient data available regarding the locations of existing VOL storage vessels. The EPA estimates that there are more than 10,000 existing storage vessels subject to NSPS subpart Kb, but we do not have a list of specific storage vessels and their locations. Therefore, we cannot perform a proximity demographic analysis of populations near existing storage vessels as a proxy for storage vessels that may be modified or reconstructed and become subject to NSPS subpart Kc. Finally, because we based the analysis of the impacts and emission reductions on model plants, we cannot ascertain specifically how the potential benefits of this rule would be distributed across the population. Thus, we are limited in our ability to estimate the potential EJ impacts of this rule.

The information supporting this Executive Order review is contained in section V.E. of this document. All pertinent supporting documents such as the technical memorandum, *Control Options for Storage Vessels* (Docket ID No. EPA–HQ–OAR–2023–0358–0002), which discusses the costs and environmental impacts of the regulatory options considered, is in the docket.

*K. Congressional Review Act (CRA)*

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

**List of Subjects in 40 CFR Part 60**

Environmental protection, Administrative practice and procedures, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements.

**Michael S. Regan,**
*Administrator.*

For the reasons set forth in the preamble, the Environmental Protection Agency is amending part 60 of title 40, chapter I, of the Code of Federal Regulations as follows:

## PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

**Authority:** 42 U.S.C. 7401 *et seq.*

### Subpart A—General Provisions

■ 2. Amend § 60.17 by:
■ a. Redesignating paragraphs (h)(198) through (233) as (h)(200) through (235); and
■ b. Adding paragraphs (h)(198) and (199).

The additions read as follows:

**§ 60.17 Incorporations by reference.**

* * * * *

(h) * * *

(198) ASTM D6377–20, Standard Test Method for Determination of Vapor Pressure of Crude Oil: $VPCR_x$ (Expansion Method), (Approved June 1, 2020); IBR approved for § 60.113c.

(199) ASTM–D6378–22, Standard Test Method for Determination of Vapor Pressure (VPX) of Petroleum Products, Hydrocarbons, and Hydrocarbon-Oxygenate Mixtures (Triple Expansion Method), (Approved July 1, 2022); IBR approved for § 60.113c.

* * * * *

### Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, and On or Before October 4, 2023

■ 3. Revise the heading of subpart Kb to read as set out above.
■ 4. Amend § 60.110b by revising paragraph (a) to read as follows:

**§ 60.110b Applicability and designation of affected facility.**

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters ($m^3$) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984, and on or before October 4, 2023.

* * * * *

■ 5. Amend § 60.115b by:
■ a. Revising paragraphs (a), (b), and (d); and
■ b. Adding paragraphs (e), (f), and (g).

The revisions and additions read as follows:

**§ 60.115b Reporting and recordkeeping requirements.**

* * * * *

(a) After installing control equipment in accordance with § 60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(1) and § 60.113b(a)(1). Prior to October 15, 2024, this report shall be an attachment to the notification required by § 60.7(a)(3). Beginning October 15, 2024, the owner or operator must submit all subsequent reports in PDF format following the procedures specified in paragraph (e) of this section.

(2) Keep a record of each inspection performed as required by § 60.113b(a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in § 60.113b(a)(2) are detected during the annual visual inspection required by § 60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made. Beginning October 15, 2024, all subsequent reports must be submitted in PDF format following the procedures in paragraph (e) of this section.

(4) After each inspection required by § 60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in § 60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the

reason it did not meet the specifications of § 60.112b(a)(1) or § 60.113b(a)(3) and list each repair made. Beginning October 15, 2024, all subsequent reports must be submitted in PDF format following the procedures in paragraph (e) of this section.

(b) After installing control equipment in accordance with § 60.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(2) and § 60.113b(b)(2), (b)(3), and (b)(4). Prior to October 15, 2024, this report shall be an attachment to the notification required by § 60.7(a)(3). Beginning October 15, 2024, the owner or operator must submit all subsequent reports in PDF format following the procedures specified in paragraph (e) of this section.

(2) Within 60 days of performing the seal gap measurements required by § 60.113b(b)(1), furnish the Administrator with a report that contains the following information. Beginning October 15, 2024, all subsequent reports must be submitted in PDF format following the procedures in paragraph (e) of this section.

(i) The date of measurement;

(ii) The raw data obtained in the measurement; and

(iii) The calculations described in § 60.113b(b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by § 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement;

(ii) The raw data obtained in the measurement; and

(iii) The calculations described in § 60.113b(b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by § 60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair. Beginning October 15, 2024, all subsequent reports must be submitted in PDF format following the procedures in paragraph (e) of this section.

* * * * *

(d) After installing a closed vent system and flare to comply with § 60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by § 60.18(f)(1) through (6) shall be furnished to the Administrator as required by § 60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date. Beginning October 15, 2024, all subsequent reports must be submitted in PDF format following the procedures in paragraph (e) of this section.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under § 60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator. Beginning October 15, 2024, all subsequent reports must be submitted in PDF format following the procedures specified in paragraph (e) of this section.

(e) An owner or operator required to submit notifications or reports following the procedures specified in this paragraph (e) must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to the owner or operator. Do not use CEDRI to submit information the owner or operator claims as CBI. Although the EPA does not expect persons to assert a claim of CBI, if an owner or operator wishes to assert a CBI claim for some of the information in the report or notification, the owner or operator must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (e)(1) and (2) of this section. Clearly mark the part or all of the information claimed to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. The owner or operator must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (e).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings, and be flagged to the attention of the NSPS Kb Lead. Owners and operators who do not have their own file sharing service and who require assistance with submitting large electronic files that exceed the file size limit for email attachments should email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If an owner or operator cannot transmit the file electronically, the owner or operator may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer and NSPS Kb Lead, Mail Drop: C404–02, 109 T.W. Alexander, P.O. Box 12055, RTP, NC 27711. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(f) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX may assert a claim of EPA system outage for failure to timely comply with the electronic submittal requirement. To assert a claim of EPA system outage, owners and operators must meet the requirements outlined in paragraphs (f)(1) through (7) of this section.

(1) The owner or operator must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) The owner or operator must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(g) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX may assert a claim of force majeure for failure to timely comply with the electronic submittal requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (g)(1) through (5) of this section.

(1) An owner or operator may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents the owner or operator from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.*, hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.*, large scale power outage).

(2) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) The owner or operator must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

■ 6. Amend § 60.116b by revising paragraph (d) to read as follows:

**§ 60.116b Monitoring of operations.**

* * * * *

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 $m^3$ storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 $m^3$ but less than 151 $m^3$ storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range. Beginning October 15, 2024, all subsequent notifications must be submitted in PDF format following the procedures specified in § 60.115b(e).

* * * * *

■ 7. Amend § 60.117b by revising paragraph (b) to read as follows:

**§ 60.117b Delegation of authority.**

* * * * *

(b) Authorities which will not be delegated to States: §§ 60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii), and approval of an alternative to any electronic reporting to the EPA required by this subpart.

■ 8. Add subpart Kc consisting of §§ 60.110c through 60.117c to part 60 to read as follows:

## Subpart Kc—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After October 4, 2023

Sec.

60.110c Applicability and designation of affected facility.
60.111c Definitions.
60.112c Standard for volatile organic compounds (VOC).
60.113c Testing, monitoring, and inspection procedures.
60.114c Alternative means of emission limitation.
60.115c Recordkeeping requirements.
60.116c Reporting requirements.
60.117c Delegation of authority.

**§ 60.110c Applicability and designation of affected facility.**

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 20,000 gallons (gal) (75.7 cubic meters ($m^3$)) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after October 4, 2023.

(b) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants;

(2) Pressure vessels designed to operate in excess of 29.7 pounds per square inch absolute (psia) (204.9 kilopascals (kPa) absolute) and without emissions to the atmosphere;

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships;

(4) Vessels with a design capacity less than or equal to 420,000 gal (1,589.874 $m^3$) used for petroleum or condensate stored, processed, or treated prior to custody transfer;

(5) Vessels located at bulk gasoline plants as defined in 40 CFR 63.11100;

(6) Vessels located at gasoline service stations;

(7) Vessels used to store beverage alcohol; or

(8) Vessels that only store VOL with a maximum true vapor pressure less than 0.25 psia (1.7 kPa absolute).

(c) Storage vessels that are affected facilities according to paragraph (a) of this section for which construction or reconstruction commenced after October 4, 2023 are subject to the standards in § 60.112c and the corresponding requirements in §§ 60.113c through 60.116c as new sources any time they meet the specifications in either paragraph (c)(1) or (2) of this section, regardless of whether they initially contained VOL with a maximum true vapor pressure below the applicable threshold in paragraph (c)(1) or (2) of this section.

(1) Storage vessels with a capacity greater than or equal to 40,000 gal (151 $m^3$) containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 0.5 psia (3.4 kPa).

(2) Storage vessels with a capacity greater than or equal to 20,000 gal (75.7

$m^3$) but less than 40,000 gal (151 $m^3$) containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 1.5 psia (10.3 kPa).

(d) Storage vessels that are affected facilities according to paragraph (a) of this section for which construction or reconstruction commenced on or before October 4, 2023, ("existing storage vessels") and are modified after October 4, 2023, are subject to the standards in § 60.112c and the corresponding requirements in §§ 60.113c through 60.116c as modified sources any time they meet the specifications in either paragraph (d)(1) or (2) of this section.

(1) For an existing storage vessel with a capacity greater than or equal to 40,000 gal (151 $m^3$), containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 0.5 psia (3.4 kPa).

(2) For an existing storage vessel with a capacity greater than or equal to 20,000 gal (75.7 $m^3$) but less than 40,000 gal (151 $m^3$), containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 1.5 psia (10.3 kPa).

(e) For the purposes of this subpart,

(1) The phrase "change in the method of operation of, an existing facility which increases the amount of any air pollutant" in the definition of modification in § 60.2 or "operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies" in § 60.14(a) means a change in operation occurs if the storage vessel is used to store a VOL that has a greater maximum true vapor pressure than all VOL historically stored or permitted; and

(2) The exemption in § 60.14(e)(4) regarding alternative fuel or raw material does not apply to storage vessels.

(f) Storage vessels that are affected facilities according to paragraph (a) of this section and do not meet the criteria in either paragraph (c)(1), (c)(2), (d)(1), or (d)(2) of this section are subject to the requirements in § 60.113c(d), if applicable, and § 60.115c(b).

(g) All standards including emission limitations shall apply at all times, including periods of startup, shutdown and malfunction. As provided in § 60.11(f), this paragraph (g) supersedes the exemptions for periods of startup, shutdown, and malfunction in subpart A of this part.

(h) Owners or operators may choose to comply with the provisions of this subpart to demonstrate compliance with subparts K, Ka, and Kb of this part. Compliance with the provisions of this subpart, including all control requirements, recordkeeping, and reporting requirements, will constitute compliance with the applicable storage vessel provisions in subparts K, Ka, and Kb.

(i) Owners or operators may choose to comply with this subpart to demonstrate compliance with 40 CFR part 63, subpart WW for storage vessels equipped with an internal or external floating roof that is subject to this subpart and 40 CFR part 63, subpart WW. Compliance with this subpart, including all floating roof requirements, recordkeeping, and reporting requirements, will constitute compliance with the applicable storage vessel provisions in 40 CFR part 63, subpart WW.

### § 60.111c Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this section as follows:

*Access hatch* means an opening in the roof with a vertical well and a cover attached to it. Access hatch provides passage for workers and materials through the roof for construction or maintenance.

*Condensate* means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

*Closed vent system* means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission point to a control device. Closed vent system does not include the vapor collection system that is part of any tank truck or railcar.

*Custody transfer* means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

*Degassing* means the process of removing VOL vapors from a storage vessel during, or in preparation of, cleaning or when taking the storage vessel out of service for inspection, repair, or other reason.

*Enclosed combustion device* means a thermal combustion device used to mix and ignite fuel, air pollutants, and air to provide a flame to heat and oxidize air pollutants and that emits the oxidized pollutants through a conveyance suitable to conduct a performance test. An *enclosed combustion device* may have recovery heat to preheat combustion air, but its primary purpose is for emission control and not to produce useful heat. *Enclosed combustion devices* include, but are not limited to, thermal oxidizers and incinerators. For the purpose of this subpart, process heaters and boilers are not *enclosed combustion devices.*

*External floating roof* means a pontoon-type or double-deck type cover that rests on the liquid surface in a storage vessel without a fixed roof.

*Fill* means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

*Flare* means a thermal combustion device using an open or shrouded flame (without full enclosure) such that the pollutants are not emitted through a conveyance suitable to conduct a performance test.

*Fuel gas system* means the offsite and onsite piping and control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices, or in- process combustion equipment such as furnaces and gas turbines, either singly or in combination.

*Gasoline service station* means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage vessels.

*Gauge float* means a device that is used to indicate the level of liquid within the storage vessel. The float rests on the liquid surface and is housed inside a well that is closed by a removable cover.

*Gauge hatch/sample port/sample well* means an opening in the roof that provides access for gauging or sampling. A gauge hatch is usually equipped with a closing cover or a funnel and slit-fabric seal to cover the opening.

*Internal floating roof* means a floating roof located in a storage vessel with a fixed roof. For the purposes of this subpart, an external floating roof located in a storage vessel to which a fixed roof has been added is considered to be an internal floating roof.

*Liquid-mounted primary seal* means a liquid or foam-filled seal mounted in continuous contact with the liquid between the wall of the storage vessel and the floating roof around the entire circumference of the storage vessel.

*Maximum true vapor pressure* means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOLs stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOLs stored at the ambient

temperature, as determined using the procedures specified in § 60.113c(d).

*Mechanical shoe primary seal* means a metal sheet (the shoe) held vertically against the wall of the storage vessel by springs or weighted levels and is connected by braces to the floating roof. A flexible coated fabric (the envelope) spans the annular space between the metal sheet and the floating roof.

*Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

*Petroleum liquids* means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

*Pressure release* means the emission of materials resulting from the system pressure being greater than the set pressure of the pressure relief device or resulting from vacuum breaking device failing to close prior to the system reaching atmospheric pressure. This release can be one release or a series of releases over a short time period.

*Pressure relief device* means a valve, rupture disk, or similar device used only to release an unplanned, nonroutine discharge of gas from process equipment in order to avoid safety hazards or equipment damage. Devices with low opening pressures must be monitored as bypass lines. A pressure relief device discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause. Such devices include conventional, spring-actuated relief valves, balanced bellows relief valves, pilot-operated relief valves, rupture disks, and breaking, buckling, or shearing pin devices. Devices that are actuated only by a vacuum are not pressure relief devices. If a device has both a pressure relief function and a vacuum breaking function, such as a conservation vent, the portion of the conservation vent that acts to relieve pressure is considered a pressure relief device and the portion of the conservation vent that acts to relieve vacuum is a vacuum breaking device and not a pressure relief device.

*Process tank* means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

*Reid vapor pressure* means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases.

*Rim-mounted secondary seal* means a secondary seal mounted on the rim of the floating roof of a storage vessel and forms continuous seal from the rim of the floating roof to the wall of the storage vessel.

*Rim seal system* means a primary seal or a primary and secondary seal, which is mounted above the primary seal, and is attached to the deck perimeter and contacts the storage vessel wall.

*Rim vent* means a device consisting of a weighted pallet that rests on a valve seat. Rim vents are used to release any excess pressure or vacuum present in the vapor pocket between the seal and the rim area of a floating roof storage vessel.

*Routed to a process or route to a process* means the emissions are conveyed by hardpiping or a closed vent system to any enclosed portion of a process unit where the emissions are predominately recycled and/or consumed in the same manner as a material that fulfills the same function in the process; and/or transformed by chemical reaction into materials that are not volatile organic liquids; and/or incorporated into a product; and/or recovered.

*Storage vessel* means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;

(2) Subsurface caverns or porous rock reservoirs; or

(3) Process tanks.

*Vacuum breaker/automatic bleeder vent* means a device used to equalize the pressure of the vapor space across the deck of a floating roof as the floating roof is either being landed on or floated off its roof supports. A vacuum breaker/automatic bleeder vent consists of a well with a cover. The cover is designed to open as the floating roof is landed. Opening of the cover may be accomplished by mechanisms such as leg actuation or pressure actuation.

*Vacuum breaking device* means a device on a fixed roof of a storage vessel used to prevent mechanical failure of the storage vessel due to vacuum created as liquids are withdrawn from the storage vessel. If a device has both a pressure relief function and a vacuum breaking function, such as a conservation vent, the portion of the conservation vent that acts to relieve vacuum is considered a vacuum breaking device and the portion of the conservation vent that acts to relieve excess pressure is a pressure relief device and not a vacuum breaking device.

*Volatile organic liquid (VOL)* means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

*Waste* means any liquid resulting from industrial, commercial, mining, or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.

**§ 60.112c Standard for volatile organic compounds (VOC).**

(a) *General storage vessel control requirements.* You must equip and operate each storage vessel affected facility meeting the thresholds in § 60.110c(c)(1), (c)(2), (d)(1), or (d)(2) as specified in paragraphs (a)(1) through (4) of this section, as applicable.

(1) For each storage vessel affected facility containing a VOL that, as stored, has a maximum true vapor pressure less than 11.1 psia (76.6 kPa), you may elect to install and operate either an internal floating roof meeting the requirements in paragraph (b) of this section, an external floating roof meeting the requirements in paragraph (c) of this section, or a closed vent system routed to a control device, fuel gas system, or process as specified in paragraph (d) of this section.

(2) For each storage vessel affected facility containing a VOL that, as stored, has a maximum true vapor pressure of 11.1 psia (76.6 kPa) or more, you must install and operate a closed vent system routed to a control device, fuel gas system, or process as specified in paragraph (d) of this section.

(3) For each storage vessel affected facility complying with the closed vent system routed to a control device, fuel gas system, or process provisions specified in paragraph (d) of this section regardless of size and for each storage vessel with a design capacity greater than or equal to 1,000,000 gal (3,790 $m^3$) containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 1.5 psia (10.3 kPa), you must also comply with the requirements in paragraph (e) of this section.

(4) You must meet the applicable testing, monitoring, and inspection requirements specified in § 60.113c, recordkeeping requirements specified in § 60.115c, and reporting requirements specified in § 60.116c.

(b) *Requirements for an internal floating roof.* You must equip and operate each internal floating roof as specified in paragraphs (b)(1) through (16) of this section, as applicable.

(1) The internal floating roof must rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof must be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the roof supports, the process of filling, emptying, or refilling must be continuous and must be accomplished as rapidly as possible.

(2) Except as provided in paragraph (b)(14) of this section, each internal floating roof must be equipped with the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(i) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(ii) The primary seal must be either a mechanical shoe seal or a liquid-mounted seal. If a mechanical shoe seal is used, it must be installed so that one end of the shoe extends into the stored VOL and the other end extends a minimum vertical distance of 6 inches (15 centimeters) above the stored organic liquid surface.

(iii) The secondary seal must be rim-mounted.

(3) Each opening in a noncontact internal floating roof except for vacuum breaker/automatic bleeder vents and the rim vents is to provide a projection below the liquid surface.

(4) Vacuum breaker/automatic bleeder vents must be equipped with a gasket and are to be closed at all times, with no visible gaps, when the roof is floating. Vacuum breaker/automatic bleeder vents must be set to open only when the roof is being floated off or is being landed on the roof supports.

(5) Rim vents must be equipped with a gasket and must be closed at all times with no visible gaps when the roof is floating. Rim vents must be set to open only when the internal floating roof is not floating or when the pressure beneath the rim seal system exceeds the manufacturer's recommended setting.

(6) Each penetration of the internal floating roof for the purpose of sampling must be a gauge hatch/sample well. Except as specified in paragraph (b)(14) of this section, the gauge hatch/sample well must have a gasketed cover, which must be closed at all times, with no visible gaps, except when the hatch or well must be opened for access.

(7) Each access hatch and gauge float well must be equipped with a cover that is gasketed and that is bolted or otherwise mechanically secured. The cover must be closed and must be bolted or otherwise mechanically secured at all times, with no visible gaps, except when the hatch or well must be opened for access.

(8) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof must have a flexible fabric sleeve seal or a gasketed sliding cover.

(9) Each penetration of the internal floating roof that allows for passage of an unslotted leg ladder or unslotted ladder/guidepole combination must have a gasketed sliding cover. The cover must be closed at all times, with no visible gaps, except when the well must be opened for access.

(10) Each slotted guidepole must be equipped with one of the controls specified in paragraphs (b)(10)(i) through (v) of this section. The covers must be designed to be closed at all times, with no visible gaps, except when the cover must be opened for access.

(i) Gasketed sliding well cover, with pole sleeve. The sleeve must extend into the stored liquid.

(ii) Gasketed sliding well cover, with pole sleeve and pole wiper. The sleeve must extend into the stored liquid.

(iii) Gasketed sliding well cover, with pole float and pole wiper. The wiper or seal of the pole float must be at or above the height of the pole wiper.

(iv) Gasketed sliding well cover, with pole float, pole sleeve, and pole wiper. The sleeve must extend into the stored liquid. The wiper or seal of the pole float must be at or above the height of the pole wiper.

(v) A flexible device that completely encloses the slotted guidepole and eliminates the hydrocarbon vapor emissions pathway from inside the storage vessel through the guidepole slots to the outside air; a gasketed guidepole cover at the top of the guidepole; and a gasketed sliding well cover positioned at the top of the guidepole well that seals any openings between the well cover and the guidepole (*e.g.,* pole wiper), any openings between the well cover and any other objects that pass through the well cover, and any other openings in the top of the guidepole well.

(11) Ladder-slotted guidepole combination wells must be equipped with a gasketed sliding well cover and a ladder sleeve. The sliding well cover must be designed to be closed at all times with no visible gaps, except when gauging or sampling.

(12) Unslotted guidepoles must be equipped with one of the controls specified in paragraph (b)(12)(i) or (ii) of this section. The controls must be designed to be closed at all times with no visible gaps.

(i) A gasketed guidepole cover at the top of the guidepole; a gasketed sliding well cover; and a pole sleeve. The guidepole cover must be closed at all times, except when required to be opened for access. The gasketed sliding well cover must seal any openings between the well cover and the guidepole, any openings between the well cover and any other objects that pass through the well cover, and any other openings in the top of the guidepole well.

(ii) A gasketed guidepole cover at the top of the guidepole; a gasketed sliding well cover; and a pole wiper. The guidepole cover must be closed at all times, except when required to be opened for access. The gasketed sliding well cover must seal any openings between the well cover and the guidepole (*e.g.,* pole wiper), any openings between the well cover and any other objects that pass through the well cover, and any other openings in the top of the guidepole well.

(13) Except for leg sleeves and stub drains, each opening in the internal floating roof not specified in paragraphs (b)(4) through (12) of this section, must be equipped with a cover or lid which is to be maintained in a closed position at all times (*i.e.,* no visible gap) except when the device must be opened for access. The cover or lid must be equipped with a gasket.

(14) For each modified storage vessel as specified in § 60.110c(d) with an existing internal floating roof, you may elect to comply with the rim seal system requirements in § 60.112b(a)(1)(ii) or § 60.110b(e) instead of the requirements in paragraph (b)(2) of this section, and you may elect to comply with the gauge hatch/sample well requirements in § 60.112b(a)(1)(vii) or § 60.110b(e) instead of the requirements in paragraph (b)(6) of this section.

(15) A system equivalent to those described in paragraphs (b)(1) though (14) of this section, as applicable, as provided in § 60.114c.

(16) Equip, maintain, and operate each internal floating roof control system to maintain the vapor concentration above the floating roof at or below 25 percent of the lower explosive limit (LEL) on a 5-minute

rolling average basis without the use of purge gas. This standard may require additional controls, such as improved seam seals, beyond those specified in paragraphs (b)(1) through (15) of this section. Compliance with this paragraph (b)(16) must be determined using the methods in § 60.113c(a)(3). Exceeding the LEL is considered an inspection failure under § 60.113c(a)(2)(i) and must be remedied as such. Any repairs made must be confirmed effective through re-monitoring of the LEL and meeting the limits in this paragraph (b)(16) within the timeframes specified in § 60.113c(a)(2)(i).

(c) *Requirements for an external floating roof.* You must equip and operate each external floating roof as specified in paragraphs (c)(1) through (4) of this section.

(1) The roof must be floating on the liquid at all times (*i.e.,* off the roof supports) except during initial fill until the roof is lifted off roof supports and when the storage vessel is completely emptied or subsequently emptied and refilled. The process of filling, emptying, or refilling when the roof is resting on the roof supports must be continuous and must be accomplished as rapidly as possible.

(2) Each external floating roof must be equipped with a primary and secondary rim seal system as specified in paragraph (b)(2) of this section, except that if a mechanical shoe primary seal is used, it must be installed so that one end of the shoe extends into the stored VOL and the other end extends a minimum vertical distance of 24 inches (61 centimeters) above the stored organic liquid surface. The external floating roof also must have welded deck seams, and it must have deck fitting controls as specified in paragraphs (c)(2)(i) through (ix) of this section, as applicable. References to an internal floating roof in paragraph (b)(2) of this section means an external floating roof for the purposes of this paragraph (c)(2).

(i) Each opening in an external floating roof except for vacuum breaker/automatic bleeder vents and the rim vents is to provide a projection below the liquid surface.

(ii) Vacuum breaker/automatic bleeder vents must be equipped with a gasket and are to be closed at all times, with no visible gaps, when the roof is floating. Vacuum breaker/automatic bleeder vents must be set to open only when the roof is being floated off or is being landed on the roof supports.

(iii) Rim vents must be equipped with a gasket and must be closed at all times with no visible gaps when the roof is floating. Rim vents must be set to open only when the external floating roof is not floating or when the pressure beneath the rim seal system exceeds the manufacturer's recommended setting.

(iv) Each penetration of the external floating roof for the purpose of sampling must be a gauge hatch/sample well. The gauge hatch/sample well must have a gasketed cover, which must be closed at all times, with no visible gaps, except when the hatch or well must be opened for access.

(v) Each access hatch and gauge float well must be equipped with a cover that is gasketed and that is bolted or otherwise mechanically secured. The cover must be closed and must be bolted or otherwise mechanically secured at all times, with no visible gaps, except when the hatch or well must be opened for access.

(vi) Except as specified in paragraph (c)(3) of this section, if the external floating roof does not have a liquid-mounted primary seal, all guidepoles must be unslotted and must be equipped as specified in paragraph (b)(12) of this section.

(vii) Except as specified in paragraph (c)(3) of this section, if the external floating roof has a liquid-mounted primary seal, equip each guidepole as specified in paragraphs (c)(2)(vii)(A) and (B) of this section.

(A) Each slotted guidepole must be equipped as specified in paragraphs (b)(10)(ii) or (iv) of this section.

(B) Each unslotted guidepole must be equipped as specified in paragraph (b)(12) of this section.

(viii) Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(ix) Except for leg sleeves, each opening in the external floating roof not subject to controls specified in paragraphs (c)(2)(i) through (viii) of this section must be equipped with a cover or lid which is to be maintained in a closed position at all times (*i.e.,* no visible gap), except when the device must be opened for access. The cover or lid must be equipped with a gasket.

(3) For each modified storage vessel as specified in § 60.110c(d) with an existing external floating roof, you may elect to comply with any of the guidepole controls specified in paragraphs (b)(10) and (12) of this section regardless of the type of primary seal used.

(4) A system equivalent to those described in paragraphs (c)(1) through (3) of this section as provided in § 60.114c.

(d) *Requirements for closed vent system routed to a control device, fuel gas system, or process.* You must design, install, and operate each affected storage vessel with a closed vent system that routes to a control device, fuel gas system, or process as specified in paragraphs (d)(1) through (7) of this section.

(1) The storage vessel must be designed and operated to be routed through a closed vent system to a control device, fuel gas system, or process at all times the storage vessel contains VOL without venting to the atmosphere through either meeting the storage vessel design requirements specified in paragraph (d)(1)(i) of this section or the vapor recovery system design requirements specified in paragraph (d)(1)(ii) of this section. Compliance with this requirement must be demonstrated according to paragraph (d)(1)(iii) of this section. Any vacuum breaking device on the storage vessel must close while the storage vessel is still under vacuum of at least −0.1 inches of water (−0.0036 psig or −0.025 kPa gauge).

(i) The storage vessel must be designed to operate at a gauge pressure of no less than 1 psi greater than the maximum true vapor pressure of the stored liquid and any back pressure anticipated when the storage vessel is filled at its maximum rate without venting to the atmosphere.

(ii) The vapor recovery system must be designed and operated to maintain the pressure in each storage vessel routed to a control device below the venting pressure of that storage vessel.

(iii) You must equip each pressure relief device and vacuum breaking device on a storage vessel with a device(s) or use a monitoring system that is capable of meeting the requirements in paragraphs (d)(1)(iii)(A) through (C) of this section. If all emissions from a pressure relief device are routed through a closed vent system to a control device, process, or fuel gas system, then you are not required to comply with the requirements of this paragraph (d)(1)(iii).

(A) Identifying the pressure release.

(B) Recording the time and duration of each pressure release.

(C) Notifying operators immediately that a pressure release is occurring. The device or monitoring system must be either specific to the pressure relief device or vacuum breaking device itself or must be associated with each storage vessel to indicate a pressure release to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the pressure relief valve stem, flow monitor, or pressure monitor.

(2) Except for closed vent systems operated and maintained under negative pressure, each closed vent system must meet the requirements specified in paragraphs (d)(2)(i) through (iii) of this section.

(i) The closed vent system must be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 parts per million by volume (ppmv) above background, as determined using Method 21 of appendix A–7 to this part as specified in § 60.113c(c)(2) and (3), and as determined by observations for visible, audible, and olfactory indications of leaks. Visible, audible, and olfactory inspections must be performed quarterly and Method 21 of appendix A–7 instrument monitoring must be conducted at least annually.

(ii) Except for pressure relief devices and except for open-ended valves or lines that use a cap, blind flange, plug, or second valve and follow the requirements specified in § 60.482–6(a)(2), (b), and (c) or follow requirements codified in another regulation that are the same as § 60.482–6(a)(2), (b), and (c), you must comply with the provisions of either paragraph (d)(2)(ii)(A) or (B) of this section for each closed vent system that contains bypass lines that could divert a vent stream to the atmosphere.

(A) Properly install, maintain, and operate a flow indicator that is capable of taking readings every 15 minutes. Install the flow indicator at the entrance to any bypass line.

(B) Secure the bypass line valve in the non-diverting position with a car-seal or a lock-and-key type configuration.

(iii) You must equip each pressure relief device on a closed vent system with a device(s) or use a monitoring system that is capable of meeting the requirements in paragraphs (d)(2)(iii)(A) through (C) of this section. If all releases and potential leaks from a pressure relief device are routed through a closed vent system to a control device, process, or fuel gas system, then you are not required to comply with the requirements of this paragraph (d)(2)(iii).

(A) Identifying the pressure release.

(B) Recording the time and duration of each pressure release.

(C) Notifying operators immediately that a pressure release is occurring. The device or monitoring system must be either specific to the pressure relief device itself or must be associated with the process system or piping, sufficient to indicate a pressure release to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the pressure relief valve stem, flow monitor, or pressure monitor.

(3) If you route emissions from a storage vessel to a control device, the control device must be designed and operated to reduce inlet VOC emissions by 98 percent or greater. If a flare is used as the control device or if an enclosed combustion device is used for which you elect to comply with the flare operating limits, you must meet the specifications described in paragraph (d)(5) of this section. The control device must be operated at all times when emissions from an affected storage vessel are routed to it except as provided in paragraph (d)(7) of this section.

(4) A system equivalent to those described in paragraphs (d)(1) through (3) of this section as provided in § 60.114c.

(5) If you route from a storage vessel to a flare or enclosed combustion device for with you elect to comply with these flare operating limits, you must meet all applicable requirements specified in 40 CFR 63.670(b) through (g) and (i) through (n) except as provided in paragraphs (d)(5)(i) through (v) of this section.

(i) For the purpose of this subpart,

(A) The term "regulated materials" refers to "vapors from a storage vessel affected facility";

(B) The term "pilot flame" means "pilot flame or flare flame";

(C) The terms "petroleum refinery" and "refinery" mean "storage vessel affected facility".

(ii) For visible emissions, use the following text instead of 40 CFR 63.670(c): The owner or operator shall operate with no visible emissions, except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours, when regulated material is routed to the flare. You must monitor for visible emissions from the flare as specified in § 60.113c(c)(1)(iv)(A).

(iii) The phrase "and the flare vent gas flow rate is less than the smokeless design capacity of the flare" in 40 CFR 63.670(d) for flare tip velocity requirements does not apply.

(6) If you route emissions from a storage vessel to a fuel gas system or process, you must meet the requirements in paragraphs (d)(6)(i) through (iv) of this section, as applicable.

(i) The fuel gas system or process must be operating at all times when emissions from an affected storage vessel are routed to it.

(ii) If all emissions are routed to a process, the VOL in the emissions must meet one or more of the conditions specified in paragraphs (d)(6)(ii)(A) through (D) of this section and you must comply with the compliance demonstration requirements in paragraph (d)(6)(iii) of this section.

(A) Recycled and/or consumed in the same manner as a material that fulfills the same function in that process.

(B) Transformed by chemical reaction into materials that are not regulated materials.

(C) Incorporated into a product.

(D) Recovered.

(iii) To demonstrate compliance with paragraph (d)(6)(ii) of this section for an affected storage vessel, you must prepare a design evaluation (or engineering assessment) that demonstrates the extent to which one or more of the conditions specified in paragraphs (d)(6)(ii)(A) through (D) of this section are being met.

(iv) If emissions from an affected storage vessel are routed to a fuel gas system, you must submit the statement of connection for fuel gas systems specified in § 60.116c(a)(7).

(7) To the extent practical, routine maintenance on the control device should be conducted when the storage vessel(s) is(are) out of VOL service. If you comply with all the provisions in paragraphs (d)(7)(i) through (iv) of this section, you may conduct routine maintenance on a control device while one or more storage vessels vented to the control device are storing a VOL.

(i) The storage vessel(s) storing VOL must be designed to operate above the maximum true vapor pressure of the stored VOL according to paragraph (d)(1)(i) of this section.

(ii) The control device must be isolated from the storage vessel(s) using valves(s), blind flange(s), or similar device(s) at the control device or in the closed vent system as near as practical to the control device. You may purge the control device and downstream portion of the closed vent system to remove potentially explosive vapors and create a safe work environment only after the control device is isolated from the storage vessel(s).

(iii) You must continue to comply with the bypass and pressure relief device monitoring requirements in paragraphs (d)(1)(iii), (d)(2)(ii), and (d)(2)(iii) of this section and their associated recordkeeping and reporting requirements. If there are multiple storage vessels connected to the closed vent system with significantly different pressure design limits, you must isolate individual storage vessels to prevent venting during planned maintenance.

Compliance with this paragraph (d)(7)(iii) may limit VOL addition to the storage vessel. If VOL is added to the storage vessel, there must be an approximately equivalent withdrawal of VOL such that the liquid level does not rise sufficiently to increase the pressure in the storage vessel to cause a pressure release from the storage vessel or the closed vent system.

(iv) During this routine maintenance period the affected storage vessels cannot be actively degassed. If the storage vessel is to be emptied and actively degassed, the planned maintenance activity must be conducted when the storage vessel is out of VOL service.

(e) *Requirements for storage vessel degassing.* For each storage vessel meeting the specifications in paragraph (a)(3) of this section, you must meet the requirements in paragraphs (e)(1) through (3) of this section during emptying and degassing of a storage vessel until the vapor space concentration in the storage vessel is less than 10 percent of the LEL or, for nonflammable liquids, 5,000 ppmv as methane. You must determine the LEL or methane concentration using process instrumentation or a portable measurement device and follow procedures for calibration and maintenance according to manufacturer's specifications. You must check instrument calibration and check the instrumental offset response each day the instrument is used and prior to discontinuing controlled degassing to confirm the accuracy of the instrument's readings.

(1) Remove liquids from the storage vessel as much as practicable. Chemicals or a diluent such as a distillate fuel may be introduced into the storage vessel for the purpose of reducing vapor concentration before or during active degassing.

(2) Comply with one of the following:

(i) Reduce total VOC emissions by venting emissions through a closed vent system to a flare or enclosed combustion device for which you elect to comply with the flare provisions and meet the requirements specified in paragraph (d)(5) of this section.

(ii) Reduce total VOC emissions by 98 weight percent by venting emissions through a closed vent system to any combination of non-flare control devices.

(iii) Reduce total VOC emissions by routing emissions to a fuel gas system or process and meet the requirements specified in paragraph (d)(6) of this section.

(3) For floating roof storage vessels, the storage vessel may be opened to set up equipment (*e.g.,* making connections to a temporary control device) for the shutdown operations but must not be actively degassed during this time period.

**§ 60.113c Testing, monitoring, and inspection procedures.**

For each storage vessel subject to the provision in § 60.112c(a), you must meet the requirements of paragraph (a) of this section if you installed an internal floating roof, paragraph (b) of this section if you installed an external floating roof, or paragraph (c) of this section if you route emissions through a closed vent system to a control device, fuel gas system, or process. You must also meet the applicable requirements of paragraph (d) of this section.

(a) *Requirements for an internal floating roof.* After installing the control equipment for an internal floating roof to meet the provisions in § 60.112c(b), you must meet the requirements specified in paragraphs (a)(1) through (5) of this section.

(1) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), and deck fittings prior to filling the storage vessel with VOL. Any of the conditions described in paragraphs (a)(1)(i) through (iii) of this section constitutes inspection failure. You must repair the items before filling the storage vessel.

(i) Holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric;

(ii) Defects in the internal floating roof; or

(iii) A rim seal or deck fitting control not meeting the applicable requirements in § 60.112c(b)(2) through (13).

(2) Inspect the internal floating roof as specified in paragraph (a)(2)(i) of this section at least once every 12 calendar months after initial fill, and inspect the internal floating roof as specified in paragraph (a)(2)(ii) of this section each time the storage vessel is emptied and degassed, or at a frequency no greater than every 120 calendar months, whichever occurs first.

(i) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is service), and deck fittings, through openings in the fixed roof and conduct LEL monitoring. Any of the conditions described in paragraphs (a)(2)(i)(A) through (F) of this section constitutes inspection failure. Identification of holes or tears in the rim seal is required only for the seal that is visible from the top of the storage vessel. You must repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph (a)(2)(i) cannot be repaired within 45 days and if the storage vessel cannot be emptied within 45 days, you may request a 30-day extension from the Administrator. Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the storage vessel will be emptied as soon as possible.

(A) Stored liquid on the floating roof;

(B) The internal floating roof is not resting on the surface of the VOL inside the storage vessel;

(C) Holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric;

(D) Defects in the internal floating roof;

(E) A rim seal or deck fitting control not meeting the applicable requirements in § 60.112c(b)(2) through (13); or

(F) The concentration measured according to paragraph (a)(3) of this section exceeds 25 percent of the LEL.

(ii) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes, and sleeve seals (if any). Any of the conditions described in paragraphs (a)(2)(ii)(A) through (C) of this section constitutes an inspection failure. You must repair the items as necessary so that none of the conditions specified in this paragraph (a)(2)(ii) exist before refilling the storage vessel with VOL. The inspection may be performed entirely from the top side of the floating roof, as long as there is visual access to all deck fittings and rim seal system specified in § 60.112c(b). You must repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph (a)(2)(ii) cannot be repaired within 45 days and if the storage vessel cannot be emptied within 45 days, you may request a 30-day extension from the Administrator. Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the storage vessel will be emptied as soon as possible.

(A) Defects in the internal floating roof;

(B) Holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric; or

(C) A rim seal or deck fitting control not meeting the applicable requirements in § 60.112c(b)(2) through (13).

(3) Compliance with the LEL limit for internal floating roof storage vessels at

§ 60.112c(b)(16) must be determined based on the procedures specified in paragraphs (a)(3)(i) through (v) of this section. If tubing is necessary to obtain the measurements, the tubing must be non-crimping and made of Teflon or other inert material.

(i) You must conduct LEL monitoring as part of the annual inspection specified in paragraph (a)(2)(i) of this section and at other times upon request by the Administrator. If the measurement cannot be performed during the visual inspection due to wind speeds exceeding those specified in paragraph (a)(3)(iii)(C) of this section, the measurement must be performed within 30 days of the visual inspection. If there is an exceedance of the LEL limit, you must re-monitor in accordance with § 60.112c(b)(16) within 30 days after repair or placing the storage vessel back in service.

(ii) The calibration of the LEL meter must be checked per manufacturer specifications immediately before and after the measurements as specified in paragraphs (a)(3)(ii)(A) and (B) of this section. If tubing will be used for the measurements, the tubing must be attached during calibration so that the calibration gas travels through the entire measurement system.

(A) Conduct the span check using a calibration gas recommended by the LEL meter manufacturer. The calibration gas must contain a single hydrocarbon at a concentration of the vapor corresponding to 50 percent of the LEL (*e.g.,* 2.50 percent by volume when using methane as the calibration gas). The vendor must provide a Certificate of Analysis for the gas, and the certified concentration must be within ±2 percent (*e.g.,* 2.45 percent–2.55 percent by volume when using methane as the calibration gas). The LEL span response must be between 49 percent and 51 percent. If the span check prior to the measurements does not meet this requirement, the LEL meter must be recalibrated or replaced. If the span check after the measurements does not meet this requirement, the LEL meter must be recalibrated or replaced, and the measurements must be repeated.

(B) Check the instrumental offset response using a certified compressed gas cylinder of zero air or an ambient environment that is free of organic compounds. The pre-measurement instrumental offset response must be 0 percent LEL. If the LEL meter does not meet this requirement, the LEL meter must be recalibrated or replaced.

(iii) Conduct the monitoring measurements as specified in paragraphs (a)(3)(iii)(A) through (D) of this section.

(A) Measurements of the vapors within the internal floating roof storage vessel must be collected no more than 3 feet above the internal floating roof.

(B) Measurements must be taken for a minimum of 20 minutes, logging the measurements at least once every 15 seconds, or until one 5-minute average as determined according to paragraph (a)(3)(v)(B) of this section exceeds the limit specified in § 60.112c(b)(16).

(C) Measurements shall be taken when the wind speed at the top of the storage vessel is 5 mph or less to the extent practicable, but in no case shall measurements be taken when the sustained wind speed at top of storage vessel is greater than the annual average wind speed at the site or 15 mph, whichever is less.

(D) Measurements should be conducted when the internal floating roof is floating with limited product movement (limited filling or emptying of the storage vessel).

(iv) To determine the actual concentration of the vapor within the storage vessel, the percent of the LEL "as the calibration gas" must be corrected according to one of the procedures in paragraph (a)(3)(iv)(A) or (B) of this section. Alternatively, if the LEL meter used has correction factors that can be selected from the meter's program, you may enable this feature to automatically apply one of the correction factors in paragraph (a)(3)(iv)(A) or (B) of this section.

(A) Multiply the measurement by the published vapor correction factor for the specific LEL meter, stored VOL, and calibration gas used; or

(B) If there is no published correction factor for the specific LEL meter used and the vapors of the stored VOL, multiply the measurement by the published correction factor for butane as a surrogate for determining the LEL of the vapors of the stored VOL. The correction factor must correspond to the calibration gas used.

(v) Use the calculation procedures in paragraphs (a)(3)(v)(A) through (C) of this section to determine compliance with the LEL limit.

(A) For each minute while measurements are being taken, determine the 1-minute average reading as the arithmetic average of the corrected individual measurements (taken at least once every 15 seconds) during the minute.

(B) Starting with the end of the fifth minute of data, calculate a 5-minute rolling average as the arithmetic average of the previous five 1-minute readings determined under paragraph (a)(3)(v)(A) of this section. Determine a new 5-minute average reading for every subsequent 1-minute reading.

(C) Each 5-minute rolling average must meet the LEL limit specified in § 60.112c(b)(16).

(4) Notify the Administrator as specified in § 60.116c(b) at least 30 days prior to the inspection of each storage vessel for which an inspection is required by paragraph (a)(1) or (a)(2)(ii) of this section to afford the Administrator the opportunity to have an observer present.

(5) You must equip each affected storage vessel that has an internal floating roof with an alarm system that provides a visual or audible signal that alerts the operator when the internal floating roof is approaching the landed height and that provides a separate visual or audible signal to alert the operator when the roof has landed. The roof is considered landed when the floating roof first rests on supports or when the vacuum breaker/automatic bleeder vent begins to open, whichever is first (for example, when using a leg-actuated vent that triggers the vent prior to resting on the roof supports).

(b) *Requirements for an external floating roof.* After installing the control equipment for an external floating roof to meet the provisions in § 60.112c(c), you must inspect the external floating roof according to the specifications in paragraphs (b)(1) through (8) of this section.

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the frequency provided in paragraphs (b)(1)(i) and (ii) of this section. You must visually inspect all roof fittings to ensure that covers are closed and gasketed with no visible gaps and that there are no tears in sleeves, wipers, or similar controls used for a given fitting during each measurement of gaps as required under this paragraph (b)(1).

(i) Measurements of gaps between the storage vessel wall and the primary seal (seal gaps) must be performed during the hydrostatic testing of the storage vessel or within 60 days of the initial fill with VOL and at least once every 60 calendar months thereafter.

(ii) Measurements of gaps between the storage vessel wall and the secondary seal must be performed within 60 days of the initial fill with VOL and at least once every 12 calendar months thereafter.

(iii) If any source ceases to store VOL for a period of 12 calendar months or more, subsequent introduction of VOL into the storage vessel must be

considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof supports.

(ii) Measure seal gaps around the entire circumference of the storage vessel in each place where a 0.125-inch (0.32-centimeter (cm)) diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section must be determined by using probes of various widths to measure accurately the actual distance from the storage vessel wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the storage vessel and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Except as provided in paragraph (b)(5) of this section, make necessary repairs or empty the storage vessel within 45 days of identification in any inspection failure as specified in paragraphs (b)(4)(i) through (iii) of this section.

(i) For primary seals, any deviation of the requirements in paragraphs (b)(4)(i)(A) through (D) of this section is an inspection failure.

(A) The accumulated area of gaps between the storage vessel wall and the mechanical shoe or liquid-mounted primary seal must not exceed 10 square inches ($in^2$) per foot of storage vessel diameter (212 square centimeters ($cm^2$) per meter of storage vessel diameter).

(B) The maximum width of any portion of any gap must not exceed 1.5 inches (3.81 cm).

(C) If a mechanical shoe seal is used, one end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 2 feet (61 cm) above the stored liquid surface.

(D) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) For secondary seals, any deviation of the requirements in paragraphs (b)(4)(ii)(A) through (D) of this section is an inspection failure.

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the storage vessel wall except for allowed gaps as provided in paragraphs (b)(4)(ii)(B) and (C) of this section.

(B) The accumulated area of gaps between the storage vessel wall and the secondary seal must not exceed 1 $in^2$ per foot (21.2 $cm^2$ per meter) of storage vessel diameter.

(C) The maximum width of any portion of any gap must not exceed 0.5 inches (1.27 cm).

(D) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) For roof fittings (*e.g.,* vacuum breaker/automatic bleeder vents and rim vents, gauge hatch/sample wells, access hatches, guidepoles, ladders, and emergency roof drains), any deviation of the requirements in paragraphs (b)(4)(iii)(A) through (D) of this section is an inspection failure.

(A) Each opening in an external floating roof except for vacuum breaker/automatic bleeder vents and the rim vents provides a projection below the liquid surface.

(B) Vacuum breaker/automatic bleeder vents and rim vents are equipped with a gasket and are closed with no visible gaps when the roof is floating.

(C) The gauge hatch/sample well, access hatch, and gauge float must have a gasketed cover and closed with no visible gaps.

(D) There are to be no tears or visible defects of sleeves, wipers, or fabric covers used to control emissions from a roof fitting.

(5) If a failure that is detected as specified in paragraph (b)(4) of this section cannot be repaired within 45 days and if the storage vessel cannot be emptied within 45 days, you may request a 30-day extension from the Administrator. Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the storage vessel will be emptied as soon as possible.

(6) Notify the Administrator, as specified in § 60.116c(b)(2), 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(7) Visually inspect the external floating roof, primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, the secondary seal has holes, tears, or other openings in the seal or the seal fabric, covers have visible openings or missing or torn gaskets, or there are tears or other visible defects in flexible covers, sleeves, wipers, or other fitting controls, you must repair the items as necessary so that none of the conditions specified in this paragraph (b)(7)(i) exist before filling or refilling the storage vessel with VOL.

(ii) For each inspection required by paragraph (b)(7) of this section, notify the Administrator as specified in § 60.116c(b)(1) at least 30 days prior to the inspection of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel.

(8) You must equip each affected storage vessel that has an external floating roof with an alarm system that provides a visual or audible signal that alerts the operator when the external floating roof is approaching the landed height and that provides a separate visual or audible signal to alert the operator when the roof has landed. The roof is considered landed when the floating roof first rests on supports or when the vacuum breaker/automatic bleeder vent begins to open, whichever is first (for example, when using a leg-actuated vent that triggers the vent prior to resting on the roof supports).

(c) *Requirements for closed vent systems routed to a control device, fuel gas system, or process.* For each source that is equipped with a closed vent system and routes to a control device, fuel gas system, or process to meet the requirements in § 60.112c(d), you must conduct performance testing and monitoring of the control device as specified in paragraph (c)(1) of this section, conduct monitoring and inspections of the closed vent system as specified in paragraph (c)(2) of this section, repair leaks as specified in paragraph (c)(3) of this section, and develop a monitoring plan as specified in paragraph (c)(4) of this section.

(1) For each control device used to meet the requirements in § 60.112c(d), you must comply with the requirements in paragraphs (c)(1)(i) through (iv) of this section, as applicable.

(i) For each enclosed combustion device or flare, you must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an

engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(ii) For each control device other than a flare, except as specified in paragraph (c)(1)(iii) of this section, you must conduct a performance test as specified in paragraphs (c)(1)(ii)(A) through (E) of this section not later than 180 days after becoming subject to § 60.112c(d). You must conduct subsequent performance tests within 60 calendar months after each previous performance test. Submit the results of all performance tests following the procedures in § 60.116c(e).

(A) Each performance test must demonstrate that the control device achieves greater than or equal to the required control device performance level specified in § 60.112c(d)(3). Performance tests must be conducted under such conditions as the Administrator specifies based on representative performance of the affected source for the period being tested. You may not conduct performance tests during periods of malfunction. You must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such conditions represent the entire range of normal operation, including operational conditions for maximum emissions if such emissions are not expected during maximum production. You must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(B) You must conduct a minimum of three test runs. Each test run must be at least 1 hour long.

(C) The following methods in appendix A to this part, except as provided in § 60.8(b), must be used as reference methods to determine compliance with the percent reduction requirement.

(*1*) Method 1 or 1A of appendix A–1 to this part, as appropriate, for selection of the sampling sites. Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device to determine compliance with a control device percent reduction requirement.

(*2*) Method 2, 2A, 2C, or 2D of appendix A–1 to this part, as appropriate to determine the gas volumetric flow rate.

(*3*) Method 25A of appendix A–7 to this part. Use propane as the calibration gas. You must use Method 4 of appendix A–3 to this part to convert the Method 25A of appendix A–7 results to a dry basis.

(D) You must use the procedures in paragraphs (c)(1)(ii)(D)(*1*) and (*2*) of this section to calculate percent reduction efficiency.

(*1*) You must compute the mass rate of TOC using the following equations:

$E_i = K_2 C_i M_p Q_i$

$E_o = K_2 C_o M_p Q_o$

Equations 1 and 2 to Paragraph (c)(1)(ii)(D)(*1*)

Where:

$E_i$, $E_o$ = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

$K_2$ = Constant, $2.494 \times 10^{-6}$ (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees Celsius.

$C_i$, $C_o$ = Concentration of TOC, as propane, of the gas stream as measured by Method 25A of appendix A–7 to this part at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

$M_p$ = Molecular weight of propane, 44.1 gram/gram-mole.

$Q_i$, $Q_o$ = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(*2*) You must calculate the percent reduction in TOC as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} \times 100\%$$

Equation 3 to Paragraph (c)(1)(ii)(D)(*2*)

Where:

$R_{cd}$ = Control efficiency of control device, percent.

$E_i$ = Mass rate of TOC at the inlet to the control device as calculated under paragraph (c)(1)(ii)(D)(*1*) of this section, kilograms per hour.

$E_o$ = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (c)(1)(ii)(D)(*1*) of this section, kilograms per hour.

(E) Except as provided in paragraph (c)(1)(ii)(E)(*5*) of this section, you must establish the applicable operating parameter limit as specified in paragraphs (c)(1)(ii)(E)(*1*) through (*3*) of this section by calculating the value(s) as the arithmetic average of operating parameter measurements recorded during the three test runs conducted for the most recent performance test (the average of the test run averages). You may operate outside of the established operating parameter limit(s) during subsequent performance tests in order to establish new operating limits. You must include the updated operating limits with the performance test results submitted to the Administrator pursuant to § 60.116c(e). Upon establishment of a new operating limit, you must thereafter operate under the new operating limit. You must demonstrate compliance with your operating parameter according to paragraph (c)(1)(ii)(E)(*4*) of this section.

(*1*) If you use an enclosed combustion device, a boiler, or a process heater other than those specified in paragraph (c)(1)(iii) of this section to control emissions, you must set a minimum firebox temperature limit during the performance test. You must continuously monitor the firebox temperature with a temperature monitoring device installed in the firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs and equipped with a continuous recorder that records a reading at least once every 15 minutes. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in degrees Celsius, or ±2.5 degrees Celsius, whichever value is greater.

(*2*) If you use a catalytic incinerator other than those specified in paragraph (c)(1)(iii) of this section to control emissions, you must set a minimum temperature limit on the temperature at the inlet of the catalyst bed and a minimum temperature limit on the temperature difference between the catalyst bed outlet and inlet. You must continuously monitor the temperatures with a temperature monitoring device equipped with a continuous recorder that records a reading at least once every 15 minutes. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in degrees Celsius, or ±2.5 degrees Celsius, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet. You must install the temperature sensor at a location representative of the firebox temperature.

(*3*) If you use a control device other than a flare or other than a device listed in paragraphs (c)(1)(ii)(E)(*1*), (c)(1)(ii)(E)(*2*), (c)(1)(ii)(E)(*5*), or (c)(1)(iii) to control emissions, you must submit the operating parameters you plan to monitor in the performance test

notice you provide to the Administrator pursuant to § 60.8(d).

(*4*) Using the continuous monitoring system (CMS) data, you must calculate the hourly average of each operating parameter. You must demonstrate compliance by maintaining the operating parameter at or above the minimum operating parameter limit on a 3-hour rolling average basis. For each hour, calculate the hourly value of the operating parameter from your CMS. Average the three most recent hours of data to determine the 3-hour average. Determine the 3-hour rolling average by recalculating the 3-hour average each hour. You must not include periods of data collected during monitoring system breakdowns, repairs, maintenance periods, instrument adjustments, or checks to maintain precision and accuracy in the operating parameter averages.

(*5*) For enclosed combustion devices for which you elect to comply with the flare requirements in § 60.112c(d)(5), you must comply with the monitoring provisions in paragraph (c)(1)(iv) of this section instead of paragraphs (c)(1)(ii)(E)(*1*) through (*4*) of this section.

(iii) No performance test is required for the control devices identified in paragraphs (c)(1)(iii)(A) through (C) of this section.

(A) A boiler or process heater with a design heat input capacity of 44 megawatts (150 million British thermal units per hour) or greater.

(B) A boiler or process heater into which the vent stream is introduced with the primary fuel.

(C) A boiler, process heater, or incinerator burning hazardous waste, which is regulated under 40 CFR part 63, subpart EEE; part 264; part 265; or part 266.

(iv) For each source that is equipped with a closed vent system and a flare to meet the requirements in § 60.112c(d) or enclosed combustion device electing to comply with the requirements in § 60.112c(d)(5), you must conduct visible emission observations as specified in paragraph (c)(1)(iv)(A) of this section and install, operate, and maintain CMS for flares following the requirements specified in 40 CFR 63.671 and as specified in paragraphs (c)(1)(iv)(B) and (C) of this section.

(A) If visible emissions are observed for more than 1 continuous minute during normal duties, visible emissions observation using Method 22 of appendix A–7 to this part must be conducted for 2 hours or until 5-minutes of visible emissions are observed.

(B) Substitute "pilot flame or flare flame" for each occurrence of "pilot flame."

(C) As an alternative to determining the flare tip velocity rate for each 15-minute block to determine compliance with the flare tip velocity operating limit as specified in 40 CFR 63.670(k)(2), you may elect to conduct a one-time flare tip velocity operating limit compliance assessment as provided in paragraphs (c)(1)(iv)(C)(*1*) through (*4*) of this section. If the flare or storage vessel control configurations change (*e.g.*, flare tip modified or additional storage vessel or other sources are added for which vapors are directed to the flare), you must repeat this one-time assessment based on the new configuration.

(*1*) Determine the unobstructed cross-sectional area of the flare tip, in units of square feet, as specified in 40 CFR 63.670(k)(1).

(*2*) Determine the maximum flow rate, in units of cubic feet per second, based on the maximum cumulative loading rate for a 15-minute block period considering maximum filling rates for all storage vessel affected facilities controlled by the flare and, if applicable, considering the maximum release pressure of any other vapors directed to the flare.

(*3*) Calculate the maximum flare tip velocity as the maximum flow rate from paragraph (c)(1)(iv)(C)(*2*) of this section divided by the unobstructed cross-sectional area of the flare tip from paragraph (c)(1)(iv)(C)(*1*) of this section.

(*4*) Demonstrate that the maximum flare tip velocity as calculated in paragraph (c)(1)(iv)(C)(*3*) of this section is less than 60 feet per second.

(2) For each closed vent system, you must conduct the instrument monitoring in paragraphs (c)(2)(i) through (iii) of this section. You must conduct the initial instrument monitoring within 180 days of an affected facility being connected to the closed vent system. Subsequent instrument inspections must be conducted within 365 days of the previous inspection. Visual, audible, and olfactory inspections must be conducted quarterly.

(i) Conduct instrument monitoring using the procedures in Method 21 of appendix A–7 to this part. The detection instrument must meet the performance criteria of Method 21 of appendix A–7, except that the instrument response factor criteria in section 8.1.1 of Method 21 of appendix A–7 must be for the average composition of the fluid and not for each individual organic compound in the stream. For streams that contain nitrogen, air, water, or other inerts that are not organic VOC, the representative stream response factor must be determined on an inert-free basis. The instrument reading that defines a leak is 500 ppmv (as methane). The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A–7. The calibration gases in paragraphs (c)(2)(i)(A) and (B) of this section must be used. The drift assessment specified in paragraph (c)(2)(i)(C) of this section must be performed at the end of each monitoring day.

(A) Zero air (less than 10 ppm of hydrocarbon in air).

(B) A mixture of methane in air at a concentration of approximately 500 ppmv.

(C) At the end of each monitoring day, check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 to this part, section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage. If a calibration drift assessment shows a negative drift of more than 10 percent, then re-monitor all equipment monitored since the last calibration with instrument readings between the leak definition and the leak definition multiplied by (100 minus the percent of negative drift) divided by 100. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the leak definition and below the leak definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

(ii) Any parts of the closed vent system that are designated as unsafe to inspect are exempt from the inspection requirements of paragraph (c)(2)(i) of this section if the conditions of paragraphs (c)(2)(ii)(A) and (B) of this section are met.

(A) The owner or operator determines that the equipment is unsafe-to-inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraph (c)(2)(i) of this section; and

(B) The owner or operator has a written plan that requires inspection of

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the equipment as frequently as practical during safe-to-inspect times. Inspection is not required more than once annually.

(iii) Any parts of the closed vent system that are designated as difficult-to-inspect are exempt from the inspection requirements of paragraph (c)(2)(i) of this section if the provisions of paragraphs (c)(2)(iii)(A) and (B) of this section apply.

(A) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters (7 feet) above a support surface; and

(B) The owner or operator has a written plan that requires inspection of the equipment at least once every 60 calendar months.

(3) Leaks, as indicated by an instrument reading greater than 500 ppmv or emissions detected by visible, audible, and olfactory methods, shall be repaired as soon as practical following the requirements outlined in paragraphs (c)(3)(i) and (ii) of this section.

(i) Except as allowed by paragraph (c)(3)(ii) of this section, a first attempt at repair shall be made no later than 5 days after the leak is detected. Repairs shall be completed no later than 15 days after the leak is detected or at the beginning of the next introduction of vapors to the system, whichever is later.

(ii) Delay of repair of a closed vent system for which leaks have been detected is allowed if repair within 15 days after a leak is detected is technically infeasible or unsafe or if the owner or operator determines that emissions resulting from immediate repair would be greater than the emissions likely to result from delay of repair. Repair of such equipment shall be completed as soon as practical.

(4) You must develop a monitoring plan that covers each CMS used to demonstrate continuous compliance for your control device as outlined in paragraphs (c)(4)(i) and (ii) of this section. You must install, calibrate, operate, and maintain each CMS in accordance with the procedures in your monitoring plan.

(i) For each control device other than those specified in paragraph (c)(4)(ii) of this section, your monitoring plan must contain the information required in paragraphs (c)(4)(i)(A) through (G) of this section.

(A) The parameter to be monitored and the operating limit for the parameter.

(B) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements.

(C) Description of the monitoring system specifications, including the detector signal analyzer, data acquisition, and calculations.

(D) Equipment performance checks, system accuracy audits, or other audit procedures, including the information in paragraphs (c)(4)(i)(D)(*1*) through (*4*) of this section.

(*1*) You must conduct the CMS equipment performance checks, system accuracy audits, or other audit procedures specified in the monitoring plan at least once every 12 calendar months.

(*2*) You must also conduct calibration checks following any period of more than 24 hours throughout which the sensor exceeded the manufacturer's specified maximum range unless you install a new sensor.

(*3*) At least quarterly, you must inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless you use a redundant CMS.

(*4*) Daily checks for indications that the system is responding.

(E) Description of how periods of data collected during CMS breakdowns, out-of-control periods, repairs, maintenance periods, instrument adjustments, or checks to maintain precision and accuracy, calibration checks, and zero (low-level), mid-level (if applicable), and high-level adjustments will be excluded from operating parameter averages.

(F) Ongoing operation and maintenance procedures.

(G) Ongoing recordkeeping procedures.

(ii) For each flare or enclosed combustion device for with you elect to comply with the flare provisions in § 60.112c(d)(5), your monitoring plan must contain the information required by 40 CFR 63.671(b).

(d) *Requirements for determining maximum true vapor pressure.* For each affected storage vessel, you must determine the maximum true vapor pressure of the stored VOL according to the requirements specified in paragraphs (d)(1) and (2) of this section. For storage vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For storage vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(1) Prior to the initial filling of the storage vessel or to the refilling of the storage vessel with a new VOL, the highest maximum true vapor pressure for the range of anticipated liquids to be stored, including mixtures for which you can define the range of concentrations for constituents in the mixture or with a known maximum Reid vapor pressure, must be determined using any one of the methods described in paragraphs (d)(1)(i) through (iv) of this section.

(i) As obtained from standard reference texts.

(ii) ASTM D6377–20 (incorporated by reference; see § 60.17). Perform the method using a vapor-to-liquid ratio of 4:1, which is expressed in the method as VPCR.

(iii) ASTM D6378–22 (incorporated by reference; see § 60.17). Perform the method using a vapor-to-liquid ratio of 4:1.

(iv) As measured by an appropriate method as approved by the Administrator.

(2) For each affected storage vessel storing a mixture of indeterminate composition or a mixture of unknown variable composition, the initial determination of the vapor pressure required by paragraph (d)(1) of this section must be a physical test using one of the methods specified in paragraphs (d)(1)(ii) through (iv) of this section. Additional physical tests using one of the methods specified in paragraphs (d)(1)(ii) through (iv) of this section are required at least once every 6 calendar months thereafter as long as the measured vapor pressure remains below the applicable thresholds in § 60.110c(c)(1), (c)(2), (d)(1), or (d)(2). If the vapor pressure measured under this paragraph (d)(2) exceeds the threshold defined in § 60.110c(c)(1), (c)(2), (d)(1), or (d)(2) you must meet the requirements in § 60.112c and the corresponding requirements in §§ 60.113c through 60.116c. If the storage vessel does not have controls meeting the requirements in § 60.112c, the storage vessel must be emptied and taken out of service until controls meeting the requirements in § 60.112c can be installed. Upon compliance with the provisions in § 60.112c, no additional vapor pressure monitoring is required.

### § 60.114c Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by the applicable requirement in § 60.112c, the Administrator will publish in the **Federal Register** a

document permitting the use of the alternative means for purposes of compliance with that requirement.

(b) Any document under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section must submit to the Administrator a written application including either:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure; or

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emission reduction as specified in § 60.112c.

**§ 60.115c Recordkeeping requirements.**

(a) Except as otherwise specified in paragraphs (b) through (d) of this section, you must keep copies of all records required by this section and all reports required under § 60.116c for at least 5 years.

(b) For each storage vessel affected facility as specified in § 60.110c(a), you must keep readily accessible records for the life of the source showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (c)(1) and (2) of this section, for each storage vessel affected facility under this subpart, you must maintain a record of the VOL currently stored, including a description of the VOL stored, the date when the VOL was first stored in the storage vessel, and the maximum true vapor pressure of that VOL.

(1) For each vessel storing a mixture of indeterminate or variable composition that meets the requirements for vapor pressure measurement at least once every 6 calendar months in § 60.113c(d), you must maintain records of each vapor pressure measurement for 5 years.

(2) Each vessel equipped with a closed vent system routed to a control device, fuel gas system, or process meeting the specification of § 60.112c(d) is exempt from the requirements of paragraph (c) of this section.

(d) For each storage vessel as specified in § 60.112c(a), you must keep records as required in paragraphs (d)(1) through (5) of this section, as applicable depending upon the control equipment installed to meet the requirements of § 60.112c.

(1) After installing control equipment for an internal floating roof to meet the provisions in § 60.112c(b), you must keep the following records.

(i) Keep a record of each inspection performed as required by § 60.113c(a)(1), (a)(2)(i), and (a)(2)(ii). Each record must identify the storage vessel on which the inspection was performed and must contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(ii) For each LEL monitoring event, keep records as specified in paragraphs (a)(1)(ii)(A) through (I) of this section.

(A) Date and time of the LEL monitoring, and the storage vessel being monitored.

(B) A description of the monitoring event (annual monitoring conducted concurrent with visual inspection required under § 60.113c(a)(2)(i); re-monitoring due to high winds during annual monitoring; re-monitoring after repair attempt; other monitoring event as required by the Administrator).

(C) Wind speed at the top of the storage vessel on the date of LEL monitoring.

(D) The LEL meter manufacturer and model number used, as well as an indication of whether tubing was used during the LEL monitoring, and if so, the type and length of tubing used.

(E) Calibration checks conducted before and after making the measurements, including both the span check and instrumental offset. This includes the hydrocarbon used as the calibration gas, the Certificate of Analysis for the calibration gas(es), the results of the calibration check, and any corrective action for calibration checks that do not meet the required response.

(F) Location of the measurements and the location of the floating roof.

(G) Each measurement (taken at least once every 15 seconds). The records should indicate whether the recorded values were automatically corrected using the meter's programming. If the values were not automatically corrected, record both the raw (as the calibration gas) and corrected measurements, as well as the correction factor used.

(H) Each of the 5-minute rolling average readings.

(I) If the vapor concentration of the storage vessel was above 25 percent of the LEL on a 5-minute rolling average basis, a description of whether the floating roof was repaired, replaced, or taken out of service.

(2) After installing control equipment for an external floating roof to meet the provisions in § 60.112c(c), you must keep a record of each inspection and gap measurement performed as required by § 60.113c(b). The record must contain:

(i) Identification of the storage vessel on which the inspection was performed;

(ii) The date the storage vessel was inspected;

(iii) The type of inspection [inspection with gap measurements as specified in § 60.113c(b)(1) through (4); visual inspection as specified in § 60.113c(b)(7)];

(iv) The observed condition of each component of the control equipment (seals, internal floating roof, and fittings); and

(v) For each inspection with gap measurements as specified in § 60.113c(b)(1) through (4):

(A) The raw data obtained in the measurement; and

(B) The calculations described in § 60.113c(b)(2) and (b)(3).

(3) After installing a closed vent system routed to a control device, fuel gas system, or process to comply with the provisions in § 60.112c(d), you must keep the following records, as well as the records in paragraph (d)(4) or (5) of this section, as applicable.

(i) The make and model of the backpressure regulator valve, date of installation, and inlet flow rating. Maintain records of the engineering evaluation and manufacturer specifications that identify the pressure set point corresponding to the minimum inlet gas flow rate, the annual confirmation that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications, and the annual confirmation that the backpressure regulator valve fully closes when not in open position.

(ii) The CMS monitoring plan required by § 60.113c(c)(4), if the closed vent system is routed to a control device. Retain this plan for the life of the control equipment.

(iii) Monitoring for the closed vent system conducted under § 60.113c(c)(2), including the date of inspection.

(iv) The written plan(s) required under § 60.113c(c)(2)(ii) and (iii) for unsafe-to-inspect and difficult-to-inspect portions of the closed vent system.

(v) For each leak detected during the monitoring conducted under § 60.113c(c)(2) and (3), you must record: the date the leak was detected; the location of the leak; the method used to detect the leak (Method 21 of appendix

A–7 to this part or visible, audible, and olfactory methods); and the maximum concentration reading obtained by Method 21 of appendix A–7, if applicable. For each repair attempt, you must record: the date of each repair attempt; the actions taken to repair the leak during each repair attempt; and date the repair was completed. If the repair is delayed, you must record the reason for the delay and the date you expect to complete the repair.

(vi) For each bypass line, maintain a record of the following, as applicable: readings from the flow indicator; each inspection of the seal or closure mechanism; the date and time of each instance when the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out.

(vii) For each pressure relief device or vacuum breaking device on a storage vessel or closed vent system required to be monitored according to § 60.112c(d)(1)(iii) or (d)(2)(iii): the device type; the monitoring device or system used for the device; data from the device or system indicating whether a pressure release occurred; and the date, time, and duration of each pressure release, if applicable.

(4) After installing a closed vent system routed to a control device other than a flare or enclosed combustion device electing to comply with § 60.112c(d), you must keep the following records.

(i) Each performance test.

(ii) All CMS performance checks, audits, maintenance, and repairs.

(iii) The hourly values recorded by the CMS and all 3-hour rolling averages.

(iv) The periods when the CMS is not operational.

(5) After installing a closed vent system routed to a flare to comply with § 60.112c(d) or an enclosed combustion device for which you elected to comply with § 60.112c(d)(5), you must keep the following records.

(i) Pilot flame or flare flame monitoring as specified in paragraphs (d)(5)(i)(A) and (B) of this section.

(A) The output of the monitoring device used to detect the presence of a pilot flame as required in 40 CFR 63.670(b). Retain these records for a minimum of 2 years.

(B) Each 15-minute block during which there was at least 1 minute that no pilot flame was present when VOL vapors were routed to the flare. Each record must identify the start and end time and date of each 15-minute block.

(ii) Visible emissions observations as specified in paragraphs (d)(5)(ii)(A) through (B) of this section, as applicable.

(A) If visible emissions observations are performed using Method 22 of appendix A–7 to this part, the record must identify the date, the start and end time of the visible emissions observation, and the number of minutes for which visible emissions were observed during the observation. If the owner or operator performs visible emissions observations more than one time during a day, include separate records for each visible emissions observation performed.

(B) For each 2-hour period for which visible emissions are observed for more than 5 minutes in 2 consecutive hours but visible emissions observations according to Method 22 of appendix A–7 to this part were not conducted for the full 2-hour period, the record must include the date, the start and end time of the visible emissions observation, and an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible based on best information available to the owner or operator.

(iii) Each 15-minute block period during which operating values are outside of the applicable operating limits specified in 40 CFR 63.670(d) through (f) when vapors from a storage vessel affected facility are directed to the flare for at least 15-minutes identifying each specific operating limit that was not met.

(iv) The 15-minute block average cumulative flows for the enclosed combustion device vent gas or flare vent gas and, if applicable, total steam, perimeter assist air, and premix assist air specified to be monitored under 40 CFR 63.670(i), along with the date and start and end time for the 15-minute block. If multiple monitoring locations are used to determine cumulative vent gas flow, total steam, perimeter assist air, and premix assist air, retain records of the 15-minute block average flows for each monitoring location for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If pressure and temperature monitoring is used, retain records of the 15-minute block average temperature, pressure and molecular weight of the flare vent gas, enclosed combustion device vent gas, or assist gas stream for each measurement location used to determine the 15-minute block average cumulative flows for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years.

(v) The flare vent gas or enclosed combustion device vent gas compositions specified to be monitored under 40 CFR 63.670(j). Retain records of individual component concentrations from each compositional analyses for a minimum of 2 years. If an $NHV_{vg}$ analyzer is used, retain records of the 15-minute block average values for a minimum of 5 years, as well as records of quality assurance activities conducted on the analyzer and any cylinder gas certificates. If you demonstrate your gas streams have consistent composition using the provisions in 40 CFR 63.670(j)(6), retain records of the current application for which you are using for as long as you use the fixed $NHV_{vg}$ as determined using the provisions in 40 CFR 63.670(j)(6).

(vi) Each 15-minute block average operating parameter calculated following the methods specified in 40 CFR 63.670(k) through (n), as applicable.

(vii) All periods during which you did not perform monitoring according to the procedures in 40 CFR 63.670(g), (i), and (j) as applicable. Note the start date, start time, and duration in minutes for each period.

(viii) If you conduct a one-time flare tip velocity operating limit compliance assessment according to § 60.113c(c)(1)(iv)(C), a copy of the assessment, including all calculations for as long as you use this compliance method.

(ix) For each parameter monitored using a CMS, retain the records specified in paragraphs (d)(5)(ix)(A) through (C) of this section, as applicable:

(A) For each deviation, record the start date and time, duration, cause, and corrective action taken.

(B) For each period when there is a CMS outage or the CMS is out of control, record the start date and time, duration, cause, and corrective action taken.

(C) Each inspection or calibration of the CMS including a unique identifier, make, and model number of the CMS, and date of calibration check.

(x) For an enclosed combustion device for which you elected to comply with § 60.112c(d)(5), you must also keep a copy of each performance test.

(e) If you are required to meet the degassing requirements in § 60.112c(a)(3), you must maintain records necessary to demonstrate compliance with the requirements in § 60.112c(e) including, if appropriate, records of existing standard site procedures used to empty and degas (deinventory) equipment for safety purposes.

**§ 60.116c Reporting requirements.**

(a) *Initial notification requirements.* You must submit initial notifications to the Administrator within 60 days after October 15, 2024 or within 60 days after becoming an affected storage vessel, whichever is later. Once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, you must submit all subsequent initial notifications using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (f) of this section. The date report templates become available will be listed on the CEDRI website. For each storage vessel affected facility subject to the standards in § 60.112c, include the following information in the initial notification:

(1) The following general facility information:

(i) Facility name;

(ii) Facility physical address, including city, county, State, and zip code;

(iii) Latitude and longitude of facility's physical location. Coordinates must be in decimal degrees with at least five decimal places; and

(iv) The following information for the facility contact person:

(A) Name;

(B) Mailing address, including city, county, State, and zip code;

(C) Telephone number; and

(D) Email address.

(2) Identification of the storage vessel(s) subject to this subpart.

(3) Capacity (in gallons) of each storage vessel.

(4) Maximum true vapor pressure of the liquid stored (in psia) in each storage vessel.

(5) Indication of the standards for which the storage vessel complies [§§ 60.112c(b); 60.112c(c); 60.112c(d); 60.112c(e)].

(6) If you route emissions to a control device, specify the design of the storage vessel and closed vent system (*i.e.,* storage vessel designed according to § 60.112c(d)(1)(i); or closed vent system designed according to § 60.112c(d)(1)(ii)), the type of control device (*i.e.,* enclosed combustion device complying with temperature operating limit; enclosed combustion device electing to comply with § 60.112c(d)(5); process heater or boiler; catalytic incinerator; flare, or other control device (specify)).

(7) If you route emissions to a process, submit the information specified in § 60.112c(d)(6)(ii) and (iii).

(8) If you route emissions to a fuel gas system, as specified in § 60.112c(d)(6)(iv), submit a statement that the emission stream is connected to the fuel gas system.

(b) *Other notifications.* Submit notifications for filling and refilling an affected storage vessel and for conducting gap measurements as specified in paragraphs (b)(1) and (2) of this section.

(1) As specified in § 60.113c(a)(4) and (b)(7)(ii), you must notify the Administrator at least 30 days prior to inspection of each storage vessel for which an inspection is required by § 60.113c(a)(1), (a)(2)(ii) or (b)(7) to afford the Administrator the opportunity to have an observer present. Submit the notification using CEDRI as specified in paragraph (f) of this section. If the inspection required by § 60.113c(a)(2)(ii) or (b)(7) is not planned and you could not have known about the inspection 30 days in advance of refilling the storage vessel, you must notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation using CEDRI demonstrating why the inspection was unplanned.

(2) As specified in § 60.113c(b)(6), you must notify the Administrator 30 days in advance of any gap measurements required by § 60.113c(b)(1) to afford the Administrator the opportunity to have an observer present. Submit the notification using CEDRI as specified in paragraph (f) of this section. If the inspection required by § 60.113c(b)(1) is not planned and you could not have known about the inspection 30 days in advance of the gap measurement, you must notify the Administrator at least 7 days prior to the conducting the gap measurement. Notification must be made by telephone immediately followed by written documentation using CEDRI demonstrating why the gap measurement was unplanned.

(c) *Reporting requirements for semiannual report.* You must submit to the Administrator semiannual reports with the applicable information in paragraphs (c)(1) through (12) of this section by the dates specified in paragraph (d) of this section. For this subpart, the semiannual reports supersede the excess emissions and monitoring systems performance report and/or summary report form required under § 60.7. Once the report template for this subpart has been available on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, you must submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (f) of this section. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(1) Report the following general facility information:

(i) Facility name;

(ii) Facility physical address, including city, county, and State;

(iii) Latitude and longitude of facility's physical location. Coordinates must be in decimal degrees with at least five decimal places;

(iv) The following information for the facility contact person:

(A) Name;

(B) Mailing address;

(C) Telephone number; and

(D) Email address.

(v) Date of report and beginning and ending dates of the reporting period. You are no longer required to provide the date of report when the report is submitted via CEDRI; and

(vi) Statement by a responsible official, with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (c)(1)(vi).

(2) For storage vessels complying with the provisions of § 60.112c(b) or (c):

(i) Identification of the storage vessel and an indication of whether you comply with § 60.112c(b) or (c).

(ii) An indication whether the storage vessel was inspected during the reporting period, and if so, the date and type of each inspection conducted during the reporting period [the type of inspection shall be selected from the following list: initial IFR inspection according to § 60.113c(a)(1), IFR visual inspection from fixed roof according to § 60.113c(a)(2)(i), combined IFR visual inspection with LEL monitoring according to § 60.113c(a)(2)(i) and (3), internal IFR inspection according to § 60.113c(a)(2)(ii), IFR LEL monitoring according to § 60.113c(a)(3), EFR gap measurements according to § 60.113c(b)(1) through (4), or visual EFR inspection according to § 60.113c(b)(7)].

(iii) For storage vessels complying with the provisions of § 60.112c(b) that were not inspected according to

§ 60.113c(a)(2)(ii) during the reporting period, report the last date the storage vessel was inspected according to the provisions in § 60.113c(a)(2)(ii).

(3) For each failure of a visual inspection required under § 60.113c(a)(2)(i), report the information in paragraphs (c)(3)(i) through (iii) of this section. For each failure of LEL monitoring required under § 60.113c(a)(3), report the information in paragraphs (c)(3)(i) through (iv) of this section.

(i) Identification of the storage vessel;

(ii) The date of the inspection;

(iii) The nature of the defects; and

(iv) The following information regarding the LEL monitoring conducted:

(A) Date and start and end times of the LEL monitoring conducted.

(B) Wind speed in miles per hour at the top of the storage vessel on the date of LEL monitoring.

(C) The highest 5-minute rolling average reading during the monitoring event.

(D) If re-monitoring was required due to excessive wind or repair during the visual inspection, report the information in paragraphs (b)(3)(iv)(A) through (C) of this section for the re-monitoring event.

(E) Whether the floating roof was repaired, replaced, or taken out of VOL service. If the storage vessel was taken out of VOL service, report the date the storage vessel was emptied. If the floating roof was replaced or repaired, report the nature of and date the repair was made and the information in paragraphs (b)(3)(iv)(A) through (C) of this section for each re-monitoring conducted to confirm the repair.

(4) For each inspection required by § 60.113c(a)(2)(ii) that finds holes or tears in the seal or seal fabric, defects in the internal floating roof, or other control equipment defects listed in § 60.113c(a)(2)(ii), report:

(i) Identification of the storage vessel and date of inspection;

(ii) The reason it did not meet the specifications of § 60.112c(b) or § 60.113c(a)(2)(ii);

(iii) A description of each repair made; and

(iv) Date of repair.

(5) For each inspection required under § 60.113c(b)(1), report the following information:

(i) Identification of the storage vessel and the date of the inspection;

(ii) The accumulated area of gaps between the storage vessel wall and the primary seal (in square inches per foot of storage vessel diameter);

(iii) The maximum width of any portion of any gap in the primary seal (in inches);

(iv) The accumulated area of gaps between the storage vessel wall and the secondary seal (in square inches per foot of storage vessel diameter);

(v) The maximum width of any portion of any gap in the secondary seal (in inches); and

(vi) An indication whether there was an inspection failure. If there was an inspection failure, also include the following information in the report:

(A) An indication of the type of deviation(s) [indicating all that apply from: §§ 60.113c(b)(4)(i)(A), 60.113c(b)(4)(i)(B), 60.113c(b)(4)(i)(C), 60.113c(b)(4)(i)(D), 60.113c(b)(4)(ii)(A), 60.113c(b)(4)(ii)(B), 60.113c(b)(4)(ii)(C), 60.113c(b)(4)(ii)(D), 60.113c(b)(4)(iii)(A), 60.113c(b)(4)(iii)(B), 60.113c(b)(4)(iii)(C), 60.113c(b)(4)(iii)(D)]; and

(B) The date the storage vessel was emptied or the repairs made and date of repair.

(6) For each inspection required by § 60.113c(b)(7) that finds defects as listed in § 60.113c(b)(7)(i), report:

(i) Identification of the storage vessel and date of inspection;

(ii) The reason it did not meet the specifications of § 60.112c(c) or § 60.113c(b)(7);

(iii) A description of each repair made; and

(iv) Date of repair.

(7) For each landing of an internal floating roof or an external floating roof that triggers an alarm required by § 60.113c(a)(5) or (b)(8), report:

(i) Identification of the storage vessel;

(ii) Date the roof was landed; and

(iii) Indication of whether the roof landed because the storage vessel was being emptied.

(8) After installing a closed vent system that routes to a control device, fuel gas system, or process to comply with § 60.112c, report the following, as well as the information in paragraphs (c)(9) or (10) of this section, as applicable:

(i) Results of annual inspections that indicate a backpressure regulator valve is not set correctly or does not fully close when not in the open position. Include the date and time of the inspection, the type of deviation, the corrective action taken, and the date and time when the backpressure regulator valve is set correctly, repaired, or replaced.

(ii) For each inspection conducted under § 60.113c(c)(2), identification of the closed vent system, the date of inspection, the type of inspection (Method 21 of appendix A–7 to this part or visible, audible, and olfactory methods) and summary result of the inspection (no leaks detected or leaks were detected). For each leak detected, provide an identification of the part of the closed vent system associated with the leak, the date of the first attempt at repair, and the date of successful repair or anticipated repair if the repair is delayed.

(iii) The start date and time, duration in hours, and an estimate of the mass quantity in pounds of VOL released for times when flow is detected or emissions are diverted from the control device through a bypass line while a storage vessel affected facility vented to the closed vent system contains VOL or is being degassed.

(9) After installing a closed vent system and control device to comply with § 60.112c other than a flare or an enclosed combustion device electing to comply with § 60.112c(d)(5), report:

(i) For each instance when the CMS measured 3-hour rolling averages below the established operating limit:

(A) The date and start time of the deviation;

(B) The duration of the deviation in hours;

(C) The lowest 3-hour rolling average operating parameter reading during the period of the deviation;

(D) A unique identifier for the CMS;

(E) The make, model number, and date of last calibration check of the CMS; and

(F) The cause of the deviation and the corrective action taken.

(ii) For all instances when the CMS was inoperative:

(A) The date and start time of the deviation;

(B) The duration of the deviation in hours;

(C) A unique identifier for the CMS;

(D) The make, model number, and date of last calibration check of the CMS; and

(E) The cause of the deviation and the corrective action taken.

(10) After installing a closed vent system and a flare to comply with § 60.112c or an enclosed combustion device electing to comply with § 60.112c(d)(5), report:

(i) The date and start and end times for each of the following instances:

(A) Each 15-minute block during which there was at least 1 minute when storage vessel vapors were routed to the flare and no pilot flame or flare flame was present.

(B) Each period of 2 consecutive hours during which visible emissions exceeded a total of 5 minutes. Additionally, report the number of minutes for which visible emissions were observed during the observation or an estimate of the cumulative number of minutes in the 2-hour period for which

emissions were visible based on best information available to the owner or operator.

(C) Each 15-minute period for which the applicable operating limits specified in 40 CFR 63.670(d) through (f) were not met. You must identify the specific operating limit that was not met and report the value of the net heating value operating parameter(s) during the deviation determined following the methods in 40 CFR 63.670(k) through (n) as applicable.

(ii) The start date, start time, and duration in minutes for each period when storage vessel vapors were routed to the flare or enclosed combustion device and the applicable monitoring was not performed.

(iii) For each instance reported under paragraphs (c)(10)(i) and (ii) of this section that involves CMS, report the following information:

(A) A unique identifier for the CMS;

(B) The make, model number, and date of last calibration check of the CMS; and

(C) The cause of the deviation or downtime and the corrective action taken.

(11) For pressure relief devices on a storage vessel or closed vent system subject to § 60.112c(d)(1)(iii) or (d)(2)(iii), report each pressure release to the atmosphere, including pressure relief device identification name or number, the start date, start time, and duration (in minutes) of the pressure release; and an estimate of the mass quantity in pounds of VOL released.

(12) For vacuum breaking devices on a storage vessel subject to § 60.112c(d) and (d)(1)(iii), report the following information for each time the vacuum breaking device failed to close prior to the storage vessel reaching atmospheric pressure: identification name or number of vacuum breaking device; the start date, start time, and duration (in minutes) of the pressure release; and an estimate of the mass quantity in pounds of VOL released.

(d) *Timeframe for semiannual report submissions.* (1) The first semiannual report will cover the period starting with the date the source first becomes an affected facility subject to this subpart and ending June 30 or December 31, whichever date is earlier. For example, if the source becomes an affected facility on April 15, the first semiannual report would cover the period from April 15 to June 30. The first semiannual report must be submitted on or before the last day of the month 2 months after the last date covered by the semiannual report. In this example, the first semiannual report would be due August 31.

(2) Subsequent semiannual reports will cover subsequent 6 calendar month periods (January 1 through June 30 or July 1 through December 31, as applicable) with each report due on or before the last day of the month 2 months after the last date covered by the semiannual report (August 31 or February 28 or 29, as applicable).

(3) For each affected facility that is subject to permitting regulations pursuant to 40 CFR parts 70 or 71, if the delegated authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent semiannual reports according to the dates the delegated authority has established instead of the dates in paragraphs (d)(1) and (2) of this section.

(e) *Reporting requirements for performance tests.* Within 60 days after the date of completing each performance test, you must submit the results following the procedures specified in paragraph (f) of this section. Data collected using test methods that are supported by the U.S. Environmental Protection Agency (EPA) Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or an alternate electronic file.

(f) *Requirements for electronically submitting reports.* If you are required to submit notifications or reports following the procedures specified in this paragraph (f), you must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (f)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data are not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (f).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Measurement Policy Group Leader and all other files should be flagged to the attention of the NSPS Kc Rule Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404–02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. ERT files should be sent to the secondary attention of the Measurement Policy Group Leader and all other files should be sent to the secondary attention of the NSPS Kc Rule Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(g) *Claims of EPA system outage.* If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (g)(1) through (7) of this section.

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(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(h) *Claims of force majeure.* If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (h)(1) through (5) of this section.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

### § 60.117c Delegation of authority.

(a) In delegating implementation and enforcement authority of this subpart to a State, local, or Tribal agency under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or Tribal agency.

(b) Authorities which will not be delegated to State, local, or Tribal agencies: §§ 60.113c(d)(1)(iv) and 60.114c and approval of an alternative to any electronic reporting to the EPA required by this subpart.

[FR Doc. 2024–22823 Filed 10–11–24; 8:45 am]

BILLING CODE 6560–50–P

**IN THE UNITED STATES COURT OF APPEALS**
**FOR THE DISTRICT OF COLUMBIA CIRCUIT**

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|---|---|
| INTERNATIONAL LIQUID TERMINALS ASSOCIATION,<br>Petitioner,<br>v.<br>U.S. ENVIRONMENTAL PROTECTION AGENCY, and MICHAEL S. REGAN, ADMINISTRATOR, U.S. ENVIRONMENTAL PROTECTION AGENCY,<br>Respondents. | Case No: 24-1377 |

## RULE 26.1 CORPORATE DISCLOSURE STATEMENT

Pursuant to Rule 26.1 of the Federal Rules of Appellate Procedure and D.C. Circuit Rule 26.1, the International Liquid Terminals Association ("ILTA") provides the following corporate disclosure statement:

ILTA is a nonprofit trade association within the meaning of D.C. Circuit Rule 26.1(b). Its members operate liquid terminals in all 50 states and over 40 countries. It operates for the purpose of promoting the general commercial, legislative, and other common interests of its members. ILTA does not have a parent company, and

no publicly held company has a 10% or greater ownership interest in it.

Dated: December 16, 2024

Respectfully submitted,

*/s/ Svend Brandt-Erichsen*

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*Attorneys for International Liquid Terminals Association*

**IN THE UNITED STATES COURT OF APPEALS**
**FOR THE DISTRICT OF COLUMBIA CIRCUIT**

| | |
|---|---|
| INTERNATIONAL LIQUID TERMINALS ASSOCIATION,<br><br>Petitioner,<br><br>v.<br><br>U.S. ENVIRONMENTAL PROTECTION AGENCY, and MICHAEL S. REGAN, ADMINISTRATOR, U.S. ENVIRONMENTAL PROTECTION AGENCY,<br><br>Respondents. | Case No: 24-1377 |

## CERTIFICATE OF SERVICE

Pursuant to Rules 15(c) and 25(d) Federal Rules of Appellate Procedure and Circuit Rule 15, I hereby certify that the International Liquid Terminals Association's Petition for Review and Rule 26.1 Corporate Disclosure Statement have been served by first class mail, postage prepaid, this 16th$^{th}$ day of December, 2024, upon each of the following:

Hon. Michael S. Regan, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

U.S. Environmental Protection Agency
Correspondence Control Unit
Office of General Counsel (2311)
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Hon. Merrick B. Garland
Attorney General of the United States
U.S. Department of Justice
950 Pennsylvania Avenue, N.W.
Washington, D.C. 20530

Hon. Todd Kim
Assistant Attorney General
Environmental and Natural Resources Division
U.S. Department of Justice
950 Pennsylvania Avenue, N.W.
Washington, D.C. 20530

Dated: December 16, 2024

Respectfully submitted,

*/s/ Svend Brandt-Erichsen*

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*Attorneys for International Liquid Terminals Association*

**IN THE UNITED STATES COURT OF APPEALS**
**FOR THE DISTRICT OF COLUMBIA CIRCUIT**

| | |
|---|---|
| **AMERICAN CHEMISTRY COUNCIL, AMERICAN FUEL & PETROCHEMICAL MANUFACTURERS and AMERICAN PETROLEUM INSTITUTE,** | **No. 24-1379** |
| **Petitioners,** | |
| **v.** | |
| **UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,** | |
| **Respondent.** | |

## PETITION FOR REVIEW

Pursuant to Rule 15 of the Federal Rules of Appellate Procedure, D.C. Circuit Rule 15, and section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), Petitioners the American Chemistry Council, the American Fuel & Petrochemical Manufacturers and the American Petroleum Institute hereby petition this Court to review a final action of the United States Environmental Protection Agency entitled, "New Source Performance Standards Review for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)," published at 89 Fed. Reg. 83296 (Oct. 15, 2024).

Respectfully submitted,

/s/ *William L. Wehrum*
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Wagner@api.org

Dated: December 16, 2024

## CERTIFICATE OF SERVICE

I hereby certify that on this 16th day of December 2024, the foregoing Petition for Review and Rule 26.1 Corporate Disclosure Statements of Petitioners the American Chemistry Council, the American Fuel and Petrochemical Manufacturers and the American Petroleum Institute have been served by first-class mail, postage prepaid, on each of the following:

The Honorable Michael Regan
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

The Honorable Merrick Garland
Attorney General of the United States
United States Department of Justice
950 Pennsylvania Ave., N.W.
Washington, D.C. 20530-0001

Dimple Chaudhary
Acting General Counsel
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

/s/ *William L. Wehrum*
William L. Wehrum

**IN THE UNITED STATES COURT OF APPEALS**
**FOR THE DISTRICT OF COLUMBIA CIRCUIT**

| | | |
|---|---|---|
| **AMERICAN CHEMISTRY COUNCIL, AMERICAN FUEL & PETROCHEMICAL MANUFACTURERS and AMERICAN PETROLEUM INSTITUTE,** | ) | **No. 24-1379** |
| **Petitioners,** | ) | |
| **v.** | ) | |
| **UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,** | ) | |
| **Respondent.** | ) | |

## RULE 26.1 DISCLOSURE STATEMENT OF PETITIONERS

Pursuant to Rule 26.1 of the Federal Rules of Appellate Procedure and D.C. Circuit Rule 26.1, petitioners the American Chemistry Council ("ACC"), the American Fuel & Petrochemical Manufacturers ("AFPM") and the American Petroleum Institute ("API") file the following statements:

ACC represents the leading companies engaged in the business of chemistry. ACC members apply the science of chemistry to make innovative products and services that make people's lives better, healthier and safer. ACC is committed to improved environmental, health and safety performance through Responsible

Care®; common sense advocacy designed to address major public policy issues; and health and environmental research and product testing. The business of chemistry is a $639 billion enterprise and a key element of the nation's economy. It is among the largest exporters in the nation, accounting for fourteen percent of all U.S. goods exported. ACC participates on behalf of its members in administrative proceedings and in litigation arising from those proceedings. ACC has no outstanding shares or debt securities in the hands of the public and no parent company. No publicly held company has a ten percent (10%) or greater ownership interest in ACC.

AFPM is a national trade association representing most United States refining and petrochemical manufacturing capacity. AFPM has no parent company, and no publicly held company has a 10 percent or greater ownership interest in AFPM.

API is a national trade association representing all aspects of America's oil and natural gas industry. API has more than 630 members, from the largest major oil company to the smallest of independents, from all segments of the industry, including producers, refiners, suppliers, pipeline operators, and marine transporters, as well as service and supply companies that support all segments of industry. API has no parent company, and no publicly held company has a 10 percent or greater ownership interest in API.

Respectfully submitted,

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Dated: December 16, 2024

USCA Case #24-1379 Document #2090128 Filed: 12/16/2024 Page 7 of 47


**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Part 60**

**[EPA–HQ–OAR–2023–0358; FRL–10655–02–OAR]**

**RIN 2060–AV93**

## New Source Performance Standards Review for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** The Environmental Protection Agency (EPA) is finalizing amendments to the new source performance standards (NSPS) for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) pursuant to the review required by the Clean Air Act (CAA). The EPA is finalizing revisions to the NSPS that are applicable to volatile organic liquid (VOL) storage vessels that commence construction, reconstruction, or modification after October 4, 2023, under a new NSPS subpart, as well as amendments to an existing subpart. In the new NSPS subpart Kc, the EPA is finalizing requirements to reduce the vapor pressure applicability thresholds and revise the volatile organic compound (VOC) standards to reflect the best system of emission reduction (BSER) for affected storage vessels. In addition, the EPA is finalizing degassing emission controls; clarification of startup, shutdown, and malfunction (SSM) requirements; additional monitoring requirements; and other technical improvements

**DATES:** This final rule is effective on October 15, 2024. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of October 15, 2024.

**ADDRESSES:** The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2023–0358. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only as portable document format (PDF) versions that can only be accessed on the EPA computers in the docket office reading room. Certain databases and physical items cannot be downloaded from the docket but may be requested by contacting the Public Reading Room at (202) 566–1744. The docket office has up to 10 business days to respond to these requests. With the exception of such material, publicly available docket materials are available electronically in *Regulations.gov* or on the EPA computers in the Public Reading Room at the EPA Docket Center, WJC West Building, Room Number 3334, 1301 Constitution Ave. NW, Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

**FOR FURTHER INFORMATION CONTACT:** Mr. Michael Cantoni III, Sector Policies and Programs Division (E143–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5593; and email address: *cantoni.michael@epa.gov*.

**SUPPLEMENTARY INFORMATION:**

*Preamble acronyms and abbreviations.* Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

AMEL alternative means of emissions limitation
API American Petroleum Institute
ASTM American Society for Testing and Materials
AVO audible, visual, and olfactory
BSER best system of emission reduction
CAA Clean Air Act
CBI Confidential Business Information
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
EFR external floating roof
EIA economic impact analysis
EJ environmental justice
EPA Environmental Protection Agency
FR Federal Register
gal gallons
HAP hazardous air pollutant(s)
IBR incorporate by reference
ICR information collection request
IFR internal floating roof
kg/hr kilograms per hour
kPa kilopascals
LEL lower explosive limit
m3 cubic meters
MON Miscellaneous Organic Chemical Manufacturing NESHAP
MTVP maximum true vapor pressure
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NSPS new source performance standards
NTAA National Tribal Air Association
NTTAA National Technology Transfer and Advancement Act
OMB Office of Management and Budget
PDF portable document format
PRA Paperwork Reduction Act
PRD pressure relief device
ppmv parts per million by volume
psia pounds per square inch absolute
psig pounds per square inch gauge
RFA Regulatory Flexibility Act
RIN Regulatory Information Number
SCAQMD South Coast Air Quality Management District
SSM startup, shutdown, and malfunction
STERPP 2000 U.S. EPA Storage Tank Emission Reduction Partnership Program
UMRA Unfunded Mandates Reform Act
VCU vapor combustion unit
VOC volatile organic compound(s)
VOL volatile organic liquid

*Organization of this document.* The information in this preamble is organized as follows:

I. General Information
A. Does this action apply to me?
B. Where can I get a copy of this document and other related information?
C. Judicial Review and Administrative Review
II. Background
A. What is the statutory authority for this action?
B. How does the EPA perform the NSPS review?
C. What is the source category regulated in this final action?
D. What outreach and engagement did the EPA conduct?
III. What changes did we propose for the VOL Storage Vessel NSPS?
IV. What actions are we finalizing and what is our rationale for such decisions?
A. Revised NSPS for VOL Storage Vessels That Commenced Construction, Reconstruction, or Modification After July 23, 1984, and on or Before October 4, 2023
B. Revised NSPS for VOL Storage Vessels That Commenced Construction, Reconstruction, or Modification After October 4, 2023
C. NSPS Subpart Kc Without Startup, Shutdown, and Malfunction Exemptions
D. Testing, Monitoring, and Inspection Requirements
E. Recordkeeping and Electronic Reporting
F. Other Final Amendments
G. Effective Date and Compliance Dates
V. Summary of Cost, Environmental, and Economic Impacts
A. What are the air quality impacts?
B. What are the cost impacts?
C. What are the economic impacts?
D. What are the benefits?
E. What analysis of environmental justice did we conduct?
VI. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive

# ATTACHMENT 6A: CertainTeed Gypsum Manufacturing RACT

CertainTeed
SAINT-GOBAIN

RECEIVED CC DAQ
2025 JUL 29 AM 11:27

July 29, 2025

Permitting Supervisor
Clark County Division of Air Quality
4701 W. Russell Road, Suite 200
Las Vegas, NV 89118-2231

**RE: PART 70 OPERATING PERMIT REVISION APPLICATION**
**CERTAINTEED GYPSUM MANUFACTURING, INC. - SOURCE 4**

Enclosed please find a completed application for a minor revision to this facility's Part 70 Operating Permit. The purpose of this Part 70 Permit significant revision application is for submission of the Reasonably Available Control Technology (RACT) analysis required by AQR Section 120 and to correct the maximum ratings and emissions for the burners associated with the calcining kettles, (EUs G.8.4a(1)-g(7)).

Should you have any questions regarding this submittal, or require additional information, please do not hesitate to contact Alin Mot at 702-209-9769 (alin.mot@saint-gobain.com) or Russell Harms with Broadbent & Associates at 702-553-6219 (rharms@broadbentinc.com).

Sincerely,
CertainTeed Gypsum, Inc.

Sean Brennan
Plant Manager

Enclosure –Part 70 Permit Revision Application

SAINT-GOBAIN
**CertainTeed Gypsum**
13500 Blue Diamond Road • Las Vegas, NV 89161 • USA • Tel: 1.702.875.4111 • Fax: 1.702.875.4213 • www.certainteed.com
CertainTeed Gypsum Manufacturing, Inc.

# Title V (Part 70) Permit Application

**Clark County Department of Environment & Sustainability**
**Division of Air Quality**

**Submit Application to:**
**Division of Air Quality**
**4701 W. Russell Road, Suite 200**
**Las Vegas NV 89118**

**For DAQ Use Only**

RECEIVED CC DAQ
2025 JUL 29 AM 11:27

## Section A: Permit Application Basis (check all that apply):

- ☐ Initial Permit
- ☐ Renewal Permit
- ☐ Administrative Revision
- ■ Minor Revision*
- ■ Significant Revision*

*For all AQR 12.4.3.2 modifications, including Title V permit revisions based on AQR 12.4.3.2(d) and (e), use the Title V ATC application form (see Section G, "Application Instructions").

If applying for a revision: Has an NSR Authority to Construct already been issued? ☐ Yes ■ No

***Application Description:*** Describe the Title V permitting action being proposed, e.g., new process, change to equipment, change to permit conditions, Voluntarily Accepted Emission Limit (VAEL), incorporating ATC, etc.

Significant/minor revision of the Part 70 Operating Permit. The revisions include the submittal of an AQR Section 120 RACT analysis (with conditions) and the correction of the maximum ratings and emissions for the burners associated with the calcining kettles, (EUs G.8.4a(1)-g(7)).

**Applications for a Part 70 permit shall include the information requested in Sections B–F.**

***Complete the fields in Sections B–F even if there is no change from the previous application.***

## Section B: Source Information

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**

Source ID No: 4

Source Name (as listed on Clark County/State of Nevada business license): CertainTeed Gypsum Manufacturing, Inc.

Permit Expiration Date (existing permits only): June 1, 2026

City/County Business License #: 2000541.560

**Source Location Information**

| Number: | Direction (E., W.): | Street Name: | Cross Streets: |
|---|---|---|---|
| 13500 | | Blue Diamond Rd | |

City: Las Vegas | State: NV | Zip: 89161

**Phone Numbers**

Office: 702-875-4111 | Fax:

**North American Industry Classification System (NAICS) / Source Industry Classification Code**

Primary NAICS: 327420 | Additional NAICS (optional):

***Source Description:*** Describe the nature of your business, including processes and products.

Gypsum wallboard and plaster production.

## Section C: Company Information (AS LISTED ON THE SECRETARY OF STATE'S BUSINESS CERTIFICATE/FILING)

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**
If company ownership and/or name has changed, separately submit a Transfer of Ownership / Change of Name form+ fee (SS-PER-020-01).

Company Name: CertainTeed Gypsum Manufacturing, Inc.

**Location Information**

| Number: | Direction (W., E.): | Street Name: | Street Type (Rd., Ave.): | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| 13500 | | Blue Diamond | Rd | | |

City: Las Vegas | State: NV | ZIP: 89161

***Proof of Company Name:*** Have you selected "New Permit" for the action type above? ☐ YES ■ NO

If YES, attach a printout of your company's business listing on the Nevada Secretary of State website, or other formal documentation that includes your company's full legal name.

**Phone Numbers**

Office: 702-875-4111 | Fax:

**Type of Organization**

■ Corporation ☐ Individual Owner ☐ Partnership ☐ Government Entity ☐ Other

## Section D: Responsible Official (RO) Information

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**
If the RO has changed, separately submit a Declaration of Responsible Official form (RO-PER-003).

Name: Sean Brennan | Title: Plant Manager

**Location Information**

| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| 13500 | | Blue Diamond | Rd | | |

City: Las Vegas | State: NV | Zip: 89161

Email: sean.brennan@saint-gobain.com | Primary Communication Method: ■ Email ☐ U.S. Postal

**Phone Numbers**

Office: 702-875-4111 | Extension: | Cell: 702-526-7998 | Fax:

## Section E: Plant Manager/Environmental Representative Contact Information

Name: Alin Mot | Title: EH&S Manager

**Location Information**

| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| 13500 | | Blue Diamond | Rd | | |

City: Las Vegas | State: | Zip:

Email: alin.mot@saint-gobain.com | Primary Communication Method: ■ Email ☐ U.S. Postal

**Phone Numbers**

Office: 702-875-4111 | Extension: | Cell: 702-209-9769 | Fax:

## Section F: Billing Contact (Accounts Payable) Information (Optional)

Name: | Title:

Email: | Primary Communication Method: ☐ Email ☐ U.S. Postal

**Phone Numbers**

Office: | Extension: | Cell: | Fax:

## Section G: Application Instructions

1. For all construction, modification, or reconstruction, the owner or operator shall use the Title V ATC Application Form instead of this Title V Application Form.
2. An owner or operator of an existing or new Part 70 source shall obtain an Authority to Construct (ATC) Permit from the Control Officer before beginning actual construction or continuing with any of the following:
   a. Operating a new Part 70 source;
   b. "Major modification," as defined in AQR 12.2 or 12.3;
   c. Modification that increases the Part 70 source's potential to emit (PTE) by an amount equal to or greater than the minor New Source Review (NSR) significant level in AQR 12.4.2.1;
   d. Construction, modification, or reconstruction of an affected facility that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 60;
   e. Construction or reconstruction of a new source or of an affected source that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 63, including, but not limited to, construction or modification that requires preconstruction review under 40 CFR Part 63.5; or
   f. Modification to a solid waste incinerator unit, as defined by an applicable standard under 40 CFR Part 60.
3. For each Part 70 source, the owner or operator shall submit a timely and complete permit application in accordance with AQR 12.5.2.1.
4. Claims of confidentiality as to information submitted to EPA shall be made pursuant to applicable federal requirements in 40 CFR Part 2. Claims of confidentiality as to information submitted to the department shall be made pursuant to AQR 12.6.

## Section H: Application Supplemental Documents

*Information worksheets for common source types and emission units are posted on the DES website under **Applications/Forms → Stationary Source Permitting Forms → Emission Unit/Control Device Worksheets & Tools**. Applicants can use these documents to provide some of the technical information requested below.*

1. To comply with the requirements of AQR 12.5, the applicant shall submit all of the following information for initial and renewal Title V permit applications. For all other applications, the applicant may omit information that is not related to the proposed changes.
   A. Process description, including any alternative operating scenarios or federally enforceable emissions caps. Emission unit descriptions, including material/fuel usage and/or operating schedules.
   B. Emissions information with supporting calculations for all regulated air pollutants and HAPs, including fugitive emission rates, which shall include calculations of emission rates, short-term limits, hourly rates and tons per year emissions of each emission unit..
   C. Emission information in tons per year for each emission unit and the entire source.
   D. Description of all applicable requirements and/or exemptions, including Voluntarily Accepted Emission Limits (VAEL) and/or Plant-wide Applicability Limits (PAL).
   E. Air pollution control information with associated monitoring and testing requirements (example: for a baghouse, opacity test, pressure drop range and periodic inspections).
   F. Information related to stack height limitations and stack parameters.
   G. An explanation of any proposed exemptions from otherwise applicable requirements.
   H. Any alternative operating scenarios that are proposed in the application pursuant to paragraph (j) of Section 12.5.2.6, such information as is necessary for the Control Officer to define those scenarios and determine the applicable requirements for each proposed scenario.
   I. Compliance plan for all applicable requirements, as set forth in AQR 12.5.2.3(j).
   J. Compliance certification, as set forth in AQR 12.5.2.3(k).
   K. Compliance Assurance Monitoring plan, if determined to be applicable.
   L. Acid rain application, if applicable.

M. Permit shield (optional).

N. Other information that may be necessary to implement and enforce other requirements of the Clean Air Act or determine the applicability of such requirements.

2. In addition to the requirements above, an application for a minor revision shall include the following:

   A. A description of the change, the emissions estimated to result from the change, and any new applicable requirements that will apply if the change occurs.

   B. Suggested draft permit conditions from the source, including a markup of the operating permit with the changes.

   C. Justification that the proposed modifications meet the criteria for use of minor revision procedures.

   D. All relevant forms, completed, for the Control Officer to submit to EPA and affected states or tribes.

## Section I: Application Advisories

**Permit Applications: Duty to Supplement or Correct (AQR 12.5.2.2).** When an applicant learns of missing or incorrect information in its permit application, it must provide or correct the information as soon as practicable. If additional requirements are deemed to apply after an applicant files a complete application but before the draft permit is released, the applicant must furnish all information needed to address them. The applicant's Responsible Official shall certify the additional information consistent with the requirements of Section 12.5.2.4.

1. **Small Business Assistance.** A DAQ program that offers free assistance on permitting and compliance matters to small businesses (100 employees or fewer). Please ask for an SBA representative at our front counter or call (702) 455-5942 to schedule an appointment.

2. **Fees and Payments.**

   A. Application Filing Fee: There is no application filing fee for Title V permits.

   B. Permit Issuance: All outstanding invoices for the source and associated with the parent company of the source must be paid in full; otherwise, DAQ cannot issue the source any permits. This includes the invoice for the permit fees resulting from this application.

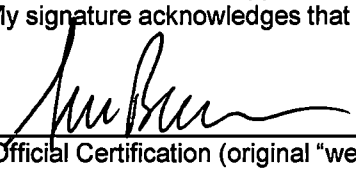
   C. Payment: Invoices must be paid by check, money order, or credit card. Make checks and money orders payable to Division of Air Quality or DAQ. Credit card payments must be made in person at DAQ's main office.

## Section J: Grant of Authority

I authorize DAQ to transmit all communications, permits, and billing invoices by the primary communication method selected in Section D of this application. I acknowledge that if I select "Email," DAQ will transmit all listed items electronically. I further acknowledge that if I select "U.S. Postal Service," I may incur applicable postage fees.

## Section K: Certification of Truth, Accuracy, and Completeness

As the Responsible Official, I declare, under penalty of perjury under the laws of the state of Nevada, that the statements and information in this application and the attached supplemental documents and worksheets are true and correct. My signature acknowledges that I am subject to liability for perjury under NRS Chapter 199.145.



7/29/2025

Responsible Official Certification (original "wet" signature) Date

Sean Brennan

Printed Name of Responsible Official

**If this application is being submitted for an existing permit holder, it must be signed by an RO on file for this source.**

**Part 70 Permit Significant Revision Application**
**CertainTeed Gypsum Manufacturing, Inc.**
**Source ID No. 4**
**July 29, 2025**

## 1.0 Purpose of Application

The purpose of this Part 70 Permit significant revision application is for submission of the Reasonably Available Control Technology (RACT) analysis required by AQR Section 120 and to correct the maximum ratings and emissions for the burners associated with the calcining kettles, (EUs G.8.4a(1)-g(7)).

No other changes to the current Part 70 Permit are being proposed with this significant revision application.

## 2.0 Process Description

CertainTeed Gypsum Manufacturing, Inc. (CertainTeed) operates a wallboard manufacturing facility located in Clark County, Nevada. CertainTeed is located on Blue Diamond Road, approximately 20 miles west of the city of Las Vegas (T20S, R64E, Section 8) in the Las Vegas Valley, Clark County, Nevada (Hydrographic Area 212). Hydrographic Area 212 is classified as a serious nonattainment area for the 2015 O3 National Ambient Air Quality Standards (NAAQS) as of January 21, 2025, and is an attainment area subject to a maintenance plan for the CO and $PM_{10}$ NAAQS. CertainTeed is a major source for CO, synthetic minor 80 source (SM 80) for $NO_x$, synthetic minor source for $PM_{10}$ and a minor source for $PM_{2.5}$, $SO_2$, VOC and HAPs, as well as a source of GHG. Emission units included at the source involve transporting raw rock and product, milling and calcining operations, plaster operations, wallboard manufacturing and waste recycling.

The list of emission units affected by the correction of the maximum ratings and emissions proposed in this application are provided in Table 1.

**Table 1 - List of Emission Units**

| EU | Rating | Description |
|---|---|---|
| G.8.4a(1)-g(7) | 12 MMBtu/hr | Kettle Calciners #1-7 (Burners) |

Emission units affected by the RACT analysis required by AQR Section 120 are described in the attached AQR Section 120 Reasonably Available Control Technology Analysis.

## 3.0 Applicable Regulations (AQR Section 120)

AQR Section 120 establishes and implements RACT requirements for major stationary sources of $NO_x$ and/or VOCs in areas of serious nonattainment for ozone, including Hydrographic Area 212. According to the regulation, owners and operators of existing stationary sources affected by the regulation must submit a major source RACT demonstration for all affected units by applying for a new stationary source permit or a significant permit revision. In addition to the definition in Section 120.3, DAQ has specified that affected units are individual emissions units located at the major stationary source with a PTE for $NO_x$ or VOC that is equal to, or greater than five tons per year. This application must comply with the submittal

requirements outlined in AQR Sections 12.4 and/or 12.5. Even if the demonstration does not result in additional control requirements, sources still must submit a complete application to the Control Officer. Compliance with the application requirements of AQR Section 120 is due on or before August 1, 2025, which is within 120 days after the Control Officer issued a written notice dated April 3, 2025.

Saguaro has prepared the required RACT analysis and has included the analysis with this application as required. The analysis provides details regarding the applicability of AQR Section 120 requirements, which emissions unit are affected and the RACT assessment methodology and results. Since the results of the RACT analysis did not result in any requirements to add or modify existing controls, an AQR Section 12.4 application is not necessary. The analysis includes the specific RACT control, monitoring, testing, recordkeeping and reporting conditions necessary to ensure compliance with AQR Section 120.

## 4.0 Required Revisions to Permit

The required revisions to the permit pertain only to the correction of the maximum ratings and emissions for the burners associated with the calcining kettles, (EUs G.8.4a(1)-g(7)) and the AKI board dryer (EU J.3) and incorporation of the AQR Section 120 RACT conditions for affected emission units.

### *4.1 Correction of Burner Ratings*

Correction of the maximum ratings and emissions for the burners associated with the calcining kettles (EUs G.8.4a(1)-g(7)) requires revisions to the Executive Summary and the Equipment and Limitations and Standards sections of the permit. The existing burners are Hauck Model HMC 1080/2080 combination type rated for a maximum heat input of 9.0 MMBtu/hr. Emissions calculations and a copy of the manufacturer's specifications for the burners are attached to this application.

The specific revisions required are discussed below for each section.

Executive Summary

1. Table 1: Source-wide PTE should be revised as shown below.

| Pollutant | $PM_{10}$ | $PM_{2.5}$ | $NO_x$ | CO | $SO_2$ | VOC | HAPs | GHG[1] |
|---|---|---|---|---|---|---|---|---|
| Existing Permit (tons/year) | 63.54 | 32.48 | 84.86 | 171.28 | 0.79 | 27.16 | 3.40 | 141,561 |
| Revised Permit (tons/year) | 62.91 | 31.85 | 75.83 | 163.72 | 0.72 | 26.67 | 3.19 | 131796 |
| PTE Change (tons/year) | -0.63 | -0.63 | -9.03 | -7.56 | -0.07 | -0.49 | -0.21 | -9765 |
| AQR Section 12.5 Minor NSR Significant Levels (tons/year) | 7.5 | 5.0 | 20 | 50 | 20 | 20 | NA | NA |

[1] GHG is greenhouse gas pollutants, emissions are in metric tons per year of $CO_2$ equivalent.

The change in PTE due to the correction of the maximum ratings and emissions for the burners associated with the calcining kettles, (EUs G.8.4a-g(1-7)) is as shown below.

| Emission Unit | $PM_{10}$ | $PM_{2.5}$ | $NO_x$ | CO | $SO_2$ | VOC | HAPs | GHG[1] |
|---|---|---|---|---|---|---|---|---|
| G.8.4a(1)-g(7) Current Permit (tons/year) | 2.73 | 2.73 | 36.05 | 30.31 | 0.21 | 1.96 | 0.70 | 39081 |
| G.8.4a(1)-g(7) Revised (tons/year) | 2.10 | 2.10 | 27.02 | 22.75 | 0.14 | 1.47 | 0.49 | 29316 |
| G.8.4a(1)-g(7) Net Change (tons/year) | -0.63 | -0.63 | -9.03 | -7.56 | -0.07 | -0.49 | -0.21 | -9765 |

[1] GHG is greenhouse gas pollutants, emissions are in metric tons per year of $CO_2$ equivalent.

No additional AQR Section 12.5 requirements are triggered by this change as shown above.

Equipment (Section 1.0)

1. Revise the rating for EUs G.8.4a(1)-g(7) from 12 MMBtu/hr to 9 MMBtu/hr and rating for EU J.3 from 144 MMBtu/hr to 148 MMBtu/hr in Table 1-1: List of Emission Units.

Limitations and Standards (Section 3.0)

1. Revise the PTE emissions for Group 7 - Kettles in Table 3-1: Emission Unit PTE (tons per year) as shown below.

| Group | Process Description | $PM_{10}$ | $PM_{2.5}$ | $NO_x$ | CO | $SO_2$ | VOC | HAPs |
|---|---|---|---|---|---|---|---|---|
| Group 7 | Kettles | 2.10 | 2.10 | 27.02 | 22.75 | 0.14 | 1.47 | 0.49 |

2. Revise the rating for EUs G.8.4a(1)-g(7) from 12 MMBtu/hr to 9 MMBtu/hr in Table 3-2: Emission Unit Opacity Summary.

Please note that the revisions noted herein apply to current permit. CertainTeed submitted a minor revision application dated June 6, 2025 to add alternative operating scenarios to the current permit and the correction of the burner ratings for the kettles also affects certain parts of that application. The change in emissions due to the corrected ratings described in this application can be applied to that application as well.

*4.2 AQR Section 120 RACT requirements*

Revisions required to address AQR Section 120 RACT requirements are detailed in the attached AQR Section 120 Reasonably Available Control Technology Analysis.

# Emissions Calculations

**DAQ Source 4** **Emission Calculations - Kettle Burners**

**Kettle Emissions - Current Permit**

| | | | | Emission Factor | Potential Emissions | | | |
|---|---|---|---|---|---|---|---|---|
| **EU#:** | G.8.4a(1)-g(7) | | | | | | | |
| **Make:** | Hauck | | | (lb/mmBtu) | lb/hr | lb/day | ton/yr* | ton/yr** |
| **Model:** | | | **PM10** | 0.0075 | 0.09 | 2.16 | 0.39 | 2.73 |
| **S/N:** | | | **PM2.5** | 0.0075 | 0.09 | 2.16 | 0.39 | 2.73 |
| | | | **NOx** | 0.0980 | 1.18 | 28.22 | 5.15 | 36.05 |
| 12.0 | mmBtu/hr* | | **CO** | 0.0824 | 0.99 | 23.73 | 4.33 | 30.31 |
| 24.0 | hr/day | | **$SO_2$** | 6.00E-04 | 0.01 | 0.17 | 0.03 | 0.21 |
| 8760 | hr/yr | | **VOC** | 0.0054 | 0.06 | 1.56 | 0.28 | 1.96 |
| | | | **HAP** | 1.90E-03 | 0.02 | 0.55 | 0.10 | 0.70 |
| **BACT:** | | **%O2** | **Lead** | 4.90E-07 | 5.88E-06 | 1.41E-04 | 2.58E-05 | 1.80E-04 |
| | ppm NOx | 3.0 | | | **kg/hr** | **kg/day** | **mt/yr*** | **mt/yr**** |
| | ppm CO | 3.0 | **GHG***** | Various****** | 637 | 15297 | 5583 | 39081 |
| **Fuel:** | Natural Gas | | | | | | | |

* Each kettle
** 7 kettles
*** $CO_2eq$
****40 CFR Part 98 emission factors for GHG

**Kettle Emissions - Revised**

| | | | | Emission Factor | Potential Emissions* | | | |
|---|---|---|---|---|---|---|---|---|
| **EU#:** | G.8.4a(1)-g(7) | | | | | | | |
| **Make:** | Hauck | | | (lb/mmBtu) | lb/hr | lb/day | ton/yr* | ton/yr** |
| **Model:** | | | **PM10** | 0.0075 | 0.07 | 1.62 | 0.30 | 2.10 |
| **S/N:** | | | **PM2.5** | 0.0075 | 0.07 | 1.62 | 0.30 | 2.10 |
| | | | **NOx** | 0.098 | 0.88 | 21.17 | 3.86 | 27.02 |
| 9.0 | mmBtu/hr* | | **CO** | 0.0824 | 0.74 | 17.80 | 3.25 | 22.75 |
| 24.0 | hr/day | | **$SO_2$** | 6.00E-04 | 0.01 | 0.13 | 0.02 | 0.14 |
| 8760 | hr/yr | | **VOC** | 0.0054 | 0.05 | 1.17 | 0.21 | 1.47 |
| | | | **HAP** | 1.900E-03 | 0.02 | 0.41 | 0.07 | 0.49 |
| **BACT:** | | **%O2** | **Lead** | 4.90E-07 | 4.41E-06 | 1.06E-04 | 1.93E-05 | 1.35E-04 |
| | ppm NOx | 3.0 | | | **kg/hr** | **kg/day** | **mt/yr*** | **mt/yr**** |
| | ppm CO | 3.0 | **GHG***** | Various****** | 478 | 11473 | 4188 | 29316 |
| **Fuel:** | Natural Gas | | | | | | | |

* Each kettle
** 7 kettles
*** $CO_2eq$
**** 40 CFR Part 98 emission factors for GHG

# HM HIGH MOMENTUM BURNERS
# GAS, OIL & COMBINATION

| HM BURNER NO. | ITEM | SECONDARY AIR TEMPERATURE °F 100 | 700 | 950 | 1200 |
|---|---|---|---|---|---|
| | **NATURAL GAS OPERATION** | | | | |
| HMC1060 | Maximum Btu/hr x 1000 (@ high fire) | 5000 | 3525 | 3215 | 2970 |
| HMC2060 | Gas flow rate, scfh | 4808 | 3388 | 3090 | 2860 |
| (Combination) | Gas supply pressure (in. w.c.) | 6.5 | 3.3 | 2.7 | 2.3 |
| | Primary air flow at 4" w.c. (scfm) | 27 | 27 | 27 | 27 |
| | Secondary air flow at 11.0" w.c. (scfm) | 762 | 529 | 480 | 442 |
| | Turndown | 8:1 | 7:1 | 6.8:1 | 6.5:1 |
| | **NO. 2 OIL OPERATION** | | | | |
| | Maximum Btu/hr x 1000 (@ high fire) | 5080 | 3660 | 3360 | 3125 |
| | Oil flow rate, GPH | 36.8 | 26.5 | 24.3 | 22.7 |
| | Primary air flow at 27.7" w.c. (scfm) | 70 | 70 | 70 | 70 |
| | Secondary air flow at 11.0" w.c. (scfm) | 762 | 529 | 480 | 442 |
| | Turndown | 8:1 | 5:1 | 4.7:1 | 4.6:1 |
| HMG1060 | Maximum Btu/hr x 1000 (@ high fire) | 5000 | 3480 | 3155 | 2910 |
| HMG2060 | Gas flow rate, scfh | 4807 | 3345 | 3035 | 2800 |
| (Gas Only) | Gas supply pressure (in. w.c) | 6.5 | 3.3 | 2.7 | 2.3 |
| | Secondary air flow at 12.5" w.c. (scfm) | 790 | 549 | 498 | 459 |
| | Turndown | 10:1 | 9.5:1 | 8.4:1 | 7.6:1 |

| HM BURNER NO. | ITEM | SECONDARY AIR TEMPERATURE °F 100 | 400 | 800 | 1200 |
|---|---|---|---|---|---|
| | **NATURAL GAS OPERATION** | | | | |
| HMC1080 | Maximum Btu/hr x 1000 (@ high fire) | 9000 | 7290 | 6080 | 5340 |
| HMC2080 | Gas flow rate, scfh | 8654 | 7008 | 5850 | 5132 |
| (Combination) | Gas supply pressure (in. w.c.) | 6.5 | 4.3 | 3.0 | 2.3 |
| | Primary air flow at 4" w.c. (scfm) | 40 | 40 | 40 | 40 |
| | Secondary air flow at 10.4" w.c. (scfm) | 1380 | 1110 | 920 | 802 |
| | Turndown | 8:1 | 7.7:1 | 6.7:1 | 5.9:1 |
| | **NO. 2 OIL OPERATION** | | | | |
| | Maximum Btu/hr x 1000 (@ high fire) | 9080 | 7430 | 6260 | 5550 |
| | *Oil flow rate, GPH* | *65.8* | *53.8* | *45.4* | *40.2* |
| | Primary air flow at 27.7" w.c. (scfm) | 107 | 107 | 107 | 107 |
| | Secondary air flow at 12.0" w.c. (scfm) | 1380 | 1110 | 920 | 802 |
| | Turndown | 8:1 | 5.6:1 | 5.2:1 | 4.8:1 |
| HMG1080 | Maximum Btu/hr x 1000 (@ high fire) | 9030 | 7290 | 6020 | 5250 |
| HMG2080 | Gas flow rate, scfh | 8685 | 7010 | 5790 | 5046 |
| (Gas Only) | *Gas supply pressure (in. w.c)* | *6.5* | *4.3* | *3.0* | *2.3* |
| | Secondary air flow at 11.0" w.c. (scfm) | 1425 | 1150 | 950 | 828 |
| | Turndown | 10:1 | 8.1:1 | 6.7:1 | 5.8:1 |

| HM BURNER NO. | ITEM | SECONDARY AIR TEMPERATURE °F 100 | 700 | 950 | 1200 |
|---|---|---|---|---|---|
| | ***NATURAL GAS OPERATION*** | | | | |
| HMC1100 | Maximum Btu/hr x 1000 (@ high fire) | 14000 | 9870 | 8990 | 8320 |
| HMC2100 | Gas flow rate, scfh | 13460 | 9490 | 8642 | 8002 |
| (Combination) | Gas supply pressure (in. w.c.) | 6.5 | 3.2 | 2.7 | 2.3 |
| | Primary air flow at 4" w.c. (scfm) | 70 | 70 | 70 | 70 |
| | Secondary air flow at 11.0" w.c. (scfm) | 2140 | 1487 | 1348 | 1243 |
| | Turndown | 8:1 | 7:1 | 6.4:1 | 5.9:1 |
| | **NO. 2 OIL OPERATION** | | | | |
| | Maximum Btu/hr x 1000 (@ high fire) | 14220 | 10240 | 9390 | 8750 |
| | Oil flow rate, GPH | 103.0 | 74.2 | 68.0 | 63.4 |
| | Primary air flow at 27.7" w.c. (scfm) | 190 | 190 | 190 | 190 |
| | Secondary air flow at 11.0" w.c. (scfm) | 2140 | 1487 | 1348 | 1243 |
| | Turndown | 8:1 | 5.2:1 | 4.9:1 | 4.8:1 |
| HMG1100 | Maximum Btu/hr x 1000 (@ high fire) | 14010 | 9730 | 8820 | 8140 |
| HMG2100 | Gas flow rate, scfh | 13470 | 9355 | 8483 | 7825 |
| (Gas Only) | Gas supply pressure (in. w.c) | 6.5 | 3.1 | 2.6 | 2.2 |
| | Secondary air flow at 11.0" w.c. (scfm) | 2210 | 1535 | 1392 | 1284 |
| | Turndown | 10:1 | 7:1 | 6.3:1 | 5.8:1 |

***HM 1120 & 2120 AND CAPACITY TABLE NOTES ON REVERSE SIDE.***

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| HM BURNER NO. | ITEM | SECONDARY AIR TEMPERATURE °F 100 | 700 | 950 | 1200 |
|---|---|---|---|---|---|
| | **NATURAL GAS OPERATION** | | | | |
| HMC1120 | Maximum Btu/hr x 1000 (@ high fire) | 22000 | 15540 | 14162 | 13109 |
| HMC2120 | Gas flow rate, scfh | 20050 | 14128 | 12875 | 11917 |
| (Combination) | Gas supply pressure (in. w.c.) | 6.10 | 3.0 | 2.5 | 2.2 |
| | Primary air flow at 8.6" w.c. (scfm) | 120 | 120 | 120 | 120 |
| | Secondary air flow at 9.5" w.c. (scfm) | 3555 | 2470 | 2240 | 2065 |
| | Turndown | 9.6:1 | 8.4:1 | 7.7:1 | 7.1:1 |
| | **NO. 2 OIL OPERATION** | | | | |
| | Maximum Btu/hr x 1000 (@ high fire) | 25000 | 17618 | 16099 | 14937 |
| | Oil flow rate, GPH | 180.0 | 128.0 | 117.0 | 108.0 |
| | Primary air flow at 27.7" w.c. (scfm) | 251 | 251 | 251 | 251 |
| | Secondary air flow at 13.5" w.c. (scfm) | 4622 | 3211 | 2913 | 2685 |
| | Turndown | 8.0:1 | 6.2:1 | 5.9:1 | 5.8:1 |
| HMG1120 | Maximum Btu/hr x 1000 (@ high fire) | 22000 | 15216 | 13802 | 12720 |
| HMG2120 | Gas flow rate, scfh | 20570 | 14288 | 12959 | 11944 |
| (Gas Only) | Gas supply pressure (in. w.c) | 7.2 | 3.5 | 2.9 | 2.4 |
| | Secondary air flow at 9.5" w.c. (scfm) | 3650 | 2536 | 2300 | 2120 |
| | Turndown | 10.0:1 | 7.0:1 | 6.3:1 | 5.8:1 |

## CAPACITY TABLES AND APPLICATION NOTES

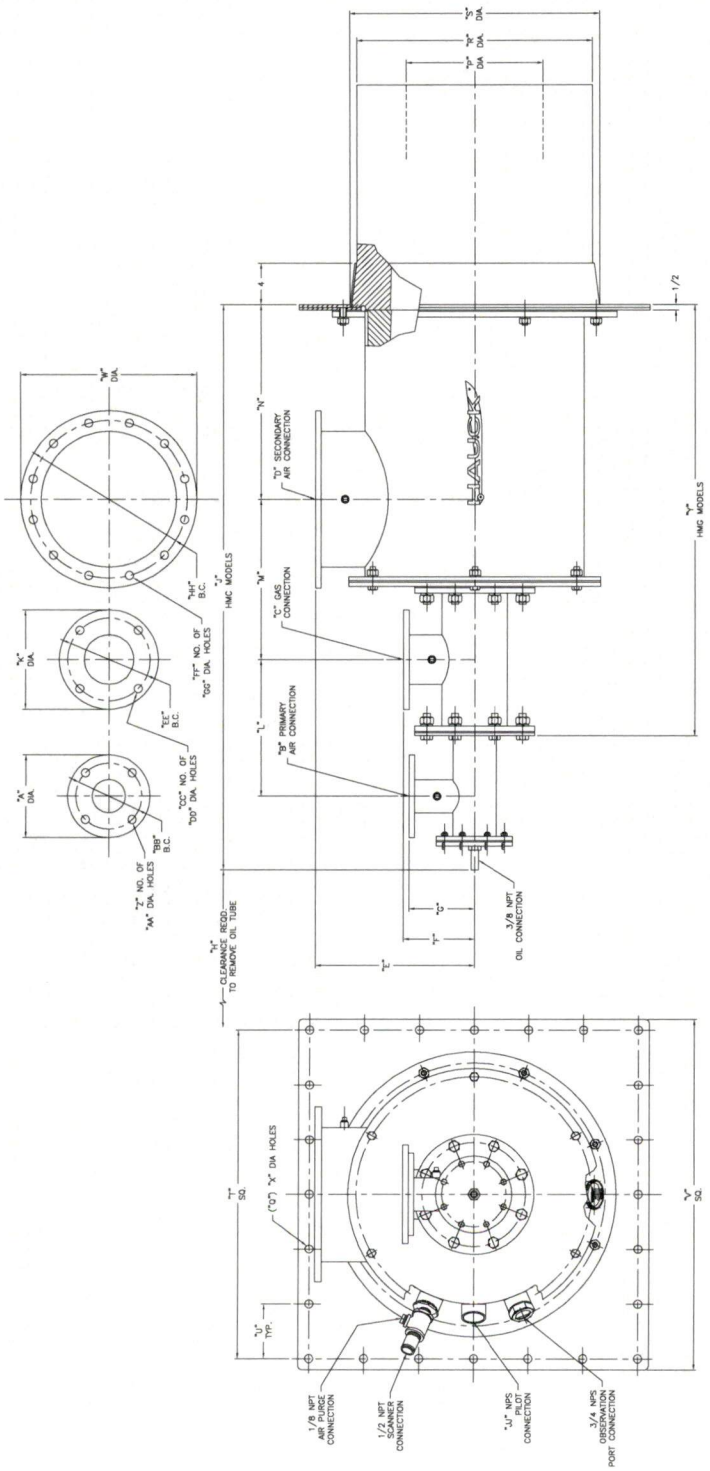
1. Fuel capacities based on natural gas at 1040 Btu/cu. ft., light No. 2 oil at 138,000 Btu/gal.
2. Maximum fuel capacities and turndown listed for stoichiometric operation.
3. Do not preheat primary air.
4. When operating HMC on gas, primary air should be kept between 4 and 10.0" w.c.
5. HMG has no primary air supplied.
6. Excess fuel capability is at least 5-10% with all fuel. Consult Hauck for specific information.
7. Excess air rates vary substantially depending on specific burner model, preheat temperature, primary air pressure and fuel. Consult Hauck for specific information.
8. Air flows at lower pressures proportional to $\sqrt{\frac{P}{\text{Pressure at known flow rate.}}}$ Air flows at intermediate temperatures proportional to $\sqrt{\frac{560}{T_{int} + 460}}$ times the flow at 100°F.
9. Include sensible heat of preheated air when computing total burner output. Sensible heat Btu/hr = scfm x 1.11 x $\Delta$T (in °F).
10. To size pipe for preheated air, compute acfm = scfm $(\frac{T + 460}{520})$.
11. When supervising flame, provide at least 8 osig ambient purge air (1½-2 cfm) to standard scanner purge assembly.
12. When sizing blower, consider application and operation so as to prevent overloading the blower motor at ambient scfm.

## FLAME CHARACTERISTICS*

| BURNER | FUEL | LENGTH (ft.) | EXHAUST VEL. (ft. min.) |
|---|---|---|---|
| HMC1060 | Nat. Gas | 4¾ | 15,000 |
| | No. 2 Oil | 6½ | 15,000 |
| HMG1060 | Nat. Gas | 4½ | 17,000 |
| HMC1080 | Nat. Gas | 5½ | 17,000 |
| | No. 2 Oil | 6 | 17,500 |
| HMG1080 | Nat. Gat | 5½ | 16,800 |
| HMC1100 | Nat. Gas | 7½ | 16,000 |
| | No. 2 Oil | 8 | 15,000 |
| HMG1100 | Nat. Gas | 8 | 15,000 |
| HMC1120 | Nat. Gas | 9 | 16,000 |
| | No. 2 Oil | 12 | 16,000 |
| HMG1120 | Nat. Gas | 9 | 16,000 |

*Based on stoichiometric operation at maximum Btu/hr with 100 °F secondary air.

# HIGH MOMENTUM BURNERS
# HMC-HMG SERIES




CY3261
(NOT TO SCALE)

DIMENSIONS IN INCHES

| BURNER NO. | "A" | "B" | "C" | "D" | "E" | "F" | "G" | "H" | "J" | "K" | "L" | "M" | "N" | "P" | "Q" | "R" | "S" | "T" | "U" | "V" | "W" | "X" | "Y" | "Z" | "AA" | "BB" | "CC" | "DD" | "EE" | "FF" | "GG" | "HH" | "JJ" |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HM_1060-2060 | --- | 2 1/2 NPS | 2 1/2 NPS | 6 RPM | 10 | 4 1/2 | 4 1/2 | 24 | 31 5/8 | 9 | 6 | 9 | 10 5/8 | 7 1/8 | 16 | 13 3/4 | 15 1/8 | 21 | 5 1/4 | 22 1/2 | 9 | 5/8 | 22 7/8 | --- | 3/4 | --- | --- | --- | --- | 8 | 7/16 | 7 7/8 | 1 1/4 |
| HM_1060-2080 | 7 1/2 | 3 ASA | 3 ASA | 8 RPM | 12 | 10 | 6 | 30 | 36 5/8 | 7 1/2 | 8 | 12 7/8 | 10 5/8 | 10 | 16 | 17 | 18 3/8 | 24 | 6 | 26 | 11 | 3/4 | 27 1/2 | 4 | 3/4 | 6 | 4 | 3/4 | 6 | 8 | 9/16 | 10 | 1 1/4 |
| HM_1100-2100 | 7 1/2 | 3 ASA | 4 ASA | 10 RPM | 13 | 11 | 6 | 36 | 45 1/2 | 9 | 10 | 15 | 13 5/8 | 12 1/2 | 16 | 19 1/2 | 20 7/8 | 26 | 6 1/2 | 28 | 14 | 3/4 | 33 5/8 | 4 | 3/4 | 7 1/2 | 8 | 3/4 | 7 1/2 | 12 | 5/8 | 12 1/4 | 1 1/4 |
| HM_1120-2120 | 7 1/2 | 3 ASA | 4 ASA | 12 RPM | 14 1/2 | 6 1/2 | 6 | 42 | 51 1/8 | 9 | 12 1/2 | 14 1/2 | 17 5/8 | 14 7/16 | 24 | 21 1/2 | 22 3/4 | 30 | 5 | 32 | 16 | 3/4 | 39 | 4 | 3/4 | 7 1/2 | 8 | 3/4 | 7 1/2 | 12 | 3/4 | 14 1/4 | 1 1/2 |

In accordance with Hauck's commitment to Total Quality Improvement, Hauck reserves the right to change the specifications of products without prior notice.

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# AQR Section 120 Reasonably Available Control Technology Analysis

# AQR Section 120 Reasonably Available Control Technology Analysis

**Clark County Department of Environment and Sustainability**
**Division of Air Quality**

CertainTeed Gypsum Manufacturing, Inc.
13500 Blue Diamond Road
Las Vegas, NV 89161

Source ID 4

July 29 , 2025

Prepared by:

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Project No. 15-01-149

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Attachment A - Cost Effectiveness Calculations

## 1.0 Background

On December 19, 2024, EPA advanced the Clark County Hydrographic Area 212 (Las Vegas Valley) airshed classification to the serious nonattainment category under the 2015 ozone National Ambient Air Quality Standards (NAAQS) for failing to comply with the standard by August 2024. This reclassification became effective on January 21, 2025, and brought the following changes to permit requirements for existing, new, and modified sources of ozone precursors, including volatile organic compounds (VOCs) and nitrogen oxides ($NO_x$) [40 CFR Part 51, Appendix S]:

- The major source threshold for VOC and $NO_x$ emissions, previously a potential to emit (PTE) of 100 tons per year (tpy) under the "moderate" classification, is lowered to 50 tpy.
- The significant emissions increase threshold, which determines whether a modification is subject to Nonattainment New Source Review (NNSR), is lowered from 40 to 25 tpy of VOC and/or $NO_x$.
- The Non-attainment New Source Review (NNSR) emissions offset ratio, which was 1.15:1 under moderate nonattainment, is raised to 1.2:1 under serious nonattainment and will apply to all NNSR for new major sources and major modifications to existing major sources.

The Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) adopted AQR Section 120 - Reasonably Available Control Technology Demonstration and Determination Requirements for Major Stationary Sources in Ozone Nonattainment Areas effective on December 3, 2024. AQR Section 120 establishes and implements RACT requirements for major stationary sources of $NO_x$ and/or VOCs in areas of serious nonattainment for ozone, including Hydrographic Area 212. According to the regulation, owners and operators of existing stationary sources affected by the regulation must submit a major source RACT demonstration for all affected units by applying for a new stationary source permit or a significant permit revision. In addition to the definition in Section 120.3, DAQ has specified that affected units are individual emission units located at the major stationary source with a PTE for $NO_x$ or VOC that is equal to, or greater than five tons per year. This application must comply with the submittal requirements outlined in AQR Sections 12.4 and/or 12.5. Even if the demonstration does not result in additional control requirements, sources still must submit a complete application to the Control Officer. Compliance with the application requirements of AQR Section 120 is due on or before August 1, 2025, which is within 120 days after the Control Officer issued a written notice dated April 3, 2025. In lieu of submitting a major source RACT analysis, owners and operators of existing stationary sources affected by the regulation may request voluntary emission limitations that reduce the source's or individual emission unit's $NO_x$ and/or VOC PTE below the major source or affected units' thresholds.

AQR Section 120 defines RACT as follows:

> *The lowest emissions limitation an affected unit is capable of meeting by applying control technology that is reasonably available, considering technological and economic feasibility. In determining RACT, the following factors shall be considered on a case-by-case basis:*
>
> - *Energy and environmental impacts and costs;*
> - *Cost-effectiveness;*
> - *Control technology in use by similar sources;*
> - *Technical feasibility;*
> - *Relevant findings and determinations in EPA's RACT/BACT/LAER Clearing-house website; and*

- *Relevant control technique guidelines and documents.*

A RACT analysis should, therefore, take into account the technological and economic impacts of controls. For example, if a certain type of emission control or emission limitation is determined to be too costly compared to the amount of emission reduction it achieves, that control might not be considered RACT. Also, as economic factors may vary by region, a control technology or emission limitation designated as meeting RACT in one location does not necessarily define RACT for another location.

This report summarizes the RACT analysis performed by CertainTeed Gypsum Manufacturing, Inc. (CertainTeed) and contains its source specific recommendations for RACT.

## 2.0 RACT Applicability

CertainTeed operates a wallboard manufacturing facility located in Clark County, Nevada. CertainTeed is located on Blue Diamond Road, approximately 20 miles west of the city of Las Vegas (T20S, R64E, Section 8) in the Las Vegas Valley, Clark County, Nevada (Hydrographic Area 212). It currently operates as a Part 70 major stationary source and according to the conditions contained in the Part 70 Operating Permit Source ID 4 issued by DAQ. AQR Section 120 RACT is required only if the permitted PTE for either VOC or $NO_x$ exceeds the serious nonattainment area major source threshold of 50 tons per year. According to Table 1 contained in the facility's current Part 70 operating permit, the PTE for $NO_x$ emissions is 84.86 tons per year and the PTE for VOC emissions is 27.16 tons per year so only $NO_x$ emissions exceed the serious nonattainment area major source thresholds. This analysis is therefore limited to emissions of $NO_x$.

## 3.0 Affected Emission Units Subject to RACT

As noted above, DAQ delineated the emission unit applicability requirement to a so-called "affected unit" that includes only those individual emission units at the major stationary source with a PTE that exceeds 5 tons per year. Table 1 lists the emission units at the CertainTeed facility that exceed this threshold for $NO_x$. Although the PTE for each of the kettle calciner burners, EUs G.8.4a(1)-g(7), exceeds the 5 tons per year threshold as currently permitted, they are not included in Table 1 since the permit application that includes this analysis requests a revision to their PTE which results in emissions below the threshold.

Except as noted, the $NO_x$ PTE for each emission unit is based 8,760 hr/year of operation. In addition to the PTE limits listed in Table 1, the CP mill is limited to burning only natural gas (Condition 2.2.7) and $NO_x$ emissions for the CP mill are limited to 40 parts per million (ppm), corrected to 3% oxygen (Condition 2.2.9). The diesel engine is required to be equipped with a turbocharger and aftercooler and operated and maintained in accordance with the manufacturer's operations and maintenance manual (Condition 2.2.8).

**Table 1 – Affected Emission Units Subject RACT**

| Emission Unit ID[1] | Description | Maximum Rating[2] | Manufacturer[2] | Model | Fuel Type | $NO_X$ PTE[3] (tons per year) |
|---|---|---|---|---|---|---|
| E.11 | CP Mill | 37 MMBtu/hr | Maxon | Kinedizer® LE | Natural gas | 7.88 |
| J.3 | AKI Board Dryer | 141 MMBtu/hr | Maxon | Crossfire | Natural gas | 28.41[4] |
| N.5 | Diesel Engine DOM: 2017 | 575 hp | Caterpillar | C-18 | Diesel | 5.73[5] |

Notes: [1] Emission Unit ID from Part 70 Operating Permit Table 1-1: List of Emission Units.
[2] Refers to fuel burning component of emission unit only.
[3] PTE from Part 70 Operating Permit Table 3-1: Emission Unit PTE (tons per year).
[5] Not including PTE for paper heaters.
[6] Emissions based on 2,400 hours per year of operation.

## 4.0 RACT Analysis

The RACT analysis consists of various steps:

- Identification of existing equipment and baseline emissions
- Identification of available control options
- Elimination of technically infeasible control options
- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options
- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping and reporting requirements

RACT emissions limitations can take various forms depending on the type of source and as long as the emissions limitations achieve the required emissions reductions and are legally and practically enforceable through appropriate monitoring, recordkeeping and reporting requirements. In addition, RACT is a continuous emissions reduction requirement and must apply over the range of operations [steady-state, startup, shutdown, and malfunctions (SSM)]; however RACT can include alternative emissions limitations or work practices for SSM.

For uniformity of comparison, AQR Section 120 requires major sources to use a 6% interest rate to compute annualized costs. This rate was used in all cost analyses contained in this report. In addition, AQR Section 120 requires sources to use each emissions units permitted PTE as the base case for determining potential emission reductions associated with any control measures being evaluated for RACT. A cost-effectiveness threshold of $5,500/ton was used for this review, which is consistent with the October 19, 2023 DAQ RACT review report prepared for the ozone moderate nonattainment implementation plan.

## 5.0 $NO_x$ RACT Assessment

The RACT assessment follows the procedures outlined in Section 4.0 for each affected unit.

### 5.1 Existing Equipment and Baseline Emissions

The CP Mill system (EU E.11) is used to fine grind, dry (remove free moisture) and calcine (remove chemically bound water) the raw gypsum ($CaSO_4 \cdot 2H_2O$) to form stucco ($CaSO_4 \cdot ½H_2O$). Heat for the drying and calcining reaction in the system is provided by a Maxon Kinedizer LE low-$NO_x$ natural gas burner with a design rating of approximately 37 MMBtu/hr. The combined process stream, consisting of the stucco and combustion byproducts, flows through a large baghouse to separate the stucco product from the gas. This gas is then recirculated to the mill with a portion of it released to a stack in order to remove moisture from the system. The hot stucco product is conveyed through a cooling system. The heated exhaust gas from the cooling system is recirculated to the CP Mill burner combustion chamber to conserve heat and thereby lowering the amount of fuel burned for stucco production. $NO_x$ emissions from the system are limited to 40 ppm, corrected to 3% oxygen (0.049 lb $NO_x$/MMBtu) based on the equipment manufacturer's specifications. This results in a PTE and baseline emission rate of 7.88 tons of $NO_x$ per year.

The board dryer (EU J.3) removes excess moisture from wet gypsum boards after they have been formed and cut to length. It is a long, enclosed structure where boards are conveyed through a series of heating zones, using hot air to evaporate the water. The boards are passed through the dryer in multiple layers to conserve on space. The board dryer consists of four heating zones, each with its own low-$NO_x$ burner, to provide direct heating to the wallboard. The burners are fired with natural gas and the design rating of the burners in zones 1, 2, 3, and 4 range from 18 - 50 MMBtu/hr with a total heat input capacity of 141 MMBtu/hr. The burners consist of Maxon Crossfire nozzle-mixing, modular line, low-$NO_x$ burners. This type of burner is typical for board dryers since they can be configured to provide direct heat across the entire width of the dryer for uniform temperature distribution and the number of individual modular burners required is therefore dependent on the width of the dryer. Moisture removed from the board and emissions associated with the burners are exhausted to the atmosphere through a single stack near the end of the dryer. $NO_x$ emissions from the system are based on the results of stack testing performed when the dryer was installed. The emission factor derived from this testing is 0.046 lb $NO_x$/MMBtu (approximately 38 ppm). This results in a PTE and baseline emission rate of 28.41 tons of $NO_x$ per year.

The diesel engine is associated with the Crambo portable, self-propelled, waste wallboard grinding machine. The engine is integral to the machine and directly powers the low speed, high torque, dual shaft shredding screws within the machine as well as providing power for locomotion. The engine is a 575 hp Caterpillar model C-18 manufactured to meet U.S. EPA Tier 3 emission standards for $NO_x$. It is equipped with a turbocharger and aftercooler, and operated and maintained in accordance with the manufacturer's operations and maintenance manual. In addition, the operation of the equipment associated with the engine is limited to 2,400 hours per any consecutive 12-month period. This results in a PTE and baseline emission rate of 5.73 tons $NO_x$ per year.

### 5.2 Identification of Available Controls

As described above, the CP Mill and board dryer systems are of a unique design quite dissimilar to other conventional combustion systems used to provide process heat (e.g., steam boilers). Designs for calciners and board dryers in the gypsum wallboard industry are highly customized to each particular site application based on the nature and properties of the supplied gypsum, desired production rates and range of wallboard products, the plant footprint and layout limitations, as well as numerous other factors. Therefore, it is not feasible to compare these systems and their related emissions levels to other types of

fuel-burning systems. For this reason, the identification of available controls in this analysis is limited to those options that have been demonstrated to be effective for existing gypsum wallboard manufacturing facilities.

A typical starting point for conducting RACT analyses is to search the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) for records of RACT/BACT/LAER determinations that could be relevant. Although comparisons with other systems are difficult without detailed process equipment information, the RBLC was searched for process codes 90.017 (Calciners and Dryers and Mineral Processing Facilities) and 90-024 (Non-metallic Mineral Processing (except 90.011, 90.019, 90.017, 90.026)) and the pollutant $NO_x$. However, in the past 10 years there were no applicable entries in the RBLC for these processes.

In addition, suitable technology and corresponding emission limits that satisfy RACT for the CP Mill and board dryer were identified through a review of general technical literature on $NO_x$ control; other jurisdiction's rules and regulations regarding RACT for calciners and dryers; other facility permits; burner manufacturer literature; facility stack test results.; and discussions with burner suppliers familiar with gypsum wallboard process units.

Based on the review of general technical literature on $NO_x$ control, various $NO_X$ control options were identified for evaluation. Post-combustion add-on control technologies available for $NO_X$ control for the CP Mill and board dryer include Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). However, both technologies require exhaust temperatures of 550 F to more than 1,000 F and the exhaust gas temperatures of the CP Mill and board dryer are both less than 300 F. For this reason, neither of these post-combustion controls options is considered technically feasible. Flue gas recirculation (FGR) was also identified for $NO_x$ control in the literature. However, both the CP mill and board dryer process equipment is not capable of being configured to reroute flue gas to the burners. The literature review also identified low-$NO_x$ and ultra low-$NO_x$ burner technologies that reduce $NO_x$ emissions through the use of control staged combustion (either staged air or staged fuel or both) within the burner (as opposed to within the combustion zone) to reduce $NO_x$ formation. These options are considered technically feasible and are discussed in more detail below.

The review of other jurisdiction's rules and regulations regarding RACT for calciners and dryers was only able to identify a few regulations with such requirements. The most stringent that were noted include certain air quality management districts in California that limit $NO_x$ emissions for these types of sources to less than 30 ppm for processes operating at less than 1,200 F and 60 ppm for processes operating at greater than 1,200 F which is within the range of what is considered low-$NO_x$ technology's capability. The lower limit is comparable to the operating temperature range of the board dryer and the higher limit to the CP mill. It was noted that Good Combustion Practices (GCP) which includes operating an emission unit in accordance with the manufacturer's O&M recommendations to maximize its energy output or thermal efficiency while maintaining optimized oxygen levels to assure complete combustion and compliance with emission limitations are also a component of the regulations reviewed. GCP is therefore considered as an important addition to any $NO_x$ RACT control option evaluated.

In order to determine what level of emissions low-NOx and ultra low-NOx technologies are capable of achieving, an extensive search for information regarding currently permitted facilities (including those owned and operated by CertainTeed) with the same or similar equipment used for calcining of gypsum and drying of gypsum wallboard was conducted to determine the emissions levels achievable in practice with low-NOx and ultra low-NOx burner technology. However, since permitted emissions are frequently

established at significantly higher levels than the actual capability of the equipment, the review of other facility permits and applications was only able to identify a few facilities that did not just simply rely on a published emission factor (AP-42) for allowable emissions of $NO_x$ for calciners and dryers for gypsum wallboard production. The AP-42 emission factor used for many recently constructed and permitted facilities is approximately 0.1 lb $NO_x$/MMBtu and so likely does not represent the actual capability of the equipment with respect to $NO_x$ emissions. In addition, most permits and applications reviewed did not contain any information regarding the specific type of burners installed or manufacturer's guaranteed $NO_x$ emissions levels. Despite these limitations, a small number of facilities were noted to be permitted at lower levels and stack test reports that were reviewed indicate that $NO_x$ emissions associated with board dryers for gypsum wallboard production are capable of being controlled to an ultra low-$NO_x$ level. The same conclusion could not be made for the CP mill. Options for the CP mill were discussed with two separate burner suppliers and both indicated the current burners represent the state of the art for $NO_x$ emissions for the particular operating conditions required for use with a CP mill. One supplier indicated that a newer ultra low-$NO_x$ burner that is currently available for small installations (less than 10 MMBtu/hr) may be made available for larger installations in 2026. Although not currently available, this technology is being conservatively included in this analysis to provide a potential long-term option for reducing $NO_x$ emissions for the CP mill. It should also be noted that the current CP mill burner was installed with a 2023 permit revision that reduced the facility's PTE for $NO_x$ by approximately 10 tons per year.

Based on the review described above and a review of manufacturer's literature for the specific types of burners that are feasible for the CP mill and board dryer, this analysis has established a maximum achievable $NO_x$ level for further analysis of 18 ppm for the CP mill and 10 ppm for the board dryer. Table 2 summarizes the selection of available and technologically feasible control options for the CP mill (EU E.11) and the board dryer (EU J.3).

**Table 2 – CP Mill and Board Dryer Control Options Summary**

| EU | Control Option | $NO_x$ Control Level | Potential Emission Reduction (%) |
|---|---|---|---|
| E.11 | GCP/Low $NO_x$ burners[1] | 40 ppm (0.049 lb/MMBtu) | NA |
| E.11 | GCP/Ultra-Low $NO_x$ burners | 18 ppm (0.018 lb/MMBtu)[2] | 55 |
| J.3 | GCP/Low $NO_x$ burners[1] | 38 ppm (0.046 lb/MMBtu) | NA |
| J.3 | GCP/Ultra-Low $NO_x$ burners | 10 ppm (0.012 lb/MMBtu)[3] | 74 |

Notes: [1] Current emission control technology for existing equipment.
[2] Manufacturer literature only states $NO_x$ emissions can be reduced to 45% of a conventional burner.
[3] Manufacturer literature states $NO_x$ emissions are as low as 5 ppm, however, based on discussions with burner suppliers, the actual manufacturer guarantees obtained for board dryers is 10 ppm.

A review of available controls to reduce emissions from the 575 hp diesel engine associated with the waste wallboard grinder did not identify any technology that is technically feasible or viable. As noted above, the equipment is designed to be portable. In practice, the machine, which is self-propelled, is routinely moved to different locations within the waste wallboard processing area. For this reason, add-on controls such as Selective Catalytic Reduction or Direct Water Injection which may be feasible for stationary engines, is not feasible for this type of application. As noted above, the engine is manufactured to meet U.S. EPA Tier 3 emission standards for $NO_x$. Although ignition retardation may be technically feasible,

engine manufacturer's restrictions typically limit any significant timing adjustments to avoid severe impacts on engine durability and compliance with other emission standards. This option therefore does not represent a technically viable option. Non-road industrial duty engines of this size are available with more efficient built-in $NO_x$ control. These engines are manufactured to meet U.S. EPA Tier 4 emission standards for $NO_x$. Komptech, the manufacturer of the Crambo waste wallboard grinder offers units equipped with Tier 4 certified engines. However, due to the significant differences in the size (a Tier 4 engine being significantly larger due mainly to exhaust aftertreatment additions), weight and the complexity of controls, a retrofit is not technically feasible. For this reason, although technically feasible, consideration of a Tier 4 certified engine as an option is only possible with a complete replacement of a machine designed and built to accommodate the Tier 4 engine with advanced controls. An engine manufactured to meet U.S. EPA Tier 4 emission standards for $NO_x$ represents an approximately 90% reduction in NOx emissions compared to one that is manufactured to meet U.S. EPA Tier 3 emission standards.

**5.3 Cost Effectiveness of Controls**

In order to determine the cost-effectiveness of each control option, the total annualized capital and operating costs are compared to the potential emissions reduction to derive a value of cost per ton of pollutant removed ($/ton). The total annualized capital cost is calculated by applying a capital recovery factor to the total capital investment which includes both the initial capital investment and any direct and indirect costs. The capital recovery factor is based on the estimated equipment life in years and the applicable investment interest rate.

The cost of the ultra low-$NO_x$ control option for the CP mill is based on the actual costs incurred for the recent CP mill burner replacement noted in Section 5.2. Replacement with an ultra low-$NO_x$ burner would be more expensive so this cost represents a conservatively low estimate of what the actual cost would be. The $360.480 cost includes equipment, engineering, installation, start-up and tuning.

The cost of the ultra low-$NO_x$ control option for the board dryer is based on the actual costs incurred for a complete replacement of the burner system for a similar CertainTeed facility (140 MMBtu/hr board dryer) in 2017. The $1,944,182 cost includes equipment, engineering, installation, start-up and tuning. The Chemical Engineering Plant Cost Index (CEPCI) was used to estimate the increase in cost from 2017 to 2025. One burner supplier estimated an installed cost of more than $2.2 MM so the 2017 adjusted cost represents a conservatively low estimate for this analysis.

The $916,850 cost of the equipment replacement option for the continuous duty diesel engine is conservatively based on the actual cost of a used Crambo equipped with Tier 4 engine and includes an estimate of taxes and a delivery charge.

As noted in Section 4, an interest rate of 6% was used in the calculation of the capital recovery factor. In addition, an estimated equipment life of 20 years was used for both the CP Mill and board dryer reflecting the estimated useful life of each. At present, both are more than 25 years old so 20 years represents a conservative estimate. The installation of new burners would not affect the estimated remaining useful life of the equipment overall and the newer burners would not be useful as a retrofit for a new CP mill or board dryer. An estimated equipment life of 30 years was used for the Crambo replacement (continuous duty diesel engine).

The detailed cost effectiveness calculations for each control option are provided in Attachment A. A summary of the results is provided in Table 4 below.

**Table 4 – Cost-effectiveness Calculation Summary**

| EU | Control Option | Emission Reduction (tons per year) | Total Annualized Cost ($) | Cost-effectiveness ($/ton) |
|---|---|---|---|---|
| E.11 | GCP/Ultra Low-NOx Burners | 4.33 | 31,428 | 7.252 |
| J.3 | GCP/Ultra Low-NOx Burners | 21.02 | 169,503 | 8,063 |
| N.5 | Tier 4 Equipment Replacement | 5.16 | 78,128 | 15,150 |

As shown above, the calculated cost-effectiveness of each option analyzed exceeds the RACT threshold of $5,500.

### 5.4 Evaluation of the Benefits and Disadvantages

Evaluation of the benefits and disadvantages includes an evaluation of any additional environmental, energy and economic impacts associated with the control technologies evaluated for RACT. These additional impacts are discussed in this section.

Environmental Impacts

Installation of ultra low $NO_x$ burners typically results in an increase in carbon monoxide (CO) emissions potentially offsetting the benefit of $NO_x$ emissions reduction and may necessitate a revision to the current permit.

Energy Impacts

It is anticipated that only minimal adverse energy impacts would be associated with an ultra low $NO_x$ burner technology since there would be a minimal decrease in burner efficiency.

Economic Impacts

Installation of any of the control options identified would entail significant capital costs. As shown above in Section 5.3, the cost-effectiveness of the control options evaluated exceeds the established RACT threshold of $5,500 per ton.

### 5.5 $NO_x$ RACT Determination

After reviewing similar facilities for emission control technologies, eliminating technically infeasible options and evaluating the remaining technologies for environmental, energy, and economic impacts it is determined that the existing low-$NO_x$ burners on the CP Mill and AKI board dryer and the Tier 3 level of

control for the continuous-duty engine diesel engine on the grinder satisfy RACT for compliance with AQR Section 120.

The specific RACT control, monitoring, testing, recordkeeping and reporting conditions necessary to ensure compliance are described below.

RACT Control Requirements

For the CP Mill (EU: E11):
(1) Limit $NO_x$ emissions to 40 ppmvd at 3% O2, excluding startup and shutdown;
(2) Limit $NO_x$ emissions PTE to 7.88 tons per year;
(3) Use only pipeline-quality natural gas; and
(3) Operate and maintain the units using GPC during startup, shut-down, and other non-normal operations, to include operating the units in accordance with the manufacturer's O&M manual.

For the AKI board dryer (EU: J.5):
(1) Limit $NO_x$ emissions PTE to 7.88 tons per year; and
(2) Use only pipeline-quality natural gas; and
(3) Operate and maintain the units using GPC during startup, shut-down, and other non-normal operations, to include operating the units in accordance with the manufacturer's O&M manual.

For the continuous-duty engine diesel engine (EU: N.5):
(1) Equip engine with a turbocharger and aftercooler;
(2) Operate In compliance with the emissions limits and requirements of applicable federal regulations incorporated by reference in AQR 14.2; and
(3) Use GCP, to include operating the units in accordance with the manufacturer's O&M manual.

RACT Monitoring, Testing, Recordkeeping and Reporting Requirements

No additional monitoring, testing, recordkeeping or reporting requirements are required.

**Attachment A - Cost Effectiveness Calculations**

| COST EFFECTIVENESS CALCULATION | |
|---|---|
| CERTAINTEED GYPSUM MANUFACTURING, INC. | |
| CP MILL | |
| **Emissions Unit** | E.11 |
| Pollutant | NOx |
| Control Technology | LOW NOX STAGED |
| Baseline Emissions Rate (tpy) | 7.88 |
| Emissions Reduction (%) | 55% |
| Controlled Emissions (tpy) | 3.55 |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment[1] | 360,480 |
| Direct & Indirect Costs | |
| Total Capital Investment | 360,480 |
| Estimated Equipment Life, years | 20 |
| Interest Rate, % | 6.00% |
| Capital Recovery Factor[2] | 0.087 |
| Annualized Total Capital Investment[3] | 31,428 |
| | |
| **Annual Operating Costs** | |
| | |
| | |
| | |
| | |
| **Total Annualized Cost** | **31,428** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 4.33 |
| Cost Effectiveness ($/ton) | **7,252** |

[1] Includes all direct and indirect costs.

[2] Capitol Recovery Factor = $r(1 + r)^n / ((1 + r)^n - 1)$, where r is the interest rate and n is the equipment life in years

[3] Annualized Total Capital Investment = Total Capital Investment x Capital Recovery Factor

| COST EFFECTIVENESS CALCULATION | |
|---|---|
| CERTAINTEED GYPSUM MANUFACTURING, INC. | |
| AKI BOARD DRYER | |
| **Emissions Unit** | J.3 |
| Pollutant | NOx |
| Control Technology | ULTRA LOW NOX |
| Baseline Emissions Rate (tpy) | 28.41 |
| Emissions Reduction (%) | 74% |
| Controlled Emissions (tpy) | 7.387 |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment[1] | 1,944,182 |
| Direct & Indirect Costs | |
| Total Capital Investment | 1,944,182 |
| Estimated Equipment Life, years | 20 |
| Interest Rate, % | 6.00% |
| Capital Recovery Factor[2] | 0.087 |
| Annualized Total Capital Investment[3] | 169,503 |
| | |
| **Annual Operating Costs** | |
| | |
| | |
| | |
| | |
| **Total Annualized Cost** | **169,503** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 21.02 |
| Cost Effectiveness ($/ton) | **8,063** |

[1] Includes all direct and indirect costs. 2017 cost from similar facility of $1,388,701 adjusted for CEPCI (796.5/567.5)

[2] Capitol Recovery Factor = $r(1 + r)^n / ((1 + r)^n - 1)$, where r is the interest rate and n is the equipment life in years

[3] Annualized Total Capital Investment = Total Capital Investment x Capital Recovery Factor

| COST EFFECTIVENESS CALCULATION | |
|---|---|
| **CERTAINTEED GYPSUM MANUFACTURING, INC.** | |
| **CONTINOUS DUTY DIESEL ENGINE** | |
| **Emissions Unit** | N.5 |
| Pollutant | NOx |
| Control Technology | New Tier 4 Machiine |
| Baseline Emissions Rate (tpy) | 5.73 |
| Emissions Reduction (%) | 90% |
| Controlled Emissions (tpy) | 0.573 |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment[1] | 916,850 |
| Direct & Indirect Costs | |
| Total Capital Investment | 916,850 |
| Estimated Equipment Life, years | 30 |
| Interest Rate, % | 6.00% |
| Capital Recovery Factor[2] | 0.073 |
| Annualized Total Capital Investment | 66,608 |
| | |
| **Annual Operating Costs** | |
| Urea | 11,520 |
| | |
| | |
| | |
| **Total Annualized Cost** | **78,128** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 5.16 |
| Cost Effectiveness ($/ton) | **15,150** |

[1] Includes all direct and indirect costs.

[2] Capitol Recovery Factor = $r(1 + r)^n / ((1 + r)^n - 1)$, where r is the interest rate and n is the equipment life in years

[3] Annualized Total Capital Investment = Total Capital Investment x Capital Recovery Factor

# ATTACHMENT 6B: CertainTeed Gypsum Manufacturing RACT Supplemental

| COST EFFECTIVENESS CALCULATION | |
|---|---|
| CERTAINTEED GYPSUM MANUFACTURING, INC. | |
| CONTINOUS DUTY DIESEL ENGINE | |
| **Emissions Unit** | N.5 |
| Pollutant | NOx |
| Control Technology | New Tier 4 Machiine |
| Baseline Emissions Rate (tpy) | 5.73 |
| Emissions Reduction (%) | 90% |
| Controlled Emissions (tpy) | 0.573 |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment[1] | 916,850 |
| Direct & Indirect Costs | |
| Total Capital Investment | 916,850 |
| Estimated Equipment Life, years | 30 |
| Interest Rate, % | 6.00% |
| Capital Recovery Factor[2] | 0.073 |
| Annualized Total Capital Investment | 66,608 |
| | |
| **Annual Operating Costs** | |
| Urea | 11,520 |
| | |
| | |
| | |
| **Total Annualized Cost** | **78,128** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 5.16 |
| Cost Effectiveness ($/ton) | **15,150** |

[1] Includes all direct and indirect costs.

[2] Capitol Recovery Factor = $r(1 + r)^n / ((1 + r)^n - 1)$, where r is the interest rate and n is the equipment life in years

[3] Annualized Total Capital Investment = Total Capital Investment x Capital Recovery Factor

# ATTACHMENT 7A: NV Energy Las Vegas Generating Station RACT

NVEnergy

RECEIVED CC DAQ
2025 JUL 28 PM4:03

July 24, 2025

Theodore Lendis
Planning Manager
Clark County Department of Environment and Sustainability
Division of Air Quality
4701 W. Russell Road
Las Vegas, NV 89118

Re: Response to Regulatory Notification – Major Stationary Source RACT Requirements
Letter Dated April 3, 2025

Dear Mr. Lendis:

Nevada Power Company, d/b/a, NV Energy (NVE) owns and operates Clark (Source 7), Sun Peak (Source 423) and Las Vegas (Source 329) Generating Stations, electrical power generating stations located in Hydrographic Area 212 within Clark County, Nevada. Per your letter dated April 3, 2025, the Division of Air Quality (DAQ) has informed NV Energy that compliance with applicable requirements of Air Quality Regulation (AQR) Section 120 is due on or before August 1, 2025, which is within 120 days after the Control Officer issues the written notice.

Reasonably Available Control Technology (RACT) applies to major stationary sources of nitrogen oxide (NOx) or volatile organic compounds (VOC). Major stationary sources defined in the Clean Air Act (CAA) Section §302(j) are any stationary facility or source of air pollutants which directly emits, or has the potential to emit, one hundred tons per year or more of any air pollutant. CAA Section 182(b) and (c) classifies major stationary source thresholds for NOx and VOC in moderate and serious nonattainment areas if the source emits or has the potential to emit 100 or 50 tons or more respectively. Clark Generating Station is a major source for both NOx and VOC while Sun Peak Generating Station is only major for NOx emissions under the moderate nonattainment designation.

On January 21, 2025, Hydrographic Area 212 within Clark County, Nevada received a serious nonattainment designation (Federal Register dated December 9, 2024). Consequently, the Las Vegas Generating Station underwent a RACT evaluation, as it qualifies as a major source of NOx under this designation. Las Vegas Generating Station is only major for NOx under the serious nonattainment designation.

Per the referenced letter and your email dated April 30, 2025, included below, and attached are:

- Applicable sections of the final "Case-By-Case RACT for Major VOC and NOx Sources in Hydrographic Area 212", prepared for Clark County Department of Environment and

Sustainability by RTP Environmental Associates, dated October 19, 2023, for Clark and Sun Peak Generating Stations.

- The required verbiage as stated in AQR Section 120.5(c) attesting that the RACT determination remains RACT for Clark and Sun Peak Generating Stations.

- A RACT evaluation and permit application as required in AQR Section 120 for Las Vegas Generating Station.

*I certify the basis of the Clark and Sun Peak RACT determinations continue to be RACT because there are no relevant changes to the available control technologies, technical feasibility, control effectiveness, cost effectiveness, or environmental, energy, and other impacts since the determinations were initially performed.*

If you have any questions or comments about the information presented in this letter, please do not hesitate to contact me at Mathew.Johns@nvenergy.com.

Sincerely,

Jason Hammons
Vice President, Generation
Responsible Official
NV Energy

cc: Matt Johns, NV Energy
Jason Reed, NV Energy
Chris Heintz, NV Energy

# Las Vegas Generating Station (Source ID: 329)

# Reasonably Available Control Technology (RACT) Review for NOx Emissions

## Las Vegas Generating Station

Prepared for:




NV Energy
6226 W Sahara Ave
Las Vegas, NV 89146

Prepared by:

AECOM

AECOM Technical Services, Inc.
250 Apollo Drive
Chelmsford, MA 01824

July 2025

# 1.0 Overview

On August 3, 2018 the Environmental Protection Agency (EPA) classified a portion of the Las Vegas Valley as a marginal non-attainment area for the 2015 National Ambient Air Quality Standard (NAAQS) for ozone. In a Federal Register notice published on July 22, 2022 the EPA proposed to find that this area had failed to attain the ozone NAAQS by the originally designated attainment date (August 3, 2021). Accordingly, the agency proposed to reclassify the area to a serious non-attainment area for this pollutant. Subsequently, in a Federal Register notice published on December 19, 2024, EPA finalized the Las Vegas Valley non-attainment area designation. In the final notice, the area was classified as a serious non-attainment area based on the area's 2021 – 2023 ambient ozone monitoring data.

The area reclassification triggers certain statutory requirements for the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ), which is the air regulatory agency responsible for ensuring that the Las Vegas Valley complies with the NAAQS. In particular, the DAQ is mandated to prepare and submit State Implementation Plan (SIP) revisions to the EPA that include provisions for major sources in the area. Per DAQ rule§12.3.2(r)(1)(C)(ii), in serious non-attainment area for ozone, a source with a potential-to-emit (PTE) of at least 50 tons/yr (tpy) of nitrogen oxides (NOx) or volatile organic compounds (VOC) is classified as a major source.

According to its Part 70 Operating Permit, the NOx and VOC PTEs for NV Energy's Las Vegas Generating Station (LVGS) are 94.66 tpy and 35.56 tpy, respectively. As such, the LVGS is a major source for NOx emissions but not for VOC emissions. Consequently, the station is only subject to the requirement to demonstrate RACT for NOx.

The principal emission units at the LVGS are five 44 MW natural gas-fired combined cycle generating systems. Each system utilizes GE LM-6000 stationary combustion turbines, with one equipped with a heat recovery steam generator and the other four equipped with once-through steam generators. Supplemental firing is not conducted in any of these units. The generating systems (designated as Units 1 – 5) are each equipped with selective catalytic reduction (SCR) and water injection to control NOx emissions and oxidation catalyst systems to control carbon monoxide (CO) and VOC emissions. Unit 1 is subject to a NOx emission limit of 10 ppmv @ 15% O2, whereas Units 2 – 5 are each subject to a NOx limit of 2.0 ppmv @ 15% O2. Each generating system is equipped with NOx and CO continuous emissions monitors. Units 2 – 5 are collectively limited to a total of 30,480 operating hours and a total of 792 startup/shutdown occurrences in any consecutive 12-month period.

The DAQ has exempted from RACT consideration any emission units at major sources that have potential emission rates that are less than or equal to 5 tpy. Accordingly, the emergency firewater pump at the LVGS is not subject to the RACT requirement.

EPA has defined RACT[1] as "... the lowest emission limitation a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." RACT can be the use of add-on controls, process modifications, or any other means by which to reduce NOx and/or VOC emissions. RACT may also be a numerical emission limit or specified emission reduction percent, or a commitment to a set of enforceable process modifications.

The DAQ requires that RACT be assessed on a case-by-case basis, including identification of potential additional emission control options for each unit and an evaluation of the feasibility of installing such options

[1] 44 Federal Register 53672, September 17, 1979

considering any specific technical or economic feasibility considerations for each particular unit subject to evaluation.

# 2.0 RACT Assessment Methodology

A five-step approach to conducting this RACT assessment has been utilized. The steps, which are similar to the steps that are followed when conducting a top-down Best Available Control Technology (BACT) assessment, are:

- Identification of available control options
- Elimination of technically infeasible alternatives,
- Determination of the cost effectiveness of each remaining option,
- Evaluating the benefits and disbenefits associated with each option, and
- Identification of RACT

The following sections describe the five factors that make up the RACT assessment approach that was utilized in this analysis for the existing emission units at the LVGS.

**Step 1 – Identification of Available Options**

The first step consists of defining the spectrum of process and/or add-on control alternatives potentially applicable to the subject emissions unit.

A control technology must be "available" to be considered in a RACT determination. This means that the technology has progressed beyond the conceptual stage and pilot testing phase and must have been demonstrated successfully on full-scale operations for a sufficient period. Theoretical, experimental, or developing technologies are not "available" under RACT. A control technology is neither demonstrated nor available if government subsidies are required to fund evaluations of the technology. In many cases, a technology is not "available" for all sizes of a unit. A control technology must also be "commercially available." This means that the technology must be offered for sale through commercial channels with commercial terms.

The following categories of technologies are addressed in identifying candidate control alternatives:

- Demonstrated add-on control technologies applied to the same emissions unit at other similar source types;
- Add-on controls not demonstrated for the source category in question but transferred from other source categories with similar emission stream characteristics;
- Combustion controls;
- Add-on control devices serving multiple emission units in parallel; and
- Equipment or work practices, especially for fugitive or area emission sources where add-on controls are not feasible.

There is no specific methodology that is required to be used to identify all available emission control technologies and levels for a given source or pollutant. The most comprehensive source of this information, however, is EPA's RACT/BACT/LAER Clearinghouse (RBLC). This searchable database of emission control technology determinations is maintained by EPA, and as such is generally the starting point for developing the required ranking of emission control technologies and levels.

**Step 2 – Technical Feasibility**

The second step is an evaluation of the technical feasibility of the identified alternatives and to reject those that can be demonstrated as technically infeasible based on an engineering evaluation or on chemical or

physical principles. The following criteria were considered in determining technical feasibility: previous commercial-scale demonstrations, precedents based on issued PSD permits, state requirements for similar sources, technology transfer, and engineering evaluations for the control devices or work practice standards considered.

**Step 3 – Economic Feasibility/Cost Effectiveness**

The economic evaluation is carried out using procedures recommended by the EPA's Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual[2]. The economic evaluation looks at the annualized control cost (in dollars per ton of emissions removed) for a particular control technology or level on the source under consideration in comparison to commonly accepted values for cost effective emission controls established by the state regulatory agency. As noted above, this is a site-specific evaluation and the fact that a particular technology or level of emissions control has been concluded to be representative of RACT at another facility does not mean that the same technology or level constitutes RACT for the existing units at the LVGS.

**Step 4 – Benefits and Disbenefits**

The fourth step consists of an objective evaluation of the advantages and disadvantages of each alternative, including any significant or unusual impacts to other media (i.e., water, solid waste, etc.) as well as adverse energy or environmental impacts, including emissions of toxic or hazardous air pollutants.

**Step 5 – Identification of RACT**

The final step in the process is to summarize the selection of RACT and propose the associated emission limits or work practices to be incorporated into the permit plus any recommended recordkeeping and monitoring conditions that should be incorporated into the final permit.

[2] EPA, *EPA Air Pollution Control Cost Manual*, at Sec. 1, Ch. 2 (7th ed. 2018).

# 3.0 Baseline Actual and Future Projected Actual Emissions

All the emission units that are the subject of this study are operated in an intermittent fashion when dispatched to supply electricity to the grid during periods of peak power demand. Typically, the units operate more often in the summer months; however, they are dispatched as needed year-round. In the most recent five years, the annual output of each unit has been considerably lower than its potential output capacity, as is shown in Table 3-1. Units 2 – 5 are limited as a group to a combined total of 30,480 hours per year, so the potential output of the units in this group are best represented by their combined total rather than as individual units.

**Table 3-1: LVGS Actual Output Data by Unit, 2020 – 2024 (MWhr/yr)**

| | Potential Output | Actual Output | | | | |
|---|---|---|---|---|---|---|
| | | 2020 | 2021 | 2022 | 2023 | 2024 |
| Unit 1 | 385,440 | 56,565 | 48,668 | 37,342 | 33,144 | 38,704 |
| Unit 2 | | 51,292 | 55,065 | 51,556 | 64,992 | 82,760 |
| Unit 3 | | 48,917 | 55,162 | 50,455 | 63,017 | 82,879 |
| Unit 4 | | 53,191 | 56,878 | 49,606 | 57,228 | 82,997 |
| Unit 5 | | 53,021 | 57,036 | 50,917 | 59,160 | 82,407 |
| Units 2 – 5 Total | 1,341,120 | 206,421 | 224,141 | 202,533 | 244,397 | 331,043 |

Because of each unit's low actual output level, annual NOx emissions from each unit over the past five years have also been low, as shown in Table 3-2.

**Table 3-2: Actual LVGS NOx Emissions by Unit, 2020 – 2024 (tons/yr)**

| | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Unit 1 | 6.98 | 5.65 | 3.80 | 3.84 | 5.27 |
| Unit 2 | 2.35 | 2.56 | 2.89 | 3.44 | 3.95 |
| Unit 3 | 2.44 | 2.61 | 3.60 | 3.69 | 4.10 |
| Unit 4 | 2.33 | 2.45 | 2.77 | 2.93 | 4.19 |
| Unit 5 | 2.74 | 2.64 | 2.99 | 3.08 | 3.87 |

Source: EPA CAMP Database

With respect to the expected future operation of these units, as part of its Life Span Analysis Process (LSAP), NV Energy periodically makes planning forecasts of the annual output levels for each of the generating system assets at the LVGS. Table 3-3 compares the average of the forecasted annual output levels for each unit over the course of the next ten years (i.e., 2025 – 2034) with the maximum two-year

annual average output for each unit in the past five years. This comparison demonstrates that the forecasted future average output of each of these assets will be less than their actual annual average output over the past five years.

**Table 3-3: Comparison – Actual and Forecasted Future Annual Output by Unit**

| | Maximum Annual (Two-Year Average) Actual Output (MWhr/yr) | Forecasted Future Annual Average Output (MWhr/yr) |
|---|---|---|
| Unit 1 | 52,617 | 49,898 |
| Unit 2 | 73,876 | 46,936 |
| Unit 3 | 72,948 | 46,936 |
| Unit 4 | 70,112 | 48,230 |
| Unit 5 | 70,784 | 48,230 |

Therefore, NV Energy asserts that the highest two-year actual annual average emissions rate from each unit over the past five years represents a conservative prediction of the unit's future projected actual emissions over the next ten years. The projected future actual emission rates calculated on this basis are shown below in Table 3-4.

**Table 3-4: Projected Future Actual NOx Emission Rates by Unit**

| | Projected NOx Emissions (ton/yr) |
|---|---|
| Unit 1 | 6.32 |
| Unit 2 | 3.70 |
| Unit 3 | 3.89 |
| Unit 4 | 3.56 |
| Unit 5 | 3.47 |

# 4.0 RACT for Nitrogen Oxides Emissions

## 4.1 Formation

$NO_x$ emissions are formed in combustion sources in three ways: 1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NOx), 2) the oxidation of nitrogen contained in the fuel (fuel NOx), and 3) the reaction of molecular nitrogen with certain free radical compounds (e.g., $NH_2$) that are typically present in the fuel-rich zones of a combustion flame. Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen, and at typical combustor conditions, the contribution of free radical-based (or "prompt") NOx formation is relatively small. Therefore, the most predominant formation mechanism for NOx emissions from natural gas fired combustion turbine units is thermal NOx. The rate of formation of thermal NOx is a function of residence time and free oxygen concentration; it increases exponentially with increasing peak flame temperature.

"Front end" NOx control techniques are aimed at controlling thermal NOx and/or fuel NOx. The two primary front-end combustion control types for combustion turbine systems include water or steam injection into the combustor and specific combustor design features. The addition of an inert diluent such as water or steam into the high temperature region of the combustor decreases NOx formation by quenching peak flame temperature. Combustor design improvements, specifically the development of dry low-NOx (DLN) combustors, limit peak flame temperature and excess oxygen with lean, pre-mix flames that decrease NOx formation to levels that are equal or better than achieved via water or steam injection when burning natural gas.

Other control methods, known as "back-end" or post combustion controls and described in greater detail in the following subsections, remove NOx from the exhaust gas stream once it has been formed.

## 4.2 Description of Existing NOx Controls

The combustion turbine-based generating systems at the LVGS (Units 1 – 5) are equipped with Singular Annular Combustor (SAC) systems that utilize water injection for power augmentation and NOx control, followed by and SCR systems to further control NOx emissions. Unit 1 is required to meet a NOx emission limit of 10 ppmv @ 15% O2, while Units 2 – 5 are required to meet a NOx emission limit of 2.0 ppmv @ 15% O2.

## 4.3 Step 1 - Available NOx Control Alternatives

Available control technologies to reduce NOx emissions include SCR systems, DLN combustors, and water or steam injection which are each discussed in the following sections.

**Selective Catalytic Reduction (SCR)**

SCR is a process which involves post combustion removal of NOx from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the combustion turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The SCR process converts nitrogen oxides to nitrogen and water by the following chemical reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \qquad (1)$$

$$6\ NO + 4\ NH_3 \rightarrow 5\ N_2 + 6\ H_2O \qquad (2)$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \qquad (3)$$

$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H2O \qquad (4)$$

$$NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O \qquad (5)$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NOx decomposition reactions. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to "crumbling," design of the $NH_3$ injection system, and high $NH_3$ slip.

For most SCR catalyst formulations, the NOx reduction reactions take place within the temperature range of 650 to 850°F. For combined-cycle units, the catalyst grid is installed within the heat recovery steam generator at a location where the combustion turbine exhaust temperature has been reduced by the steam generating banks to within this range.

SCR catalyst materials lose activity over time, necessitating catalyst cleaning or replacement. In base-loaded natural gas-fired applications, the expected SCR catalyst life is within the range of 32,000 to 80,000 operating hours.[3] Catalyst life is lower in non-base load applications as frequent temperature cycling associated with episodic use causes catalyst sintering and loss of activity.

**Dry Low NOx Combustors**

Combustion control techniques that utilize design and/or operational features of the turbine's combustors which reduce NOx emissions without injecting an inert diluent (water or steam) are generically referred to as "dry" Low NOx (DLN) measures. The design features of a DLN combustor design are vendor-specific, but generally DLN combustors seek to reduce thermal NOx formation by controlling peak combustion temperature, combustion zone residence time, and combustion zone free oxygen concentration. Alternatives include combustion distribution over several burner stages and pre-mixing air and fuel prior to injection into the combustion zone. These measures produce a lean, pre-mixed flame that burns at a lower flame temperature and excess oxygen levels than conventional combustors.

**Water or Steam Injection**

Water or steam injection as a NOx control alternative was concluded to represent the Best Demonstrated Technology (BDT) for control of NOx emissions from stationary combustion turbines when the original NSPS for this source category was promulgated in 1977[4]. This alternative involves the injection of water or steam into the high temperature region of the combustor flame, and as noted above all of the combustion turbine units at the LVGS are equipped with SAC combustor systems that utilize water injection. Thermal NOx formation is minimized with this alternative because peak combustion temperature, combustion zone residence time, and combustion zone free oxygen are all reduced. Water or steam injection also serves to augment a combustion turbine's power output due to the additional mass of fluid it provides through the turbine section.

## 4.4 Steps 2-3 - Technical Feasibility Assessment and Ranking of NOx Control Alternatives

A search of EPA's RBLC was carried out to identify listings containing NOx BACT or RACT determinations for large natural gas-fired combined-cycle units permitted since 2015. The results of this RBLC search are summarized in Appendix A.

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[3] EPA Air Pollution Control Cost Manual, Section 4 Chapter 2 "Selective Catalytic Reduction" (June 2019)

[4] 42 Fed. Reg. 53,782, 53,785 (Oct. 3, 1977).

Among the 101 combined-cycle unit listings in the RBLC that met these criteria there are 96 listings that identify the NOx emission control alternative. The following provides a breakdown of these listings for the emission control alternatives employed:

- 88 list the use of SCR (either alone or in conjunction with other alternatives),
- 71 list the use of DLN combustors,
- 4 list water or steam injection,
- 4 list natural gas or clean fuels, and
- 12 list good combustion practices.

Consequently, the use of SCR, DLN combustors, and water or steam injection are technically feasible alternatives for control of NOx emissions from natural gas-fired combined cycle units.

The lowest NOx emissions level among the natural gas-fired combined-cycle combustion turbine listings in the RBLC is 2 ppmv @15% $O_2$. This is the emission level for 76 of the 101 combined cycle turbine listings, and SCR is listed as the NOx emission control alternative for each of the listings where 2 ppmv @ 15% $O_2$ is the emission limit listed. SCR is also listed as the NOx emission control alternatives for each listing with the emission limit is 3 ppmv @ 15% $O_2$ or less. The emission limits for combined cycle combustion turbines listed as employing Dry Low NOx combustors, water or steam injection, or good combustion practices are generally 9 ppmv @ 15% $O_2$ or higher. Based on the RBLC search results, the hierarchy of NOx emission controls for natural gas-fired combined-cycle units is as follows:

- SCR, either alone or in combination with DLN,
- DLN alone, and
- Water or steam injection alone

As described previously in Section 1.0, all of the units at LVGS are already equipped with SCR and water injection, and so each unit already employs the most stringent alternative for NOx control for combined cycle combustion turbines. Units 2 – 5 are already subject to a NOx limit of 2 ppmv @15% $O_2$, which is equal to the lowest NOx emissions level listed for combined cycle combustion turbines in the RBLC. As such, there are no feasible alternatives available to further reduce NOx emissions from Units 2 – 5, and the current emission controls (use of SCR with an emissions limit of 2 ppmv @ 15% $O_2$) can be concluded to be representative of RACT for these units.

Unit 1 is currently subject to a NOx emissions limit of 10 ppmv at 15% $O_2$. A further reduction in this emissions limit would require an upgrade to the existing SCR system, either alone or in conjunction with replacing the existing turbine combustors.

GE LM-6000 combustion turbines, when equipped with DLN combustor systems, are typically capable of meeting a NOx concentration of 15 ppm in the turbine exhaust. Therefore, a straightforward replacement of the existing SAC combustors with DLN combustors alone would not yield an improvement in LVGS Unit 1's current NOx emissions profile.

Achieving a NOx emissions limit lower than the Unit's existing 10 ppm limit would therefore necessitate an upgrade to the unit's SCR system.

## 4.5 Step 4 – NOx Control Effectiveness Evaluation

### Economic Impacts

Because the current NOx emission limits on Units 2 – 5 at LVGS are already representative of RACT, this section focuses on the economic impact of further reducing NOx emissions from Unit 1 by improving the NOx removal efficiency of the existing SCR system. As noted above, replacing the SAC combustors with

DLN combustors alone would not be sufficient for Unit 1 to meet an emissions level lower than the unit's current emissions limit. Based on preliminary information received from Environex, Inc., a company that specializes in catalytic emissions control technologies and services for electric power generating stations, the SCR system serving Unit 1 would need to be upgraded in order for the unit to be capable of achieving the same NOx emissions level as LVGS Units 2 – 5 (2 ppm). The SCR system upgrade would include replacing the existing SCR catalyst with a new formulation, replacing the existing ammonia injection grid (AIG), and performing AIG tuning. Environex indicated that these upgrades would render the unit capable of meeting a 2 ppm emissions limit without needing to incur the expense of retrofitting Unit 1 with DLN combustors.

Table 4-1 summarizes the economic impact of these system changes; detailed cost calculations are provided in Appendix B.

The annualized costs of these system changes include capital recovery (estimated assuming a 20-year equipment life and NV Energy's Public Utility Commission-approved capital recovery rate of 7.14%, see page 9, item 4 of Appendix C), operating and equipment maintenance costs, and the additional cost of increasing the ammonia injection rate. Ammonia costs are estimated using the current unit cost for this material (19 weight% ammonia solution at $0.69/gallon) and a reagent consumption rate calculated from the estimated annual NOx reduction level. Operating and maintenance costs are estimated using factors presented in the EPA's OAQPS Control Cost Manual.

**Table 4-1: Estimated Economic Impact of Alternative NOx Controls: LVGS Unit 1**

| | **SCR System Upgrades** |
|---|---|
| Baseline Emissions Level (ton/yr) | 6.32 |
| Achievable Emissions Level (ton/yr) | 1.26 |
| Annual Emissions Reduction (tons/yr) | 5.06 |
| Total Installed Capital Cost | $1,242,680 |
| Annualized Capital Cost | $118,600 |
| Annual O&M Cost | $77,500 |
| Total Annualized Cost | $196,100 |
| Cost Effectiveness ($/ton removed) | $38,768 |

**Energy impacts**

There are adverse energy impacts associated with the use of SCR because backpressure imposed by the catalyst grid reduces the electrical generating capacity of a combustion turbine system. NV Energy may thus incur an energy penalty if the SCR system upgrade were to require more catalyst than the existing SCR system. In addition to the power generation efficiency losses, NV Energy may need to purchase additional generating capacity elsewhere to maintain the total system generating capacity that would be lost by installing additional catalyst.

**Environmental Impacts**

The use of SCR requires that a reducing agent (aqueous ammonia solution) be injected into the turbine exhaust to react with NOx, which creates two forms of adverse environmental impacts. Ammonia that is not consumed in the SCR system is discharged to the atmosphere as ammonia slip, and excess ammonia can react with $SO_2$ and $SO_3$ in the turbine exhaust to form ammonium salt compounds (ammonium sulfate and

ammonium bisulfate) which can foul downstream heat transfer equipment and/or be subsequently discharged as particulate matter. Also, the catalyst must periodically be regenerated and must be disposed of or recycled at the end of its useful life.

Reducing the NOx emission limit on Unit 1 from 10 ppm to 2 ppm would be expected to increase the amount of ammonia slip the unit discharges. In practice, an excess of ammonia is injected upstream of the SCR system to overcome mixing limitations between NOx and ammonia within the catalyst grid. Achieving lower NOx concentrations generally requires that a higher level of excess ammonia needs to be injected, thereby increasing the potential for ammonia slip to occur.

## 4.6 Step 5 - Evaluation of RACT for NOx Control

**Las Vegas Generating Station Unit 1:** For the Unit 1 combustion turbine at LVGS, the only available alternative to reduce NOx emissions is to improve the performance of the existing SCR system by upgrading the SCR catalyst and ammonia injection grid (AIG) and performing AIG tuning. However, considering the low rates that this unit has historically and is projected to operate in the future, only modest reductions in NOx emissions from the unit would be realized by implementing this alternative. Therefore, the cost effectiveness of this alternative on this unit is estimated to be extremely unreasonable at over $38,000 per ton removed, and the current NOx emission controls on the unit (use of SCR with an emissions limit of 10 ppmv @ 15% $O_2$) is concluded to be representative of RACT.

**Las Vegas Generating Station Units 2 - 5:** There are no NOx control alternatives available to improve the performance of the existing emission control on Units 2 – 5. The current NOx emission controls on these units (use of SCR with an emissions limit of 2 ppmv @ 15% $O_2$) represent the most stringent NOx control alternative for natural gas-fired combustion turbines, and thus the current NOx controls are concluded to be representative of RACT.

## Appendix A

## RACT/BACT/LAER Clearinghouse Search Results

**RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS**
**PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2015 and 7/1/2025**
**LISTINGS FOR NITROGEN OXIDES (NOx)**

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT DATE | PROCESS NAME | THROUGHPUT | THROUGHPUT UNIT | CONTROL METHOD DESCRIPTION | STANDARAD EMISSION LIMIT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| MI-0454 | LBWL-ERICKSON STATION | MI | 12/20/2022 | EUCTGHRSG1 | 667 | MMBTU/H | Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit. | 3 | PPM | PPMVD AT 15%O2; 24-HR |
| MI-0454 | LBWL-ERICKSON STATION | MI | 12/20/2022 | EUCTGHRSG2 | 667 | MMBTU/H | Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit. | 3 | PPM | @15%OX; 24-HR ROLL AVG EXCEPT |
| IL-0133 | CENTER (A/K/A EMBERCLEAR) | IL | 7/29/2022 | Combined-Cycle Combustion Turbines | 3647 | mmBtu/hour | Dry low-NOx combustion with ultra-low NOx combustors; low-NOx duct burners; and selective catalytic reduction (SCR) | 2 | PPMV @ 15% O2 | |
| *IN-0365 | | IN | 6/19/2023 | Combined Cycle Turbine CTGB | 4200 | MMBtu per hour | Selective Catalytic Reduction system and dry-low-NOx combustors. | 2 | PPMVD | |
| *IN-0365 | | IN | 6/19/2023 | Combined Cycle Turbine CTGA | 3800 | MMBtu per hour | Selective catalytic reduction system and dry-low-NOx combustors | 2 | 2 | @15% O2 BASED ON A 3-HR |
| LA-0391 | MAGNOLIA POWER LLC | LA | 6/3/2022 | Combined Cycle Gas Turbine w/ Duct Burners and HRSG | 5081 | mm BTU/h | Dry low-NOx combustor design, selective catalytic reduction (SCR), and good combustion practices. | 2 | PPMVD | 24-HR ROLLING AVG BASED ON 1- |
| LA-0391 | MAGNOLIA POWER LLC | LA | 6/3/2022 | Combined Cycle Gas Turbine Startup and Shutdown | 5081 | mm BTU/h | Good combustion practices. | | | |
| MI-0451 | MARSHALL ENERGY CENTER, LLC | MI | 6/23/2022 | EUCTGHRSG (North Plant): A combined cycle natural gas fired combustion turbine | 3064 | MMBTU/H | SCR with DLNB (Selective catalytic reduction with Dry low NOx burners) | 2.5 | PPM | 24-HR ROLLING AVG |
| MI-0452 | MARSHALL ENERGY CENTER, LLC | MI | 6/23/2022 | EUCTGHRSG (South Plant): A combined-cycle natural gas-fired combustion turbine | 3064 | MMBTU/H | SCR with DLNB [Selective Catalytic Reduction with Dry Low NOx Burners] | 2 | PPM | 24-HR ROLLING AVG |
| MI-0455 | COGENERATION VENTURE LIMITED | MI | 2/1/2023 | EUCTGHRSG1 | 4197.6 | MMBTU/H | Selective catalytic regeneration | 2 | PPM | PPMVD AT 15%O2; 24-HR |
| *AK-0088 | LIQUEFACTION PLANT | AK | 7/7/2022 | Four Combined Cycle Gas-Fired Turbines | 384 | MMBtu/hr | SCR, DLN combustors, and good combustion practices | 2 | PPMV @ 15% O2 | 3-HOURS |
| *WV-0033 | MAIDSVILLE | WV | 1/5/2022 | Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2) | 1275 | mw | Dry Low NOx Combustion w/ SCR | 2 | PPMDV @ 15% O2 | 3-HOUR ROLLING AVERAGE |
| *WV-0033 | MAIDSVILLE | WV | 1/5/2022 | Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2) | 1275 | mw | Dry Low NOx Combustor with SCR | 2 | PPMDV @ 15% O2 | 3-HOUR ROLLING AVERAGE |
| FL-0371 | SHADY HILLS COMBINED CYCLE FACILITY | FL | 6/7/2021 | GE 7HA.02 Combustion Turbine and HRSG with Duct Firing | 3622.1 | MMBtu/hour | Dry low-NOX combustors and Selective Catalytic Reduction (SCR) | 2 | PPMVD AT 15% O2 | 24-HOUR BLOCK AVERAGE BASIS (BACT) |
| MI-0447 | LBWL--ERICKSON STATION | MI | 1/7/2021 | EUCTGHRSG1 | 667 | MMBTU/H | Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit. | 3 | ppmvd @ 15% O2 | 24 hour rolling average |
| MI-0447 | LBWL--ERICKSON STATION | MI | 1/7/2021 | EUCTGHRSG2 | 667 | MMBTU/H | Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit. | 3 | ppmvd @ 15% O2 | 24 hour rolling average |
| AL-0328 | PLANT BARRY | AL | 11/9/2020 | Two 744 MW Combined Cycle Units | 744 | MW | SCR | 2 | PPM | 3 HOUR AVG / @15% O2 |
| *WI-0300 | NEMADJI TRAIL ENERGY CENTER | WI | 9/1/2020 | Natural-Gas-Fired Combined-Cycle Turbine (P01) | 4671 | MMBTU/H | Selective Catalytic Reduction (SCR), low-NOx burners, Water injection when firing diesel fuel oil. | 2 | PPM AT 15% O2 | 24-HR ROLLING AVG., NATURAL GAS |
| *PA-0331 | GRAYS FERRY COGENERATION PARTNERSHIP - SCHUYLKILL STATION | PA | 3/4/2020 | Combustion Turbine | 1515 | MMBTU/hr | SCR | 9 | ppmvd @ 15% O2 | |

**RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS**
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**LISTINGS FOR NITROGEN OXIDES (NOx)**

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT DATE | PROCESS NAME | THROUGHPUT | THROUGHPUT UNIT | CONTROL METHOD DESCRIPTION | STANDARAD EMISSION LIMIT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| *WI-0306 | WPL- RIVERSIDE ENERGY CENTER | WI | 2/28/2020 | Natural Gas Fired Combustion Turbine (P20, P21) Phase I Commissioning | 2208 | MMBTU/H | | 110 | PPMVD, 15% OXYGEN | AVG. ANY 24-HR OPERATIONAL PERIOD |
| *WI-0306 | WPL- RIVERSIDE ENERGY CENTER | WI | 2/28/2020 | Natural Gas Fired Combustion Turbine (P20, P21)- Startup operation during Phase I Commissioning | 2208 | MMBTU/H | | 110 | PPMVD, 15% OXYGEN | AVG. ANY 24-HR OPERATIONAL PERIOD |
| *WI-0306 | WPL- RIVERSIDE ENERGY CENTER | WI | 2/28/2020 | Natural Gas Fired Combustion Turbine (P20, P21) Phase II Commissioning | 2208 | MMBTU/H | | 55 | PPMVD, 15% OXYGEN | AVG. ANY 24-HR OPERATIONAL PERIOD |
| LA-0364 | FG LA COMPLEX | LA | 1/6/2020 | Cogeneration Units | 2222 | mm btu/h | Dry low NOx combustor design along with SCR. | 2 | PPMVD | 12-MONTH ROLLING AVERAGE |
| *MI-0445 | INDECK NILES, LLC | MI | 11/26/2019 | FGCTGHRSG | 3421 | MMBTU/H | SCR with DLNB (Selective Catalytic Reduction with Dry Low NOx Burners) | 2 | PPM | PPMVD @15% O2. 24HR ROLL AVG EXCEPT SS |
| MI-0442 | THOMAS TOWNSHIP ENERGY, LLC | MI | 8/21/2019 | FGCTGHRSG | 625 | MW | Good combustion practices, dry low NOx burners and selective catalytic reduction (SCR). | 2 | PPM | EACH; 24-HR ROLL.AVG EXCEPT START/SHUT |
| NJ-0088 | COGEN TECH LINDEN VENTURE LP | NJ | 7/30/2019 | 250 MW COMBINED CYCLE COMBUSTION TURBINE FIRING NATURAL GAS | 21042 | MMCubic ft/yr | Selective Catalytic Reduction, Dry Low NOx, and use of Natural gas as Primary fuel | 2 | PPMVD@15%O2 | 3 H ROLLING AV BASED ON ONE H BLOCK |
| *LA-0365 | BIG CAJUN I POWER PLANT | LA | 6/27/2019 | Combustion Turbine #1 (EQT0002, CTG-1) | 1679 | MM BTU/hr | Dry low NOX Burners & water injection | 23 | PPMV | THREE HOUR ROLLING AVERAGE |
| *LA-0365 | BIG CAJUN I POWER PLANT | LA | 6/27/2019 | Combustion Turbine #2 (EQT0003, CTG-2) | 1679 | MM BTU/hr | Dry low NOX burners & water injection | 23 | PPMV | THREE HOUR ROLLING AVERAGE |
| VA-0332 | CHICKAHOMINY POWER LLC | VA | 6/24/2019 | Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators | 35000 | MMCF/YR | Controlled by dry, low NOx burners and selective catalytic reduction (SCR). | 2 | PPMVD 15% O2 | 1 HR AVG |
| MI-0439 | JACKSON GENERATING STATION | MI | 4/2/2019 | FGLMDB1-6 (6 combined cycle natural gas fired CTG each equipped with a HRSG) | 420 | MW | Steam injection, good combustion practices and only combust natural gas. | 25 | PPM | AT 15% O2; 30 DAY ROLLING AVG; EACH UNIT |
| IL-0130 | JACKSON ENERGY CENTER | IL | 12/31/2018 | Combined-Cycle Combustion Turbine | 3864 | mmBtu/hr | Selective Catalytic Reduction (SCR) and low-NOx technology (dry low NOx combustion technology) | 2 | PPMV | 3-UNIT OPERATING HOURS @ 15% O2 |
| MI-0441 | LBWL--ERICKSON STATION | MI | 12/21/2018 | EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG. | 667 | MMBTU/H | Dry low NOx burners and selective catalytic reduction for NOx control. | 3 | PPM | PPMVD@15%O2; 24-H AVG; SEE NOTES |
| MI-0441 | LBWL--ERICKSON STATION | MI | 12/21/2018 | EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG) | 667 | MMBTU/H | Dry low NOx burners and selective catalytic reduction for NOx control. | 3 | PPM | PPMVD@15%O2; 24-H ROLL AVG; SEE NOTES |

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**PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2015 and 7/1/2025**
**LISTINGS FOR NITROGEN OXIDES (NOx)**

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT DATE | PROCESS NAME | THROUGHPUT | THROUGHPUT UNIT | CONTROL METHOD DESCRIPTION | STANDARAD EMISSION LIMIT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| LA-0331 | CALCASIEU PASS LNG PROJECT | LA | 9/21/2018 | Combined Cycle Combustion Turbines (CCCT1 to CCCT5) | 921 | MM BTU/h | Low NOx Burners, SCR, and Good Combustion Practices | 2.5 | PPMV | 30 DAY ROLLING AVERAGE |
| *WV-0032 | BROOKE COUNTY POWER PLANT | WV | 9/18/2018 | GE 7HA.01 Turbine | 2737.7 | mmBtu/hr | Dry-Low NOx Burners, SCR | 2 | PPM | |
| *PA-0319 | RENAISSANCE ENERGY CENTER | PA | 8/27/2018 | COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT | 2665.9 | MMBtu/hr | SCR | 2 | PPMDV | @15% O2 |
| IL-0129 | CPV THREE RIVERS ENERGY CENTER | IL | 7/30/2018 | Combined Cycle Combustion Turbines | 3474 | mmBtu/hr | Selective catalytic reduction (SCR) and low-NOx combustion technology (dry low-NOx combustion technology for natural gas; water injection for ULSD) | 2 | PPMV @ 15% O2 | 3-UNIT OPERATING HOURS |
| MI-0432 | NEW COVERT GENERATING FACILITY | MI | 7/30/2018 | FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains) | 1230 | MW | Good combustion practices, DLN burners and SCR. | 2 | PPMVD | AT 15%O2; EACH INDIV. CT/HRSG TRAIN |
| FL-0367 | SHADY HILLS COMBINED CYCLE FACILITY | FL | 7/27/2018 | 1-on-1 combined cycle unit (GE 7HA) | 3266.9 | MMBtu/hour | Dry low-NOX combustors and Selective Catalytic Reduction (SCR) | 2 | PPMVD AT 15% O2 | 24-HOUR BLOCK AVERAGE BASIS (BACT) |
| MI-0435 | BELLE RIVER COMBINED CYCLE POWER PLANT | MI | 7/16/2018 | FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2) | | | SCR with DLNB (Selective catalytic reduction with dry low NOx burners). | 2 | PPMVD | AT 15%O2; 24-H ROLL AVG; EACH UNIT; |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | MI | 6/29/2018 | EUCTGHRSG (South Plant): A combined cycle natural gas-fired combustion turbine generator with heat recovery steam generator. | 500 | MW | SCR with DLNB (Selective catalytic reduction with dry low NOx burners). | 2 | PPMV | AT 15%O2; 24-HR ROLL AVG NOT S.S. |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | MI | 6/29/2018 | EUCTGHRSG (North Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator. | 500 | MW | SCR with DLNB (Selective catalytic reduction with Dry Low NOx burners). | 2 | PPMVD | AT 15%O2; 24-H ROLL AVG; NOT S.S. |
| MI-0431 | INDECK NILES LLC | MI | 6/26/2018 | FGCTGHRSG (2 Combined Cycle CTG with HRSGs) | 3421 | MMBTU/H | SCR with DLNB (Selective Catalytic Reduction with Dry Low NOx Burners) | 2 | PPM | AT 15%O2; 24-HR ROLL AVG |
| VA-0328 | C4GT, LLC | VA | 4/26/2018 | GE Combustion Turbine - Option 1 - Normal Operation | 34000 | MMCF/YR | dry, low NOx burners and selective catalytic reduction | 2 | PPMVD @ 15% O2 | 1 H AV |
| VA-0328 | C4GT, LLC | VA | 4/26/2018 | Siemens Combusion Turbine - Option 2 - Normal Operation | 35000 | MMCF/YR | DRY, LOW NOx BURNERS & SCR | 2 | PPMVD @ 15% O2 | 1 H AV |
| CA-1251 | PALMDALE ENERGY PROJECT | CA | 4/25/2018 | Combustion Turbines (GEN1 and GEN2) | 2217 | MMBTU/H | Selective Catalytic Reduction, Dry Low NOx Burners | 2 | PPM @ 15% O2 | 1-HOUR |
| OH-0377 | HARRISON POWER | OH | 4/19/2018 | General Electric (GE) Combustion Turbines (P005 & P006) | 3459.6 | MMBTU/H | dry low NOx burners and an SCR system | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |
| OH-0377 | HARRISON POWER | OH | 4/19/2018 | Mitsubishi Hitachi Power Systems (MHPS) Combustion Turbines (P007 & P008) | 3231 | MMBTU/H | dry low NOx burners and an SCR system | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |
| TX-0834 | MONTGOMERY COUNTY POWER STATIOIN | TX | 3/30/2018 | Combined Cycle Turbine | 2635 | MMBTU/HR/UNIT | SCR and Dry Low NOx burners | 2 | PPMVD | 15% O2 1-HOUR AVERAGE |

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**LISTINGS FOR NITROGEN OXIDES (NOx)**

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT DATE | PROCESS NAME | THROUGHPUT | THROUGHPUT UNIT | CONTROL METHOD DESCRIPTION | STANDARAD EMISSION LIMIT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| TX-0834 | MONTGOMERY COUNTY POWER STATIOIN | TX | 3/30/2018 | COMBINED CYCLE TURBINE MSS REDUCED LOAD | | | minimizing duration of startup / shutdown events, engaging the pollution control equipment as soon as practicable (based on vendor recommendations and guarantees), and meeting the emissions limits on the MAERT | | | |
| *WV-0029 | HARRISON COUNTY POWER PLANT | WV | 3/27/2018 | GE 7HA.02 Turbine | 3496.2 | mmBtu/hr | Dry-Low NOx Burners, SCR | 2 | PPM | |
| *TN-0164 | TVA - JOHNSONVILLE COGENERATION | TN | 2/1/2018 | Dual-fuel CT and HRSG with duct burner | 1020 | MMBtu/hr | SCR, good combustion design & practices | 2 | PPMVD @ 15% O2 | 30-DAY AVG WHEN BURNING NATURAL GAS |
| *PA-0316 | RENOVO ENERGY CENTER, LLC | PA | 1/26/2018 | Combustion Turbine Firing NG | | | SCR | 2 | PPMDV | CORRECTED TO 15% O2 |
| MI-0427 | FILER CITY STATION | MI | 11/17/2017 | EUCCT (Combined cycle CTG with unfired HRSG) | 1934.7 | MMBTU/H | SCR with DLNB (Selective catalytic reduction with dry low NOx burners). | 3 | PPM | 24-H ROLL.AVG., EXCEPT STARTUP/SHUTDOWN |
| OH-0375 | LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER | OH | 11/7/2017 | General Electric Combustion Turbine (P004) | 3544 | MMBTU/H | dry low NOx burners and an SCR system | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |
| OH-0375 | LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER | OH | 11/7/2017 | Mitsubishi Combustion Turbine (P005) | 3320 | MMBTU/H | dry low NOx burners and an SCR system | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |
| OH-0375 | LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER | OH | 11/7/2017 | Siemens Combustion Turbine (P006) | 3602 | MMBTU/H | dry low NOx burners and an SCR system | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |
| OH-0374 | GUERNSEY POWER STATION LLC | OH | 10/23/2017 | Combined Cycle Combustion Turbines (3, identical) (P001 to P003) | 3516 | MMBTU/H | dry low NOx burners and SCR | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |
| OH-0372 | OREGON ENERGY CENTER | OH | 9/27/2017 | Combined Cycle Combustion Turbines (two, identical) (P001 and P002) | 3055 | MMBTU/H | Dry low NOX combustors and selective catalytic reduction (SCR) | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |
| OH-0370 | TRUMBULL ENERGY CENTER | OH | 9/7/2017 | Combined Cycle Combustion Turbines (two, identical) (P001 and P002) | 3025 | MMBTU/H | dry low NOx combustors (DLN) and selective catalytic reduction (SCR) | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |
| CT-0161 | KILLINGLY ENERGY CENTER | CT | 6/30/2017 | Natural Gas w/o Duct Firing | 2969 | MMBtu/hr | SCR | 2 | PPMVD @15% O2 | 1 HOUR BLOCK |
| CT-0161 | KILLINGLY ENERGY CENTER | CT | 6/30/2017 | Natural Gas w/Duct Firing | 2639 | MMBtu/hr | SCR | 2 | PPMVD @15% O2 | 1 HOUR BLOCK |
| TX-0819 | GAINES COUNTY POWER PLANT | TX | 4/28/2017 | Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator | 426 | MW | Selective Catalytic Reduction (SCR) and Dry Low NOx burners | 2 | PPMVD | 15% O2 3-H AVG |
| *PA-0315 | HILLTOP ENERGY CENTER, LLC | PA | 4/12/2017 | Combustion Turbine without Duct Burner | 3509 | MMBtu/hr | | 2 | PPMDV | CORRECTED TO 15% O2 |

**RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS**
**PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2015 and 7/1/2025**
**LISTINGS FOR NITROGEN OXIDES (NOx)**

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT DATE | PROCESS NAME | THROUGHPUT | THROUGHPUT UNIT | CONTROL METHOD DESCRIPTION | STANDARAD EMISSION LIMIT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| MI-0423 | INDECK NILES, LLC | MI | 1/4/2017 | FGCTGHRSG (2 Combined Cycle CTGs with HRSGs) | 8322 | MMBTU/H | SCR with DLNB (selective catalytic reduction with dry low NOx burners) | 3 | ppmvd @ 15% O2 | |
| MI-0424 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | MI | 12/5/2016 | FGCTGHRSG (2 Combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11) | 554 | MMBTU/H, each | Selective catalytic reduction with dry low NOx burners (SCR with DLNB). | 3 | PPM AT 15% O2 | 24-H ROLLING AVG; EACH EU |
| OH-0367 | SOUTH FIELD ENERGY LLC | OH | 9/23/2016 | Combined Cycle Combustion Turbines (two, identical) (P001 and P002) | 3131 | MMBTU/H | Dry low NOx (DLN) burners for natural gas firing, wet injection when firing ultra low sulfur diesel, and selective catalytic reduction (SCR) for both natural gas and ultra low sulfur diesel. | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |
| PA-0310 | CPV FAIRVIEW ENERGY CENTER | PA | 9/2/2016 | Combustion turbine and HRSG with duct burner NG only | 3338 | MMBtu/hr | Dry Low NOx combustion technology, SCR at all steady state operating loads, good combustion and operating practices | 2 | PPMDV @ 15% O2 | |
| LA-0313 | ST. CHARLES POWER STATION | LA | 8/31/2016 | SCPS Combined Cycle Unit 1A | 3625 | MMBTU/hr | Selective Catalytic Reduction (SCR) with Dry Low NOx Burners (DLNB) during normal operations; Good Combustion Practices during Startup/Shutdown operations. | 15 | PPM@15% O2 | 4-HOUR AVERAGE |
| LA-0313 | ST. CHARLES POWER STATION | LA | 8/31/2016 | SCPS Combined Cycle Unit 1B | 3625 | MMBTU/hr | Selective Catalytic Reduction (SCR) with Dry Low NOx Burners (DLNB) during normal operations, and good combustion practices during startup/shutdown operations. | 15 | PPM@15% O2 | 4-HOUR AVERAGE |
| NJ-0085 | MIDDLESEX ENERGY CENTER, LLC | NJ | 7/19/2016 | Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner | 4000 | h/yr | SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX | 2 | PPMVD@15%O2 | 3 H ROLLING AV BASED ON ONE H BLOCK AV |
| NJ-0085 | MIDDLESEX ENERGY CENTER, LLC | NJ | 7/19/2016 | Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner | 8040 | H/YR | Selective Catalytic Reduction System and Dry Low NOx | 2 | PPMVD@15%O2 | 3 H ROLLING AV BASED ON ONE H BLOCK AV |
| VA-0325 | GREENSVILLE POWER STATION | VA | 6/17/2016 | COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3) | 3227 | MMBTU/HR | SCR | 2 | PPMVD | 1 HR AVG |
| TN-0162 | JOHNSONVILLE COGENERATION | TN | 4/19/2016 | Natural Gas-Fired Combustion Turbine with HRSG | 1339 | MMBtu/hr | Good combustion design and practices, selective catalytic reduction (SCR) | 2 | PPMVD @ 15% O2 | 30 UNIT-OPERATING-DAY MOVING AVERAGE |
| TX-0788 | NECHES STATION | TX | 3/24/2016 | Large Combustion Turbines >25 MW | 232 | MW | Dry low-NOx burners (DLN), good combustion practices | 9 | PPM | |
| TX-0788 | NECHES STATION | TX | 3/24/2016 | Combined Cycle & Cogeneration | 231 | MW | Selective Catalytic Reduction | 2 | PPM | |
| NJ-0084 | PSEG FOSSIL LLC SEWAREN GENERATING STATION | NJ | 3/10/2016 | Combined Cycle Combustion Turbine with Duct Burner firing natural gas | | | SCR and use of natural gas a clean burning fuel | 2 | PPMVD@15%O2 | 3 H ROLLING AV BASED ON ONE H BLOCK |
| NJ-0084 | PSEG FOSSIL LLC SEWAREN GENERATING STATION | NJ | 3/10/2016 | Combined Cycle Combustion Turbine without Duct Burner Firing Natural Gas | 28169501 | MMBTU/YR | SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM | 2 | PPMVD@15%O2 | 3 H ROLLING AV BASED ON ONE H BLOCK |
| FL-0356 | OKEECHOBEE CLEAN ENERGY CENTER | FL | 3/9/2016 | Combined-cycle electric generating unit | 3096 | MMBtu/hr per turbi | Selective catalytic reduction; dry low-NOx; and wet injection | 2 | PPMVD@15% O2 | GAS, 24-HR BLOCK, EXCLUDING SSM |
| TX-0789 | DECORDOVA STEAM ELECTRIC STATION | TX | 3/8/2016 | Combined Cycle & Cogeneration | 231 | MW | Selective Catalytic Reduction | 2 | PPM | |

**RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS**
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**LISTINGS FOR NITROGEN OXIDES (NOx)**

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT DATE | PROCESS NAME | THROUGHPUT | THROUGHPUT UNIT | CONTROL METHOD DESCRIPTION | STANDARAD EMISSION LIMIT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| PA-0306 | TENASKA PA PARTNERS/WESTMOREL AND GEN FAC | PA | 2/12/2016 | Large combustion turbine | | | SCR, DLN, and good combustion practice | 2 | PPMVD@15% O2 | |
| PA-0306 | TENASKA PA PARTNERS/WESTMOREL AND GEN FAC | PA | 2/12/2016 | Large combustion turbine | | | SCR, DLN, and good combustion practice | 2 | PPMVD@15% O2 | |
| NY-0103 | CRICKET VALLEY ENERGY CENTER | NY | 2/3/2016 | Turbines and duct burners | 228 | mw | dry low NOx burners in combination with selective catalytic reduction | 2 | PPMVD @ 15% O2 | 1 H |
| PA-0309 | LACKAWANNA ENERGY CTR/JESSUP | PA | 12/23/2015 | Combustion turbine with duct burner | 3304.3 | MMBtu/hr | Dry low-NOx burners, SCR, exclusive natural gas | 2 | PPMDV @15% O2 | |
| CT-0157 | CPV TOWANTIC, LLC | CT | 11/30/2015 | Combined Cycle Power Plant | 21200000 | MMBtu/12 months | SCR | 2 | PPMVD @15% O2 | 1 HR BLOCK |
| CT-0158 | CPV TOWANTIC, LLC | CT | 11/30/2015 | Combined Cycle Power Plant | 21200000 | MMBtu/yr | SCR | 2 | PPMVD @15% O2 | 1 HR BLOCK |
| MD-0045 | MATTAWOMAN ENERGY CENTER | MD | 11/13/2015 | 2 COMBINED-CYCLE COMBUSTION TURBINES | 286 | MW | GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR) | 2 | PPMVD @ 15% O2 | 3-HOUR BLOCK AVERAGE (EXCLUDING SU/SD) |
| TX-0773 | FGE EAGLE PINES PROJECT | TX | 11/4/2015 | Combined Cycle Turbines (>25 MW) | 321 | MW | Selective Catalytic Reduction | 2 | PPM | 24-HR AVERAGE |
| OK-0169 | PSO COMANCHE POWER STATION | OK | 10/8/2015 | COMBINED CYCLE COMBUSTION TURBINE | 1250 | MMBTUH | Use of Dry Low NOx Burners | 41 | ppmvd @ 15% O2 | |
| TX-0767 | LON C. HILL POWER STATION | TX | 10/2/2015 | Combined Cycle Turbines (>25 MW) | 195 | MW | Selective Catalytic Reduction | 2 | PPM | ROLLING 24-HR AVERAGE |
| PA-0311 | MOXIE FREEDOM GENERATION PLANT | PA | 9/1/2015 | Combustion Turbine With Duct Burner | 3727 | MMBtu/hr | DLN burner, SCR, good engineering practice | 2 | PPMDV @ 15% O2 | |
| OH-0366 | CLEAN ENERGY FUTURE - LORDSTOWN, LLC | OH | 8/25/2015 | Combined Cycle Combustion Turbines (two, identical) (P001 and P002) | 2725 | MMBTU/H | dry low NOx combustors, selective catalytic reduction (SCR) | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |
| PA-0305 | SHELL CHEM APPALACHIA/PETROCHE MICALS COMPLEX | PA | 6/18/2015 | Combustion turbine wih duct burner and heat recovery steam generator | Three 40.6 MW turbines | | | 2 | PPMDV @ 15% O2 | 1 HOUR AVG EX DURING STARTUP AND SHUTDOW |
| TX-0751 | EAGLE MOUNTAIN STEAM ELECTRIC STATION | TX | 6/18/2015 | Combined Cycle Turbines (>25 MW) natural gas | 210 | MW | Selective Catalytic Reduction | 2 | PPM | ROLLING 24-HR AVERAGE |
| PA-0307 | YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT | PA | 6/15/2015 | Two Combine Cycle Combustion Turbine with Duct Burner | 3001.57 | MCF/hr | SCR, Dry Lo-NOx combustor, good combustion practices and low sulfur fuels | 2 | PPVDM @ 15 O2 | |
| KY-0104 | CASH CREEK GENERATING STATION | KY | 6/10/2015 | Combined cycle combustion turnbine with HRSG and duct firing | 849 | MW | SCR, low NOx burners | 2 | PPMVD | @15% O2 THREE HOUR ROLLING AVERAGE |
| OH-0365 | ROLLING HILLS GENERATING, LLC | OH | 5/20/2015 | Combustion Turbines, Scenario 1 (4, identical) (P001, P002, P004, P005) | 2022 | MMBTU/H | dry-low NOx (DLN) burner and selective catalytic reduction (SCR) | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |
| OH-0365 | ROLLING HILLS GENERATING, LLC | OH | 5/20/2015 | Combustion Turbines, Scenario 2 (4, identical) (P001, P002, P004, P005) | 2144 | MMBTU/H | dry-low NOx (DLN) burner and selective catalytic reduction (SCR) | 2 | PPM | BY VOLUME, DRY AT 15% O2. SEE NOTES. |

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**LISTINGS FOR NITROGEN OXIDES (NOx)**

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT DATE | PROCESS NAME | THROUGHPUT | THROUGHPUT UNIT | CONTROL METHOD DESCRIPTION | STANDARAD EMISSION LIMIT | | |
|---|---|---|---|---|---|---|---|---|---|---|
| TX-0730 | COLORADO BEND ENERGY CENTER | TX | 4/1/2015 | Combined-cycle gas turbine electric generating facility | 1100 | MW | efficient processes, practices, and designs | | | |
| TX-0730 | COLORADO BEND ENERGY CENTER | TX | 4/1/2015 | Combined-cycle gas turbine electric generating facility | 1100 | MW | SCR and oxidation catalyst | 2 | PPMVD @ 15% O2 | 24-HR AVERAGE |

# Appendix B

## Capital and Annual Cost Calculation Summary

**LVGS Unit 1**
**SCR System Upgrade**
**Summary of Economic Impact**

| | | *Basis* |
|---|---|---|
| Baseline Operation (hours/yr) | 1,523.7 | *Highest two-year average in past five years* |
| Baseline NOx Emissions Level | | |
| (tons/yr) | 6.32 | *Highest two-year average in past five years* |
| (avg lb/MMBtu) | 0.031 | *Plant data* |
| (ppm @ 15% O2) | 10 | *permit limit* |
| Achievable Emissions Level | | |
| (ppm @ 15% O2) | 2 | *estimate (permit limit for Units 2 - 5)* |
| (tons/yr) | 1.26 | *calculated* |
| Annual Emissions Reduction (tons/yr) | 5.06 | *calculated* |
| Capital Equipment Cost | **$880,000** | ***Vendor (Environex) capital cost estimate*** |
| Sales Tax | $40,480 | *4.6% Nevada sales tax* |
| Direct Installation Cost | - | ***Included in capital cost estimate*** |
| Indirect Installation Cost | $322,200 | *35% of capital equipment cost (OAQPS Manual)* |
| Total Capital Cost | **$1,242,680** | |
| Annualized Capital Cost | $118,600 | *20 yr equipment life, 7.14% ROI* |
| O&M Costs | | |
| Catalyst changeout | **$69,400** | ***5 year life, 7.14% ROI, Vendor catalyst cost*** |
| Annual maintenance | $6,200 | *0.5% of total capital investment (OAQPS Manual)* |
| NH3 usage | $1,900 | *Estimated additional NH3 consumption at 1.05 lbmol NH3/lbmol NOx removed and $0.69/gal* |
| Total | **$77,500** | |
| Total Annualized Cost | **$196,100** | |
| **Cost Effectiveness ($/ton)** | **$38,786** | |

## Appendix C

## Public Utility Commission Capital Recovery Rate Information

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

| | | |
|---|---|---|
| Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto. | ) | Docket No. 20-06003 |

At a general session of the Public Utilities Commission of Nevada, held at its offices on December 9, 2020.

PRESENT: Chair Hayley Williamson
Commissioner C.J. Manthe
Commissioner Tammy Cordova (Abstained)
Assistant Commission Secretary Trisha Osborne

**FINAL ORDER**

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

## I. INTRODUCTION

On June 1, 2020, Nevada Power Company d/b/a NV Energy ("NPC") filed with the Commission an application, designated as Docket No. 20-06003, for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto ("Application").

On September 9, 2020, the Commission issued an Interim Order directing NPC to return to ratepayers approximately $59.7 million in the form of a one-time bill credit.

On September 24, 2020, a Stipulation was filed with the Commission signed by all parties to this Docket (the "Parties"), which effectively modified the Interim Order and resolved all issues except for whether the overearnings sharing mechanism ("ESM") in NPC's Application should be continued.

On October 7, 2020, the Commission issued Interim Order No. 2 accepting the Stipulation and directing NPC to return to ratepayers approximately $120 million in the form of a one-time bill credit.

On October 12, 2020, the Commission held a hearing on whether the ESM in NPC's Application should be continued.

This final order incorporates the first Interim Order and Interim Order No. 2, including the entire Stipulation, and finds that continuation of the ESM is just and reasonable.

## II. SUMMARY

The Commission incorporates into this order the first Interim Order and Interim Order 2, wherein the Commission accepted the Stipulation granting in part the Application as modified by this order, and finds that there should be a continuation of the ESM ordered in Docket No. 17-06003.

## III. EXECUTIVE SUMMARY

Every three years, the Commission conducts a comprehensive review and financial analysis of NPC and the rates charged to Southern Nevada customers in a general rate case ("GRC"). The purpose of this review is to ensure that the interests of Southern Nevada ratepayers and those of NPC are reasonably and fairly balanced and to ensure that prudent decisions are being made that result in just and reasonable rates. The purpose of a GRC is to determine the amount of money that NPC needs to collect from customers through rates, otherwise known as a utility's revenue requirement, and establish rates that customers must pay to allow NPC to meet its revenue requirement. Generally, a GRC is split into three phases: (1) Cost of Capital; (2) Revenue Requirement; and (3) Rate Design. The Cost of Capital phase determines a utility's return on equity ("ROE"); the Revenue Requirement phase addresses the amount of revenue the utility must receive from the customers to cover its operating costs and investments in facilities, provide safe and reliable service to customers, and provide an opportunity to earn a fair return for shareholders on investments; and the Rate Design phase determines the rates that each class of customers must pay to provide the utility with its revenue requirement.

In this docket, NPC filed an Application seeking a $120-million reduction in its revenue requirement. The Commission did not hold a hearing regarding the Cost of Capital, Revenue Requirement, or Rate Design as the Parties settled all aspects of the case except for the ESM. The Parties stipulated that NPC would issue a $120-million one-time bill credit to customers, utilize an ROE of 9.4 percent, have a total revenue requirement of $1.0702 billion, and make certain agreed-upon adjustments to rates and fees.

In NPC's 2017 GRC, the Commission adopted an ESM to allow ratepayers to share in any potential overearnings by NPC. Under the terms of the mechanism, NPC was allowed to retain 100 percent of overearnings above its authorized 9.4-percent ROE up to 9.7 percent and 50 percent of overearnings above 9.7 percent. The remaining 50 percent of overearnings above 9.7 percent was to be returned to ratepayers in the instant proceeding. NPC recorded the ratepayers' share of overearnings for the calendar years 2018 and 2019 in a regulatory liability account for presentation in this docket.

The Commission, after a hearing on this issue, finds that continuation of the ESM is just and reasonable. The Commission finds that there were extenuating circumstances in 2017 that led the Commission to implement earnings-sharing, but that does not diminish the potential

effectiveness of the mechanism on a going-forward basis. The ESM approved by the Commission in Docket No. 17-06003 includes a band of 30 basis points above the approved ROE of 9.4 percent, within which NPC retains all of the overearnings. The Commission notes that the earnings-sharing has accumulated approximately $63 million in the regulatory liability for the 2018 and 2019 calendar years.

This order summarizes the Stipulation filed in this case as well as the relevant evidence and arguments presented by the Parties in the ESM hearing.

## IV. LEGAL STANDARD OF REVIEW

The filings in this case are made pursuant to the Nevada Revised Statutes ("NRS") Chapters 703 and 704, as well as the Nevada Administrative Code ("NAC") Chapters 703 and 704.

The Commission's statutory obligation in GRC proceedings is to ensure that the rates charged for service by the utility are just and reasonable.[1] More specifically, NRS 704.001(4) requires that the Commission "balance the interests of customers and shareholders of public utilities by providing public utilities with the opportunity to earn a fair return on their investments while providing customers with just and reasonable rates." Similarly, NRS 704.040(1) provides that "[e]very public utility shall furnish reasonably adequate service and facilities" and "the charges made for any service rendered or to be rendered, or for any service in connection therewith or incidental thereto, must be just and reasonable." Meanwhile, NRS 704.040(2) states that every unjust and unreasonable charge for service of a public utility is unlawful.

NRS 704.120(1) provides that "[i]f, upon any hearing and after due investigation, the rates, tolls, charges, schedules or joint rates shall be found to be unjust, unreasonable or unjustly discriminatory, ... the Commission shall have the power to fix and order substituted therefore such rate or rates, tolls, charges or schedules as shall be just and reasonable."

The PUCN has broad authority to fix and remedy rates and charges that are unjust, unreasonable, discriminatory or preferential. *See* NRS 704.120(1). An order by the Commission will be upheld by a court on judicial review when it is "within the legal framework of the law, and based on substantial evidence in the record." *NPC Co. v. Public Utilities Commission of Nevada, et al.*, 122 Nev. 821, 834, 138 P.3d 486, 494 (2006) (other internal citations and quotations omitted). Substantial evidence is that which "'a reasonable mind might accept as adequate to support a conclusion.'" *Id.* (quoting *State of Nevada Emp. Security v. Hilton Hotels*, 102 Nev. 606, 608, 729 P.2d 497, 498 (1986)).

Great deference is afforded to the Commission's "interpretation of its governing statutes or regulations," *see Dutchess Business Service, Inc. v. Nevada State Board of Pharmacy*, 124 Nev. 701, 709, 191 P.3d 1159, 1165 (2008), and a court will not "reweigh the evidence" or substitute its judgment on factual questions. *NPC Co.*, 122 Nev. at 495, 138 P.3d at 494; NRS 703.373(11). Evaluating the credibility of witness testimony and the weight to be given to it

[1] *See* Nevada Revised Statutes ("NRS") 703.150, 704.001, 704.040 704.110, 704.120.

resides well-within the province of the Commission, *i.e.*, fact finder. *See In the Matter of TR v. State*, 119 Nev. 646, 649, 80 P.3d 1276, 1278 (2003). This standard holds true even when expert testimony is conflicting. *See Allen v. State*, 99 Nev. 485, 487-88, 665 P.2d 238 (1983). Indeed, the Nevada Supreme Court has recognized that "[e]xpert testimony is not binding on the trier of fact; [triers of fact] can either accept or reject the testimony as they see fit." *Id.*

The Commission may also take "[n]otice of judicially cognizable facts and generally recognized technical or scientific facts within the specialized knowledge of the agency," NRS 233B.123(5), and its final decisions "shall be deemed reasonable and lawful" and have operative effect unless they are set aside by a higher court on review upon a showing of clear error or abuse of discretion. *See* NRS 703.373(9) and (11); *see also* NRS 703.374(2).

## V. PROCEDURAL HISTORY

- On June 1, 2020, NPC filed the Application.
- NPC filed the Application pursuant to the NRS and the NAC, Chapters 703 and 704, including, but not limited, to NRS 704.100, NRS 704.110, NAC 703.2201 through 703.2481, NAC 703.535, and NAC 704.6502 through 704.6546.
- On June 8, 2020, the Commission issued a Notice of Application for Authority to Adjust Annual Revenue Requirement for General Rates Charged to all Classes of Electric Customers.
- On June 9, 2020, the Commission issued a Notice of Prehearing Conference, and the Nevada Bureau of Consumer Protection ("BCP") filed a Notice of Intent to Intervene pursuant to NRS Chapter 228.
- The Regulatory Operations Staff of the Commission ("Staff") participates as a matter of right pursuant to NRS 703.301.
- On June 12, 2020, Walmart, Inc. ("Walmart") filed a Petition for Leave to Intervene ("PLTI").
- On June 17, 2020, Kroger Co. ("Kroger") filed a PLTI, Motion for Admission Pro Hac Vice, and Notice of Association of Counsel.
- On June 29, 2020, the Colorado River Commission of Nevada ("CRCNV") filed a PLTI.
- On June 30, 2020, Nevada Cogeneration Associates #1 ("NCA"), Sunrun, Inc. ("Sunrun"), MGM Resorts International ("MGM"), and Caesars Enterprise Services, LLC ("Caesars") each filed PLTIs.
- On July 1, 2020, Wynn Las Vegas, LLC ("Wynn"), Circus Circus Las Vegas, LLC ("CCLV"), and Smart Energy Alliance ("SEA") (collectively, "WCS") filed a joint PLTI,

and the Southern Nevada Gaming Group ("SNGG")[2] filed a PLTI.

- On July 9, 2020, the Commission held a prehearing conference. NPC, Staff, BCP, Caesars, CRCNV, Kroger, MGM, NCA, SNGG, Sunrun, Walmart, and WCS appeared and discussed a procedural schedule and the PLTIs.

- On July 15, 2020, the Commission issued a Procedural Order.

- On July 16, 2020, the Commission issued a Notice of Consumer Session and Notice of Hearing, and an Order granting the PLTIs of Caesars, CRCNV, Kroger, MGM, NCA, SNGG, Sunrun, Walmart, and WCS.

- On July 21, 2020, Staff and BCP (together, the "Movants") filed a Joint Motion for an Order Shortening Time, and the Commission issued Procedural Order No. 2.

- On July 22, 2020, NPC filed a Response to the Joint Motion's request for an Order Shortening Time, and the Commission issued an Order denying the Movant's request for an Order Shortening Time.

- On July 28, 2020, Caesars and MGM, NPC, and WCS filed Responses.

- On August 3, 2020, the Movants filed a Reply, and NPC submitted its Cost of Capital certification filing.

- On August 7, 2020, the Commission issued an Order denying the Joint Motion, Procedural Order No. 3, and a Notice of Hearing.

- On August 13, 2020, the Commission issued a Notice of Prehearing Conference and Procedural Order No. 4.

- On August 17, 2020, BCP, SNGG, Staff, and WCS each filed Prepared Direct Testimony, Caesars and MGM filed Joint Prepared Direct Testimony, and NPC submitted its Revenue Requirement Certification filing.

- On August 18, 2020, Kroger filed Prepared Direct Testimony.

- On August 25, 2020, the Commission held an informal prehearing conference. NPC, BCP, Staff, Caesars, MGS, Kroger, Sunrun, SNGG, CRCNV, WCS, and Walmart participated. The Commission gave a presentation on the functionality of Microsoft Teams to the participants.

- On August 26, 2020, NPC filed Prepared Rebuttal Testimony.

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[2] Southern Nevada Gaming Group consists of the Boyd Gaming Corporation, Las Vegas Sands Corp., Stations Casinos LLC, Plaza Hotel and Casino, LLC, Tropicana Las Vegas Inc., and LVGV, LLC.

- On August 27, 2020, the Commission issued Procedural Order No. 5.
- On August 28, 2020, NPC, WCS, SNGG, MGM and Caesars, BCP, and Staff each filed an exhibit list and cross-examination statement, and NPC submitted its Rate Design Certification filing.
- On August 31, 2020, Kroger filed an exhibit list, and NPC filed the information requested by the Commission in Procedural Order No. 5.
- On September 1, 2020, NPC filed a whitepaper providing Supplemental Direct Testimony, and Staff, BCP, Caesars, MGM, SNGG, Kroger, Walmart, WCS, and CRCNV (collectively, Signatories to the Agreement") filed an Agreement.
- On September 1, 2020, the Presiding Officer held a hearing. NPC and the Signatories to the Agreement, except for CRCNV, made appearances, presented their witnesses and exhibits, and conducted cross-examination. During the hearing, the Presiding Officer granted oral motions to accept exhibits into the record pursuant to NAC 703.730.
- On September 3, 2020, NPC filed a revised attachment to its Revenue Requirement Certification testimony.
- On September 4, 2020, BCP and Staff filed Prepared Direct Testimony in the Cost-of-Capital phase of the proceeding; MGM, Caesars, and WCS filed Joint Prepared Direct Testimony in the Cost-of-Capital phase of the proceeding; and NPC filed late-filed Exhibit No. 148.
- On September 8, 2020, BCP filed a correction to Direct Testimony.
- On September 9, 2020, the Commission issued Procedural Order No. 6 and the Interim Order.
- On September 10, 2020, the Commission held a consumer session.
- On September 22, 2020, the Commission issued Procedural Order No. 7.
- On September 24, 2020, the Parties filed a Stipulation and Supplement to the Stipulation. Staff and BCP filed Direct Testimony, SNGG filed Direct Testimony, and the Supplement to Direct Testimony as agreed to in the Stipulation.
- On September 28, 2020, the Commission issued Procedural Order No. 8.
- On September 29, 2020, NPC filed information regarding rates proposed in the Stipulation as requested in Procedural Order No. 8.
- On September 30, 2020, NPC filed a letter advising the Commission that it had filed Exhibit 3 to the Stipulation containing Settlement Statement O.

- On September 30, 2020, the Presiding Officer held a continued prehearing conference. The Parties made appearances and discussed the Stipulation. At the conclusion of the prehearing conference, the Presiding Officer granted an oral motion to accept Exhibits 150 - 151 into the record pursuant to NAC 703.370.

- On October 1, 2020, the Commission issued a Notice of Hearing.

- On October 6, 2020, NPC filed Prepared Rebuttal Testimony.

- On October 7, 2020, the Commission issued Procedural Order No. 9 and Interim Order No. 2.

- On October 8, 2020, NPC, SNGG, BCP, and Staff each filed an exhibit list and cross-examination statement.

- On October 12, 2020, the Presiding Officer held a hearing. NPC, SNGG, BCP, and Staff made appearances, presented their witnesses and exhibits, and conducted cross-examination. During the hearing, the Presiding Officer granted oral motions to accept exhibits 152, 153, 154, 1001, 1002, 1003, 1004, 403, and 305 into the record pursuant to NAC 703.730.

- On October 14, 2020, NPC filed information for issuing bill credits to customers as directed in Interim Order No. 2.

- On November 13, 2020, NPC filed revised tariff sheets.

- On November 20, 2020, NPC filed information regarding the number of credits issued and total dollar value of credits for each customer class and the impact of the bill credit as directed in Interim Order No. 2.

## VI. STIPULATION

1. The Parties agree that the Stipulation provides a reasonable resolution of issues raised in the Application and that the Stipulation is in the public interest. (Ex. 150 at 1.) The Parties agree that NPC will issue a $120-million one-time bill credit to customers, utilize a Return on Equity of 9.4 percent, have a total revenue requirement of $1.0702 billion, and make certain agreed-upon adjustments to rates and fees. (*Id.*)

Cost of Capital and Revenue Requirement

2. The Parties agree that NPC shall issue a $120-million one-time bill credit to be distributed to customers based on the calculation of recorded rate base tariff general rate

("BTGR") revenues using non-normalized billing determinants for calendar year 2019. (*Id.* at 4-5.) The one-time bill credit includes: (1) the $59.7-million earnings sharing regulatory liability as ordered by the Commission in the September 9, 2020, Interim Order; (2) $26 million from the unprotected excess accumulated deferred income tax ("ADIT") regulatory liability; (3) expected earnings-sharing for 2020 of $20 million, which will act as a reduction to the 2020 overearnings balance accepted by the Commission in future proceedings; (4) approximately $9 million in carrying charges on the earnings-sharing regulatory liability that accrued during calendar years 2019 and 2020, and (5) approximately $5 million in other expense adjustments. (*Id.* at 5.)

3. The final class allocations of the credit amounts are presented in Exhibit 1 to the Stipulation entitled Settlement One-Time Credit Allocation. (*Id.*) The Parties explain that:

a. BTGR revenues will include impact fee revenues for distribution-only service ("DOS") customers consistent with "present" BTGR revenues for 2019 as presented in Statements J and O in the original application.

b. A proportionate allocation to each rate schedule would result in each rate schedule receiving an equal percentage credit applicable to each rate schedule's recorded 2019 BTGR revenues.

c. For rate schedules applicable to large non-residential customers (LGS-2, LGS-3, LGS-X, LGS-2-DOS, LGS-3-DOS, LGS-X-DOS), the overearnings refund will be based directly on the total recorded BTGR revenue contributed by each such large customer by meter during calendar year 2019. Using this method, the meter-specific refund would apply the equal percentage credit to the BTGR revenues attributable to each large-customer meter in 2019.

d. If the final calculation of the 2020 overearnings is less than $20 million, NPC will not seek recovery from customers of any of the $20 million representing the 2020 overearnings. If the final calculation of the 2020 overearnings is more than $20 million, such amount will be due to ratepayers consistent with the Order in Docket No. 17-06003 or other applicable Commission Order.

(*Id.* at 5-6.)

4. The Parties agree that NPC's ROE will be set at 9.4 percent and that the rate of return ("ROR") will be set at 7.14 percent. (*Id.* at 6.)

5. The Parties agree that NPC's total revenue requirement will be set at $1.0702 billion, which reflects: (1) NPC's expected change in circumstance adjustments; (2) Staff's weather normalization adjustment; (3) the $59.7-million of 2018 and 2019 earnings sharing regulatory liability as part of the $120-million one-time credit; (4) $26 million of unprotected ADIT regulatory liability as part of the $120-million one-time credit; (5) a 9.4-percent ROE; and (6) a "black box" settlement revenue requirement adjustment to reach the stipulated amount. (*Id.*)

6. The Parties agree that the cost recovery associated with the Reid Gardner and Navajo power plants is incorporated into the revenue requirement as proposed by NPC such that there is no impairment of cost recovery relative to NPC's filing. This includes a regulatory asset balance of $112.4 million in decommissioning and remediation costs for Reid Gardner per I-CERT-30, a regulatory asset and balance credit of $1.65 million for Navajo per I-CERT-31, and a regulatory asset balance of $0.678 million per I-CERT-28 for Mohave. These costs are to be recovered over the period of 2021-2023 as reflected in the filing and are approved by all parties. Future additional costs incurred by NPC associated with these facilities will be included as part of future GRC proceedings. All parties reserve their rights to review and make

recommendations regarding recovery of future costs and whether and how the costs should be allocated to all customers in future GRC proceedings. (*Id.*)

7. NPC agrees to a tiered interconnection fee that provides for a lower fee for smaller distributed generation ("DG") systems and higher fee for larger DG systems, instead of the averaged fee currently proposed for all DG systems. The tiered interconnection fees are provided in Exhibit 2 to the Stipulation. (*Id.* at 7.)

8. NPC agrees to convene an ad hoc interconnection working group open to all interested stakeholders, with a goal to gain process efficiencies and cost reductions. The working group will convene at the request of any stakeholder on an as-needed basis. Topics for discussion shall include process improvements and cost reductions for interconnections that involve main panel upgrades, energy storage, and other issues as they arise. NPC agrees to jointly petition the Commission along with stakeholders to seek any necessary approvals to implement agreed-upon process changes, as appropriate. In the event that NPC and stakeholders disagree regarding any interconnection issue addressed in the working group, NPC agrees, on an annual basis and if necessary, to jointly petition the Commission to seek formal resolution. (*Id.*)

9. NPC commits to engaging in good-faith negotiations with the CRCNV prior to April 1, 2021, to discuss modifications to the Hoover D tariff that is scheduled to change January 1, 2022. (*Id.*)

Rate Design

10. The Parties agree that NPC's rate design will use Staff's trend weather normalization methodology that the Commission adopted in Sierra Pacific Power Company's ("SPPC") 2019 rate case. (*Id.*)

11. The Parties agree that NPC's rate design will use Generation Allocators, not Generation & Energy Allocators, which the Commission adopted to allocate generation demand costs in SPPC's 2019 rate case. (*Id.*)

12. The Parties agree that NPC's rate design will not include energy costs (Base Tariff Energy Rate ("BTER")) in adjusting class revenue requirement for policy considerations in Statement O, Tab "Passes." More broadly, while it is acceptable to list energy costs (BTER) in Cost of Service Study and Statement O, they should not be used in any BTGR calculations or "Interclass Revenue Adjustments." (*Id.* at 8.)

13. The Parties agree that NPC's rate design will not shift all claimed net energy metering ("NEM") revenue shortfalls to the corresponding otherwise applicable class (e.g., NMR schedules to RS schedule), which inflates NPC's calculated subsidy for the corresponding otherwise applicable class (e.g., RS). (*Id.*)

14. The Parties agree that NPC's rate design will use Exhibit Pollard Cert-20, Statement O-ECS-E Proposed Revenue Requirement-Proposed Rates, as adjusted and proposed in Exhibit 3 attached to the Stipulation ("Settlement Statement O"). In the event of any ambiguity or perceived divergence between the language of this Stipulation and the rates identified in Settlement Statement O, Settlement Statement O will control. (*Id.*)

15. The Parties agree to accept the rates contained in Settlement Statement O as the tariffed rates effective January 1, 2021. (*Id.*)

16. The Parties agree that when the claimed NEM revenue shortfalls are placed back to their appropriate rate classes (e.g., from RS to RS-NEM and RM to RM-NEM), Settlement Statement O shows that there is no subsidy for non-NEM residential customers. (*Id.*)

17. The Parties agree that NPC's embedded cost-of-service study filed in this GRC used marginal cost allocators and such allocators are not generally accepted in embedded cost-of-service studies used in other state jurisdictions. (*Id.*)

18. The Parties agree that, not later than January 5 of the year in which NPC files its next GRC, NPC agrees to meet with Staff, BCP, and interested interveners to discuss embedded cost allocators to be used in an embedded cost-of-service study that will be filed in NPC's next GRC. NPC will notify the Parties of such meeting(s) reasonably in advance to provide the Parties an opportunity to participate. (*Id.* at 8-9.)

19. The Parties agree that NPC will make the following changes to the LGS-2S schedule rates:

a. Adjust the On Peak Generation Demand per-kilowatt charge to $12.81 and increase the Mid Peak Generation Demand per-kilowatt charge to $2.65.

b. Commensurately decrease the On Peak, Mid Peak, Off Peak, and Other time-of-use ("TOU") energy per-kilowatt-hour charges so that the net impact is revenue-neutral to NPC, while also maintaining NPC's proposed ratios between the TOU energy charges.

(*Id.* at 9.)

20. The Parties agree that NPC will provide an updated review of TOU periods in its next GRC. (*Id.*)

21. The Parties agree that NPC has complied with Directive 20 in the Commission's Modified Final Order in Docket No. 19-06002 to review its TOU periods. (*Id.*)

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Continuation of the Earnings-Sharing Mechanism

22. The Parties agree that the issue of whether to continue the ESM ordered in Docket No. 17-06003 will be resolved via a limited hearing before the Commission. (*Id.* at 1-2.)

23. The Parties agree that Staff, BCP, SNGG, and NPC will file testimony and participate in a hearing and that all other Parties have agreed to not file testimony and have waived their rights to perform cross-examination of any witness during the hearing on October 12, 2020. (*Id.* at 10.)

24. The Parties agree that nothing in the Stipulation shall be construed to prevent any party from addressing earnings-sharing in Docket No. 19-06008, the rulemaking for Senate Bill 300 ("SB 300") alternative ratemaking, or in future general rate review proceedings. (*Id.*)

25. The Parties agree that as part of the Stipulation, NPC agrees to withdraw its appeal filed with the Nevada Supreme Court (Case No 81154, regarding the ADIT tax issues.) (*Id.*)

**Commissions Discussion and Findings**

26. The Commission finds that the Stipulation complies with the requirements of NAC 703.845 in that it settles only issues relating to the instant proceeding and does not seek relief that the Commission is not otherwise empowered to grant. The Stipulation is a consensus resolution of the issues pursuant to the Parties' negotiations and is a reasonable recommendation and resolution of the issues in this proceeding.

27. All arguments of the Parties raised in these proceedings not expressly addressed herein have been considered and either rejected or found to be non-essential for further discussion in this Order. Any agreements and recommendations contained in the Stipulation, but not expressly addressed herein, are either agreements by the Parties regarding matters non-

essential to the disposition of this docket or are recommendations for specific findings that do not require delineation given the Commission's acceptance of the Stipulation.

28. Therefore, the Commission incorporates the first Interim Order and Interim Order No. 2, wherein the Commission accepted the Stipulation, into this order.

## VII. CONTINUATION OF THE EARNINGS-SHARING MECHANISM

### Background and Overview

29. In NPC's 2017 GRC, Docket No. 17-06003, the Commission adopted an ESM to capture any potential overearnings by NPC.[3] Under the terms of the mechanism, NPC was allowed to retain 100 percent of overearnings above its authorized 9.4 percent ROE up to 9.7 percent and 50 percent of overearnings above 9.7 percent. The remaining 50 percent of overearnings above 9.7 percent was to be returned to ratepayers in the instant proceeding.

30. In the instant proceeding, the Parties were unable to reach consensus on whether to continue the ESM and agreed to hold a limited hearing on the issue. (*See* Stipulation.) NPC and Staff recommend ceasing the ESM. (Ex. 154 and 305.) Both NPC and Staff have taken the position that the ESM is better addressed through the alternative ratemaking process being considered in Docket No. 19-06008 implementing SB 300. (Ex. 154 and 305.) SNGG recommends the continuation of the ESM and states that any changes to the ESM should occur through the alternative ratemaking process. (Ex. 1001.) BCP recommends continuing the ESM and makes other recommendations regarding carrying charges, excludable costs, audit timing, and the appropriate asymmetry of the mechanism. (Ex. 403.)

31. NPC also states that other unresolved issues and specific concerns exist regarding continuing the ESM, including that: it is discriminatory in that only NPC and SPPC are subject

[3] Administrative notice was taken of the Modified Final Order in Docket No. 17-06003.

to earnings-sharing; the current regulatory framework without earnings-sharing already effectively balances customer and shareholder interests; extenuating circumstances existed in 2017; the current asymmetrical earnings-sharing, without a corresponding sharing of under-earnings, deprives a utility of the opportunity to earn a fair and reasonable return in different economic environments; and achieving a fair incentive ratemaking mechanism is complicated and outstanding issues exist with the current mechanism. (Ex. 154 at 3-6.)

**Party Positions**

**SNGG's Position**

32. SNGG states that there is no reason to discontinue the currently-approved ESM and disrupt the status quo for ratemaking, especially at a time in which earnings-sharing has proven to provide considerable customer protection, there is economic uncertainty related to the ongoing COVID-19 pandemic, and the Commission is in the process of adopting procedures within Docket No. 19-06008, pursuant to NRS 704.762. (Ex. 1001 at 2, Tr. 322-25.)

33. SNGG states that the facts may have changed since the last rate case but the need for continued customer protection has not changed. (Ex. 1001 at 3.) SNGG states that, based on 2018 and 2019, NPC earned at least $120 million in excess of the 9.7-percent ROE, with 50 percent of that shared with customers, plus another $14.5 million[4] in equity earnings between the approved ROE of 9.4 percent and 9.7 percent (*Id.*) SNGG states that, even with the rate reduction expected from this rate case, it is not known whether this excess earning will continue because it is dependent on a number of variables once this rate case is complete. (*Id.*)

34. SNGG states that SB 300 mandated that the Commission establish procedures for an electric utility to apply to the Commission for approval of an alternative ratemaking plan. (*Id.*

[4] Assuming a rate base of $4.819,552,000, multiplying it by 49.99 percent and then by 0.30 percent (30 basis points) equals $7,227,837; multiplying that by 2 years equals $14,455,674.

at 4.) SNGG states that, at the time of passage of SB 300, NPC was already operating under the currently approved earnings sharing mechanism and SPPC had an earnings sharing approved by the Commission just last year, shortly following passage of SB 300.[5] (*Id.*) SNGG states that ESMs are now part of the current ratemaking plan for electric utilities in Nevada based upon Commission orders and SB 300. (*Id.*) SNGG explains that the Commission Order in Docket No 17-06003 created a rule of general applicability to the ESM for NPC, which remains in effect until the Commission alters that mechanism. (*Id.*; Tr. 308.)

35. SNGG states that, if NPC wants to petition the Commission for a change in ratemaking methodology, it should wait until the rulemaking considerations in Docket No. 19-06008 are completed and then, at a more appropriate time, the Commission may consider the role of the ESM. (*Id.*; Tr. 323.)

36. SNGG states that NPC's history of excess earnings above the approved rate of return supports the ESM's continuation. (Ex. 1001.at 5; *see* Blank Table 1, Tr. 323-24.) SNGG points out that even as recently as the 12 months that ended on June 30, 2020, NPC is reporting over $66 million in excess of the approved ROE. (*Id.*) SNGG argues that this demonstrates that the specific concerns at issue when the Commission first approved the ESM are not the only reasons why excessive earnings may occur. (*Id.*)

37. SNGG dismisses NPC's concerns regarding the asymmetrical nature of the ESM, noting that NPC can file a rate case at any time and has control over the timing of expenditures and investments. (*Id.* at 7.) SNGG states that, furthermore, one reason why the ESM is designed asymmetrically and not symmetrically is to avoid perverse incentives for cost control by the utility if it can recover uncontrolled excess expenditures through the ESM. (*Id.*)

[5] Docket No. 19-06002, Modified Final Order dated April 2, 2020.

38. SNGG states that NPC's references to NRS 703.151 and 704.120(1) do not alter SNGG's belief that the ESM helps balance asymmetry in the timing of rate cases. (*Id.*) SNGG states that, although the Commission indeed has the authority to issue an order for a utility to appear and show cause as to why its rates continue to be just and reasonable, show-cause proceedings are rare and this authority does not reside with customers. (*Id.*) Further, SNGG states that the Commission's authority is not a substitute for an ESM, which allows a partial remedy for excessive returns within the year in which they occur. (*Id.* at 7-8.)

39. SNGG notes that the current pandemic weighs in favor of retaining the ESM. (*Id.* at 8.) SNGG states that the Commission allowed NPC to create a regulatory asset for COVID-19-related costs.[6] (*Id.*) SNGG asserts that the disposition of the COVID-19 regulatory asset could increase earnings but, without the ESM, customers would have no protection against overearnings that may result. (*Id.*)

**BCP's Position**

40. BCP states that it supports the continuation of the ESM. (Ex. 403. at 10.) BCP states that, first, the ESM mechanism not only incentivizes cost-cutting measures by the utility, but it also protects ratepayers against excessive over-earnings by the utility that could result from these cost-cutting measures between rate cases. (*Id.*) BCP notes that this utility has had a long and consistent history of overearning. (*Id.*) BCP states that, moreover, it is important to note the reasonableness of the current ESM structure that allows NPC to retain 100 percent of any excess earnings up to 30 basis points above the authorized ROE and then shares excess earnings with ratepayers after that. (*Id.* at 10-11.)

[6] Emergency Order related to utility service and COVID-19, Docket No. 20-03021, March 27, 2020.

41. BCP states that it does not agree that the ESM should be changed to make it symmetrical in that under-earnings, like overearnings, should be shared with ratepayers. (*Id.* at 11.) BCP states that, first, any discussion of a symmetrical ESM where under-earnings (below the band) are shared evenly with ratepayers is, at this time, a theoretical discussion at best because NPC has consistently over-earned from 2014 forward. (*Id.*) BCP notes that ratepayers have little to no recourse when a public utility is over-earning but that utilities have ample protection against the risk of under-earnings: (1) by controlling investment levels between rate cases, which is where the under-earnings would come from or (2) by filing a rate case when under-earnings are eminent or start to appear at any significant level. (*Id.*)

42. BCP states that the ESM regulatory liability balance is being filed in NPC's annual Deferred Energy Accounting Adjustment ("DEAA") filing each year but that the merits of the calculations and resulting balance are not being analyzed in those filings.[7] (*Id.* at 12; Tr. 362, 370-71.)

43. BCP states that the merits of the ESM calculations should be audited in NPC's next GRC because the merits of the ESM calculations cannot be thoroughly reviewed in the DEAA filings because no other BTGR information is filed in those cases, only BTER information is filed in a DEAA filing. (*Id.* at 12-13; Tr. 371.)

44. BCP recommends that the Commission clarify that the ESM calculations will be audited in NPC's next GRC. (*Id.*at 13.)

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[7] Docket No. 19-03001, Commission Order, August 1, 2019, Attachment 1 Stipulation; and, Docket 20-02026, Commission Order, August 1, 2019, Attachment 1 Stipulation.

**Staff's Position**

45. Staff states that it recommends that the Commission authorize NPC to cease the accrual of an earnings-sharing regulatory liability after December 31, 2020. (Ex. 305 at 1.)

46. Staff states that the Commission established the ESM in NPC's last GRC, Docket No. 17-06003, and it was initiated to address a unique situation where future benefits, such as debt refinancing at lower interest rates and the effect of a lower income tax rate, could flow to the benefit of NPC's shareholders as well as its ratepayers.[8] (*Id.* at 1-2.) Staff states that the benefits to shareholders and ratepayers have been captured for calendar years 2018 and 2019, while potential benefits for 2020 will be addressed in NPC's next GRC and DEAA proceeding. (*Id.* at 2.) Staff states that, with the setting of new rates effective January 1, 2021, the unique set of circumstances have passed and the impetus for an ESM will have passed. (*Id.*)

47. Staff states that in open Docket No. 19-06008, the rulemaking to amend, adopt, and/or repeal regulations in accordance with SB 300, the Commission and interested parties are exploring, in a collaborative manner, alternative ratemaking methods, including an ESM. (*Id.*) Staff states that Docket No. 19-06008 is the appropriate forum in which to evaluate the benefits and disadvantages of implementing any ESM. (*Id.*) Staff explains that, for example, one issue that will need to be considered in the context of an ESM is the symmetry between excess earnings and a shortfall in earnings and, if so, whether there should be a resulting change in ROE. (*Id.*) Therefore, Staff recommends that the Commission authorize NPC to cease accrual of an earnings-sharing regulatory liability after December 31, 2020. (*Id.*)

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[8] *See* Docket No. 17-06003, Modified Order Granting in Part and Denying in Part General Rate Application by Nevada Power at 3, Executive summary: New Earnings-Sharing Mechanism to Capture Overearnings, issued December 29, 2017.

**NPC Rebuttal**

48. NPC states that an ESM is not necessary for the Commission to fulfill its obligations to establish fair and reasonable rates. (Ex. 154 at 6.) NPC states that NPC and SPPC (electric operations) are required pursuant to NRS 704.110(3) to make a GRC filing no less frequently than every three years. (*Id.*) NPC states that, moreover, the Commission has the ability, pursuant to NRS 703.151 and 704.120(1), to require NPC to file for a rate review at any time. (*Id.*) NPC states that regulatory lag is an inherent part of the regulatory construct but, when combined with the Nevada statutes referenced above, the existing regulatory framework ensures fair and reasonable rates. (*Id.*)

49. NPC states that the key factors that supported an ESM in Docket Nos. 17-06003 and 17-06004[9] no longer exist. (*Id.* at 7.) NPC notes that the testimony in Docket Nos. 17-06003 and 17-06004 recommended an ESM based on historical overearnings, along with significant debt maturities and potential tax reform over the rate-effective period. (*Id.*) NPC further notes that the Commission order reiterated the key factors by stating, "This earning sharing mechanism eases concerns regarding NPC receiving a windfall for refinancing long-term debt at cheaper rates and incurring savings from future changes to federal tax legislation."[10] (*Id.*) NPC asserts that the factors that supported earnings-sharing in 2017 will be fully reflected in customer rates effective January 1, 2021; thus, the factors that drove the establishment of the ESM no longer exist. (*Id.*) Moreover, NPC explains that it is not scheduled for any major debt refinancing and that NPC revised rates via a tax rate reform rider approved in Docket No. 18-02010. (*Id.* at 7-9, *see also* Chart Cole 1 and Chart Cole 2.)

[9] Docket No. 17-06003 was consolidated with Docket No. 17-06004 wherein NPC filed a separate application for approval of new and revised depreciation and amortization rates for its electric and common accounts.
[10] *See* Docket Nos. 17-06003 and 17-06004, December 19, 2018, Modified Final Order at 114, para. 466.

50. NPC explains that the continuation of the ESM is unfair to NPC because it is asymmetrical as it must share potential upside with customers but bears all the potential downward risks. (*Id.* at 9.) NPC explains that, under symmetrical ESM, NPC benefits or is disadvantaged within a certain deadband on either side of the allowed return on equity. (*Id.*) For example, assuming a deadband of 30 basis points and a 9.4-percent allowed return on equity, NPC retains all risks and benefits so long as the actual returns are between 9.1 percent and 9.7 percent. (*Id.*) NPC further explains that underperformance below 9.1 percent and over-performance above 9.7 percent would be shared with customers using a sharing percentage (i.e., 50 percent in Docket Nos. 17-06003 and 17-06004). (*Id.* at 9-10.)

51. NPC explains that a simple example will illustrate the inequities of an asymmetrical ESM. (*Id.* at 10.) NPC states that the revenue requirement utilizes historical costs and tariffs that are based on normal weather. (*Id.*) NPC states that, if weather in a particular year is much warmer than normal, asymmetrical ESM would require the utility to share excess earnings with customers. (*Id.*) NPC notes, if weather in the following year is much cooler than normal by an equal amount, then asymmetrical ESM would result in the utility bearing the full financial impact of these under-earnings. (*Id.*)

52. NPC asserts that the design of an asymmetrical ESM deprives NPC of the ability to earn the established rate of return given that the downside risk exceeds the potential upside return. (*Id.* at 11.) NPC argues that the solution is either a symmetrical ESM or an increase in the stipulated ROE of 9.4 percent to alleviate these inequities. (*Id.*) NPC notes that whether the risk materializes is not relevant; rather, the appropriate consideration is the existence of a risk which warrants an upward adjustment to the allowed return on equity. (*Id.*) NPC states that the

issues created by continuing the ESM provide another reason why a more thorough discussion in Docket No. 19-06008 is necessary to address the current mechanism's inequities. (*Id.*)

53. NPC states that SNGG's argument[11] for an asymmetrical ESM is based simply on the following: (1) NPC can file for a rate increase if it is under-earning; (2) NPC can over-earn by controlling its cost structure; (3) customers do not have the ability to force a show-cause proceeding or initiate a rate case; and, (4) there is a pandemic; therefore, NPC should continue to be subject to an ESM. (*Id.* at 11-12.)

54. NPC states that the first argument contains several flaws. (*Id.* at 12.) NPC notes that it takes approximately five months to prepare and 210 days to complete a general rate review; thus, any new rates would take effect nearly two years after NPC under-earned, failing to compensate NPC for the under-earnings over those two years. (*Id.*)

55. NPC states that SNGG's second argument is also flawed. (*Id.*) NPC states that it certainly controls its cost structure, but this is neither a risk nor a detriment to customers. (*Id.*) NPC notes that the mandated triennial rate filing limits the upside benefit to NPC of cost reductions and ensures that customers benefit from the lower cost structure in a timely manner. (*Id.*)

56. NPC states that the third argument, a customer's inability to affect rates between rate cases, also lacks merit. (*Id.*) NPC states that subsections 3 and 4 of NRS 704.120 address a customer complaint of one or more rates. (*Id.*) NPC explains that, in contrast, subsection 5 allows the Commission to investigate and change any rate on its own motion. (*Id.*) NPC states that it is puzzling what possible meaning SNGG is attributing to NRS 704.120 as a whole, and subsections 3 and 4 specifically, to read it as precluding a customer from making a filing with the

[11] Ex. 1001, Direct Testimony of Larry Blank at 6-7, Q/A 7.

Commission to change rates. (*Id.* at 12-13.) NPC states that the statute unambiguously provides this protection to customers. (*Id.* at 13.)

57. NPC states that SNGG's fourth argument, arbitrarily using NPC to provide pandemic assistance, is equally perplexing. (*Id.*) NPC states that this logic's implication suggests that all Nevada utilities should be subject to an ESM to benefit Nevada citizens. (*Id.*) NPC states that COVID-19's impact on Nevada residents and the economy is unfortunate; nevertheless, the existence of COVID-19 does not support the continuation of the ESM. (*Id.*)

58. NPC states that, in Docket Nos. 17-06003 and 17-06004, the assertion of overearnings was based, in part, on the quarterly earned rate of return and return on equity reports filed with the Commission.[12] (*Id.*) NPC asserts that these reports' inability to accurately measure NPC's returns was addressed in Docket Nos. 17-06003 and 17-06004 and the Commission recognized the shortcomings of these reports by instructing parties to work together to develop a new methodology that accurately measures returns and overearnings.[13] (*Id.* at 13-14.) NPC states that the parties worked collaboratively and developed a new methodology that more accurately measures returns. (*Id.* at 14.)

59. NPC notes that, interestingly, SNGG also relies on the same rate of return reports, as did MGM in Docket Nos. 17-06003 and 17-06004, as justification for the continuation of the ESM.[14] (*Id.*) NPC states that the Commission declined to find that these rate of return reports fairly represent NPC's returns and should be used in determining overearnings.[15] (*Id.*) NPC

[12] Administrative notice taken of Docket Nos. 17-06003 and 17-06004, Direct Testimony of Dennis E. Peseau at 3-4, Q/A6.
[13] Docket Nos. 17-06003 and 17-06004, December 19, 2018, Modified Final Order at 116, para. 475.
[14] Exhibit 1001, Direct Testimony of Larry Blank at 5-6.
[15] *See, e.g.*, Docket Nos. 17-06003 and 17-06004, December 19, 2018, Modified Final Order at 116, para. 475.

states that, therefore, SNGG's reference to these reports as support for the continuation of the ESM is of questionable value. (*Id.*)

60. NPC states that assuming an ESM is even warranted, these types of discussions surrounding the mechanics of an ESM are best addressed in rulemaking dockets such as Docket No. 19-06008. (*Id.* at 17.)

61. NPC states that the Commission's Order in Docket Nos. 17-06003 and 17-06004 clearly states that the annual DEAA "proceeding is the proper forum for determining whether, when and in what amount Nevada Power is earning in excess of the ROE approved by the PUCN."[16] (*Id.* at 17-18.)

**Commission Discussion and Findings**

62. Pursuant to NRS 704.001(4), the Commission must "balance the interests of customers and shareholders of public utilities by providing public utilities with the opportunity to earn a fair return on their investments while providing customers with just and reasonable rates".

63. The Commission notes that, pursuant to paragraph 49 of the Stipulation and in accordance with the notice issued on October 1, 2020, the Commission has two options with respect to the ESM in this docket. First, to discontinue the ESM for NPC effective December 31, 2020, or, second, to continue the ESM as ordered in NPC's prior GRC, Docket No. 17-06003.

64. NPC and Staff recommend that the ESM be discontinued in its current form and any future changes with regard to an ESM mechanism be addressed within the framework of SB 300 and the attendant investigation and rulemaking in Docket No. 19-06008. SNGG also acknowledges that Docket No. 19-06008 is the place for making any changes to the ESM, although in the context of continuing the current mechanism.

[16] Docket Nos. 17-06003 and 17-06004, December 19, 2018, Modified Final Order at 114, para. 468.

65. The Commission agrees with BCP that the ESM not only preserves the incentive for the utility to institute cost-cutting measures but it also protects ratepayers against excessive over-earnings by the utility that could result from these cost-cutting measures between rate cases. As noted by SNGG, the Commission approved an earnings-sharing mechanism for SPPC in Docket No. 19-06002[17] shortly after passage of SB 300. As further noted by SNGG, the earnings-sharing mechanism provides considerable customer protection, especially during economic uncertainty related to the ongoing COVID-19 pandemic. SNGG notes that the current pandemic weighs in favor of retaining the ESM. The Commission agrees that customers would receive protection from maintaining the ESM during this rate cycle beginning on January 1, 2021.

66. Those who recommend discontinuation rely, in part, on the ongoing rulemaking in Docket No. 19-06008. The Commission agrees that Docket No. 19-06008 is where an in-depth discussion of the complexities of an ESM should take place. The evidence presented by SNGG and BCP in this proceeding indicates that continuing the ESM in its current state is just and reasonable compared to completely eliminating the ESM and the protection that it affords to consumers, especially given that the ESM still allows NPC to retain a significant majority of its excess earnings. The Commission finds, therefore, that there shall be a continuation of the ESM ordered in Docket No. 17-06003. NPC shall retain 100 percent of its earnings in excess of its authorized return on equity of 9.40 percent up to 9.70 percent. Any earnings in excess of 9.70 percent shall be shared 50/50 between ratepayers and the utility.

67. The Commission agrees that it will be beneficial to evaluate an ESM in the context of an alternative ratemaking plan. However, given the timing of when such a plan could

[17] The Modified Final Order in Docket No. 19-06002 approved a Stipulation by the parties to an earnings sharing mechanism to be tracked and reported in the same manner as for NPC.

be filed for approval and the fact that NPC is not required to file an alternative ratemaking plan at all, the Commission declines to cease the current earnings-sharing paradigm pending the outcome of any alternative ratemaking proceeding. NPC's ESM may be modified as applicable should an alternative rate plan including an ESM be approved prior to December 31, 2023. Therefore, the Commission will address this mechanism as part of the ongoing rulemaking in Docket No. 19-06008 and in subsequent rate proceedings, as appropriate.

68. NPC has expressed concern with the fact that the current ESM is asymmetrical and that there is no corresponding mechanism should NPC not achieve its authorized ROE of 9.40 percent. The Commission finds this concern to be mitigated by the structure of the continued ESM. NPC retains all earnings up to an ROE of 9.70 percent, and 50 percent of all earnings in excess of that amount.

69. The Commission finds that, with respect to the annual DEAA filing, that portion of the ESM to be adjudicated within the annual DEAA filing shall be limited to proposed changes to the calculation methodology and verification that the calculation methodology was accurately applied in the calculation of the annual amount recorded in the regulatory liability account, if applicable.

70. The Commission acknowledges the work of the parties in Docket No. 19-03001 to come to the stipulated agreement regarding the ESM calculation methodology. However, it would be unreasonable to find that, over time and experience, changes to that calculation methodology should not be proposed and evaluated. Any changes would best be established as part of an alternative ratemaking process; however, until such time as an alternative ratemaking plan is submitted by NPC, any changes proposed to the calculation methodology shall be made in the annual DEAA filing.

71. Likewise, the annual DEAA filing is the appropriate forum in which to verify the application of the ESM calculation methodology on a strictly mathematical basis. This is necessary to establish the potential annual regulatory liability amount for future review purposes.

72. The Commission finds that the verification and vetting of the amounts recorded in the accounts used in the calculation of the earnings-sharing regulatory liability shall be performed in NPC's next GRC application.

73. The revenues and expenses used in the calculation of the earnings-sharing regulatory liability are related to GRC revenues and expenses. The Commission acknowledges the difficulty this presents to parties in performing verification of the potential three years' underlying activity in the accounts that are used in the calculation of any excess earnings. The Commission therefore encourages verification, to the extent possible, of the amounts in the annual DEAA filing. To some degree, this is similar to the review of other regulatory assets or regulatory liabilities which may have been established, such as those created pursuant to the Emissions Reduction and Capacity Replacement statutes and regulations in the past.

THEREFORE, it is ORDERED:

1. The initial Interim Order and Interim Order No. 2, wherein the Stipulation filed by Nevada Power Company d/b/a NV Energy; the Regulatory Operations Staff of the Commission; the Nevada Bureau of Consumer Protection; MGM Resorts International, Caesars Enterprise Services LLC; the Southern Nevada Gaming Group;[18] Wynn, Las Vegas, LLC; Circus Circus Las Vegas, LLC; the Smart Energy Alliance; the Kroger Co.; Walmart, Inc.; Nevada Cogeneration Associates #1; Sunrun, Inc; and the Colorado River Commission of Nevada,

[18] Southern Nevada Gaming Group consists of the Boyd Gaming Corporation, Las Vegas Sands Corp., Stations Casinos LLC, Plaza Hotel and Casino, LLC, Tropicana Las Vegas Inc., and LVGV, LLC.

appended hereto as Attachment 1, are subsumed within this order, and the Stipulation is ACCEPTED.

2. The Application of Nevada Power Company d/b/a NV Energy designated as Docket No. 20-06003, is GRANTED IN PART, as modified by the Stipulation and this order. Nevada Power Company d/b/a NV Energy shall continue the earnings-sharing mechanism ordered in Docket No. 17-06003, subject to any modifications made to the earnings-sharing mechanism pursuant to Senate Bill 300 and the attendant investigation and rulemaking in Docket No. 19-06008. The earnings-sharing mechanism will be reviewed within the annual Deferred Energy Accounting Adjustment filing, with proposed changes limited to the calculation methodology and verification that the calculation methodology was accurately applied in the calculation of the annual amount recorded in the regulatory liability account, if applicable.

**Directives**

3. All cost-of-service studies filed by Nevada Power Company d/b/a NV Energy in its next general rate case shall include one version with generation and energy costs separately reconciled. Nevada Power Company d/b/a NV Energy may include a cost-of-service study or studies with its generation and energy combined using the generation and energy allocator and must provide detailed testimony supporting the use of the generation and energy allocator should it choose to do so.

4. Nevada Power Company d/b/a NV Energy shall file in its next general rate case application a complete embedded cost-of-service study with enough detail to allow for transparent review and vetting by the parties, to include the results of the embedded cost allocators discussion pursuant to paragraph 45 of the Stipulation. Nevada Power Company d/b/a NV Energy shall, not later than January 5 of the year in which it files its next general rate case,

meet with the Regulatory Operations Staff of the Commission, the Nevada Bureau of Consumer Protection, and other interested stakeholders to discuss embedded cost allocators.

5. Nevada Power Company d/b/a NV Energy shall file in its next general rate case application a complete hybrid cost-of-service study using the Regulatory Operations Staff of the Commission's methodology with enough detail to allow for transparent review and vetting by the parties and Commission.

6. Nevada Power Company d/b/a NV Energy shall file in its next general rate case a detailed analysis of its evaluation process for the marginal unit used in its marginal cost-of-service study.

7. Nevada Power Company d/b/a NV Energy shall update its time-of-use periods in its next general rate case.

8. Nevada Power Company d/b/a NV Energy shall use the weather normalization methodology adopted in Sierra Pacific Power Company d/b/a NV Energy's 2019 rate case.

9. Nevada Power Company d/b/a NV Energy shall convene an ad hoc interconnection working group open to all interested stakeholders, with a goal of gaining process efficiencies and cost reductions. The topics for discussion shall include process improvements and cost reductions for interconnections that involve main panel upgrades, energy storage, and other issues as they arise. Nevada Power Company d/b/a NV Energy and stakeholders shall jointly petition the Commission to seek any necessary approvals to implement agreed-upon process changes, as appropriate. In the event that Nevada Power Company d/b/a NV Energy and stakeholders disagree regarding any interconnection issue addressed in the working group, Nevada Power Company d/b/a NV Energy and stakeholders shall, on an annual basis but only if necessary, jointly petition the Commission to seek formal resolution.

10. Nevada Power Company d/b/a NV Energy shall engage in good faith negotiations with the Colorado River Commission of Nevada prior to April 1, 2021, to discuss modifications to the Hoover D tariff that is scheduled to change January 1, 2022.

By the Commission,

HAYLEY WILLIAMSON, Chair

C.J. MANTHE, Commissioner and Presiding Officer

Attest: _____
TRISHA OSBORNE,
Assistant Commission Secretary

Dated: Carson City, Nevada

12/10/20

(SEAL)

# ATTACHMENT 1

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

| | | |
|---|---|---|
| In the Matter of the Application by **NEVADA POWER COMPANY D/B/A NV ENERGY,** filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers. | ) ) ) ) ) ) / | Docket No. 20-06003 |

## STIPULATION

Pursuant to Nevada Administrative Code ("NAC") §§ 703.750 and 703.845, Nevada Power Company, d/b/a NV Energy ("NV Energy," "Nevada Power," or "Company"), the Regulatory Operations Staff ("Staff") of the Public Utilities Commission of Nevada ("Commission"), the Office of the Attorney General's Bureau of Consumer Protection ("BCP"), Walmart, the Kroger Co. ("Kroger"), Colorado River Commission of Nevada ("CRCNV"), Nevada Cogeneration Associates ("NCA"), Sunrun Inc. ("Sunrun"), MGM Resorts International ("MGM"), Caesars Enterprise Services, LLC ("Caesars"); Wynn Las Vegas LLC ("Wynn"), Circus Circus Las Vegas ("Circus Circus"), LLC, Smart Energy Alliance ("SEA"), and Southern Nevada Gaming Group ("SNGG")[1] each individually a "Signatory" and together the "Signatories," enter into this Stipulation to resolve all but one issue related to the Company's Application for Authority to Adjust Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers ("Application").

## SUMMARY OF STIPULATION

The Signatories agree this Stipulation provides a reasonable resolution of issues raised in the Application and that the Stipulation is in the public interest. Specifically, through the Stipulation the Company will issue a $120 million one-time bill credit to customers, utilize a ROE of 9.4% and a total revenue requirement of $1.0702 billion, and make certain agreed upon adjustments to rates and fees. A determination whether to continue the earnings sharing

[1] Boyd Gaming Corporation, Station Casinos LLC, Las Vegas Sands, Plaza Hotel and Casino, LLC, Tropicana Las Vegas Inc., and LVGV, LLC are collectively SNGG.

mechanism ordered in Docket No. 17-06003 will be resolved via a limited hearing before the Commission.

The Stipulation only settles issues related to this docket. The Stipulation only seeks relief the Commission is empowered to grant. Accordingly, the Signatories recommend the Commission accept the Stipulation.

## RECITALS

1. On June 1, 2020, the Company filed its Application.

2. On June 8, 2020, the Commission issued a Notice of Application.

3. On June 9, 2020, the Commission issued a Notice of Prehearing Conference and the BCP filed a Notice of Intent to Intervene pursuant to NRS Chapter 228.

4. Staff participates as a matter of right pursuant to NRS 703.301.

5. On June 12, 2020, Walmart filed a Petition for Leave to Intervene ("PLTI").

6. On June 17, 2020, Kroger filed a PLTI, Motion for Admission Pro Hac Vice, and Notice of Association of Counsel.

7. On June 29, 2020, CRCNV filed a PLTI.

8. On June 30, 2020, NCA, MGM, Caesars, and Sunrun each filed PLTIs.

9. On July 1, 2020, Wynn, Circus Circus, and SEA (collectively, "WCS"), filed a joint PLTI and a Notice of appearance, and the SNGG filed a PLTI.

10. On July 9, 2020, the Commission held a prehearing conference. The Company, Staff, BCP, Caesars, CRCNV, Kroger, MGM, NCA, SNGG, Sunrun, Walmart, and WCS appeared and discussed a procedural schedule and the PLTIs.

11. On July 15, 2020, the Commission issued a Procedural Order.

12. On July 16, 2020, the Commission issued a Notice of Consumer Session and Notice of Hearing, and an Order granting the PLTIs of Caesars, CRCNV, Kroger, MGM, NCA, SNGG, Sunrun, Walmart, and WCS.

13. On July 21, 2020, the Staff and BCP filed the Joint Motion and Order Shortening Time.

14. On July 22, 2020, the Company filed a Response to the Joint Motion's request for an Order Shortening Time, Staff and BCP filed a Joint Reply to the Company's Response, and the Commission issued an Order denying the Movant's request for an Order Shortening Time.

15. On July 28, 2020, Caesars and MGM, the Company, and WCS filed Responses to the Joint Motion.

16. On August 3, 2020, the Staff and BCP filed a Joint Reply and the Company submitted its Cost of Capital certification filing.

17. On August 7, 2020, the Commission issued an order denying the Joint Motion, Procedural Order No. 3 establishing a schedule for an evidentiary hearing, and Notice of Hearing.

18. On August 13, 2020, the Commission issued a Notice of Prehearing Conference and Procedural Order No. 4.

19. On August 17, 2020, Kroger, WCS, BCP, SNGG, MGM, Caesars, and Staff filed testimony pursuant to Procedural Order No. 3. Also, on August 17, 2020, the Company submitted its Revenue Requirement certification filing pursuant to Procedural Order No. 3.

20. On August 26, 2020, the Company filed its rebuttal testimony.

21. On August 27, 2020, the Commission issued Procedural Order No. 5.

22. On August 28, 2020, the Company submitted its Rate Design certification filing.

23. On August 31, 2020, the Company filed information responsive to Procedural Order No. 5, paragraphs 24-25.

24. On September 1, 2020, the Commission held an evidentiary hearing, and the Company filed additional information responsive to paragraph 26 of Procedural Order No. 5. Also on September 1, 2020, an Overearnings Credit Allocation Stipulation was filed by Kroger, WCS, BCP, SNGG, MGM, Caesars, Walmart, CRC NV, and Staff.

25. On September 4, 2020, Staff, BCP, MGM, Caesars, and WCS filed Cost of Capital testimony.

26. On September 9, 2020, the Commission issued its Interim Order ordering the Company to return $59,675,474.00 of the Earnings Sharing Regulatory Liability in the form of a one-time bill credit. The Commission also issued Procedural Order No. 6.

27. On September 16, 2020, the Company filed information in compliance with Procedural Order No. 6.

28. On September 18, 2020, the Company filed its Cost of Capital rebuttal testimony.

29. On September 22, 2020, the Commission issued Procedural Order No. 7.

## AGREEMENT OF THE SIGNATORIES

NOW THEREFORE, in light of the foregoing considerations, the Signatories agree and recommend that the Commission approve the stipulation as follows:

**Cost of Capital and Revenue Requirement**

30. The Company shall issue a $120 million one-time bill credit to be immediately distributed to customers based on the calculation of recorded rate base tariff general rate

("BTGR") revenues using non-normalized billing determinants for calendar year 2019. The one-time bill credit includes: 1) the $59.7 million earnings sharing regulatory liability as ordered by the Commission in the September 9 Interim Order; 2) $26 million from the unprotected excess accumulated deferred income tax ("ADIT") regulatory liability; 3) expected earnings sharing for 2020 of $20 million, which will act as a reduction to the 2020 over earnings balance accepted by the Commission in future proceedings; and 4) approximately $9 million in carrying charges on the earnings sharing regulatory liability that accrued during calendar years 2019 and 2020, and 5) approximately $5 million in other expense adjustments. The final class allocations of the credit amounts are presented in Exhibit 1 ("Settlement One-Time Credit Allocation").

a. BTGR revenues will include impact fee revenues for distribution-only service ("DOS") customers consistent with "Present" BTGR revenues for 2019 as presented in Statements J and O in the original application.

b. A proportionate allocation to each rate schedule would result in each rate schedule receiving an equal percentage credit applicable to each rate schedule's recorded 2019 BTGR revenues.

c. For rate schedules serving large non-residential customers (LGS-2, LGS-3, LGS-X, LGS-2-DOS, LGS-3-DOS, LGS-X-DOS) the overearnings refund will be based directly on the total recorded BTGR revenue contributed by each such large customer by meter during calendar year 2019. Using this method, the meter-specific refund would apply the equal percentage credit to the BTGR revenues attributable to each large-customer meter in 2019.

d. If the final calculation of the 2020 overearnings is less than $20 million, the Company will not seek recovery from customers of any of the $20 million

representing the 2020 overearnings. If the final calculation of the 2020 overearnings is more than $20 million, such amount will be due to ratepayers consistent with the Order in Docket No. 17-06003 or other applicable Commission Order.

31. The Company's return on equity ("ROE") will be set at 9.4 percent and the rate of return ("ROR") will be set at 7.14 percent.

32. The Company's total revenue requirement will be set at $1.0702 billion, which reflects: 1) the Company's expected change in circumstance ("ECIC") adjustments; 2) Staff's weather normalization adjustment; 3) the $59.7 million of 2018 and 2019 earnings sharing regulatory liability as part of the $120.0 million one-time credit; 4) $26.0 million of unprotected ADIT regulatory liability as part of the $120.0 million one-time credit; 5) a 9.4 percent ROE; and 6) a "black box" settlement revenue requirement adjustments for other adjustments needed to get the Company's filing to stipulated revenue requirement amount.

33. Cost recovery associated with the Reid Gardner and Navajo power plants is incorporated into the revenue requirement as proposed by Nevada Power such that there is no impairment of cost recovery relative to Nevada Power's filing. This includes regulatory asset balance of $112.4 million in decommissioning and remediation costs for Reid Gardner per I-CERT-30, regulatory asset and balance credit of $1.65 million for Navajo per I-CERT-31, and regulatory asset balance of $0.678 million per I-CERT-28 for Mohave. These costs are to be recovered over the period 2021-2023 as reflected in the filing and are approved by all parties. Future additional costs incurred by Nevada Power regarding these facilities will be included as part of future general rate case proceedings. All parties reserve their rights to review and make recommendations regarding recovery of future costs, and whether and how the costs should be allocated to all customers in future general rate case proceedings.

34. The Company agrees to a tiered interconnection fee that provides for a lower fee for smaller distributed generation ("DG") systems and a higher fee for larger DG systems, instead of the averaged fee currently proposed for all DG systems. The tiered interconnection fees are provided in Exhibit 2.

35. NV Energy agrees to convene an ad hoc interconnection working group open to all interested stakeholders, with a goal to gain process efficiencies and cost reductions. The working group will convene at the request of any stakeholder on an as-needed basis. Topics for discussion shall include process improvements and cost reductions for interconnections that involve main panel upgrades, energy storage and other issues as they arise. NV Energy agrees to jointly petition the Commission along with stakeholders to seek any necessary approvals to implement agreed-upon process changes, as appropriate. In the event NV Energy and stakeholders disagree regarding any interconnection issue addressed in the working group, NV Energy agrees, on an annual basis and if necessary, to jointly petition with the Commission to seek formal resolution.

36. The Company commits to engaging in good faith negotiations with the CRCNV prior to April 1, 2021, to discuss modifications to the Hoover D tariff that is scheduled to change January 1, 2022.

**Rate Design**

37. The Company's rate design will use Staff's trend weather normalization methodology that the Commission adopted in Sierra Pacific Power Company's ("SPPC") 2019 rate case.

38. The Company's rate design will use Generation Allocators, not Generation & Energy Allocators, which the Commission adopted to allocate generation demand costs in SPPC's 2019 rate case.

39. The Company's rate design will not include energy costs (BTER) in adjusting class revenue requirement for policy considerations in Statement O, Tab "Passes." More broadly, while it is acceptable to list energy costs (BTER) in Cost of Service Study and Statement O, they should not be used in any BTGR calculations or "Interclass Revenue Adjustments."

40. The Company's rate design will not shift all claimed net metering ("NEM") revenue shortfalls to the corresponding otherwise applicable class (e.g., NMR schedules to RS schedule), which inflates Nevada Power's calculated subsidy for the corresponding otherwise applicable class (e.g., RS).

41. The Company's rate design will use Exhibit Pollard Cert-20, Statement O-ECS-E Proposed Revenue Requirement-Proposed Rates, as adjusted and proposed in Exhibit 3 ("Settlement Statement O"). In the event of any ambiguity or perceived divergence between the language of this Stipulation and the rates identified in Exhibit 3, Exhibit 3 will control.

42. The Signatories agree to accept the rates contained in Exhibit 3 (Settlement Statement O) as the tariffed rates effective January 1, 2021.

43. When the claimed NEM revenue shortfalls are placed back to its appropriate rate class (e.g., from RS to RS-NEM and RM to RM-NEM), Exhibit Settlement Statement O shows that there is no subsidy for non-NEM residential customers.

44. The Company's embedded cost of service study filed in this general rate case used marginal cost allocators, and such allocators are not generally accepted in embedded cost-of-service studies used in other state jurisdictions.

45. Not later than January 5 of the year in which NPC files its next general rate case, NVE agrees to meet with Staff, BCP, and interested interveners to discuss embedded cost allocators to be used in an embedded cost of service study that will be filed in Nevada Power's

next general rate case. Nevada Power will notify the Signatories of such meeting(s) reasonably in advance to provide the Signatories an opportunity to participate.

46. Nevada Power agrees to make the following changes to the LGS-2S schedule rates:

a. Adjust the On Peak Generation Demand per kW charge to $12.81 and increase the Mid Peak Generation Demand per kW charge to $2.65.

b. Commensurately decrease the On Peak, Mid Peak, Off Peak, and Other time-of-use ("TOU") energy per kWh charges so that the net impact is revenue neutral to the Company, while also maintaining the Company's proposed ratios between the TOU energy charges.

47. Nevada Power will provide an updated review of TOU periods in its next general rate case.

48. The Parties agree that NPC has complied with Directive 20 in the Commission's Modified Final Order in Docket No. 19-06002 to review its TOU periods.

**Continuation of the Earnings Sharing Mechanism**

49. The issue of whether there should be a continuation of the earnings sharing mechanism ordered in Docket No. 17-06003 will be resolved via a limited hearing on October 12, 2020, at 10:00 am.

50. Staff, BCP, SNGG and Nevada Power will file testimony and participate in a hearing pursuant to the following schedule:

a. Staff, BCP, SNGG testimony to be filed on September 24, 2020, by 2:00 PM.

b. Nevada Power rebuttal testimony to be filed on October 6, 2020, by 2:00 PM.

c. Hearing to be held on October 12, 2020, at 10:00 am.

51. All other Signatories have agreed to not file testimony and have waived their right to perform cross examination of any witness during the hearing on October 12, 2020.

52. Nothing in this stipulation shall be construed to prevent any party from addressing earnings sharing in Docket No. 19-06008 (Rulemaking for Senate Bill 300—Alternative Ratemaking), or future general rate review proceedings.

**ADIT**

53. As part of this stipulation NVE agrees to withdraw its Appeal filed with the Nevada Supreme Court (Case No. 81154, regarding the ADIT tax issues).

## GENERAL PROVISIONS

A. This Stipulation shall not serve as precedent for the resolution of any issue in the future by the Commission, with the exception of the matters enumerated herein and the findings that follow.

B. In accordance with NAC § 703.845, this Stipulation settles only issues relating to the present proceeding and seeks relief that the Commission is empowered to grant.

C. This Stipulation is entered into for the purpose of resolving all but one issue in this Docket by and among the Signatories as set forth above. This Stipulation is made upon the express understanding that it constitutes a negotiated settlement. The provisions of this Stipulation are not severable.

D. This Stipulation represents a compromise of the positions of the Signatories. As such, conduct, statements and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this Docket or any other proceeding. Except as set forth herein, neither this Stipulation, nor its terms, nor the Commission's acceptance or rejection of the terms contained in this Stipulation shall have any precedential effect in future proceedings.

E. Except as otherwise modified by the stipulation, the requests contained in the application will be deemed approved as filed.

F. This Stipulation may be executed in one or more counterparts, all of which together shall constitute the original executed document. This Stipulation may be executed by Signatories by electronic transmission, which signatures shall be as binding and effective as original signatures.

[Signature pages to follow]

This Stipulation is entered into by each Signatory as of the date entered below:

NEVADA POWER COMPANY
d/b/a NV ENERGY

Date

By: Michael Greene, Esq.
Deputy General Counsel

REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA

Date

By: Shelly Cassity, Esq.
Assistant Staff Counsel
Jesse Panoff, Esq.
Assistant Staff Counsel

BUREAU OF CONSUMER PROTECTION

Date

By: Michael Saunders, Esq.
Senior Deputy Attorney General

MGM RESORTS INTERNATIONAL

Date

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

CAESARS ENTERPRISE SERVICES

Date

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

SOUTHERN NEVADA GAMING GROUP

Date

By: Lucas Foletta, Esq.

This Stipulation is entered into by each Signatory as of the date entered below:

NEVADA POWER COMPANY
d/b/a NV ENERGY

Date

By: Michael Greene, Esq.
Deputy General Counsel

REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA

9/24/20
Date

By: Shelly Cassity, Esq.
Assistant Staff Counsel
Jesse Panoff, Esq.
Assistant Staff Counsel

BUREAU OF CONSUMER PROTECTION

Date

By: Michael Saunders, Esq.
Senior Deputy Attorney General

MGM RESORTS INTERNATIONAL

Date

By: Fred Schmidt, Esq.
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REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA

Date

By: Shelly Cassity, Esq.
Assistant Staff Counsel
Jesse Panoff, Esq.
Assistant Staff Counsel

BUREAU OF CONSUMER PROTECTION

September 24, 2020
Date

By: Michael Saunders, Esq. 20-06003
Senior Deputy Attorney General

MGM RESORTS INTERNATIONAL

Date

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

CAESARS ENTERPRISE SERVICES

Date

By: Fred Schmidt, Esq.
Austin Jensen, Esq.

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9-24-20
Date

Fred Schmidt
By: Fred Schmidt, Esq.
Austin Jensen, Esq.

SOUTHERN NEVADA GAMING GROUP

Date

By: Lucas Foletta, Esq.

WYNN LAS VEGAS, LLC, CIRCUS CIRCUS LAS VEGAS, LLC, AND SMART ENERGY ALLIANCE

SEPTEMBER 24, 2020
Date

By: Curt Ledford, Esq.
Tyler Pepple, Esq.

THE KROGER CO.

Date

By: Kurt Boehm, Esq.

WALMART

Date

By: Vicki Baldwin, Esq.

COLORADO RIVER COMMISSION

Date

By: Christine Guerci Nyhus, Esq.

SUNRUN, INC

Date

By: Kevin Fox, Esq.
Jacob Schlesinger, Esq.

NEVADA COGENERATION ASSOCIATES

Date

By: Donald Brookhyser

WYNN LAS VEGAS, LLC, CIRCUS CIRCUS LAS VEGAS, LLC, AND SMART ENERGY ALLIANCE

Date

By: Curt Ledford, Esq.
Tyler Pepple, Esq.

THE KROGER CO.

9.24.20
Date

By: Kurt Boehm, Esq.

WALMART

Date

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COLORADO RIVER COMMISSION

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Jacob Schlesinger, Esq.

NEVADA COGENERATION ASSOCIATES

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By: Donald Brookhyser

WYNN LAS VEGAS, LLC, CIRCUS CIRCUS LAS VEGAS, LLC, AND SMART ENERGY ALLIANCE

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Tyler Pepple, Esq.

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WALMART

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NEVADA COGENERATION ASSOCIATES

Date

By: Donald Brookhyser

WYNN LAS VEGAS, LLC, CIRCUS CIRCUS LAS VEGAS, LLC, AND SMART ENERGY ALLIANCE

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THE KROGER CO.

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WALMART

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COLORADO RIVER COMMISSION

9/24/2020
Date

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SUNRUN, INC

Date

By: Kevin Fox, Esq.
Jacob Schlesinger, Esq.

NEVADA COGENERATION ASSOCIATES

Date

By: Donald Brookhyser

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

WYNN LAS VEGAS, LLC, CIRCUS CIRCUS LAS VEGAS, LLC, AND SMART ENERGY ALLIANCE

Date

By: Curt Ledford, Esq.
Tyler Pepple, Esq.

THE KROGER CO.

Date

By: Kurt Boehm, Esq.

WALMART

Date

By: Vicki Baldwin, Esq.

COLORADO RIVER COMMISSION

Date

By: Christine Guerci Nyhus, Esq.

SUNRUN, INC.

9/24/2020
Date

By: Kevin Fox, Esq.
Jacob Schlesinger, Esq.

NEVADA COGENERATION ASSOCIATES

Date

By: Donald Brookhyser

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

Date

By: Kurt Boehm, Esq.

WALMART

Date

By: Vicki Baldwin, Esq.

COLORADO RIVER COMMISSION

Date

By: Christine Guerci Nyhus, Esq.

SUNRUN, INC

Date

By: Kevin Fox, Esq.
Jacob Schlesinger, Esq.

NEVADA COGENERATION
ASSOCIATES #1

Sept. 23, 2020

Date

By: Donald Brookhyser

# EXHIBIT 1

**Exhibit 1 -- Earnings Sharing Credit Allocation**

| Line No. | Rate Schedule | | Allocation: 2019 BTGR Revenue $000 [1] | Allocation: Share of BTGR Revenue | Allocation: Bill Credit for Overearnings | Customer Count: Sml-Med. Customer Recorded Bills [2] | Customer Count: Avg. Monthly Sml-Med. Customer Recorded Bills [3] | Customer Count: December 2019 Counts | Earnings Sharing Credit: Sml-Med. Credit/ Customer | Earnings Sharing Credit: Large Customer % Annual BTGR Credit |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential - Single Family | RS | 519,827 | 46.498% | 55,797,824 | 6,278,240 | 523,187 | 520,255 | $107.25 | |
| 2 | Residential - Multi-Family | RM | 150,590 | 13.470% | 16,164,213 | 3,280,788 | 273,399 | 271,599 | $59.51 | |
| 3 | Residential - Large Single Family | LRS | 2,302 | 0.206% | 247,095 | 2,615 | 218 | 215 | $1,149.28 | |
| 4 | Residential - Single Family - Flexpay | RS-FLEX | 506 | 0.045% | 54,314 | 7,421 | 618 | 3,402 | $15.97 | |
| 5 | Residential - Multi-Family - Flexpay | RM-FLEX | 442 | 0.040% | 47,444 | 9,384 | 782 | 4,384 | $10.82 | |
| 6 | Residential - Single Family - Net Metering | RS-NEM | 17,916 | 1.603% | 1,923,089 | 440,908 | 36,742 | 50,974 | $37.73 | |
| 7 | Residential - Multi-Family - Net Metering | RM-NEM | 89 | 0.008% | 9,553 | 2,344 | 195 | 260 | $36.74 | |
| 8 | Residential - Large Single Family - Net Metering | LRS-NEM | 29 | 0.003% | 3,113 | 98 | 8 | 10 | $311.28 | |
| 9 | **Total Residential - Non-TOU** | | 691,701 | 61.872% | 74,246,645 | 10,021,798 | 835,150 | 851,099 | | |
| 10 | Residential - Single Family - TOU | ORS-TOU | 193 | 0.017% | 20,716 | 2,752 | 229 | 314 | $65.98 | |
| 11 | Residential - Single Family - TOU - Net Metering | ORS-NEM | 16 | 0.001% | 1,717 | 547 | 46 | 159 | $10.80 | |
| 12 | Residential - Single Family - TOU - EVRR | ORS-TOU EVRR | 567 | 0.051% | 60,861 | 6,141 | 512 | 756 | $80.50 | |
| 13 | Residential - Single Family - TOU - EVRR - Net Metering | ORS-NEM EVRR | 56 | 0.005% | 6,011 | 1,561 | 130 | 327 | $18.38 | |
| 14 | Residential - Single Family - TOU Option A | ORS-TOU OPT A | 1,725 | 0.154% | 185,160 | 25,788 | 2,149 | 2,023 | $91.53 | |
| 15 | Residential - Single Family - TOU Option A - Net Metering | ORS-NEM OPT A | 222 | 0.020% | 23,829 | 6,632 | 553 | 584 | $40.80 | |
| 16 | Residential - Single Family - TOU Option A - EVRR | ORS-TOU OPT A EVRR | 545 | 0.049% | 58,500 | 6,179 | 515 | 472 | $123.94 | |
| 17 | Residential - Single Family - TOU Option A - EVRR Net Metering | ORS-NEM OPT A EVRR | 52 | 0.005% | 5,582 | 1,814 | 151 | 156 | $35.78 | |
| 18 | Residential - Single Family - TOU Option B | ORS-TOU OPT B | 271 | 0.024% | 29,089 | 3,646 | 304 | 279 | $104.26 | |
| 19 | Residential - Single Family - TOU Option B - Net Metering | ORS-NEM OPT B | 10 | 0.001% | 1,073 | 171 | 14 | 19 | $56.49 | |
| 20 | Residential - Single Family - TOU Option B - EVRR | ORS-TOU OPT B EVRR | 250 | 0.022% | 26,835 | 2,873 | 239 | 221 | $121.42 | |
| 21 | Residential - Single Family - TOU Option B - EVRR Net Metering | ORS-NEM OPT B EVRR | 14 | 0.001% | 1,503 | 200 | 17 | 20 | $75.14 | |
| 22 | Residential - Multi-Family - TOU | ORM-TOU | 26 | 0.002% | 2,791 | 693 | 58 | 85 | $32.83 | |
| 23 | Residential - Multi-Family - TOU - EVRR | ORM-TOU EVRR | 21 | 0.002% | 2,254 | 421 | 35 | 48 | $46.96 | |
| 24 | Residential - Multi-Family - TOU - EVRR - Net Metering | ORM-NEM EVRR | 0 | 0.000% | 0 | 5 | 0 | 2 | $0.00 | |
| 25 | Residential - Multi-Family - TOU Option A | ORM-TOU OPT A | 69 | 0.006% | 7,406 | 1,954 | 163 | 153 | $48.41 | |
| 26 | Residential - Multi-Family - TOU Option A - EVRR | ORM-TOU OPT A EVRR | 7 | 0.001% | 751 | 96 | 8 | 8 | $93.92 | |
| 27 | Residential - Multi-Family - TOU Option B | ORM-TOU OPT B | 10 | 0.001% | 1,073 | 250 | 21 | 19 | $56.49 | |
| 28 | Residential - Multi-Family - TOU Option B - EVRR | ORM-TOU OPT B EVRR | 4 | 0.000% | 429 | 111 | 9 | 9 | $47.71 | |
| 29 | Residential - Large Single Family - TOU - EVRR | OLRS-TOU EVRR | 6 | 0.001% | 644 | 13 | 1 | 1 | $644.04 | |
| 30 | **Total Residential - TOU** | | 4,064 | 0.364% | 436,227 | 61,847 | 5,154 | 5,655 | | |
| 31 | **Residential - Private Area Lighting** | RS-PAL | 46 | 0.004% | 4,938 | 8,340 | 695 | 695 | $7.10 | |
| 32 | **Total Residential** | | 695,811 | 62.240% | 74,687,809 | 10,091,985 | 840,999 | 857,449 | | |
| 33 | General Service - Non-TOU | GS | 36,948 | 3.305% | 3,965,969 | 884,736 | 73,728 | 74,879 | $52.97 | |
| 34 | General Service - Net Metering | GS-NEM | 74 | 0.007% | 7,943 | 1,216 | 101 | 118 | $67.31 | |
| 35 | General Service - TOU | OGS-TOU | 1,207 | 0.108% | 129,558 | 31,142 | 2,595 | 2,618 | $49.49 | |
| 36 | General Service - TOU EVRR | OGS-TOU EVRR | 0 | 0.000% | 0 | 8 | 1 | 1 | $0.00 | |
| 37 | General Service - Private Area Lighting | GS-PAL | 155 | 0.014% | 16,638 | 26,631 | 2,219 | 2,219 | $7.50 | |
| 38 | **Total General Service** | | 38,384 | 3.433% | 4,120,109 | 943,733 | 78,644 | 79,835 | | |
| 39 | Large General Service - 1 | LGS-1 | 173,311 | 15.503% | 18,603,067 | 389,070 | 32,423 | 31,566 | $589.34 | |
| 40 | Large General Service - 1 - Net Metering | LGS-1 NEM | 1 | 0.000% | 107 | 6 | 1 | 5 | $21.47 | |
| 41 | Large General Service - 1 - SSR | SSR-III LGS-1 | 53 | 0.005% | 5,689 | 48 | 4 | 4 | $1,422.24 | |
| 42 | Large General Service - 1 - TOU | OLGS-1 TOU | 2,874 | 0.257% | 308,493 | 3,582 | 299 | 327 | $943.40 | |
| 43 | **Total Large General Service - 1** | | 176,239 | 15.764% | 18,917,357 | 392,706 | 32,726 | 31,902 | | |
| 44 | Large General Service - 2: Primary | LGS-2P | 2,138 | 0.191% | 229,491 | | | | | 10.73% |
| 45 | Large General Service - 2: Secondary | LGS-2S | 87,098 | 7.791% | 9,349,031 | | | | | 10.73% |
| 46 | Large General Service - 2: Transmission - LSR | LSR-I LGS-2T | 66 | 0.006% | 7,084 | | | | | 10.73% |
| 47 | Large General Service - 2: Secondary EVCCR | LGS-2S EVCCR | 158 | 0.014% | 16,960 | | | | | 10.73% |
| 48 | **Total Large General Service - 2** | | 89,460 | 8.002% | 9,602,567 | | | | | |
| 49 | Large General Service - 3: Primary | LGS-3P | 42,601 | 3.811% | 4,572,758 | | | | | 10.73% |
| 50 | Large General Service - 3: Secondary | LGS-3S | 26,964 | 2.412% | 2,894,295 | | | | | 10.73% |
| 51 | Large General Service - 3: Transmission | LGS-3T | 4,370 | 0.391% | 469,072 | | | | | 10.73% |
| 52 | Large General Service - 3: Primary - HLF | OLGS-3P-HLF | 5,184 | 0.464% | 556,447 | | | | | 10.73% |
| 53 | Large General Service - 3 MPE [4] | MPE LGS-3 | 0 | 0.000% | 0 | | | | | |
| 54 | Large General Service - 3: Primary - LSR | LSR-II LGS-3P | 812 | 0.073% | 87,159 | | | | | 10.73% |

**Exhibit 1 – Earnings Sharing Credit Allocation**

| Line No. | Rate Schedule | | Allocation: 2019 BTGR Revenue '$000 [1] | Allocation: Share of BTGR Revenue | Allocation: Bill Credit for Overearnings | Customer Count: Sml-Med. Customer Recorded Bills [2] | Customer Count: Avg. Monthly Sml-Med. Customer Recorded Bills [3] | Customer Count: December 2019 Counts | Earnings Sharing Credit: Sml-Med. Credit/ Customer | Earnings Sharing Credit: Large Customer % Annual BTGR Credit |
|---|---|---|---|---|---|---|---|---|---|---|
| 55 | Large General Service - 3: Transmission - LSR | LSR-II LGS-3T | 2,495 | 0.223% | 267,811 | | | | | 10.73% |
| 56 | **Total Large General Service - 3** | | 82,426 | 7.373% | 8,847,542 | | | | | |
| 57 | **Total Large General Service - 1, 2 & 3** | | 348,125 | 31.140% | 37,367,466 | 392,706 | 32,726 | 31,902 | | |
| 58 | **Street Lighting** | SL | 1,460 | 0.131% | 156,715 | 7,224 | 7,224 | 7,224 | $21.69 | |
| 59 | LGS - Water Pumping -2: Primary | LGS-2P-WP | 318 | 0.028% | 34,134 | | | | | 10.73% |
| 60 | LGS - Water Pumping -2: Secondary | LGS-2S-WP | 167 | 0.015% | 17,926 | | | | | 10.73% |
| 61 | **Total LGS - Water Pumping - 2** | | 485 | 0.043% | 52,060 | | | | | |
| 62 | LGS - Water Pumping -3: Primary | LGS-3P-WP | 210 | 0.019% | 22,541 | | | | | 10.73% |
| 63 | LGS - Water Pumping -3: Secondary | LGS-3S-WP | 21 | 0.002% | 2,254 | | | | | 10.73% |
| 64 | **Total LGS - Water Pumping - 3** | | 231 | 0.021% | 24,795 | | | | | |
| 65 | **Total LGS - Water Pumping - 2 & 3** | | 716 | 0.064% | 76,855 | | | | | |
| 66 | **Total Bundled Non-Residential** | | 388,685 | 34.768% | 41,721,144 | 1,343,663 | 111,972 | 118,961 | | |
| 67 | **Total - Bundled Classes** | | 1,084,496 | 97.007% | 116,408,954 | 11,435,648 | 952,971 | 976,410 | | |
| 68 | General Service - DOS | GS DOS | 5 | 0.000% | 501 | 118 | 10 | 10 | $50.08 | |
| 69 | Large General Service - 1 - DOS | LGS-1 DOS | 163 | 0.015% | 17,450 | 251 | 21 | 21 | $830.95 | |
| 70 | Large General Service - 2: Primary - DOS | LGS-2P DOS | 158 | 0.014% | 16,946 | | | | | 10.73% |
| 71 | Large General Service - 2: Secondary - DOS | LGS-2S DOS | 1,598 | 0.143% | 171,491 | | | | | 10.73% |
| 72 | Large General Service - 3: Primary - DOS | LGS-3P DOS | 16,678 | 1.492% | 1,790,169 | | | | | 10.73% |
| 73 | Large General Service - 3: Secondary - DOS | LGS-3S DOS | 2,357 | 0.211% | 253,042 | | | | | 10.73% |
| 74 | Large General Service - 3: Transmission - DOS | LGS-3T DOS | 4,457 | 0.399% | 478,360 | | | | | 10.73% |
| 75 | Large General Service - X: Primary - DOS | LGS-XP DOS | 5,599 | 0.501% | 600,961 | | | | | 10.73% |
| 76 | Large General Service - X: Secondary - DOS | LGS-XS DOS | 165 | 0.015% | 17,760 | | | | | 10.73% |
| 77 | Large General Service - X: Transmission - DOS | LGS-XT DOS | 1,426 | 0.128% | 153,049 | | | | | 10.73% |
| 78 | LGS - Water Pumping - 2: Secondary - DOS | LGS-2S-WP DOS | 49 | 0.004% | 5,304 | | | | | 10.73% |
| 79 | LGS - Water Pumping - 2: Transmission - DOS | LGS-2T-WP DOS | 30 | 0.003% | 3,271 | | | | | 10.73% |
| 80 | LGS - Water Pumping - 3: Primary - DOS | LGS-3P-WP DOS | 453 | 0.040% | 48,586 | | | | | 10.73% |
| 81 | LGS - Water Pumping - 3: Secondary - DOS | LGS-3S-WP DOS | 156 | 0.014% | 16,767 | | | | | 10.73% |
| 82 | LGS - Water Pumping - 3: Transmission - DOS | LGS-3T-WP DOS | 162 | 0.014% | 17,390 | | | | | 10.73% |
| 83 | **Total DOS** | | 33,455 | 2.993% | 3,591,046 | 369 | 31 | 31 | | |
| 84 | **Total - all classes with Distribution Only Service** | | 1,117,951 | 100.000% | $ 120,000,000 | 11,436,017 | 953,001 | 976,441 | | |
| 85 | **Bill Credit % of BTGR Revenue** | | | | 10.73% | | | | | |

**Data Sources/Notes**

1. BTGR Revenue for Bundled Classes based on Recorded BTGR Revenue from Statement J, Schedule J-5 Proposed (For LGS-3 MPE, see Footnote 4).
For DOS classes, BTGR Revenue is estimated based on Present BTGR Revenue from Statement O, page 10 with scalers applied based on the ratio of Recorded kWh to Annualized kWh for each DOS schedule based on Statement J, Schedule J-9 Proposed.

2. From Schedule J-9 Proposed Recorded Bills.

3. Recorded bills divided by 12.

4. MPE allocation is set at 0.

**EXHIBIT 2**

**Exhibit 2**

| System Size | Lower Bound | Upper Bound | Count of Applications | Percentage of Total Applications | Fee |
|---|---|---|---|---|---|
| 0-10kW | 0 | 9.999 | 12808 | 84.5% | $ 130.00 |
| 10-25kW | 10 | 24.999 | 2287 | 15.1% | $ 200.00 |
| 25-100kW | 25 | 99.999 | 35 | 0.2% | $ 500.00 |
| 100-500kW | 100 | 499.999 | 20 | 0.1% | $ 500.00 |
| 500-1,000kW | 500 | 999.999 | 0 | 0.0% | $ 500.00 |
| 1,000-2,000kW | 1000 | 1999.999 | 1 | 0.0% | $ 500.00 |

**EXHIBIT 3**

## Nevada Power Company
## Statement O

Comparison of Present, Cost-based and Proposed Rate Revenue ($000s)

| Line No | Class | Note | Annualized Bills | Sales (MWh) | Present Rate Revenue | | Results if Class Revenue Requirements were Set @ Reconciled Cost [1] | | | Class Revenue Requirements Based on Proposed Capping Methodology [2] | | | | | Combined AB 405 Proposed Revenue Change | | Line No |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Revenue | Effective Rate ($/kWh) | Cost-Based Revenue | % Change from Present | Effective Rate ($/kWh) | Proposed Rate Revenue | Difference from Cost | Change from Present Rate Revenue | % Change from Present | Effective Rate ($/kWh) | % Change from Present | Effective Rate ($/kWh) | |
| 8 | | | | | | | | | | | | | | | | | 8 |
| 9 | Classes in Revenue Reconciliation | | | | | | | | | | | | | | | | 9 |
| 10 | RS | | 6,270,084 | 7,039,880 | $ 531,618 | $ 0.07552 | $ 499,991 | -5.95% | $ 0.07102 | $ 500,417 | $ 426 | $ (31,201) | -5.87% | $ 0.07108 | -5.82% | $ 0.06993 | 10 |
| 11 | RM | | 3,332,328 | 2,188,600 | 155,163 | 0.07090 | 130,308 | -16.02% | 0.05954 | 139,160 | 8,852 | (16,004) | -10.31% | 0.06358 | -10.31% | 0.06358 | 11 |
| 12 | LRS | | 2,544 | 35,987 | 2,291 | 0.06366 | 1,739 | -24.08% | 0.04833 | 2,057 | 318 | (234) | -10.22% | 0.05716 | -10.23% | 0.05729 | 12 |
| 13 | GS | | 902,424 | 584,169 | 37,466 | 0.06414 | 26,848 | -28.34% | 0.04596 | 33,539 | 6,690 | (3,928) | -10.48% | 0.05741 | -10.49% | 0.05728 | 13 |
| 14 | LGS-1 | | 378,072 | 3,897,464 | 168,894 | 0.04333 | 145,165 | -14.05% | 0.03725 | 152,129 | 6,964 | (16,765) | -9.93% | 0.03903 | | | 14 |
| 15 | LGS-2S | | 14,976 | 2,365,736 | 86,306 | 0.03648 | 75,126 | -12.95% | 0.03176 | 77,729 | 2,602 | (8,578) | -9.94% | 0.03286 | | | 15 |
| 16 | LGS-2P | | 312 | 67,742 | 1,921 | 0.02835 | 1,951 | 1.57% | 0.02879 | 1,804 | (147) | (117) | -6.08% | 0.02663 | | | 16 |
| 17 | LGS-2T | 3 | - | - | - | — | - | na | — | - | - | - | na | — | | | 17 |
| 18 | LGS-3S | | 1,512 | 800,641 | 26,409 | 0.03298 | 23,243 | -11.99% | 0.02903 | 23,746 | 503 | (2,663) | -10.08% | 0.02966 | | | 18 |
| 19 | LGS-3P | 4 | 1,284 | 1,588,420 | 51,261 | 0.03227 | 47,599 | -7.14% | 0.02997 | 47,504 | (94) | (3,757) | -7.33% | 0.02991 | | | 19 |
| 20 | LGS-3T | 4 | 60 | 397,435 | 7,409 | 0.01864 | 7,984 | 7.76% | 0.02009 | 6,987 | (997) | (422) | -5.69% | 0.01758 | | | 20 |
| 21 | LGS-XS | | - | - | - | — | - | na | — | - | - | - | na | — | | | 21 |
| 22 | LGS-XP | | - | - | - | — | - | na | — | - | - | - | na | — | | | 22 |
| 23 | LGS-XT | | - | - | - | — | - | na | — | - | - | - | na | — | | | 23 |
| 24 | LGS-2S-WP | | 264 | 6,831 | 153 | 0.02235 | 300 | 96.69% | 0.04395 | 149 | (151) | (4) | -2.32% | 0.02183 | | | 24 |
| 25 | LGS-2P-WP | | 120 | 12,229 | 292 | 0.02388 | 314 | 7.47% | 0.02567 | 274 | (40) | (18) | -6.21% | 0.02240 | | | 25 |
| 26 | LGS-2T-WP | 5 | - | - | - | — | (13) | na | — | - | 13 | - | na | — | | | 26 |
| 27 | LGS-3S-WP | | 24 | 5,752 | 18 | 0.00319 | 44 | 138.34% | 0.00760 | 18 | (26) | (0) | -2.62% | 0.00310 | | | 27 |
| 28 | LGS-3P-WP | | 60 | 17,505 | 246 | 0.01403 | 315 | 28.32% | 0.01801 | 228 | (87) | (18) | -7.22% | 0.01302 | | | 28 |
| 29 | LGS-3T-WP | 5 | - | - | - | — | - | na | — | - | - | - | na | — | | | 29 |
| 30 | SL | | 7,224 | 150,361 | 1,440 | 0.00957 | 2,862 | 98.79% | 0.01903 | 1,352 | (1,510) | (88) | -6.09% | 0.00899 | | | 30 |
| 31 | RS-Pal | | - | 648 | 45 | 0.06929 | 32 | -29.07% | 0.04915 | 40 | 9 | (4) | -9.88% | 0.06245 | | | 31 |
| 32 | GS-Pal | | - | 2,337 | 149 | 0.06357 | 105 | -29.61% | 0.04474 | 134 | 29 | (15) | -9.99% | 0.05721 | | | 32 |
| 33 | IAIWP | 3 | - | - | - | — | - | na | — | - | - | - | na | — | | | 33 |
| 34 | RS-NEM | 6 | 581,328 | 446,857 | 24,289 | 0.09183 | 45,838 | 88.72% | 0.10258 | 23,123 | (22,715) | (1,166) | -4.80% | 0.08742 | | | 34 |
| 35 | RM-NEM | 6 | 2,976 | 1,664 | 113 | 0.07478 | 161 | 43.13% | 0.09687 | 101 | (60) | (12) | -10.30% | 0.06708 | | | 35 |
| 36 | LRS-NEM | 6 | 132 | 433 | 33 | 0.08595 | 29 | -14.17% | 0.06578 | 29 | 1 | (4) | -11.21% | 0.07632 | | | 36 |
| 37 | GS-NEM | 6 | 1,356 | 2,550 | 81 | 0.04047 | 195 | 140.22% | 0.07644 | 71 | (124) | (10) | -12.86% | 0.03526 | | | 37 |
| 38 | | | | | | | | | | | | | | | | | 38 |
| 44 | Partial Requirements & Optional Schedule Groups not Included in Reconciliation | | | | | | | | | | | | | | | | 44 |
| 45 | Optional TOU | | 65,484 | 407,118 | 11,952 | 0.02936 | nc | nc | nc | 11,400 | nc | (553) | -4.62% | 0.02800 | — | — | 45 |
| 46 | Optional TOU EVRR | | 19,812 | 34,347 | 1,721 | 0.05011 | nc | nc | nc | 1,593 | nc | (128) | -7.47% | 0.04637 | | | 46 |
| 47 | NEM Optional TOU | | 8,664 | 4,744 | 349 | 0.07354 | nc | nc | nc | 321 | nc | (28) | -7.95% | 0.06769 | — | — | 47 |
| 48 | NEM EVRR | | 5,628 | 5,052 | 227 | 0.04495 | nc | nc | nc | 217 | nc | (11) | -4.64% | 0.04286 | | | 48 |
| 49 | Standby | | 192 | 118,801 | 3,501 | 0.02947 | nc | nc | nc | 3,314 | nc | (187) | -5.35% | 0.02790 | — | — | 49 |
| 50 | EVCCR | | 48 | 3,420 | 203 | 0.05936 | nc | nc | nc | 182 | nc | (21) | -10.31% | 0.05324 | | | 50 |
| 51 | DOS | | 1,956 | 2,608,913 | 34,805 | 0.01334 | nc | nc | nc | 27,975 | nc | (6,829) | -19.62% | 0.01072 | — | — | 51 |
| 53 | | | | | | | | | | | | | | | | | 53 |
| 54 | Total (Bundled & DOS) | | 11,598,888 | 22,296,207 | $ 1,137,429 | $ 0.05101 | $ 1,010,134 | na[1] | nc | $ 1,044,760 | — | $ (92,670) | -8.15% | $ 0.04686 | -8.15% | $ 0.04686 | 54 |
| 55 | | | | | | | | | | | | | | | | | 55 |

nc = Classes with existing customers, but for which reconciled marginal costs cannot or have not been determined.

1. Percent Change in revenues at full reconciled cost does not include classes where reconciled marginal costs cannot or have not been determined. Therefore, the overall change will not match the value when all revenues are included in the calculations.
2. The revenues are based upon the proposed rates, and because final rates are rounded, revenues will not exactly match the 'final' class revenue requirements shown on page 7 of Statement O. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits.
3. No Customers in class
4. Cost-based revenue requirement for LGS-3P includes OLGS-3P HLF customers billed under the OAS. Additionally, one partial requirements LSR-2 LGS-3P and LSR-2 LGS-3T customer are included as explained in rate design testimony. The results shown here include these customers.
5. All customers in class are DOS customers; no bundled customers.
6. Class level information presented here includes all customers under NMR-G and NMR-A rate schedules. NEM class effective rates for cost-based revenue are based on delivered loads. Present rate and proposed rate revenue are calculated using delivered kWh sales for NMR-A customers and net-billed kWh sales for NMR-G customers.

| | | |
|---|---|---|
| $ | 1,045,573 | Statement I Revenue Requirement |
| $ | (92,670) | Change in Revenue Requiremer |
| | -8.15% | Percent Change |

$ (9,370)

# Nevada Power Company
## Statement O

### Unbundled Revenue Requirement and Rate Design Adjustments ($000's)

| Line No. | | Note | Total | Energy | 28.71 Generation | 7.01 Transmission | 17.27 Distribution | Line No. |
|---|---|---|---|---|---|---|---|---|
| 8 | | | | | | | | 8 |
| 9 | Marginal Cost Revenue | | $ 1,043,396 | | $ 565,309 | $ 138,071 | $ 340,016 | 9 |
| 10 | | | | | | | | 10 |
| 11 | Unbundled Revenue Requirement | 1 | $ 1,045,573 | | $ 566,488 | $ 138,359 | $ 340,726 | 11 |
| 12 | | | | | | Total G, T & D | $ 1,045,573 | 12 |
| 13 | Total Revenue Requirement Adjustments for Rate Design | | | | | | | 13 |
| 14 | Revenue Credit to Dist. for Specific Class Assignment | | | | | | | 14 |
| 15 | Power Factor (PF) | | (743) | | | | (743) | 15 |
| 16 | Additional Facilities and Maintenance (AF&M) | | (65) | | | | (65) | 16 |
| 17 | | | | | | | | 17 |
| 18 | Optional TOU Revenue | | (7,255) | | (3,931) | (960) | (2,364) | 18 |
| 19 | Optional TOU NEM revenues | | (1,533) | | (831) | (203) | (500) | 19 |
| 20 | Standby Customer Revenue (Inc. Part Req. Customers) | 2 | (2,937) | | (1,591) | (389) | (957) | 20 |
| 21 | DOS BTGR Revenue (exc. IRR and Impact Fees) | 3 | (12,571) | | | | (12,571) | 21 |
| 22 | DOS Interclass Rate-Rebalancing Revenue | | (691) | | (374) | (91) | (225) | 22 |
| 23 | OLGS-3P HLF & MPE Rate Design Revenue adjustment | | 552 | | 299 | 73 | 180 | 23 |
| 24 | MPE Revenue Adjustment | | 1,931 | | 1,931 | | | 24 |
| 25 | EVCCR Discount Revenue Adjustment | | 54 | | 43 | 11 | | 25 |
| 26 | Total | | $ (23,259) | | $ (4,454) | $ (1,559) | $ (17,246) | 26 |
| 27 | | | | | | | | 27 |
| 28 | Class Specific Revenue Requirement Adjustments | | | | | | | 28 |
| 29 | Other Revenue | 4 | (1,952) | | | | (1,952) | 29 |
| 30 | Customer Specific Facilities | | 388 | | | | 388 | 30 |
| 31 | DOS Impact Fee revenue | | (14,447) | | (14,447) | | | 31 |
| 32 | BTER Energy Credits (WAPA, Hoover B, EDRR) | | - | | | | | 32 |
| 33 | Total Class Specific Adjustments | | $ (16,011) | | $ (14,447) | $ - | $ (1,564) | 33 |
| 34 | | | | | | | | 34 |
| 35 | Total Adjustments to Total Revenue Requirement | | $ (39,270) | | $ (18,901) | $ (1,559) | $ (18,810) | 35 |
| 36 | | | | | | | | 36 |
| 37 | Target Revenue Requirement for Rate Design | | $ 1,006,304 | | $ 560,104 | $ 136,800 | $ 320,385 | 37 |
| 38 | | | | | | | | 38 |

41 1. Unbundled Revenue Requirement from Unbundling Study (Statement H in Direct Filing, Statement I in Certification Filing)
42 2. Includes LSR revenues and optional time-of-use revenues.
43 3. Includes all "non-tax" DOS revenues, but excludes subsidy-related revenues.
44 4. Other Revenue include misc. revenues, returned check, power pedestal, and misc. damage revenues.
45 5. Revenue are based on reconciled cost-based revenues used for rate design and include standard flat-rate NEM customers using NMR-A rate structure.

Transmission Revenue by Class for Rate Design

| Line No. | Class | Unreconciled Cost-Based Transmission Revenue | Percent of Total | Reconciled Transmission Revenue Requirement | Rate Design Revenue Adjustments: Optional TOU Revenue | Optional TOU NEM revenues | Standby Customer Revenue | DOS BTGR Revenue (exc. IRR and Impact Fees) | DOS Interclass Rate-Rebalancing Revenue | OLGS-3P HLF Rate Design Revenue adjustment | BTER Energy Credits (WAPA, Hoover B, EDRR) | MPE Revenue Adjustment | EVCCR Revenue Adjustment | Transmission Cost Based Class Revenue for Rate Design | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | | | | | | | | | | | | | | | 8 |
| 9 | RS | $ 66,498 | 48.16% | $ 66,637 | $ (462) | $ (98) | $ (187) | $ - | $ (44) | $ 35 | | | $ 5 | $ 65,886 | 9 |
| 10 | RM | 16,406 | 11.88% | 16,440 | (114) | (24) | (46) | - | (11) | 9 | | | 1 | 16,255 | 10 |
| 11 | LRS | 258 | 0.19% | 259 | (2) | (0) | (1) | - | (0) | 0 | | | 0 | 256 | 11 |
| 12 | GS | 3,166 | 2.29% | 3,173 | (22) | (5) | (9) | - | (2) | 2 | | | 0 | 3,137 | 12 |
| 13 | LGS-1 | 21,467 | 15.55% | 21,512 | (149) | (32) | (60) | - | (14) | 11 | | | 2 | 21,269 | 13 |
| 14 | LGS-2S | 11,641 | 8.43% | 11,665 | (81) | (17) | (33) | - | (8) | 6 | | | 1 | 11,534 | 14 |
| 15 | LGS-2P | 293 | 0.21% | 294 | (2) | (0) | (1) | - | (0) | 0 | | | 0 | 290 | 15 |
| 16 | LGS-2T | - | 0.00% | - | - | - | - | - | - | - | | | - | - | 16 |
| 17 | LGS-3S | 3,574 | 2.59% | 3,581 | (25) | (5) | (10) | - | (2) | 2 | | | 0 | 3,541 | 17 |
| 18 | LGS-3P | 7,215 | 5.23% | 7,230 | (50) | (11) | (20) | - | (5) | 4 | | | 1 | 7,149 | 18 |
| 19 | LGS-3T | 1,694 | 1.23% | 1,697 | (12) | (2) | (5) | - | (1) | 1 | | | 0 | 1,678 | 19 |
| 20 | LGS-XS | - | 0.00% | - | - | - | - | - | - | - | | | - | - | 20 |
| 21 | LGS-XP | - | 0.00% | - | - | - | - | - | - | - | | | - | - | 21 |
| 22 | LGS-XT | - | 0.00% | - | - | - | - | - | - | - | | | - | - | 22 |
| 23 | LGS-2S-WP | 37 | 0.03% | 37 | (0) | (0) | (0) | - | (0) | 0 | | | 0 | 36 | 23 |
| 24 | LGS-2P-WP | 50 | 0.04% | 50 | (0) | (0) | (0) | - | (0) | 0 | | | 0 | 49 | 24 |
| 25 | LGS-2T-WP | - | 0.00% | - | - | - | - | - | - | - | | | - | - | 25 |
| 26 | LGS-3S-WP | 0 | 0.00% | 0 | (0) | (0) | (0) | - | (0) | 0 | | | 0 | 0 | 26 |
| 27 | LGS-3P-WP | 47 | 0.03% | 47 | (0) | (0) | (0) | - | (0) | 0 | | | 0 | 47 | 27 |
| 28 | LGS-3T-WP | - | 0.00% | - | - | - | - | - | - | - | | | - | - | 28 |
| 29 | SL | 93 | 0.07% | 93 | (1) | (0) | (0) | - | (0) | 0 | | | 0 | 92 | 29 |
| 30 | RS-Pal | 0 | 0.00% | 0 | (0) | (0) | (0) | - | (0) | 0 | | | 0 | 0 | 30 |
| 31 | GS-Pal | 1 | 0.00% | 1 | (0) | (0) | (0) | - | (0) | 0 | | | 0 | 1 | 31 |
| 32 | IAIWP | - | 0.00% | - | - | - | - | - | - | - | | | - | - | 32 |
| 33 | RS-NEM | 5,581 | 4.04% | 5,592 | (39) | (8) | (16) | - | (4) | 3 | | | 0 | 5,529 | 33 |
| 34 | RM-NEM | 22 | 0.02% | 22 | (0) | (0) | (0) | - | (0) | 0 | | | 0 | 22 | 34 |
| 35 | LRS-NEM | 3 | 0.00% | 3 | (0) | (0) | (0) | - | (0) | 0 | | | 0 | 3 | 35 |
| 36 | GS-NEM | 27 | 0.02% | 27 | (0) | (0) | (0) | - | (0) | 0 | | | 0 | 26 | 36 |
| 37 | | | | | | | | | | | | | | | 37 |
| 38 | TOTAL | $ 138,071 | 100.00% | $ 138,359 | $ (960) | $ (203) | $ (389) | $ - | $ (91) | $ 73 | | | $ 11 | $ 136,800 | 38 |
| 39 | | | | from Sch. I-2 | | | | | | | | | | | 39 |
| 40 | | | | | | | | | | | | | | | 40 |
| 41 | | | | | | | | | | | | | | | 41 |
| 42 | | | | | | | | | | | | | | | 42 |
| 43 | Summation of NEM customers into Standard Schedule for Rate Design | | | | | | | | | | | | | | 43 |
| 44 | RS | $ 72,079 | 52.20% | $ 72,229 | $ (501) | $ (106) | $ (203) | $ - | $ (48) | $ 38 | $ - | $ - | $ 6 | $ 71,415 | 44 |
| 45 | RM | 16,428 | 11.90% | 16,462 | (114) | (24) | (46) | - | (11) | 9 | - | - | 1 | 16,277 | 45 |
| 46 | LRS | 261 | 0.19% | 262 | (2) | (0) | (1) | - | (0) | 0 | - | - | 0 | 259 | 46 |
| 47 | GS | 3,193 | 2.31% | 3,199 | (22) | (5) | (9) | - | (2) | 2 | - | - | 0 | 3,163 | 47 |
| 48 | | | | | | | | | | | | | | | 48 |
| 49 | | | | | | | | | | | | | | | 49 |

# Nevada Power Company
## Statement O

Distribution Revenue by Class for Rate Design

| Line No. | Class | Unreconciled Cost-Based Distribution Revenue | Percent of Total | Class Specific Adjustments: Other Revenue Adjustment | Class Specific Adjustments: Adjustment for Class Cust Spec. Facilities | Reconciled Distribution Revenue Requirement | Rate Design Revenue Adjustments: Optional TOU Revenue | Optional TOU NEM revenues | Standby Customer Revenue | DOS BTGR Revenue (exc. IRR and Impact Fees) | DOS Interclass Rate-Rebalancing Revenue | OLGS-3P HLF Rate Design Revenue adjustment | MPE Revenue Adjustment | EVCCR Discount Revenue Adjustment | Distribution Cost Based Class Revenue for Rate Design | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | | | | | | | | | | | | | | | | 8 |
| 9 | RS | $ 176,976 | 52.66% | $ (1,004) | | $ 177,197 | $ (1,245) | $ (263) | $ (504) | $ (6,620) | $ (119) | $ 95 | | $ - | $ 168,541 | 9 |
| 10 | RM | 46,698 | 13.90% | (698) | | 46,323 | (329) | (69) | (133) | (1,747) | (31) | 25 | | | 44,039 | 10 |
| 11 | LRS | 493 | 0.15% | (0) | | 496 | (3) | (1) | (1) | (18) | (0) | 0 | | | 472 | 11 |
| 12 | GS | 13,073 | 3.89% | (132) | | 13,031 | (92) | (19) | (37) | (489) | (9) | 7 | | | 12,392 | 12 |
| 13 | LGS-1 | 40,770 | 12.13% | (21) | | 41,032 | (287) | (61) | (116) | (1,525) | (27) | 22 | | | 39,038 | 13 |
| 14 | LGS-2S | 17,909 | 5.33% | (1) | | 18,033 | (126) | (27) | (51) | (670) | (12) | 10 | | | 17,157 | 14 |
| 15 | LGS-2P | 536 | 0.16% | - | | 540 | (4) | (1) | (2) | (20) | (0) | 0 | | | 514 | 15 |
| 16 | LGS-2T | - | 0.00% | - | | - | - | - | - | - | - | - | | | - | 16 |
| 17 | LGS-3S | 5,565 | 1.66% | (0) | | 5,603 | (39) | (8) | (16) | (208) | (4) | 3 | | | 5,331 | 17 |
| 18 | LGS-3P | 15,776 | 4.69% | (0) | - | 15,885 | (111) | (23) | (45) | (590) | (11) | 8 | | | 15,114 | 18 |
| 19 | LGS-3T | 7 | 0.00% | - | 388 | 394.50 | (0) | (0) | (0) | (0) | (0) | 0 | | | 394 | 19 |
| 20 | LGS-XS | - | 0.00% | - | | - | - | - | - | - | - | - | | | - | 20 |
| 21 | LGS-XP | - | 0.00% | - | | - | - | - | - | - | - | - | | | - | 21 |
| 22 | LGS-XT | - | 0.00% | - | | - | - | - | - | - | - | - | | | - | 22 |
| 23 | LGS-2S-WP | 134 | 0.04% | - | | 135 | (1) | (0) | (0) | (5) | (0) | 0 | | | 128 | 23 |
| 24 | LGS-2P-WP | 100 | 0.03% | - | | 100 | (1) | (0) | (0) | (4) | (0) | 0 | | | 96 | 24 |
| 25 | LGS-2T-WP | 2 | 0.00% | - | - | 2 | (0) | (0) | (0) | (0) | (0) | 0 | | | 2 | 25 |
| 26 | LGS-3S-WP | 101 | 0.03% | - | | 101 | (1) | (0) | (0) | (4) | (0) | 0 | | | 97 | 26 |
| 27 | LGS-3P-WP | 304 | 0.09% | - | | 306 | (2) | (0) | (1) | (11) | (0) | 0 | | | 291 | 27 |
| 28 | LGS-3T-WP | 9 | 0.00% | - | - | 9 | (0) | (0) | (0) | (0) | (0) | 0 | | | 8 | 28 |
| 29 | SL | 937 | 0.28% | (5) | | 938 | (7) | (1) | (3) | (35) | (1) | 1 | | | 893 | 29 |
| 30 | RS-Pal | 25 | 0.01% | (0) | | 25 | (0) | (0) | (0) | (1) | (0) | 0 | | | 24 | 30 |
| 31 | GS-Pal | 80 | 0.02% | (0) | | 81 | (1) | (0) | (0) | (3) | (0) | 0 | | | 77 | 31 |
| 32 | IAIWP | - | 0.00% | | | - | - | - | - | - | - | - | | | - | 32 |
| 33 | RS-NEM | 16,429 | 4.89% | (89) | | 16,454 | (116) | (24) | (47) | (615) | (11) | 9 | | | 15,650 | 33 |
| 34 | RM-NEM | 53 | 0.02% | (1) | | 52 | (0) | (0) | (0) | (2) | (0) | 0 | | | 50 | 34 |
| 35 | LRS-NEM | 14 | 0.00% | (0) | | 14 | (0) | (0) | (0) | (1) | (0) | 0 | | | 13 | 35 |
| 36 | GS-NEM | 68 | 0.02% | (0) | | 68 | (0) | (0) | (0) | (3) | (0) | 0 | | | 65 | 36 |
| 37 | | | | | | not a sum | | | | | | | | | | 37 |
| 38 | TOTAL | $ 336,059 | 100.00% | $ (1,952) | $ 388 | $ 340,726 | $ (2,364) | $ (500) | $ (957) | $ (12,571) | $ (225) | $ 180 | | $ - | $ 320,385 | 38 |
| 39 | | | | | | from Sch. I-2 | | | | | | | | | $ 421 | 39 |
| 40 | | | | exc. Specific Class adjustments | | $ 338,386 | | | | | | | | | | 40 |
| 41 | | | | | | | | | | | | | | | | 41 |
| 42 | | | | | | $ - | | | | | | | | | | 42 |
| 43 | Summation of NEM customers into Standard Schedule for Rate Design | | | | | | | | | | | | | | | 43 |
| 44 | RS | $ 193,404 | 57.55% | $ (1,093) | $ - | $ 193,651 | $ (1,361) | $ (288) | $ (551) | $ (7,235) | $ (130) | $ 104 | $ - | $ - | $ 184,191 | 44 |
| 45 | RM | 46,751 | 13.91% | (699) | - | 46,376 | (329) | (70) | (133) | (1,749) | (31) | 25 | - | - | 44,089 | 45 |
| 46 | LRS | 506 | 0.15% | (0) | - | 509 | (4) | (1) | (1) | (19) | (0) | 0 | - | - | 485 | 46 |
| 47 | GS | 13,141 | 3.91% | (132) | - | 13,100 | (92) | (20) | (37) | (492) | (9) | 7 | - | - | 12,457 | 47 |
| 48 | | | | | | | | | | | | | | | | 48 |
| 49 | | | | | | | | | | | | | | | | 49 |

# Nevada Power Company
## Statement O

Generation Revenue by Class for Rate Design

| Line No. | Class | Unreconciled Cost-Based Generation Revenue | Percent of Total | DOS R-BTER and BTER Impact Fee Revenue | Reconciled Generation Revenue Requirement | Rate Design Revenue Adjustments: Optional TOU Revenue | Optional TOU NEM revenues | Standby Customer Revenue | DOS BTGR Revenue (exc. IRR and Impact Fees) | DOS Interclass Rate-Rebalancing Revenue | OLGS-3P HLF Rate Design Revenue adjustment | DOS BTGR Impact Fee Revenue | BTER Energy Credits (WAPA, Hoover B, EDRR) | MPE Revenue Adjustment | EVCCR Revenue Adjustment | Generation Cost Based Class Revenue for Rate Design | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | | | | | | | | | | | | | | | | | 8 |
| 9 | RS | $ 268,032 | 47.41% | $ - | $ 268,591 | $ (1,864) | $ (394) | $ (755) | | $ (177) | $ 142 | $ - | | | $ 21 | $ 265,564 | 9 |
| 10 | RM | 70,665 | 12.50% | - | 70,812 | (491) | (104) | (199) | | (47) | 37 | - | | | 5 | 70,014 | 10 |
| 11 | LRS | 1,021 | 0.18% | - | 1,023 | (7) | (2) | (3) | | (1) | 1 | - | | | 0 | 1,012 | 11 |
| 12 | GS | 11,425 | 2.02% | - | 11,449 | (79) | (17) | (32) | | (8) | 6 | - | | | 1 | 11,320 | 12 |
| 13 | LGS-1 | 85,607 | 15.14% | - | 85,785 | (595) | (126) | (241) | | (57) | 45 | - | | | 7 | 84,819 | 13 |
| 14 | LGS-2S | 46,945 | 8.30% | - | 47,043 | (326) | (69) | (132) | | (31) | 25 | - | | | 4 | 46,513 | 14 |
| 15 | LGS-2P | 1,239 | 0.22% | - | 1,242 | (9) | (2) | (3) | | (1) | 1 | - | | | 0 | 1,228 | 15 |
| 16 | LGS-2T | - | 0.00% | - | - | - | - | - | | - | - | - | | | - | - | 16 |
| 17 | LGS-3S | 15,056 | 2.66% | - | 15,087 | (105) | (22) | (42) | | (10) | 8 | - | | | 1 | 14,917 | 17 |
| 18 | LGS-3P | 30,831 | 5.45% | - | 30,895 | (214) | (45) | (87) | | (20) | 16 | - | | | 2 | 30,547 | 18 |
| 19 | LGS-3T | 6,926 | 1.23% | - | 6,941 | (48) | (10) | (19) | | (5) | 4 | - | | | 1 | 6,862 | 19 |
| 20 | LGS-XS | - | 0.00% | - | - | - | - | - | | - | - | - | | | - | - | 20 |
| 21 | LGS-XP | - | 0.00% | - | - | - | - | - | | - | - | - | | | - | - | 21 |
| 22 | LGS-XT | - | 0.00% | - | - | - | - | - | | - | - | - | | | - | - | 22 |
| 23 | LGS-2S-WP | 162 | 0.03% | - | 162 | (1) | (0) | (0) | | (0) | 0 | - | | | 0 | 160 | 23 |
| 24 | LGS-2P-WP | 168 | 0.03% | - | 168 | (1) | (0) | (0) | | (0) | 0 | - | | | 0 | 166 | 24 |
| 25 | LGS-2T-WP | - | 0.00% | - | - | - | - | - | | - | - | - | | | - | - | 25 |
| 26 | LGS-3S-WP | 21 | 0.00% | - | 21 | (0) | (0) | (0) | | (0) | 0 | - | | | 0 | 20 | 26 |
| 27 | LGS-3P-WP | 188 | 0.03% | - | 189 | (1) | (0) | (1) | | (0) | 0 | - | | | 0 | 187 | 27 |
| 28 | LGS-3T-WP | - | 0.00% | - | - | - | - | - | | - | - | - | | | - | - | 28 |
| 29 | SL | 1,894 | 0.34% | - | 1,898 | (13) | (3) | (5) | | (1) | 1 | - | | | 0 | 1,877 | 29 |
| 30 | RS-Pal | 8 | 0.00% | - | 8 | (0) | (0) | (0) | | (0) | 0 | - | | | 0 | 8 | 30 |
| 31 | GS-Pal | 27 | 0.00% | - | 27 | (0) | (0) | (0) | | (0) | 0 | - | | | 0 | 27 | 31 |
| 32 | IAIWP | - | 0.00% | - | - | - | - | - | | - | - | - | | | - | - | 32 |
| 33 | RS-NEM | 24,888 | 4.40% | - | 24,940 | (173) | (37) | (70) | | (16) | 13 | - | | | 2 | 24,658 | 33 |
| 34 | RM-NEM | 90 | 0.02% | - | 91 | (1) | (0) | (0) | | (0) | 0 | - | | | 0 | 90 | 34 |
| 35 | LRS-NEM | 13 | 0.00% | - | 13 | (0) | (0) | (0) | | (0) | 0 | - | | | 0 | 13 | 35 |
| 36 | GS-NEM | 104 | 0.02% | - | 105 | (1) | (0) | (0) | | (0) | 0 | - | | | 0 | 103 | 36 |
| 37 | | | | | not a sum | | | | | | | | | | | | 37 |
| 38 | TOTAL | $ 565,309 | 100.00% | $ - | $ 566,488 | $ (3,931) | $ (831) | $ (1,591) | | $ (374) | $ 299 | $ - | | | $ 43 | $ 560,104 | 38 |
| 39 | | | | | from Sch. I-2 | | | | | | | | | | | | 39 |
| 40 | | | | Generation Revenue for Rate Design | $ 565,309 | $ (1,180) | | | | | | | | | | | 40 |
| 41 | | | | w/ Specific Class adjustments | | Separate | | | | | | | | | | | 41 |
| 42 | | | | | | | | | | | | | | | | | 42 |
| 43 | | | | | | | | | | | | | | | | | 43 |
| 44 | | | | | | | | | | | | | | | | | 44 |
| 45 | Summation of NEM customers into Standard Schedule for Rate Design | | | | | | | | | | | | | | | | 45 |
| 46 | RS | $ 292,919 | 51.82% | $ - | $ 293,530 | $ (2,037) | $ (430) | $ (825) | $ - | $ (194) | $ 155 | $ - | $ - | $ - | $ 22 | $ 290,222 | 46 |
| 47 | RM | 70,755 | 12.52% | - | 70,903 | (492) | (104) | (199) | - | (47) | 37 | - | - | - | 5 | 70,104 | 47 |
| 48 | LRS | 1,034 | 0.18% | - | 1,036 | (7) | (2) | (3) | - | (1) | 1 | - | - | - | 0 | 1,024 | 48 |
| 49 | GS | 11,530 | 2.04% | - | 11,554 | (80) | (17) | (32) | - | (8) | 6 | - | - | - | 1 | 11,424 | 49 |
| 50 | | | | | | | | | | | | | | | | | 50 |
| 51 | | | | | | | | | | | | | | | | | 51 |

## Nevada Power Company
### Statement O

Energy Revenue by Class for Rate Design

| Line No. | Class | BTER Revenue | Unreconciled Cost-Based Energy Revenue | Percent of Total | Class Specific Adjustments: Hoover B, EDRR, MPE and WAPA Credits | Class Specific Adjustments: Reconciled Energy Revenue Requirement | Rate Design Revenue Adjustments: Optional TOU Revenue | Optional TOU NEM revenues | Standby Customer Revenue | DOS Interclass Rate-Rebalancing Revenue | OLGS-3P HLF Rate Design Revenue adjustment | DOS R-BTER and BTER Impact Fee Revenue | MPE Revenue Adjustment | EVCCR Revenue Adjustment | Energy Cost Based Class Revenue for Rate Design | Excess/ Deficiency Present in BTER for Rate Design | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | | | | | | | | | | | | | | | | | 8 |
| 9 | RS | | | | | | | | | | | | | | | | 9 |
| 10 | RM | | | | | | | | | | | | | | | | 10 |
| 11 | LRS | | | | | | | | | | | | | | | | 11 |
| 12 | GS | - | | | | | | | | | | | | | | | 12 |
| 13 | LGS-1 | - | - | | | | | | | | | | | | | | 13 |
| 14 | LGS-2S | | | | | | | | | | | | | | | - | 14 |
| 15 | LGS-2P | | - | | | | | | | | | | | | | | 15 |
| 16 | LGS-2T | | | | | | | | | | | | | | | | 16 |
| 17 | LGS-3S | | | | | | | | | | | | | | | | 17 |
| 18 | LGS-3P | | | | | | | | | | | | | | | | 18 |
| 19 | LGS-3T | | | | | | | | | | | | | | | | 19 |
| 20 | LGS-XS | - | - | | | | | | | | | | | | | | 20 |
| 21 | LGS-XP | - | - | - | - | - | | | | - | | | | | | | 21 |
| 22 | LGS-XT | - | | | | | | | | | | | | | | | 22 |
| 23 | LGS-2S-WP | | - | - | | | | | | | | | | | | | 23 |
| 24 | LGS-2P-WP | | | | | | | | | | | | | | | | 24 |
| 25 | LGS-2T-WP | - | | - | | - | | | | | | | | | | | 25 |
| 26 | LGS-3S-WP | | | | - | | | | | | | | | | | | 26 |
| 27 | LGS-3P-WP | | | | | | | | | | | | | | | | 27 |
| 28 | LGS-3T-WP | | | | | | | | | | | | | | | | 28 |
| 29 | SL | - | - | - | | | | | | | | | | | | - | 29 |
| 30 | RS-Pal | - | | | | | | | | | | | | | | | 30 |
| 31 | GS-Pal | | | | | | | | | | | | | | | | 31 |
| 32 | IAIWP | - | - | - | | | | | | | | | | | | - | 32 |
| 33 | RS-NEM | | | | | | | | | | | | | | | | 33 |
| 34 | RM-NEM | | - | | | | | | | | | | | | | | 34 |
| 35 | LRS-NEM | | | | | | | | | | | | | | | | 35 |
| 36 | GS-NEM | - | | | | | | | | | | | | | | | 36 |
| 37 | | | | | | not a sum | | | | | | | | | | | 37 |
| 38 | TOTAL | | | | | | | | | | | | | | | | 38 |
| 39 | | | | | | from Sch. I-2 | | | | | | | | | | | 39 |
| 40 | | | | | Energy Revenue for Rate Design | - | $ (1,180) | | | | | | | | | | 40 |
| 41 | | | | | w/ Specific Class adjustments | $ - | | | | | | | | | | | 41 |
| 42 | | | | | | | | | | | | | | | | | 42 |
| 43 | | | | | | | | | | | | | | | | | 43 |
| 44 | Summation of NEM customers into Standard Schedule for Rate Design | | | | | | | | | | | | | | | | 44 |
| 45 | RS | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | 45 |
| 46 | RM | - | - | 0.00% | - | - | - | - | - | - | - | - | - | - | - | - | 46 |
| 47 | LRS | - | - | 0.00% | - | - | - | - | - | - | - | - | - | - | - | - | 47 |
| 48 | GS | - | - | 0.00% | - | - | - | - | - | - | - | - | - | - | - | - | 48 |
| 49 | | | | | | | | | | | | | | | | | 49 |
| 50 | | | | | | | | | | | | | | | | | 50 |

## Nevada Power Company
## Statement O

### Class Revenue Results Summary

| Line No. | Class | Sales (MWh) | Cost Based Class Revenue by Function: Distribution | Transmission | Generation | Energy/ variable | Subtotal | Power Factor Revenue (exc. DOS) | Additional Facilities & Maintenance Revenue | Sum of Functional Cost Based Class Revenue for Rate Design | Interclass Rate Rebalancing Revenue | Capped Class Revenue Requirement | Revenue Proof | Percent of Total | Difference from Capped Revenue Requirement (Rounding) | Overall Effective Rate | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | | | | | | | | | | | | | | | | | 8 |
| 9 | RS | 7,039,880 | $ 168,541 | $ 65,886 | $ 265,564 | | $ 499,991 | $ - | $ - | $ 499,991 | $ (21,120) | $ 475,803 | $ 500,417 | 49.5% | $ (375) | $ 0.06759 | 9 |
| 10 | RM | 2,188,600 | 44,039 | 16,255 | 70,014 | | 130,308 | - | - | 130,308 | 8,842 | 139,637 | 139,160 | 13.8% | (56) | 0.06380 | 10 |
| 11 | LRS | 35,987 | 472 | 256 | 1,012 | | 1,739 | - | - | 1,739 | 316 | 2,034 | 2,057 | 0.2% | (1) | 0.05652 | 11 |
| 12 | GS | 586,174 | 12,392 | 3,137 | 11,320 | | 26,849 | - | - | 26,849 | 6,607 | 33,671 | 33,539 | 3.3% | 5 | 0.05744 | 12 |
| 13 | LGS-1 | 3,897,464 | 39,038 | 21,269 | 84,819 | | 145,126 | 97 | 1 | 145,224 | 6,937 | 152,103 | 152,133 | 15.1% | 31 | 0.03903 | 13 |
| 14 | LGS-2S | 2,365,736 | 17,157 | 11,534 | 46,513 | | 75,203 | 346 | - | 75,550 | 2,602 | 77,726 | 77,729 | 7.7% | 3 | 0.03285 | 14 |
| 15 | LGS-2P | 67,742 | 514 | 280 | 1,228 | | 2,032 | 6 | - | 2,038 | (147) | 1,804 | 1,804 | 0.2% | (0) | 0.02663 | 15 |
| 16 | LGS-2T | - | - | - | - | | - | - | - | - | na | | - | 0.0% | — | — | 16 |
| 17 | LGS-3S | 822,586 | 5,331 | 3,541 | 14,917 | | 23,789 | 90 | - | 23,878 | 541 | 23,783 | 23,746 | 2.3% | (38) | 0.02891 | 17 |
| 18 | LGS-3P | 1,646,666 | 15,114 | 7,149 | 30,547 | | 52,809 | 185 | 64 | 53,058 | (123) | 47,475 | 47,484 | 4.7% | 8 | 0.02883 | 18 |
| 19 | LGS-3T | 397,435 | 394 | 1,678 | 6,862 | | 8,935 | 9 | - | 8,943 | (1,025) | 6,959 | 6,958 | 0.7% | (0) | 0.01751 | 19 |
| 20 | LGS-XS | - | - | - | - | | - | - | - | - | na | | - | 0.0% | — | — | 20 |
| 21 | LGS-XP | - | - | - | - | | - | - | - | - | na | | - | 0.0% | — | — | 21 |
| 22 | LGS-XT | - | - | - | - | | - | - | - | - | na | | - | 0.0% | — | — | 22 |
| 23 | LGS-2S-WP | 6,831 | 128 | 36 | 160 | | 325 | 2 | - | 327 | (157) | 143 | 149 | 0.0% | 6 | 0.02099 | 23 |
| 24 | LGS-2P-WP | 12,229 | 96 | 49 | 166 | | 311 | 3 | - | 314 | (40) | 274 | 274 | 0.0% | (0) | 0.02243 | 24 |
| 25 | LGS-2T-WP | - | 2 | - | - | | 2 | - | - | 2 | na | | - | 0.0% | — | — | 25 |
| 26 | LGS-3S-WP | 5,752 | 97 | 0 | 20 | | 117 | 2 | - | 119 | (26) | 17 | 18 | 0.0% | 1 | 0.00299 | 26 |
| 27 | LGS-3P-WP | 17,505 | 291 | 47 | 187 | | 525 | 3 | - | 528 | (84) | 231 | 228 | 0.0% | (3) | 0.01318 | 27 |
| 28 | LGS-3T-WP | - | 8 | - | - | | 8 | - | - | 8 | na | | - | 0.0% | — | — | 28 |
| 29 | SL | 150,361 | 893 | 92 | 1,877 | | 2,862 | - | - | 2,862 | (1,510) | 1,352 | 1,352 | 0.1% | (0) | 0.00899 | 29 |
| 30 | RS-Pal | 648 | 24 | 0 | 8 | | 32 | - | - | 32 | 9 | 40 | 40 | 0.0% | 0 | 0.06240 | 30 |
| 31 | GS-Pal | 2,337 | 77 | 1 | 27 | | 105 | - | - | 105 | 29 | 134 | 134 | 0.0% | (0) | 0.05725 | 31 |
| 32 | IAIWP | - | - | - | - | | - | - | - | - | - | - | - | 0.0% | - | — | 32 |
| 33 | RS-NEM | 264,487 | 15,650 | 5,529 | 24,658 | | 45,838 | - | - | 45,838 | (793) | 23,123 | 23,123 | 2.3% | — | 0.08742 | 33 |
| 34 | RM NEM | 1,506 | 60 | 22 | 90 | | 161 | | | 161 | 6 | 101 | 101 | 0.0% | | 0.06708 | 34 |
| 35 | LRS-NEM | 386 | 13 | 3 | 13 | | 29 | - | - | 29 | 3 | 29 | 29 | 0.0% | — | 0.07632 | 35 |
| 36 | GS-NEM | 2,005 | 65 | 26 | 103 | | 195 | - | - | 195 | 23 | 71 | 71 | 0.0% | — | 0.03526 | 36 |
| 37 | | | | | | | | | | | | | | | | | 37 |
| 38 | TOTAL | 19,512,318 | $ 320,385 | $ 136,800 | $ 560,104 | | | $ 743 | $ 65 | $ 1,018,097 | $ 890 | $ 986,510 | $ 1,010,544 | 100.0% | $ (420) | $ 0.05056 | 38 |
| 39 | | | | | | | | | | | | | | | | | 39 |
| 40 | | | | | | | | | | | | | | | | | 40 |
| 41 | | | | | | | | | | | | | | | | | 41 |
| 42 | | | | | | | | | | | | | | | | | 42 |
| 43 | Summation of NEM customers into Standard Schedule for Rate Design | | | | | | | | | | | | | | | | 43 |
| 44 | RS | 7,304,367 | $ 184,191 | $ 71,415 | $ 290,222 | $ - | $ 545,828 | $ - | $ - | $ 545,828 | $ (21,913) | $ 498,926 | $ 523,539 | 51.8% | $ (375) | $ 0.06831 | 44 |
| 45 | RM | 2,190,106 | 44,089 | 16,277 | 70,104 | - | 130,469 | - | - | 130,469 | 8,848 | 139,738 | 139,261 | 13.8% | (56) | 0.06380 | 45 |
| 46 | LRS | 36,373 | 485 | 259 | 1,024 | - | 1,768 | - | - | 1,768 | 319 | 2,063 | 2,086 | 0.2% | (1) | 0.05673 | 46 |
| 47 | GS | 588,180 | 12,457 | 3,163 | 11,424 | - | 27,044 | - | - | 27,044 | 6,630 | 33,741 | 33,609 | 3.3% | 5 | 0.05737 | 47 |

Class Revenue Adjustments Due to Cap & Floor Criteria (1)

| Line No. | Class | Total Class Revenue Requirement: Sum of Functional Cost Based Class Revenue | Percent of Total | AB 405 Cost Based Class Revenue | Percent of Total | Present Rate Revenue | % change over Present Rate Revenue | First Allocation - Cap: AB 405 Present Rate Revenue | AB405 Cost-Based Pct change over Present Rate Revenue | Result of Capping/Floor Proposal | Revenue Cap at Proposed | Re-set Revenue for classes subject to Cap Criteria (1) | Revenue to be re-allocated | Cost Based Class Revenue of Remaining Classes | Difference from Cost Based/Floor revenue of Uncapped Classes | Percent of Total | Class share of re-allocated Revenue | Class Revenue Requirement, after 1st Allocation | % change over Present Rate Revenue | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | RS | $ 499,991 | 49.50% | $ 499,991 | 49.50% | $ 531,616 | -5.95% | $ 531,616 | -5.95% | | -5.95% | $ 499,991 | $ | $ 499,991 | $ (31,627) | 40.68% | $ (2,179) | 497,813 | -6.36% | 9 |
| 10 | RM | 130,308 | 12.90% | 130,308 | 12.90% | 155,183 | -16.02% | 155,183 | -16.02% | Floor | -9.00% | 141,169 | (10,821) | | (15,863) | 17.84% | (765) | 140,259 | -9.62% | 10 |
| 11 | LRS | 1,739 | 0.17% | 1,739 | 0.17% | 2,291 | -24.08% | 2,291 | -24.08% | Floor | -9.00% | 2,085 | (346) | | (206) | 0.26% | (14) | 2,071 | -9.62% | 11 |
| 12 | GS | 28,848 | 2.86% | 28,848 | 2.86% | 37,466 | -23.34% | 37,466 | -23.34% | Floor | -9.00% | 34,094 | (7,246) | | (5,372) | 4.11% | (283) | 33,993 | -9.23% | 12 |
| 13 | LGS-1 | 145,165 | 14.37% | 145,165 | 14.37% | 168,694 | -14.05% | 168,694 | -14.05% | Floor | -9.00% | 153,494 | (9,822) | | (15,200) | 19.44% | (1,084) | 152,609 | -9.52% | 13 |
| 14 | LGS-2S | 75,126 | 7.44% | 75,126 | 7.44% | 86,306 | -12.95% | 86,306 | -12.95% | Floor | -9.00% | 78,539 | (3,412) | | (7,768) | 9.93% | (554) | 78,006 | -9.62% | 14 |
| 15 | LGS-2P | 1,951 | 0.19% | 1,951 | 0.19% | 1,921 | 1.57% | 1,921 | 1.57% | Capped | -6.08% | 1,804 | 147 | | | 0.00% | | 1,804 | -6.08% | 15 |
| 16 | LGS-2T | - | 0.00% | - | 0.00% | - | | | | | | | | | | 0.00% | | | | 16 |
| 17 | LGS-3S | 23,243 | 2.30% | 23,243 | 2.30% | 26,409 | -11.99% | 26,409 | -11.99% | Floor | -9.00% | 24,052 | (789) | | (2,377) | 3.04% | (165) | 23,859 | -9.62% | 17 |
| 18 | LGS-3P | 47,599 | 4.71% | 47,599 | 4.71% | 51,261 | -7.14% | 51,261 | -7.14% | | -7.14% | 47,599 | | 47,599 | (3,663) | 4.68% | (252) | 47,347 | -7.64% | 18 |
| 19 | LGS-3T | 7,984 | 0.79% | 7,984 | 0.79% | 7,409 | 7.76% | 7,409 | 7.76% | Capped | -6.08% | 6,959 | 1,025 | | | 0.00% | | 6,959 | -6.08% | 19 |
| 20 | LGS-XS | - | 0.00% | | 0.00% | - | | | | | | | | | | 0.00% | | | | 20 |
| 21 | LGS-XP | - | 0.00% | | 0.00% | - | | | | | | | | | | 0.00% | | | | 21 |
| 22 | LGS-XT | - | 0.00% | | 0.00% | - | | | | | | | | | | 0.00% | | | | 22 |
| 23 | LGS-2S-WP | 300 | 0.03% | 300 | 0.03% | 153 | 96.69% | 153 | 96.69% | Capped | -6.08% | 143 | 157 | | | 0.00% | | 143 | -6.08% | 23 |
| 24 | LGS-2P-WP | 314 | 0.03% | 314 | 0.03% | 292 | 7.47% | 292 | 7.47% | Capped | -6.08% | 274 | 40 | | | 0.00% | | 274 | -6.08% | 24 |
| 25 | LGS-2T-WP | - | 0.00% | | 0.00% | - | | | | | | | | | | 0.00% | | | | 25 |
| 26 | LGS-3S-WP | 44 | 0.00% | 44 | 0.00% | 18 | 138.34% | 18 | 138.34% | Capped | -6.08% | 17 | 28 | | | 0.00% | | 17 | -6.08% | 26 |
| 27 | LGS-3P-WP | 316 | 0.03% | 316 | 0.03% | 248 | 28.32% | 248 | 28.32% | Capped | -6.08% | 251 | 64 | | | 0.00% | | 251 | -6.08% | 27 |
| 28 | LGS-3T-WP | 8 | 0.00% | 8 | 0.00% | - | | | | | | | | | | 0.00% | | | | 28 |
| 29 | SL | 2,862 | 0.28% | 2,862 | 0.28% | 1,440 | 98.79% | 1,440 | 98.79% | Capped | -6.08% | 1,362 | 1,500 | | | 0.00% | | 1,352 | -6.08% | 29 |
| 30 | RS-Pal | 32 | 0.00% | 32 | 0.00% | 45 | -29.07% | 45 | -29.07% | Floor | -9.00% | 41 | (9) | | (4) | 0.01% | (0) | 41 | -9.62% | 30 |
| 31 | GS-Pal | 105 | 0.01% | 105 | 0.01% | 149 | -29.61% | 149 | -29.61% | Floor | -9.00% | 136 | (31) | | (13) | 0.02% | (1) | 134 | -9.62% | 31 |
| 32 | IAWP | - | | | | | | | | | | | | | | | | | | 32 |
| 33 | RS-NEM | 45,838 | 4.54% | 45,838 | | 24,289 | 88.72% | 24,289 | 88.72% | Capped | -6.83% | 23,117 | 22,721 | | | 0.00% | | 23,117 | -4.83% | 33 |
| 34 | RM-NEM | 181 | 0.02% | 181 | | 113 | 43.13% | 113 | 43.13% | Capped | -6.83% | 107 | 74 | | | 0.00% | | 107 | -4.83% | 34 |
| 35 | LRS-NEM | 29 | 0.00% | 29 | | 33 | -14.17% | 33 | -14.17% | Floor | -9.00% | 30 | (2) | | (0) | 0.00% | (0) | 30 | -9.62% | 35 |
| 36 | GS-NEM | 195 | 0.02% | 195 | | 81 | 140.22% | 81 | 140.22% | Capped | -6.83% | 77 | 118 | | | 0.00% | | 77 | -4.83% | 36 |
| 37 | | Not a sum: | | | | Not a Sum: | Overall Increase: | | | | | | | | | | | | | 37 |
| 38 | Total | $ 1,045,573 | 100.00% | $ 1,045,573 | 100.00% | $ 1,137,429 | -8.08% | | | | | $ 1,015,519 | $ (5,372) | $ 547,590 | $ (78,198) | 100% | $ (5,372) | | | 38 |
| 39 | | $ 1,010,155 | =sum= | $ 1,010,155 | | $ 1,095,596 | $ (91,955) | | | | | | | | | | | | | 39 |
| 40 | | $ 35,418 | <Rev Credits, Revenue Credits excl. PF and AFM revenues | | | | | | | | | | | | | | | | | 40 |

Second Allocation

| Class | Class Revenue Requirement, after 1st Allocation | Pct Change over Present Rate Revenue | Result of Capping/Floor Proposal | Revenue Cap at Proposed | Re-set Revenue for classes subject to Cap Criteria | Revenue to be re-allocated | Cost Based Class Revenue of Remaining Classes | Difference from Cost Based/Floor revenue of Uncapped Classes | Percent of Total | Class share of re-allocated Revenue | Class Revenue Requirement | % change over Present Rate Revenue | Final Class Revenue Allocation: Capped Class Revenue Requirement | % change over Present Rate Revenue | Difference from Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RS | $ 497,813 | -6.36% | | -6.36% | $ 497,813 | $ | $ 497,813 | $ (33,801) | 41.92% | $ 1,107 | $ 498,920 | -6.15% | $ 498,920 | -6.15% | $ (1,058) |
| RM | 140,259 | -9.62% | Floor | -9.00% | 141,169 | (909) | | (13,954) | 17.32% | 458 | 139,736 | -9.94% | 139,736 | -9.94% | 9,430 |
| LRS | 2,071 | -9.62% | Floor | -9.00% | 2,085 | (14) | | (208) | 0.26% | 7 | 2,063 | -9.94% | 2,063 | -9.94% | 124 |
| GS | 33,993 | -9.62% | Floor | -9.00% | 34,094 | (232) | | (3,572) | 4.18% | 110 | 33,741 | -9.94% | 33,741 | -9.94% | 6,893 |
| LGS-1 | 152,609 | -9.52% | Floor | -9.00% | 153,695 | (1,044) | | (15,200) | 18.55% | 486 | 152,109 | -9.94% | 152,109 | -9.94% | 8,538 |
| LGS-2S | 78,006 | -9.62% | Floor | -9.00% | 78,539 | (534) | | (7,768) | 9.83% | 254 | 77,726 | -9.94% | 77,726 | -9.94% | 2,600 |
| LGS-2P | 1,804 | -6.08% | Capped | -6.08% | 1,804 | | 1,804 | | 0.00% | | 1,804 | -6.08% | 1,804 | -6.08% | (147) |
| LGS-2T | | | | | | | | | 0.00% | | | | | | |
| LGS-3S | 23,859 | -9.62% | Floor | -9.00% | 24,052 | (163) | | (2,377) | 2.95% | 78 | 23,783 | -9.94% | 23,783 | -9.94% | 641 |
| LGS-3P | 47,347 | -7.64% | | -7.64% | 47,347 | | 47,347 | (3,814) | 4.85% | 128 | 47,476 | -7.39% | 47,476 | -7.39% | (123) |
| LGS-3T | 6,959 | -6.08% | Capped | -6.08% | 6,959 | | 6,959 | | 0.00% | | 6,959 | -6.08% | 6,959 | -6.08% | (1,025) |
| LGS-XS | | | | | | | | | 0.00% | | | | | | |
| LGS-XP | | | | | | | | | 0.00% | | | | | | |
| LGS-XT | | | | | | | | | 0.00% | | | | | | |
| LGS-2S-WP | 143 | -6.08% | Capped | -6.08% | 143 | | 143 | | 0.00% | | 143 | -6.08% | 143 | -6.08% | (157) |
| LGS-2P-WP | 274 | -6.08% | Capped | -6.08% | 274 | | 274 | | 0.00% | | 274 | -6.08% | 274 | -6.08% | (40) |
| LGS-2T-WP | | | | | | | | | 0.00% | | | | | | |
| LGS-3S-WP | 17 | -6.08% | Capped | -6.08% | 17 | | | | 0.00% | | 17 | -6.08% | 17 | -6.08% | (28) |
| LGS-3P-WP | 231 | -6.08% | Capped | -6.08% | 231 | | 231 | | 0.00% | | 231 | -6.08% | 231 | -6.08% | (84) |
| LGS-3T-WP | | | | | | | | | 0.00% | | | | | | |
| SL | 1,352 | -6.08% | Capped | -6.08% | 1,352 | | 1,352 | | 0.00% | | 1,352 | -6.08% | 1,352 | -6.08% | (1,510) |
| RS-Pal | 41 | -9.62% | Floor | -9.00% | 41 | (0) | | (4) | 0.01% | 0 | 40 | -9.94% | 40 | -9.94% | 9 |
| GS-Pal | 134 | -9.62% | Floor | -9.00% | 136 | (1) | | (13) | 0.02% | 0 | 134 | -9.94% | 134 | -9.94% | 29 |
| IAWP | | | | | | | | | | | | | | | |
| RS-NEM | 23,117 | -4.83% | Capped | -6.08% | 22,813 | 304 | | | 0.00% | | 23,420 | -3.65% | 23,420 | -3.65% | (22,417) |
| RM-NEM | 107 | -4.83% | Capped | -6.08% | 106 | 1 | | | 0.00% | | 109 | -3.65% | 109 | -3.65% | (53) |
| LRS-NEM | 30 | -9.62% | Floor | -9.00% | 30 | (0) | | (3) | 0.00% | 0 | 30 | -9.94% | 30 | -9.94% | (117) |
| GS-NEM | 77 | -4.83% | Capped | -6.08% | 76 | 1 | | | 0.00% | | 78 | -3.65% | 78 | -3.65% | |
| Total | | | | | $ 2,642 | $ 555,945 | $ (80,622) | 100.0% | $ 2,842 | $ 1,010,147 | | | $ 1,010,147 | | |
| | | | | | | | | | | | | | $ (8) | | |

(1) Increases in rates cannot exceed the total average percentage increases in rates. For example, a 3% cap on an average increase of 10% will result in a rate increase of 13%. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits. No class will receive a decrease in rates if a 0% floor is implemented.

(2) NEM classes include all customers under NMR-G and NMR-A rate schedules.

Non-Bypassable kWh Charges: Interclass Rate Rebalancing (IRR)

| Line No. | Classes[1] | Bundled kWh Sales | DOS kWh Sales | Total kWh Sales | Sum of Functional Cost Based Class Revenue | Capped Class Revenue Requirement | Interclass Subsidy (difference) | Subsidy Component per kWh | Rounding | Note | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | RS | 7,039,880,433 | | 7,304,367,364 | [redacted] | [redacted] | $ (21,916) | $ (0.00300) | $ 3 | | 8 |
| 9 | RM | 2,188,600,072 | | 2,190,106,091 | [redacted] | [redacted] | 8,841 | 0.00404 | 7 | | 9 |
| 10 | LRS | 35,987,038 | | 36,373,364 | [redacted] | [redacted] | 319 | 0.00878 | (0) | | 10 |
| 11 | GS | 584,168,954 | | 586,174,249 | [redacted] | [redacted] | 6,628 | 0.01131 | 2 | | 11 |
| 12 | LGS-1 | 3,897,463,666 | | 3,897,463,666 | 145,165 | 152,103 | 6,938 | 0.00178 | (0) | | 12 |
| 13 | LGS-2S | 2,365,736,287 | | 2,365,736,287 | 75,126 | 77,726 | 2,600 | 0.00110 | 3 | | 13 |
| 14 | LGS-2P | 67,742,230 | | 67,742,230 | 1,951 | 1,804 | (147) | 0.00001 | 147 | | 14 |
| 15 | LGS-2T | - | | - | - | | na | 0.00178 | — | <<Set equal to LGS-1>> | 15 |
| 16 | LGS-3S | 822,585,854 | | 822,585,854 | 23,243 | 23,783 | 541 | 0.00066 | 2 | | 16 |
| 17 | LGS-3P | 1,646,665,536 | | 1,646,665,536.39 | 47,599 | 47,475 | (123) | (0.00007) | 8 | | 17 |
| 18 | LGS-3T | 397,434,700 | | 397,434,700 | 7,984 | 6,959 | (1,025) | 0.00001 | 1,029 | | 18 |
| 19 | LGS-XS | - | | - | - | | na | 0.00001 | — | <<Set equal to LGS-XS DOS>> | 19 |
| 20 | LGS-XP | - | | - | - | | na | 0.00131 | — | <<Set equal to LGS-XP DOS>> | 20 |
| 21 | LGS-XT | - | | - | - | | na | 0.00090 | — | <<Set equal to LGS-XT DOS>> | 21 |
| 22 | LGS-2S-WP | 6,831,160 | | 6,831,160 | 300 | 143 | (157) | [redacted] | 157 | | 22 |
| 23 | LGS-2P-WP | 12,228,600 | | 12,228,600 | 314 | 274 | (40) | [redacted] | 40 | | 23 |
| 24 | LGS-2T-WP | - | | - | - | | na | 0.00001 | — | <<Set equal to LGS-2T WP DOS>> | 24 |
| 25 | LGS-3S-WP | 5,751,817 | | 5,751,817 | 44 | 17 | (26) | 0.00001 | 27 | | 25 |
| 26 | LGS-3P-WP | 17,504,868 | | 17,504,868 | 315 | 231 | (84) | 0.00001 | 85 | | 26 |
| 27 | LGS-3T-WP | - | | - | 8 | | na | 0.00001 | — | <<Set equal to LGS-3T WP DOS>> | 27 |
| 28 | SL | 150,361,312 | | 150,361,312 | 2,862 | 1,352 | (1,510) | (0.01004) | (0) | | 28 |
| 29 | RS-Pal | 647,868 | | 647,868 | 32 | 40 | 9 | 0.01325 | (0) | | 29 |
| 30 | GS-Pal | 2,337,372 | | 2,337,372 | 105 | 134 | 29 | 0.01250 | (0) | | 30 |
| 31 | IAIWP | - | | na | - | - | - | na | — | | 31 |
| 32 | RS-NEM | 264,486,931 | | inc in Full Req Class | | | | | | | 32 |
| 33 | RM-NEM | 1,506,019 | | inc in Full Req Class | | | | | | | 33 |
| 34 | LRS-NEM | 386,326 | | inc in Full Req Class | | | | | | | 34 |
| 35 | GS-NEM | 2,005,295 | | inc in Full Req Class | | | | | | | 35 |
| 36 | | | | | | | | | | | 36 |
| 37 | Bundled TOTAL | 19,510,312,338 | | 19,510,312,338 | $ 1,012,944 | $ 1,013,811 | $ 876 | << Subsidy amount prior to RevReq adjustment when maintaining current rates. | | | 37 |
| 38 | | | | | | | | | | | 38 |
| 39 | **DISTRIBUTION ONLY SERVICE CLASSES – SET @ OTHERWISE APPLICABLE CLASS AS IDENTIFIED (If <0, then set to zero)[2]** | | | | | | | | | | 39 |
| 40 | DOS: GS | | 52,832 | na | na | na | na | $ 0.01131 | | <<Set equal to GS>> | 40 |
| 41 | DOS: LGS-1 | | 6,590,602 | na | na | na | na | 0.00178 | | <<Set equal to LGS-1>> | 41 |
| 42 | DOS: LGS-2S | | 80,121,153 | na | na | na | na | 0.00110 | | <<Set equal to LGS-2S>> | 42 |
| 43 | DOS: LGS-2P | | 15,934,490 | na | na | na | na | 0.00001 | | <<Set equal to LGS-2P>> | 43 |
| 44 | DOS: LGS-2T | | - | na | na | na | na | 0.00178 | | <<Set equal to LGS-2T>> | 44 |
| 45 | DOS: LGS-3S | | 95,786,342 | na | na | na | na | 0.00066 | | <<Set equal to LGS-3S>> | 45 |
| 46 | DOS: LGS-3P | | 1,282,094,633 | na | na | na | na | 0.00001 | | <<Set equal to LGS-3P>> | 46 |
| 47 | DOS: LGS-3T | | 518,278,106 | na | na | na | na | 0.00001 | | <<Set equal to LGS-3T>> | 47 |
| 48 | DOS: LGS-XS | | 7,591,814 | na | na | na | na | 0.00001 | | <<Set to 0.00001 or Current x 94%>> | 48 |
| 49 | DOS: LGS-XP | | 279,670,254 | na | na | na | na | 0.00131 | | <<Set to 0.00001 or Current x 94%>> | 49 |
| 50 | DOS: LGS-XT | | 155,676,032 | na | na | na | na | 0.00090 | | <<Set to 0.00001 or Current x 94%>> | 50 |
| 51 | DOS: LGS-2S-WP | | 5,301,743 | na | na | na | na | 0.00001 | | <<Set equal to LGS-2S-WP>> | 51 |
| 52 | DOS: LGS-2P-WP | | - | na | na | na | na | 0.00001 | | <<Set equal to LGS-2P-WP>> | 52 |
| 53 | DOS: LGS-2T-WP | | 1,289,139 | na | na | na | na | 0.00001 | | <<Set to 0.00001 or Current x 94%>> | 53 |
| 54 | DOS: LGS-3S-WP | | 26,160,182 | na | na | na | na | 0.00001 | | <<Set equal to LGS-3S-WP>> | 54 |
| 55 | DOS: LGS-3P-WP | | 74,574,362 | na | na | na | na | 0.00001 | | <<Set equal to LGS-3P-WP>> | 55 |
| 56 | DOS: LGS-3T-WP | | 59,791,256 | na | na | na | na | 0.00001 | | <<Set to 0.00001 or Current x 94%>> | 56 |
| 57 | | | | | | | | | | | 57 |

58 1. Optional TOU classes are not shown in this table, but have IRR rates equal to their otherwise applicable schedules. Any revenues collected from these classes are revenue credited (See page 2).

59 2. The DOS classes identified here are only those that presently have DOS customers in them. However, for other classes that are eligible for DOS, the IRR will be set similarly for all eligible classes.

Comparison of Present and Proposed Rate Revenue

| Line No | Class | Sales (kWh) | BTGR Revenue Present | BTGR Revenue Proposed | Percent Change | BTGR & BTER[1] Revenue Present | BTGR & BTER[1] Revenue Proposed | Percent Change | Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Present | Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Proposed | Percent Change | Line No |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | RS | 7,039,880,433 | $ 531,617,975 | $ 500,416,882 | -5.87% | $ 531,617,975 | $ 500,416,882 | -5.87% | $ 546,884,516 | $ 515,693,423 | -5.71% | 8 |
| 9 | RM | 2,188,600,072 | 155,163,338 | 139,159,725 | -10.31% | 155,163,338 | 139,159,725 | -10.31% | 159,212,249 | 143,208,636 | -10.05% | 9 |
| 10 | LRS | 35,887,038 | 2,291,094 | 2,058,945 | -10.22% | 2,291,094 | 2,058,945 | -10.22% | 2,358,231 | 2,122,082 | -9.94% | 10 |
| 11 | GS | 584,168,954 | 37,466,138 | 33,538,537 | -10.48% | 37,466,138 | 33,538,537 | -10.48% | 38,231,399 | 34,303,798 | -10.27% | 11 |
| 12 | LGS-1 | 3,897,463,668 | 169,893,509 | 152,128,952 | -8.93% | 169,893,509 | 152,128,952 | -8.93% | 174,038,089 | 157,273,532 | -9.63% | 12 |
| 13 | LGS-2S | 2,365,736,287 | 86,306,191 | 77,728,634 | -9.94% | 86,306,191 | 77,728,634 | -9.94% | 88,813,872 | 80,236,315 | -9.66% | 13 |
| 14 | LGS-2P | 67,742,230 | 1,920,539 | 1,803,827 | -6.08% | 1,920,539 | 1,803,827 | -6.08% | 1,984,895 | 1,868,183 | -5.88% | 14 |
| 15 | LGS-2T | - | - | - | na | - | - | na | - | - | na | 15 |
| 16 | LGS-3S | 800,640,755 | 25,748,757 | 23,157,270 | -10.06% | 25,748,757 | 23,157,270 | -10.06% | 26,813,609 | 24,222,122 | -9.66% | 16 |
| 17 | LGS-3P | 1,296,176,562 | 41,255,316 | 38,224,874 | -7.35% | 41,255,316 | 38,224,874 | -7.35% | 42,836,652 | 39,806,210 | -7.07% | 17 |
| 18 | LGS-3T | 291,915,629 | 5,203,130 | 4,781,629 | -8.10% | 5,203,130 | 4,781,629 | -8.10% | 5,611,812 | 5,190,311 | -7.51% | 18 |
| 19 | LGS-XS | - | - | - | na | - | - | na | - | - | na | 19 |
| 20 | LGS-XP | - | - | - | na | - | - | na | - | - | na | 20 |
| 21 | LGS-XT | - | - | - | na | - | - | na | - | - | na | 21 |
| 22 | LGS-2S-WP | 6,831,160 | 152,653 | 149,115 | -2.32% | 152,653 | 149,115 | -2.32% | 154,429 | 150,890 | -2.29% | 22 |
| 23 | LGS-2P-WP | 12,228,600 | 292,068 | 273,924 | -6.21% | 292,068 | 273,924 | -6.21% | 300,628 | 282,483 | -6.04% | 23 |
| 24 | LGS-2T-WP | - | - | - | na | - | - | na | - | - | na | 24 |
| 25 | LGS-3S-WP | 5,751,817 | 18,337 | 17,857 | -2.62% | 18,337 | 17,857 | -2.62% | 21,098 | 20,618 | -2.28% | 25 |
| 26 | LGS-3P-WP | 17,504,868 | 245,626 | 227,892 | -7.22% | 245,626 | 227,892 | -7.22% | 255,604 | 237,870 | -6.94% | 26 |
| 27 | LGS-3T-WP | - | - | - | na | - | - | na | - | - | na | 27 |
| 28 | SL | 150,361,312 | 1,439,520 | 1,351,860 | -6.09% | 1,439,520 | 1,351,860 | -6.09% | 1,519,212 | 1,431,552 | -5.77% | 28 |
| 29 | RS-Pal | 647,868 | 44,892 | 40,456 | -9.88% | 44,892 | 40,456 | -9.88% | 45,196 | 40,761 | -9.81% | 29 |
| 30 | GS-Pal | 2,337,372 | 148,576 | 133,728 | -9.99% | 148,576 | 133,728 | -9.99% | 149,674 | 134,826 | -9.92% | 30 |
| 31 | IARWP | - | - | - | na | - | - | na | - | - | na | 31 |
| 32 | **Optional Time of Use** | | | | | | | | | | | 32 |
| 33 | ORS-TOU | 4,722,752 | 237,562 | 224,377 | -5.55% | 237,562 | 224,377 | -5.55% | 247,810 | 234,625 | -5.32% | 33 |
| 34 | ORS-TOU OPT A | 26,831,203 | 1,613,289 | 1,512,632 | -6.24% | 1,613,289 | 1,512,632 | -6.24% | 1,671,513 | 1,570,856 | -6.02% | 34 |
| 35 | ORS-TOU OPT B | 5,598,680 | 246,893 | 227,871 | -7.70% | 246,893 | 227,871 | -7.70% | 259,043 | 240,020 | -7.34% | 35 |
| 39 | ORM-TOU | 680,195 | 35,856 | 31,038 | -13.44% | 35,856 | 31,038 | -13.44% | 36,930 | 32,112 | -13.05% | 39 |
| 40 | ORM-TOU OPT A | 986,040 | 64,324 | 58,802 | -8.58% | 64,324 | 58,802 | -8.58% | 66,149 | 60,628 | -8.35% | 40 |
| 41 | ORM-TOU OPT B | 133,774 | 8,063 | 7,688 | -4.65% | 8,063 | 7,688 | -4.65% | 8,311 | 7,936 | -4.51% | 41 |
| 51 | OGS-TOU | 23,843,869 | 1,243,027 | 1,190,898 | -4.19% | 1,243,027 | 1,190,898 | -4.19% | 1,274,263 | 1,222,134 | -4.09% | 51 |
| 52 | OLGS-1 TOU | 81,567,130 | 2,970,359 | 2,758,950 | -7.12% | 2,970,359 | 2,758,950 | -7.12% | 3,078,027 | 2,866,617 | -6.87% | 52 |
| 53 | OLGS-3P-HLF | 262,854,722 | 5,533,026 | 5,387,352 | -2.63% | 5,533,026 | 5,387,352 | -2.63% | 5,853,710 | 5,708,036 | -2.49% | 53 |
| 54 | **Optional Time of Use EVRR** | | | | | | | | | | | 54 |
| 55 | ORS-TOU EVRR | 17,669,841 | 959,406 | 878,752 | -8.41% | 959,406 | 878,752 | -8.41% | 998,184 | 917,530 | -8.08% | 55 |
| 56 | ORS-TOU Opt A EVRR | 9,481,782 | 489,233 | 459,937 | -5.99% | 489,233 | 459,937 | -5.99% | 509,808 | 480,513 | -5.75% | 56 |
| 57 | ORS-TOU Opt B EVRR | 6,152,819 | 225,210 | 212,741 | -5.54% | 225,210 | 212,741 | -5.54% | 238,561 | 226,092 | -5.23% | 57 |
| 60 | ORM-TOU EVRR | 441,642 | 25,866 | 22,438 | -13.59% | 25,866 | 22,438 | -13.59% | 26,783 | 23,255 | -13.17% | 60 |
| 61 | ORM-TOU OPT A EVRR | 76,095 | 5,520 | 4,979 | -9.80% | 5,520 | 4,979 | -9.80% | 5,687 | 5,126 | -9.55% | 61 |
| 62 | ORM-TOU OPT B EVRR | 58,981 | 3,183 | 3,129 | -1.71% | 3,183 | 3,129 | -1.71% | 3,292 | 3,238 | -1.65% | 62 |
| 65 | OLRS-TOU EVRR | 260,038 | 11,978 | 10,067 | -15.96% | 11,978 | 10,067 | -15.96% | 12,448 | 10,536 | -15.36% | 65 |
| 70 | OGS-TOU EVRR | 3,241 | 689 | 653 | -5.22% | 689 | 653 | -5.22% | 694 | 658 | -5.19% | 70 |
| 71 | OLGS-1-TOU EVRR | - | - | - | na | - | - | na | - | - | na | 71 |
| 72 | **Net Metering:** | | | | | | | | | | | 72 |
| 73 | RS-NEM | 264,486,931 | 24,288,978 | 23,122,592 | -4.80% | 24,288,978 | 23,122,592 | -4.80% | 24,862,917 | 23,696,531 | -4.69% | 73 |
| 74 | RM-NEM | 1,506,019 | 112,621 | 101,017 | -10.30% | 112,621 | 101,017 | -10.30% | 115,407 | 103,803 | -10.05% | 74 |
| 75 | LRS-NEM | 386,326 | 33,206 | 29,483 | -11.21% | 33,206 | 29,483 | -11.21% | 33,904 | 30,181 | -10.98% | 75 |
| 76 | GS-NEM | 2,005,295 | 81,147 | 70,713 | -12.86% | 81,147 | 70,713 | -12.86% | 83,776 | 73,342 | -12.45% | 76 |
| 77 | LGS-1 NEM | 41,534 | 4,918 | 4,356 | -11.42% | 4,918 | 4,356 | -11.42% | 4,972 | 4,410 | -11.29% | 77 |
| 78 | ORS-NEM | 952,989 | 83,343 | 73,459 | -11.86% | 83,343 | 73,459 | -11.86% | 85,411 | 76,528 | -11.67% | 78 |
| 79 | ORS-NEM OPT A | 3,564,821 | 244,840 | 229,213 | -6.38% | 244,840 | 229,213 | -6.38% | 252,578 | 236,950 | -6.19% | 79 |
| 80 | ORS-NEM OPT B | 226,466 | 15,770 | 14,101 | -10.58% | 15,770 | 14,101 | -10.58% | 16,263 | 14,594 | -10.26% | 80 |
| 97 | **NEM EVRR** | | | | | | | | | | | 97 |
| 98 | ORS-NEM EVRR | 2,947,034 | 146,012 | 137,819 | -5.54% | 146,012 | 137,819 | -5.54% | 152,406 | 144,312 | -5.31% | 98 |
| 99 | ORS-NEM OPT A EVRR | 1,703,792 | 60,815 | 60,279 | -0.88% | 60,815 | 60,279 | -0.88% | 64,513 | 63,976 | -0.83% | 99 |
| 100 | ORS-NEM OPT B EVRR | 380,504 | 17,988 | 16,430 | -8.66% | 17,988 | 16,430 | -8.66% | 18,816 | 17,257 | -8.28% | 100 |
| 103 | ORM-NEM EVRR | 20,514 | 2,272 | 1,920 | -15.50% | 2,272 | 1,920 | -15.50% | 2,310 | 1,958 | -15.24% | 103 |
| 114 | **Standby** | | | | | | | | | | | 114 |
| 116 | SSR - GS | - | - | - | na | - | - | na | - | - | na | 116 |
| 117 | SSR - LGS-1 | 1,115,600 | 53,011 | 52,984 | -0.05% | 53,011 | 52,984 | -0.05% | 54,484 | 54,457 | -0.05% | 117 |
| 118 | LSR - LGS-2S | - | - | - | na | - | - | na | - | - | na | 118 |
| 119 | LSR - LGS-2P | - | - | - | na | - | - | na | - | - | na | 119 |
| 120 | LSR - LGS-2T | 4,021,830 | 69,881 | 64,737 | -7.36% | 69,881 | 64,737 | -7.36% | 73,680 | 68,436 | -6.99% | 120 |
| 121 | LSR - LGS-3S | - | - | - | na | - | - | na | - | - | na | 121 |
| 122 | LSR - LGS-3P | 22,467,819 | 811,769 | 742,668 | -8.51% | 811,769 | 742,668 | -8.51% | 839,207 | 770,116 | -8.23% | 122 |
| 123 | LSR - LGS-3T | 91,166,026 | 2,566,769 | 2,453,596 | -4.41% | 2,566,769 | 2,453,596 | -4.41% | 2,694,402 | 2,581,229 | -4.20% | 123 |
| 133 | **EVCCR** | | | | | | | | | | | 133 |
| 134 | LGS-2S EVCCR | 3,419,851 | 203,005 | 182,083 | -10.31% | 203,005 | 182,083 | -10.31% | 206,631 | 185,709 | -10.13% | 134 |
| 135 | LGS-2P EVCCR | - | - | - | na | - | - | na | - | - | na | 135 |
| 136 | LGS-2T EVCCR | - | - | - | na | - | - | na | - | - | na | 136 |
| 137 | LGS-3S EVCCR | - | - | - | na | - | - | na | - | - | na | 137 |
| 138 | LGS-3P EVCCR | - | - | - | na | - | - | na | - | - | na | 138 |
| 139 | LGS-3T EVCCR | - | - | - | na | - | - | na | - | - | na | 139 |
| 144 | | | | | | | | | | | | 144 |
| 145 | **TOTAL Bundled** | 19,686,073,843 | $1,102,624,772 | $ 1,016,784,263 | -7.79% | $ 1,102,624,772 | $ 1,016,784,263 | -7.79% | $ 1,135,039,126 | $ 1,049,198,618 | -7.56% | 145 |
| 146 | Residential | 9,614,487,549 | $ 718,049,627 | $ 669,114,872 | -6.81% | $ 718,049,627 | $ 669,114,872 | -6.81% | $ 738,197,214 | $ 689,262,459 | -6.63% | 146 |
| 147 | Non-Residential | 10,071,586,294 | $ 384,575,145 | $ 347,669,391 | -9.60% | $ 384,575,145 | $ 347,669,391 | -9.60% | $ 396,841,913 | $ 359,936,159 | -9.30% | 147 |
| 148 | | | | | | | | | | | | 148 |
| 149 | **DISTRIBUTION ONLY SERVICE (DOS)** | | | | | | | | | | | 149 |
| 150 | GS-DOS | 52,832 | $ 4,762 | $ 4,658 | -2.18% | $ 4,762 | $ 4,658 | -2.18% | $ 4,755 | $ 4,651 | -2.18% | 150 |
| 151 | LGS-1-DOS | 6,590,602 | 159,369 | 136,894 | -14.10% | 159,369 | 136,894 | -14.10% | 158,372 | 135,897 | -14.19% | 151 |
| 152 | LGS-2S-DOS | 80,121,153 | 1,590,997 | 1,361,286 | -14.44% | 1,590,997 | 1,361,286 | -14.44% | 1,590,223 | 1,360,512 | -14.45% | 152 |
| 153 | LGS-2P-DOS | 15,934,490 | 250,948 | 207,107 | -17.47% | 250,948 | 207,107 | -17.47% | 252,291 | 208,450 | -17.38% | 153 |
| 154 | LGS-2T-DOS | - | - | - | na | - | - | na | - | - | na | 154 |
| 155 | LGS-3S-DOS | 95,786,342 | 2,316,632 | 1,961,177 | -15.34% | 2,316,632 | 1,961,177 | -15.34% | 2,320,911 | 1,965,456 | -15.32% | 155 |
| 156 | LGS-3P-DOS | 1,292,094,633 | 17,960,401 | 13,453,642 | -25.09% | 17,960,401 | 13,453,642 | -25.09% | 17,812,153 | 13,305,394 | -25.30% | 156 |
| 157 | LGS-3T-DOS | 518,278,106 | 4,464,755 | 3,681,801 | -17.54% | 4,464,755 | 3,681,801 | -17.54% | 4,388,752 | 3,605,798 | -17.84% | 157 |
| 158 | LGS-XS-DOS | 7,591,814 | 168,717 | 151,088 | -9.37% | 168,717 | 151,088 | -9.37% | 167,800 | 152,271 | -9.31% | 158 |
| 159 | LGS-XP-DOS | 278,670,254 | 5,622,732 | 5,206,499 | -7.40% | 5,622,732 | 5,206,499 | -7.40% | 5,564,811 | 5,148,578 | -7.48% | 159 |
| 160 | LGS-XT-DOS | 155,676,032 | 1,416,082 | 1,289,687 | -8.93% | 1,416,082 | 1,289,687 | -8.93% | 1,355,968 | 1,229,973 | -9.33% | 160 |
| 161 | LGS-2S-WP-DOS | 5,301,743 | 48,327 | 38,527 | -20.28% | 48,327 | 38,527 | -20.28% | 48,327 | 38,527 | -20.28% | 161 |
| 162 | LGS-2P-WP-DOS | - | - | - | na | - | - | na | - | - | na | 162 |
| 163 | LGS-2T-WP-DOS | 1,269,139 | 30,248 | 16,567 | -45.23% | 30,248 | 16,567 | -45.23% | 30,248 | 16,567 | -45.23% | 163 |
| 164 | LGS-3S-WP-DOS | 26,160,182 | 159,304 | 72,861 | -54.26% | 159,304 | 72,861 | -54.26% | 159,304 | 72,861 | -54.26% | 164 |
| 165 | LGS-3P-WP-DOS | 74,574,362 | 453,060 | 300,985 | -33.57% | 453,060 | 300,985 | -33.57% | 453,060 | 300,985 | -33.57% | 165 |
| 166 | LGS-3T-WP-DOS | 59,791,256 | 160,344 | 92,663 | -42.21% | 160,344 | 92,663 | -42.21% | 160,344 | 92,663 | -42.21% | 166 |
| 167 | | | | | | | | | | | | 167 |
| 168 | DOS TOTAL | 2,608,912,940 | $ 34,804,678 | $ 27,975,442 | -19.62% | $ 34,804,678 | $ 27,975,442 | -19.62% | $ 34,466,819 | $ 27,637,583 | -19.81% | 168 |
| 169 | | | | | | | | | | | | 169 |
| 170 | TOTAL (Inc. DOS) | 22,294,986,783 | $1,137,429,450 | $ 1,044,759,705 | -8.15% | $ 1,137,429,450 | $ 1,044,759,705 | -8.15% | $ 1,169,505,945 | $ 1,076,836,200 | -7.92% | 170 |
| 171 | | | | | | | | | | | | 171 |

172 Note: Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits.

173 1. Present BTER and DEAA revenues are based on July 1, 2020 rates.

174 2. Partial requirements customers included in LGS-3P and LGS-3T for rate design purposes are presented in their respective standby schedules.

Verification of Present Rate Components & Comparison to Proposed Revenue

| Line No. | Class | Sales | BTER Revenue Present | BTER Revenue Proposed | BTER Revenue Percent Change | DEAA Revenue Present | DEAA Revenue Proposed | DEAA Revenue Percent Change | EE Revenue Present | EE Revenue Proposed | EE Revenue Percent Change | REPR Revenue Present | REPR Revenue Proposed | REPR Revenue Percent Change | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | Residential Rate | | | | | | | Rates vary by Class | | | $ (0.00039) | $ (0.00039) | | 9 |
| 10 | | Non-Residential Rate | | | | | | | | | | $ (0.00039) | $ (0.00039) | | 10 |
| 11 | | | | | | | | | | | | | | | 11 |
| 12 | RS | 7,039,880,433 | | | na | | | na | $ 18,022,094 | $ 18,022,094 | 0.0% | $ (2,745,553) | $ (2,745,553) | 0.0% | 12 |
| 13 | RM | 2,188,600,072 | | | na | | | na | 4,802,465 | 4,802,465 | 0.0% | (853,554) | (853,554) | 0.0% | 13 |
| 14 | LRS | 35,997,038 | | | na | | | na | 79,172 | 79,172 | 0.0% | (14,035) | (14,035) | 0.0% | 14 |
| 15 | GS | 884,168,954 | | | na | | | na | 993,087 | 993,087 | 0.0% | (227,826) | (227,826) | 0.0% | 15 |
| 16 | LGS-1 | 3,897,463,666 | | | na | | | na | 6,664,591 | 6,664,591 | 0.0% | (1,520,011) | (1,520,011) | 0.0% | 16 |
| 17 | LGS-2S | 2,365,736,287 | | | na | | | na | 3,430,316 | 3,430,316 | 0.0% | (922,637) | (922,637) | 0.0% | 17 |
| 18 | LGS-2P | 67,742,230 | | | na | | | na | 90,775 | 90,775 | 0.0% | (26,419) | (26,419) | 0.0% | 18 |
| 19 | LGS-2T | - | | | na | | | na | - | - | na | - | - | na | 19 |
| 20 | LGS-3S | 809,640,755 | | | na | | | na | 1,377,102 | 1,377,102 | 0.0% | (312,250) | (312,250) | 0.0% | 20 |
| 21 | LGS-3P | 1,296,176,562 | | | na | | | na | 2,086,845 | 2,086,845 | 0.0% | (505,509) | (505,509) | 0.0% | 21 |
| 22 | LGS-3T | 291,915,629 | | | na | | | na | 522,529 | 522,529 | 0.0% | (113,847) | (113,847) | 0.0% | 22 |
| 23 | LGS-XS | - | | | na | | | na | - | - | na | - | - | na | 23 |
| 24 | LGS-XP | - | | | na | | | na | - | - | na | - | - | na | 24 |
| 25 | LGS-XT | - | | | na | | | na | - | - | na | - | - | na | 25 |
| 26 | LGS-2S-WP | 6,831,160 | | | na | | | na | 4,440 | 4,440 | 0.0% | (2,664) | (2,664) | 0.0% | 26 |
| 27 | LGS-2P-WP | 12,228,600 | | | na | | | na | 13,329 | 13,329 | 0.0% | (4,769) | (4,769) | 0.0% | 27 |
| 28 | LGS-2T-WP | - | | | na | | | na | - | - | na | - | - | na | 28 |
| 29 | LGS-3S-WP | 5,751,817 | | | na | | | na | 5,004 | 5,004 | 0.0% | (2,243) | (2,243) | 0.0% | 29 |
| 30 | LGS-3P-WP | 17,504,868 | | | na | | | na | 16,805 | 16,805 | 0.0% | (6,827) | (6,827) | 0.0% | 30 |
| 31 | LGS-3T-WP | - | | | na | | | na | - | - | na | - | - | na | 31 |
| 32 | SL | 150,361,312 | | | na | | | na | 138,333 | 138,333 | 0.0% | (58,641) | (58,641) | 0.0% | 32 |
| 33 | RS-Pal | 647,868 | | | na | | | na | 557 | 557 | 0.0% | (253) | (253) | 0.0% | 33 |
| 34 | GS-Pal | 2,337,372 | | | na | | | na | 2,010 | 2,010 | 0.0% | (912) | (912) | 0.0% | 34 |
| 35 | IAIWP | - | | | na | | | na | - | - | na | - | - | na | 35 |
| 36 | **Optional Time of Use** | | | | | | | | | | | | | | 36 |
| 37 | ORS-TOU | 4,722,752 | | | na | | | na | 12,090 | 12,090 | 0.0% | (1,842) | (1,842) | 0.0% | 37 |
| 38 | ORS-TOU OPT A | 26,831,203 | | | na | | | na | 68,688 | 68,688 | 0.0% | (10,464) | (10,464) | 0.0% | 38 |
| 39 | ORS-TOU OPT B | 5,598,580 | | | na | | | na | 14,333 | 14,333 | 0.0% | (2,183) | (2,183) | 0.0% | 39 |
| 43 | ORM-TOU | 580,195 | | | na | | | na | 1,300 | 1,300 | 0.0% | (226) | (226) | 0.0% | 43 |
| 44 | ORM-TOU OPT A | 986,040 | | | na | | | na | 2,210 | 2,210 | 0.0% | (385) | (385) | 0.0% | 44 |
| 45 | ORM-TOU OPT B | 133,774 | | | na | | | na | 300 | 300 | 0.0% | (52) | (52) | 0.0% | 45 |
| 55 | OGS-TOU | 23,843,869 | | | na | | | na | 40,535 | 40,535 | 0.0% | (9,299) | (9,299) | 0.0% | 55 |
| 56 | OLGS-1 TOU | 81,567,130 | | | na | | | na | 139,479 | 139,479 | 0.0% | (31,811) | (31,811) | 0.0% | 56 |
| 57 | OLGS-3P-HLF | 262,854,722 | | | na | | | na | 423,197 | 423,197 | 0.0% | (102,513) | (102,513) | 0.0% | 57 |
| 58 | **Optional Time of Use EVRR** | | | | | | | | | | | | | | 58 |
| 59 | ORS-TOU EVRR | 17,869,841 | | | na | | | na | 45,747 | 45,747 | 0.0% | (6,969) | (6,969) | 0.0% | 59 |
| 60 | ORS-TOU Opt A EVRR | 9,481,782 | | | na | | | na | 24,273 | 24,273 | 0.0% | (3,698) | (3,698) | 0.0% | 60 |
| 61 | ORS-TOU Opt B EVRR | 6,152,819 | | | na | | | na | 15,751 | 15,751 | 0.0% | (2,400) | (2,400) | 0.0% | 61 |
| 64 | ORM-TOU EVRR | 441,642 | | | na | | | na | 989 | 989 | 0.0% | (172) | (172) | 0.0% | 64 |
| 65 | ORM-TOU OPT A EVRR | 79,095 | | | na | | | na | 178 | 178 | 0.0% | (31) | (31) | 0.0% | 65 |
| 66 | ORM-TOU OPT B EVRR | 58,981 | | | na | | | na | 132 | 132 | 0.0% | (23) | (23) | 0.0% | 66 |
| 69 | OLRS-TOU EVRR | 260,038 | | | na | | | na | 571 | 571 | 0.0% | (101) | (101) | 0.0% | 69 |
| 74 | OGS-TOU EVRR | 3,241 | | | na | | | na | 6 | 6 | 0.0% | (1) | (1) | 0.0% | 74 |
| 75 | OLGS-1-TOU EVRR | - | | | na | | | na | - | - | na | - | - | na | 75 |
| 76 | **Net Metering:** | | | | | | | | | | | | | | 76 |
| 77 | RS-NEM | 264,486,931 | | | na | | | na | 677,089 | 677,089 | 0.0% | (103,150) | (103,150) | 0.0% | 77 |
| 78 | RM-NEM | 1,506,019 | | | na | | | na | 3,373 | 3,373 | 0.0% | (587) | (587) | 0.0% | 78 |
| 79 | LRS-NEM | 386,326 | | | na | | | na | 849 | 849 | 0.0% | (151) | (151) | 0.0% | 79 |
| 80 | GS-NEM | 2,005,295 | | | na | | | na | 3,411 | 3,411 | 0.0% | (782) | (782) | 0.0% | 80 |
| 81 | LGS-1 NEM | 41,534 | | | na | | | na | 70 | 70 | 0.0% | (16) | (16) | 0.0% | 81 |
| 82 | ORS-NEM | 952,989 | | | na | | | na | 2,440 | 2,440 | 0.0% | (372) | (372) | 0.0% | 82 |
| 83 | ORS-NEM OPT A | 3,564,821 | | | na | | | na | 9,128 | 9,128 | 0.0% | (1,390) | (1,390) | 0.0% | 83 |
| 84 | ORS-NEM OPT B | 226,466 | | | na | | | na | 581 | 581 | 0.0% | (88) | (88) | 0.0% | 84 |
| 101 | **NEM EVRR** | | | | | | | | | | | | | | 101 |
| 102 | ORS-NEM EVRR | 2,947,034 | | | na | | | na | 7,543 | 7,543 | 0.0% | (1,149) | (1,149) | 0.0% | 102 |
| 103 | ORS-NEM OPT A EVRR | 1,703,792 | | | na | | | na | 4,362 | 4,362 | 0.0% | (664) | (664) | 0.0% | 103 |
| 104 | ORS-NEM OPT B EVRR | 380,504 | | | na | | | na | 976 | 976 | 0.0% | (148) | (148) | 0.0% | 104 |
| 107 | ORM-NEM EVRR | 20,514 | | | na | | | na | 46 | 46 | 0.0% | (8) | (8) | 0.0% | 107 |
| 119 | **Standby** | | | | | | | | | | | | | | 119 |
| 120 | SSR - GS | - | | | na | | | na | - | - | na | - | - | na | 120 |
| 121 | SSR - LGS-1 | 1,115,600 | | | na | | | na | 1,908 | 1,908 | 0.0% | (435) | (435) | 0.0% | 121 |
| 122 | LSR - LGS-2S | - | | | na | | | na | - | - | na | - | - | na | 122 |
| 123 | LSR - LGS-2P | - | | | na | | | na | - | - | na | - | - | na | 123 |
| 124 | LSR - LGS-2T | 4,021,830 | | | na | | | na | 5,268 | 5,268 | 0.0% | (1,569) | (1,569) | 0.0% | 124 |
| 125 | LSR - LGS-3S | - | | | na | | | na | - | - | na | - | - | na | 125 |
| 126 | LSR - LGS-3P | 22,497,819 | | | na | | | na | 36,222 | 36,222 | 0.0% | (8,774) | (8,774) | 0.0% | 126 |
| 127 | LSR - LGS-3T | 91,166,025 | | | na | | | na | 163,188 | 163,188 | 0.0% | (35,555) | (35,555) | 0.0% | 127 |
| 137 | **EVCCR** | | | | | | | | | | | | | | 137 |
| 138 | LGS-2S EVCCR | 3,419,851 | | | na | | | na | 4,960 | 4,960 | 0.0% | (1,334) | (1,334) | 0.0% | 138 |
| 148 | | | | | | | | | | | | | | | 148 |
| 149 | **TOTAL Bundled** | 19,686,073,843 | $ - | $ - | na | - | - | na | 40,060,649 | 40,060,649 | 0.0% | (7,646,295) | (7,646,295) | 0.0% | 149 |
| 150 | Residential | 9,614,487,549 | - | - | na | - | - | na | 23,897,237 | 23,897,237 | 0.0% | (3,749,650) | (3,749,650) | 0.0% | 150 |
| 151 | Non-Residential | 10,071,586,294 | - | - | na | - | - | na | 16,163,412 | 16,163,412 | 0.0% | (3,896,644) | (3,896,644) | 0.0% | 151 |
| 152 | | | | | | | | | | | | | | | 152 |
| 153 | **DISTRIBUTION ONLY SERVICE (DOS)** | | R-BTER & BTER Impact Fee DOS Revenue | | | | | | | | | | | | 153 |
| 154 | GS-DOS | 52,832 | | | na | | | na | - | - | na | (7) | (7) | 0.0% | 154 |
| 155 | LGS-1-DOS | 6,590,602 | | | na | | | na | 614 | 614 | 0.0% | (1,611) | (1,611) | 0.0% | 155 |
| 156 | LGS-2S-DOS | 80,121,153 | | | na | | | na | 23,459 | 23,459 | 0.0% | (24,233) | (24,233) | 0.0% | 156 |
| 157 | LGS-2P-DOS | 15,934,490 | | | na | | | na | 4,338 | 4,338 | 0.0% | (2,995) | (2,995) | 0.0% | 157 |
| 158 | LGS-2T-DOS | - | | | na | | | na | - | - | na | - | - | na | 158 |
| 159 | LGS-3S-DOS | 95,786,342 | | | na | | | na | 32,064 | 32,064 | 0.0% | (27,785) | (27,785) | 0.0% | 159 |
| 160 | LGS-3P-DOS | 1,282,094,633 | | | na | | | na | 89,018 | 89,018 | 0.0% | (237,266) | (237,266) | 0.0% | 160 |
| 161 | LGS-3T-DOS | 519,276,106 | | | na | | | na | 61,946 | 61,946 | 0.0% | (137,949) | (137,949) | 0.0% | 161 |
| 162 | LGS-XS-DOS | 7,591,814 | | | na | | | na | 4,144 | 4,144 | 0.0% | (2,961) | (2,961) | 0.0% | 162 |
| 163 | LGS-XP-DOS | 279,670,254 | | | na | | | na | 51,150 | 51,150 | 0.0% | (109,071) | (109,071) | 0.0% | 163 |
| 164 | LGS-XT-DOS | 155,676,032 | | | na | | | na | - | - | na | (60,714) | (60,714) | 0.0% | 164 |
| 165 | LGS-2S-WP-DOS | 5,301,743 | | | na | | | na | - | - | na | - | - | na | 165 |
| 166 | LGS-2P-WP-DOS | - | | | na | | | na | - | - | na | - | - | na | 166 |
| 167 | LGS-2T-WP-DOS | 1,289,139 | | | na | | | na | - | - | na | - | - | na | 167 |
| 168 | LGS-3S-WP-DOS | 29,165,182 | | | na | | | na | - | - | na | - | - | na | 168 |
| 169 | LGS-3P-WP-DOS | 74,574,362 | | | na | | | na | - | - | na | - | - | na | 169 |
| 170 | LGS-3T-WP-DOS | 59,781,256 | | | na | | | na | - | - | na | - | - | na | 170 |
| 171 | | | | | | | | | | | | | | | 171 |
| 172 | DOS TOTAL | $ 2,608,912,940 | $ - | $ - | na | $ - | $ - | na | $ 266,733 | $ 266,733 | 0.0% | $ (604,592) | $ (604,592) | 0.0% | 172 |
| 173 | | | | | | | | | | | | | | | 173 |
| 174 | TOTAL | 64,276,047,409 | $ - | $ - | na | $ - | $ - | na | $ 40,327,382 | $ 40,327,382 | 0.0% | $ (8,250,887) | $ (8,250,887) | 0.0% | 174 |
| 175 | | | | $ - | | | $ - | | | $ - | | | $ - | | 175 |
| 176 | | | | | | | | | | | | | | | 176 |

# Nevada Power Company
## Statement O

### Summary of Proposed Rates – Bundled

| Line No. | Class | Note | Distribution Charges: Charge, per Cust | Distribution Charges: Meter Charge | Distribution Charges: Facilities Charge, per kW (1) | T and G Demand Charges, metered kW: Summer On Peak | Summer Mid Peak | Winter -OR - All Periods | BTGR Energy, per kWh (includes IRR): Critical Peak | Summer On Peak | Summer Mid Peak | Summer Off Peak | Winter -OR - All Periods | Summer EVRR | Winter EVRR | BTER Energy, per kWh | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | RS | | $ 12.50 | | | | | | | | | | $ 0.05995 | | | | 9 |
| 10 | RM | | 7.70 | | | | | | | | | | 0.05188 | | | | 10 |
| 11 | LRS | | 70.70 | | | | | | | | | | 0.05216 | | | | 11 |
| 12 | GS | | 25.50 | $ 2.50 | | | | | | | | | 0.01802 | | | | 12 |
| 13 | LGS-1 | | 15.80 | 6.25 | $ 3.68 | | | $ 4.01 | | | | | 0.01522 | | | | 13 |
| 14 | LGS-2S | | 122.40 | 9.75 | 2.68 | $ 12.81 | $ 2.65 | 0.60 | | $ 0.03242 | $ 0.01573 | $ 0.00053 | 0.00572 | | | | 14 |
| 15 | LGS-2P | | 207.70 | 65.00 | 2.34 | 10.59 | 2.47 | 0.60 | | 0.03817 | 0.01783 | 0.00107 | 0.00464 | | | | 15 |
| 16 | LGS-2T | | 182.00 | 23.00 | 0.61 | 11.46 | 2.67 | 0.75 | | 0.04425 | 0.00766 | 0.00001 | 0.00068 | | | | 16 |
| 17 | LGS-3S | | 122.00 | 3.00 | 2.82 | 12.44 | 3.00 | 0.80 | | 0.03591 | 0.01718 | 0.00130 | 0.00483 | | | | 17 |
| 18 | LGS-3P | | 214.10 | 76.25 | 2.73 | 13.61 | 3.36 | 0.85 | | 0.03856 | 0.01300 | 0.00116 | 0.00279 | | | | 18 |
| 19 | LGS-3T | | 182.00 | 23.00 | 0.61 | 11.46 | 2.67 | 0.75 | | 0.04425 | 0.00766 | 0.00001 | 0.00068 | | | | 19 |
| 20 | LGS-XS | | 4,743.00 | 20.52 | 0.91 | 12.44 | 3.00 | 0.80 | | 0.03591 | 0.01718 | 0.00130 | 0.00483 | | | | 20 |
| 21 | LGS-XP | | 4,743.00 | 86.85 | 1.83 | 13.61 | 3.36 | 0.85 | | 0.03856 | 0.01300 | 0.00116 | 0.00279 | | | | 21 |
| 22 | LGS-XT | | 4,743.00 | 139.05 | - | 11.46 | 2.67 | 0.75 | | 0.04425 | 0.00766 | 0.00001 | 0.00068 | | | | 22 |
| 23 | LGS-2S-WP | | 128.70 | 9.75 | 0.80 | 15.46 | 15.46 | 0.60 | | 0.00010 | 0.00010 | 0.00001 | 0.00002 | | | | 23 |
| 24 | LGS-2P-WP | | 208.60 | 65.00 | 1.17 | 13.06 | 13.06 | 0.60 | | 0.05587 | 0.09974 | 0.00104 | 0.00105 | | | | 24 |
| 25 | LGS-2T-WP | | 169.10 | - | 0.61 | 14.13 | 14.13 | 0.75 | | 0.05435 | 0.10098 | 0.00117 | 0.00117 | | | | 25 |
| 26 | LGS-3S-WP | | 149.90 | 3.00 | 0.45 | 15.44 | 15.44 | 0.80 | | 0.00010 | 0.00010 | 0.00001 | 0.00002 | | | | 26 |
| 27 | LGS-3P-WP | | 234.20 | 76.25 | 0.92 | 16.97 | 16.97 | 0.85 | | 0.03723 | 0.06984 | 0.00080 | 0.00081 | | | | 27 |
| 28 | LGS-3T-WP | | 189.10 | 23.00 | 0.61 | 17.42 | 17.42 | 0.85 | | 0.03822 | 0.07071 | 0.00089 | 0.00090 | | | | 28 |
| 29 | IAIWP | | | | | | | | | | | | | | | | 29 |
| 30 | | | | | | | | | | | | | | | | | 30 |
| 31 | ORS-TOU | | 12.50 | | | | | | | 0.30471 | | 0.01018 | 0.01631 | 0.00526 | 0.01078 | | 31 |
| 32 | ORS-TOU Opt A | | 12.50 | | | | | | | 0.26792 | | 0.00671 | 0.00601 | 0.00214 | 0.00151 | | 32 |
| 33 | ORS-TOU Opt B | | 26.90 | | | | | | | 0.40478 | | 0.00914 | 0.00469 | 0.00432 | 0.00032 | | 33 |
| 34 | ORS-TOU DDP | | 5.75 | | 0.16 | 0.16 | | 0.05 | | | | | 0.03642 | | | | 34 |
| 35 | ORS-TOU CPP | | 12.50 | | | | | | 0.62872 | 0.27394 | | 0.01391 | 0.00583 | 0.00882 | 0.00135 | | 35 |
| 36 | ORS-TOU CPP DDP | | 12.50 | | | 0.16 | | 0.05 | 0.62872 | 0.16594 | | 0.01251 | 0.01631 | 0.00736 | 0.01078 | | 36 |
| 37 | ORM-TOU | | 7.70 | | | | | | | 0.26153 | | 0.03523 | 0.01164 | 0.02781 | 0.00657 | | 37 |
| 38 | ORM-TOU Opt A | | 7.70 | | | | | | | 0.24630 | | 0.02469 | 0.00596 | 0.01832 | 0.00146 | | 38 |
| 39 | ORM-TOU Opt B | | 13.20 | | | | | | | 0.24820 | | 0.05629 | 0.01616 | 0.04676 | 0.01064 | | 39 |
| 40 | ORM-TOU DDP | | 5.25 | | 0.07 | 0.07 | | 0.05 | | | | | 0.03673 | | | | 40 |
| 41 | ORM-TOU CPP | | 7.70 | | | | | | 0.41715 | 0.23578 | | 0.02964 | 0.01504 | 0.02277 | 0.00963 | | 41 |
| 42 | ORM-TOU CPP DDP | | 7.70 | | | 0.07 | | 0.05 | 0.41715 | 0.21104 | | 0.02964 | 0.00593 | 0.02277 | 0.00144 | | 42 |
| 43 | OLRS-TOU | | 70.70 | | | | | | | 0.30090 | | 0.01793 | 0.01592 | 0.01224 | 0.01034 | | 43 |
| 44 | OLRS-TOU Opt A | | 70.70 | | | | | | | 0.27813 | | 0.00888 | 0.00866 | 0.00391 | 0.00389 | | 44 |
| 45 | OLRS-TOU Opt B | | 161.10 | | | | | | | 0.23279 | | 0.03210 | 0.00788 | 0.02499 | 0.00317 | | 45 |
| 46 | OLRS-TOU DDP | | 13.00 | | 0.18 | 0.23 | | 0.05 | | | | | 0.03668 | | | | 46 |
| 47 | OLRS-TOU CPP | | 70.70 | | | | | | 0.33084 | 0.27169 | | 0.01498 | 0.02229 | 0.00956 | 0.01616 | | 47 |
| 48 | OLRS-TOU CPP DDP | | 70.70 | | | 0.23 | | 0.05 | 0.33084 | 0.22227 | | 0.01498 | 0.01893 | 0.00956 | 0.01314 | | 48 |
| 49 | OGS-TOU | | 25.50 | 2.50 | | | | | | 0.06215 | | 0.01391 | 0.01260 | 0.00854 | 0.00736 | | 49 |
| 50 | OLGS-1-TOU | | 15.80 | 6.25 | 3.68 | 7.60 | <- Summer Winter-> | 0.26 | | 0.10994 | | 0.00680 | 0.00578 | 0.00214 | 0.00122 | | 50 |
| 51 | OLGS-3P-HLF | | 214.10 | 76.25 | 1.06 | 20.79 | 5.83 | 0.90 | | 0.01088 | 0.00096 | 0.00043 | 0.00044 | | | | 51 |
| 52 | | | | | | | | | | | | | | | | | 52 |
| 58 | Incremental EVCCR | | | | | EVCCR Demand Reduction Rates | | | | EVCCR Transition kWh Adder Rates | | | | EVCCR Credits | | | 58 |
| 59 | OLGS-1 EVCCR | | | | | (6.84) | | (0.23) | | 0.05131 | | | 0.00078 | (0.00419) | (0.00410) | | 59 |
| 60 | LGS-2S EVCCR | | | | | (11.53) | (2.38) | (0.54) | | 0.08897 | 0.01964 | - | 0.00131 | (0.00005) | (0.00057) | | 60 |
| 61 | LGS-2P EVCCR | | | | | (9.53) | (2.22) | (0.54) | | 0.07034 | 0.01685 | - | 0.00115 | (0.00011) | (0.00046) | | 61 |
| 62 | LGS-2T EVCCR | | | | | (10.31) | (2.40) | (0.67) | | 0.03983 | 0.00689 | - | 0.00059 | - | (0.00007) | | 62 |
| 63 | LGS-3S EVCCR | | | | | (11.20) | (2.70) | (0.72) | | 0.08265 | 0.02057 | - | 0.00148 | (0.00013) | (0.00048) | | 63 |
| 64 | LGS-3P EVCCR | | | | | (12.25) | (3.02) | (0.76) | | 0.08923 | 0.02317 | - | 0.00157 | (0.00012) | (0.00028) | | 64 |
| 65 | LGS-3T EVCCR | | | | | (10.31) | (2.40) | (0.67) | | 0.06470 | 0.01554 | - | 0.00122 | - | (0.00007) | | 65 |
| 66 | | | | | | | | | | | | | | | | | 66 |
| 67 | | | | | | | | | | | | | | | | | 67 |

68 Additional Charges:

| | | | | |
|---|---|---|---|---|
| 69 | Separate Billing | | | |
| 70 | LGS-X & LGS-WP-X: | $ 93.50 | Per additional bill | |
| 71 | DOS LGS-X & LGS-WP-X: | $ 93.50 | Per additional bill | |
| 72 | Power Factor Charges ($/kVarh): | | | |
| 73 | Summer: | $ 0.00200 | $/kVarh | |
| 74 | Winter: | $ 0.00100 | $/kVarh | |

| Customer Specific Facilities Charges | Charge per $ of: Utility | Customer Contributed |
|---|---|---|
| Transmission non-X customers | $ 0.00313 | $ 0.00057 |
| DOS Transmission non-X customers | $ 0.00313 | $ 0.00057 |
| OLGS-3P HLF customers | $ 0.00313 | $ 0.00057 |

75 Notes:

76 (1) The facilities charge is per kWh for Residential and GS, per metered demand for LGS-1 and per the highest measured demand for the billing period and the prior twelve billing periods for all other. For non-transmission level customers, and non-X customers, the facilities charge
77 recovers both the Rule 9 and primary distribution facility costs. For LGSX customers the per kW facility charge recovers only the primary distribution costs, with other facilities recovered in a customer specific facility charge (CSFC).

78 (2) The non-LGS-X transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M
79 recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facility calculations be incomplete at the start
80 of service. The $/kW charge for transmission level classes is a placeholder until a CSFC is implemented. All new, permanent customers served under these tariffs will be placed on a CSF charge as soon as reasonably practical.

81 (3) The per kW facility charge applies only to the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the customer
82 facilities identified to serve them. See page 22 in Statement O for the CSFCs by LGS-X customer.

Summary of Proposed Rates – Bundled (continued)

| Line No. | Class | BTGR & BTER Energy, per kWh (the BTGR includes IRR Subsidy) | | | | | | | Additional Charges on per kWH Basis | | | | Total Energy, per kWh (BTGR & BTER + EE + DEAA) | | | | | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Critical Peak | On Peak | Mid Peak | Off Peak | Winter -OR- All Periods | Summer EVRR | Winter EVRR | REPR | TRED | DEAA | EE | Critical Peak | On Peak | Mid Peak | Off Peak | Winter -OR- All Periods | Summer EVRR | Winter EVRR | |
| 8 | | | | | | | | | | | | | | | | | | | | 8 |
| 9 | RS | | | | | $ 0.05995 | | | $ (0.00039) | $ 0.00070 | | $ 0.00256 | | | | | $ 0.06282 | | | 9 |
| 10 | RM | | | | | 0.05186 | | | (0.00039) | 0.00070 | | 0.00224 | | | | | 0.05441 | | | 10 |
| 11 | LRS | | | | | 0.05216 | | | (0.00039) | 0.00070 | | 0.00220 | | | | | 0.05467 | | | 11 |
| 12 | GS | | | | | 0.01802 | | | (0.00039) | 0.00068 | | 0.00170 | | | | | 0.02001 | | | 12 |
| 13 | LGS-1 | | | | | 0.01522 | | | (0.00039) | 0.00068 | | 0.00171 | | | | | 0.01722 | | | 13 |
| 14 | LGS-2S | | $ 0.03242 | $ 0.01573 | $ 0.00053 | 0.00572 | | | (0.00039) | 0.00068 | | 0.00145 | | $ 0.03416 | $ 0.01747 | $ 0.00227 | 0.00746 | | | 14 |
| 15 | LGS-2P | | 0.03817 | 0.01763 | 0.00107 | 0.00464 | | | (0.00039) | 0.00068 | | 0.00134 | | 0.03980 | 0.01926 | 0.00270 | 0.00627 | | | 15 |
| 16 | LGS-2T | | 0.04425 | 0.00766 | 0.00001 | 0.00066 | | | (0.00039) | 0.00068 | | 0.00131 | | 0.04585 | 0.00926 | 0.00161 | 0.00226 | | | 16 |
| 17 | LGS-3S | | 0.03591 | 0.01718 | 0.00130 | 0.00483 | | | (0.00039) | 0.00068 | | 0.00172 | | 0.03792 | 0.01919 | 0.00331 | 0.00684 | | | 17 |
| 18 | LGS-3P | | 0.03856 | 0.01300 | 0.00116 | 0.00279 | | | (0.00039) | 0.00068 | | 0.00161 | | 0.04046 | 0.01490 | 0.00306 | 0.00469 | | | 18 |
| 19 | LGS-3T | | 0.04425 | 0.00766 | 0.00001 | 0.00066 | | | (0.00039) | 0.00068 | | 0.00179 | | 0.04633 | 0.00974 | 0.00209 | 0.00274 | | | 19 |
| 20 | LGS-XS | | 0.03591 | 0.01718 | 0.00130 | 0.00483 | | | (0.00039) | 0.00068 | | 0.00192 | | 0.03812 | 0.01939 | 0.00351 | 0.00704 | | | 20 |
| 21 | LGS-XP | | 0.03856 | 0.01300 | 0.00116 | 0.00279 | | | (0.00039) | 0.00068 | | 0.00178 | | 0.04063 | 0.01507 | 0.00323 | 0.00486 | | | 21 |
| 22 | LGS-XT | | 0.04425 | 0.00766 | 0.00001 | 0.00066 | | | (0.00039) | 0.00068 | | 0.00205 | | 0.04659 | 0.01000 | 0.00235 | 0.00300 | | | 22 |
| 23 | LGS-2S-WP | | 0.00010 | 0.00010 | 0.00001 | 0.00002 | | | (0.00039) | 0.00068 | | 0.00065 | | 0.00104 | 0.00104 | 0.00095 | 0.00096 | | | 23 |
| 24 | LGS-2P-WP | | 0.05587 | 0.09974 | 0.00104 | 0.00105 | | | (0.00039) | 0.00068 | | 0.00109 | | 0.05725 | 0.10112 | 0.00242 | 0.00243 | | | 24 |
| 25 | LGS-2T-WP | | 0.05435 | 0.10098 | 0.00117 | 0.00117 | | | (0.00039) | 0.00068 | | 0.00109 | | 0.05573 | 0.10236 | 0.00255 | 0.00255 | | | 25 |
| 26 | LGS-3S-WP | | 0.00010 | 0.00010 | 0.00001 | 0.00002 | | | (0.00039) | 0.00068 | | 0.00087 | | 0.00126 | 0.00126 | 0.00117 | 0.00118 | | | 26 |
| 27 | LGS-3P-WP | | 0.03723 | 0.06984 | 0.00080 | 0.00081 | | | (0.00039) | 0.00068 | | 0.00096 | | 0.03848 | 0.07109 | 0.00205 | 0.00206 | | | 27 |
| 28 | LGS-3T-WP | | 0.03622 | 0.07071 | 0.00089 | 0.00090 | | | (0.00039) | 0.00068 | | 0.00096 | | 0.03747 | 0.07196 | 0.00214 | 0.00215 | | | 28 |
| 29 | IAIWP | | | | | - | | | - | - | | | | | | | - | | | 29 |
| 30 | | | | | | | | | | | | | | | | | | | | 30 |
| 31 | ORS-TOU | | 0.30471 | | 0.01018 | 0.01631 | $ 0.00526 | $ 0.01078 | (0.00039) | 0.00070 | | 0.00256 | | 0.30758 | | 0.01305 | 0.01918 | $ 0.00813 | $ 0.01365 | 31 |
| 32 | ORS-TOU Opt A | | 0.26792 | | 0.00671 | 0.00601 | 0.00214 | 0.00151 | (0.00039) | 0.00070 | | 0.00256 | | 0.27079 | | 0.00958 | 0.00888 | 0.00501 | 0.00438 | 32 |
| 33 | ORS-TOU Opt B | | 0.40478 | | 0.00914 | 0.00469 | 0.00432 | 0.00032 | (0.00039) | 0.00070 | | 0.00256 | | 0.40765 | | 0.01201 | 0.00756 | 0.00719 | 0.00319 | 33 |
| 34 | ORS-TOU DDP | | | | | 0.03642 | | | (0.00039) | 0.00070 | | 0.00256 | | | | | 0.03929 | | | 34 |
| 35 | ORS-TOU CPP | 0.63007 | 0.27394 | | 0.01391 | 0.00583 | 0.00862 | 0.00135 | (0.00039) | 0.00070 | | 0.00256 | 0.63294 | 0.27681 | | 0.01678 | 0.00870 | 0.01149 | 0.00422 | 35 |
| 36 | ORS-TOU CPP DDP | 0.63950 | 0.16594 | | 0.01251 | 0.01631 | 0.00736 | 0.01078 | (0.00039) | 0.00070 | | 0.00256 | 0.64237 | 0.16881 | | 0.01538 | 0.01918 | 0.01023 | 0.01365 | 36 |
| 37 | ORM-TOU | | 0.26153 | | 0.03523 | 0.01164 | 0.02781 | 0.00657 | (0.00039) | 0.00070 | | 0.00224 | | 0.26408 | | 0.03778 | 0.01419 | 0.03036 | 0.00912 | 37 |
| 38 | ORM-TOU Opt A | | 0.24830 | | 0.02469 | 0.00596 | 0.01832 | 0.00146 | (0.00039) | 0.00070 | | 0.00224 | | 0.25085 | | 0.02724 | 0.00851 | 0.02087 | 0.00401 | 38 |
| 39 | ORM-TOU Opt B | | 0.24920 | | 0.05629 | 0.01616 | 0.04676 | 0.01064 | (0.00039) | 0.00070 | | 0.00224 | | 0.25175 | | 0.05884 | 0.01871 | 0.04931 | 0.01319 | 39 |
| 40 | ORM-TOU DDP | | | | | 0.03673 | | | (0.00039) | 0.00070 | | 0.00224 | | | | | 0.03928 | | | 40 |
| 41 | ORM-TOU CPP | 0.42678 | 0.23578 | | 0.02964 | 0.01504 | 0.02277 | 0.00963 | (0.00039) | 0.00070 | | 0.00224 | 0.42933 | 0.23833 | | 0.03219 | 0.01759 | 0.02532 | 0.01218 | 41 |
| 42 | ORM-TOU CPP DDP | 0.41859 | 0.21104 | | 0.02964 | 0.00593 | 0.02277 | 0.00144 | (0.00039) | 0.00070 | | 0.00224 | 0.42114 | 0.21359 | | 0.03219 | 0.00848 | 0.02532 | 0.00399 | 42 |
| 43 | OLRS-TOU | | 0.30090 | | 0.01793 | 0.01582 | 0.01224 | 0.01034 | (0.00039) | 0.00070 | | 0.00220 | | 0.30341 | | 0.02044 | 0.01833 | 0.01475 | 0.01285 | 43 |
| 44 | OLRS-TOU Opt A | | 0.27813 | | 0.00868 | 0.00866 | 0.00391 | 0.00389 | (0.00039) | 0.00070 | | 0.00220 | | 0.28064 | | 0.01119 | 0.01117 | 0.00642 | 0.00640 | 44 |
| 45 | OLRS-TOU Opt B | | 0.23279 | | 0.03210 | 0.00786 | 0.02499 | 0.00317 | (0.00039) | 0.00070 | | 0.00220 | | 0.23530 | | 0.03461 | 0.01037 | 0.02750 | 0.00568 | 45 |
| 46 | OLRS-TOU DDP | | | | | 0.03668 | | | (0.00039) | 0.00070 | | 0.00220 | | | | | 0.03919 | | | 46 |
| 47 | OLRS-TOU CPP | 0.34680 | 0.27169 | | 0.01496 | 0.02229 | 0.00956 | 0.01616 | (0.00039) | 0.00070 | | 0.00220 | 0.34931 | 0.27420 | | 0.01747 | 0.02480 | 0.01207 | 0.01867 | 47 |
| 48 | OLRS-TOU CPP DDP | 0.34378 | 0.22227 | | 0.01496 | 0.01893 | 0.00956 | 0.01314 | (0.00039) | 0.00070 | | 0.00220 | 0.34629 | 0.22478 | | 0.01747 | 0.02144 | 0.01207 | 0.01565 | 48 |
| 49 | OGS-TOU | | 0.06215 | | 0.01391 | 0.01260 | 0.00854 | 0.00736 | (0.00039) | 0.00068 | | 0.00170 | | 0.06414 | | 0.01590 | 0.01459 | 0.01053 | 0.00935 | 49 |
| 50 | OLGS-1-TOU | | 0.10994 | | 0.00680 | 0.00578 | 0.00214 | 0.00122 | (0.00039) | 0.00068 | | 0.00171 | | 0.11194 | | 0.00880 | 0.00778 | 0.00414 | 0.00322 | 50 |
| 51 | OLGS-3P-HLF | | 0.01088 | 0.00096 | 0.00043 | 0.00044 | | | (0.00039) | 0.00068 | | 0.00161 | | 0.01278 | | 0.00233 | 0.00234 | 0.00190 | 0.00190 | 51 |
| 52 | | | | | | | | | | | | | | | | | | | | 52 |

53 (1) The bundled proposed rates for Streetlights and PAL are shown on pages 14-16 of Statement O.

**Proposed Street Lighting (SL) Rate Summary**

| Line No. | Lamp Type | Size & Pole Type | Watts | Class | Note | Monthly kWh | BTGR | BTER | Proposed BTGR & BTER Rate | DEAA Rate | TRED Rate | EE Rate | REPR Rate | UEC Rate | Total All Components Rate | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | | | | | | | | | | | | | | | 9 |
| 10 | | | | | | | | | | [redacted] | $ 0.00068 | $ 0.00039 | $ (0.00039) | $ 0.00039 | | 10 |
| 11 | | | | | | | | | | | | | | | | 11 |
| 12 | Street Lights - Non-metered | | | | | | | | | | | | | | | 12 |
| 13 | Mercury Vapor | Non-Metered | 100W | CLS 20 | | 73 | $ 1.16 | [redacted] | $ 1.16 | $ - | $ 0.05 | $ 0.03 | $ (0.03) | — | $ 1.21 | 13 |
| 14 | Mercury Vapor | Non-Metered | 100W | CLS 20 | | 73 | 1.16 | | 1.16 | - | 0.05 | 0.03 | (0.03) | — | 1.21 | 14 |
| 15 | Mercury Vapor | Non-Metered | 200W | CLS 21 | | 103 | 1.38 | | 1.38 | - | 0.07 | 0.04 | (0.04) | — | 1.45 | 15 |
| 16 | Mercury Vapor | Non-Metered | 200W | CLS 21 | | 103 | 1.38 | | 1.38 | - | 0.07 | 0.04 | (0.04) | — | 1.45 | 16 |
| 17 | Mercury Vapor | Non-Metered | 200W | CLS 22 | | 165 | 1.80 | | 1.80 | - | 0.11 | 0.06 | (0.06) | — | 1.91 | 17 |
| 18 | Mercury Vapor | Non-Metered | 200W | CLS 22 | | 165 | 1.80 | | 1.80 | - | 0.11 | 0.06 | (0.06) | — | 1.91 | 18 |
| 19 | High Pressure | Non-Metered | 200W | CLS 24 | | 83 | 0.81 | | 0.81 | - | 0.06 | 0.03 | (0.03) | — | 0.87 | 19 |
| 20 | High Pressure | Non-Metered | 200W | CLS 24 | | 83 | 1.23 | | 1.23 | - | 0.06 | 0.03 | (0.03) | — | 1.29 | 20 |
| 21 | Municipal Street Lights - Public | | | | | | | | | | | | | | | 21 |
| 22 | Incandescent | n/a | 100W | CLS 30 | | 73 | 8.95 | | 8.95 | - | 0.05 | 0.03 | (0.03) | — | 9.00 | 22 |
| 23 | Incandescent | n/a | 200W | CLS 31 | | 120 | 8.55 | | 8.55 | - | 0.08 | 0.05 | (0.05) | — | 8.63 | 23 |
| 24 | Incandescent | n/a | 200W | CLS 32 | | 167 | 8.06 | | 8.06 | - | 0.11 | 0.07 | (0.07) | — | 8.17 | 24 |
| 25 | Mercury Vapor | Wood Pole | 200W | CLS 33 | | 73 | 8.90 | | 8.90 | - | 0.05 | 0.03 | (0.03) | — | 8.95 | 25 |
| 26 | Mercury Vapor | Wood Pole | 200W | CLS 34 | | 103 | 8.73 | | 8.73 | - | 0.07 | 0.04 | (0.04) | — | 8.80 | 26 |
| 27 | Mercury Vapor | Wood Pole | 200W | CLS 35 | | 165 | 8.09 | | 8.09 | - | 0.11 | 0.06 | (0.06) | — | 8.20 | 27 |
| 28 | Mercury Vapor | Steel Pole | 200W | CLS 43 | | 73 | 8.90 | | 8.90 | - | 0.05 | 0.03 | (0.03) | — | 8.95 | 28 |
| 29 | Mercury Vapor | Steel Pole | 200W | CLS 44 | | 103 | 8.73 | | 8.73 | - | 0.07 | 0.04 | (0.04) | — | 8.80 | 29 |
| 30 | Mercury Vapor | Steel Pole | 200W | CLS 45 | | 165 | 8.09 | | 8.09 | - | 0.11 | 0.06 | (0.06) | — | 8.20 | 30 |
| 31 | Sodium Vapor | n/a | 100W | CLS 89 | | 42 | 9.22 | | 9.22 | - | 0.03 | 0.02 | (0.02) | — | 9.25 | 31 |
| 32 | Sodium Vapor | n/a | 200W | CLS 90 | | 83 | 8.92 | | 8.92 | - | 0.06 | 0.03 | (0.03) | — | 8.98 | 32 |
| 33 | Municipal Street Lights - Customer Owned | | | | | | | | | | | | | | | 33 |
| 34 | Incandescent | n/a | 200W | CLS 51 | | 120 | 1.10 | | 1.10 | - | 0.08 | 0.05 | (0.05) | 0.05 | 1.23 | 34 |
| 35 | Mercury Vapor | n/a | 200W | CLS 53 | | 73 | 1.54 | | 1.54 | - | 0.05 | 0.03 | (0.03) | 0.03 | 1.62 | 35 |
| 36 | Mercury Vapor | n/a | 200W | CLS 54 | | 103 | 1.24 | | 1.24 | - | 0.07 | 0.04 | (0.04) | 0.04 | 1.35 | 36 |
| 37 | Mercury Vapor | n/a | 200W | CLS 55 | | 165 | 0.60 | | 0.60 | - | 0.11 | 0.06 | (0.06) | 0.06 | 0.77 | 37 |
| 38 | Street Lights - LED | | | | | | | | | | | | | | | 38 |
| 39 | LED | Non-Metered | 100W | CLS 20 | | 70 | 0.10 | | 0.10 | - | 0.05 | 0.03 | (0.03) | — | 0.15 | 39 |
| 40 | LED | Non-Metered | 200W | CLS 21 | | 35 | 0.10 | | 0.10 | - | 0.02 | 0.01 | (0.01) | — | 0.12 | 40 |
| 41 | LED | Non-Metered | 200W | CLS 22 | | 70 | 0.12 | | 0.12 | - | 0.05 | 0.03 | (0.03) | — | 0.17 | 41 |
| 42 | LED | Non-Metered | 200W | CLS 24 | | 70 | 0.12 | | 0.12 | - | 0.05 | 0.03 | (0.03) | — | 0.17 | 42 |
| 43 | Municipal Street Lights - LED | | | | | | | | | | | | | | | 43 |
| 44 | LED | n/a | 100W | CLS 30 | | 35 | 8.91 | | 8.91 | - | 0.02 | 0.01 | (0.01) | — | 8.93 | 44 |
| 45 | LED | n/a | 200W | CLS 31 | | 70 | 8.48 | | 8.48 | - | 0.05 | 0.03 | (0.03) | — | 8.53 | 45 |
| 46 | LED | n/a | 200W | CLS 32 | | 70 | 7.96 | | 7.96 | - | 0.05 | 0.03 | (0.03) | — | 8.01 | 46 |
| 47 | LED | Wood Pole | 200W | CLS 33 | | 70 | 8.86 | | 8.86 | - | 0.05 | 0.03 | (0.03) | — | 8.91 | 47 |
| 48 | LED | Wood Pole | 200W | CLS 34 | | 70 | 8.67 | | 8.67 | - | 0.05 | 0.03 | (0.03) | — | 8.72 | 48 |
| 49 | | | | | | | | | | | | | | | | 49 |
| 50 | Metered | Metered | Metered | Metered | | Mtrd | 0.00879 | - | 0.00879 | - | 0.00068 | 0.00039 | (0.00039) | 0.00039 | 0.00986 | 50 |
| 51 | | | | | | | | | | | | | | | | 51 |
| 52 | Note: Municipal and Public Street Lights do not pay UEC charges. | | | | | | | | | | | | | | | 52 |

**Proposed Residential Private Area Lighting (RS-PAL) Rate Summary**

| Line No. | Lamp Type | Size & Pole Type | Watts | Class | Note | Monthly kWh | BTGR | BTER | Proposed BTGR & BTER Rate | DEAA Rate | TRED Rate | EE Rate | REPR Rate | UEC Rate | Total All Components Rate | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | | | | | | | | | | | | | | | 9 |
| 10 | | | | | | | | | | [redacted] | $ 0.00070 | $ 0.00087 | $ (0.00039) | $ 0.00039 | | 10 |
| 11 | | | | | | | | | | | | | | | | 11 |
| 12 | RS-PAL | | | | | | | | | | | | | | | 12 |
| 13 | Mercury Vapor | RATE A (Existing pole) | 200W | CLS 10 | | 73 | $ 4.86 | [redacted] | $ 4.86 | $ - | $ 0.05 | $ 0.06 | $ (0.03) | 0.03 | $ 4.97 | 13 |
| 14 | Mercury Vapor | RATE A (Existing pole) | 200W | CLS 10 | | 73 | 4.86 | | 4.86 | - | 0.05 | 0.06 | (0.03) | 0.03 | 4.97 | 14 |
| 15 | Mercury Vapor | RATE A (Existing pole) | 200W | CLS 12 | | 165 | 4.61 | | 4.61 | - | 0.12 | 0.14 | (0.06) | 0.06 | 4.87 | 15 |
| 16 | High Pressure | RATE A (Existing pole) | 100W | CLS 14 | | 42 | 4.98 | | 4.98 | - | 0.03 | 0.04 | (0.02) | 0.02 | 5.05 | 16 |
| 17 | High Pressure | RATE A (Existing pole) | 100W | CLS 14 | | 42 | 4.98 | | 4.98 | - | 0.03 | 0.04 | (0.02) | 0.02 | 5.05 | 17 |
| 18 | High Pressure | RATE A (Existing pole) | 200W | CLS 15 | | 83 | 4.94 | | 4.94 | - | 0.06 | 0.07 | (0.03) | 0.03 | 5.07 | 18 |
| 19 | High Pressure | RATE A (Existing pole) | 200W | CLS 15 | | 83 | 4.94 | | 4.94 | - | 0.06 | 0.07 | (0.03) | 0.03 | 5.07 | 19 |
| 20 | High Pressure | RATE A (Existing pole) | 200W | CLS 12 | | 165 | 4.31 | | 4.31 | - | 0.12 | 0.14 | (0.06) | 0.06 | 4.57 | 20 |
| 21 | Mercury Vapor | RATE B (30 Foot pole) | 200W | CLS 11 | | 73 | 12.00 | | 12.00 | - | 0.05 | 0.06 | (0.03) | 0.03 | 12.11 | 21 |
| 22 | Mercury Vapor | RATE B (30 Foot pole) | 200W | CLS 11 | | 73 | 12.00 | | 12.00 | - | 0.05 | 0.06 | (0.03) | 0.03 | 12.11 | 22 |
| 23 | Mercury Vapor | RATE B (30 Foot pole) | 200W | CLS 13 | | 165 | 11.75 | | 11.75 | - | 0.12 | 0.14 | (0.06) | 0.06 | 12.01 | 23 |
| 24 | High Pressure | RATE B (30 Foot pole) | 100W | CLS 16 | | 42 | 12.12 | | 12.12 | - | 0.03 | 0.04 | (0.02) | 0.02 | 12.19 | 24 |
| 25 | High Pressure | RATE B (30 Foot pole) | 200W | CLS 15 | | 83 | 12.08 | | 12.08 | - | 0.06 | 0.07 | (0.03) | 0.03 | 12.21 | 25 |
| 26 | LED | RATE A (Existing pole) | 200W | CLS 10 | | 70 | 4.77 | | 4.77 | - | 0.05 | 0.06 | (0.03) | 0.03 | 4.88 | 26 |
| 27 | LED | RATE A (Existing pole) | 200W | CLS 12 | | 70 | 2.97 | | 2.97 | - | 0.05 | 0.06 | (0.03) | 0.03 | 3.08 | 27 |
| 28 | LED | RATE A (Existing pole) | 100W | CLS 14 | | 35 | 4.70 | | 4.70 | - | 0.02 | 0.03 | (0.01) | 0.01 | 4.75 | 28 |
| 29 | LED | RATE A (Existing pole) | 200W | CLS 15 | | 70 | 4.60 | | 4.60 | - | 0.05 | 0.06 | (0.03) | 0.03 | 4.71 | 29 |
| 30 | LED | RATE B (30 Foot pole) | 200W | CLS 11 | | 70 | 11.92 | | 11.92 | - | 0.05 | 0.06 | (0.03) | 0.03 | 12.03 | 30 |
| 31 | LED | RATE B (30 Foot pole) | 200W | CLS 13 | | 70 | 9.70 | | 9.70 | - | 0.05 | 0.06 | (0.03) | 0.03 | 9.81 | 31 |
| 32 | LED | RATE B (30 Foot pole) | 100W | CLS 16 | | 35 | 11.91 | | 11.91 | - | 0.02 | 0.03 | (0.01) | 0.01 | 11.96 | 32 |
| 33 | | | | | | | | | | | | | | | | 33 |
| 34 | | | | | | | | | | | | | | | | 34 |

**Proposed General Service Private Area Lighting (GS-PAL) Rate Summary**

| Line No. | Lamp Type | Size & Pole Type | Watts | Class | Note | Monthly kWh | BTGR | BTER | Proposed BTGR & BTER Rate | DEAA Rate | TRED Rate | EE Rate | REPR Rate | UEC Rate | Total All Components Rate | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | | | | | | | | | | | | | | | 9 |
| 10 | | | | | | | | | | [redacted] | $ 0.00068 | $ 0.00086 | $ (0.00039) | $ 0.00039 | | 10 |
| 11 | | | | | | | | | | | | | | | | 11 |
| 12 | GS-PAL | | | | | | | | | | | | | | | 12 |
| 13 | Mercury Vapor | RATE A (Existing pole) | 200W | CLS 10 | | 73 | $ 4.87 | [redacted] | $ 4.87 | $ - | $ 0.05 | $ 0.06 | $ (0.03) | 0.03 | $ 4.98 | 13 |
| 14 | Mercury Vapor | RATE A (Existing pole) | 200W | CLS 10 | | 73 | 4.87 | | 4.87 | - | 0.05 | 0.06 | (0.03) | 0.03 | 4.98 | 14 |
| 15 | Mercury Vapor | RATE A (Existing pole) | 200W | CLS 12 | | 165 | 4.63 | | 4.63 | - | 0.11 | 0.14 | (0.06) | 0.06 | 4.88 | 15 |
| 16 | Mercury Vapor | RATE A (Existing pole) | 200W | CLS 12 | | 165 | 4.63 | | 4.63 | - | 0.11 | 0.14 | (0.06) | 0.06 | 4.88 | 16 |
| 17 | High Pressure | RATE A (Existing pole) | 100W | CLS 14 | | 42 | 4.98 | | 4.98 | - | 0.03 | 0.04 | (0.02) | 0.02 | 5.05 | 17 |
| 18 | High Pressure | RATE A (Existing pole) | 100W | CLS 14 | | 42 | 4.98 | | 4.98 | - | 0.03 | 0.04 | (0.02) | 0.02 | 5.05 | 18 |
| 19 | High Pressure | RATE A (Existing pole) | 200W | CLS 15 | | 83 | 4.94 | | 4.94 | - | 0.06 | 0.07 | (0.03) | 0.03 | 5.07 | 19 |
| 20 | High Pressure | RATE A (Existing pole) | 200W | CLS 15 | | 83 | 4.94 | | 4.94 | - | 0.06 | 0.07 | (0.03) | 0.03 | 5.07 | 20 |
| 21 | High Pressure | RATE A (Existing pole) | 200W | CLS 88 | | 165 | 4.62 | | 4.62 | - | 0.11 | 0.14 | (0.06) | 0.06 | 4.87 | 21 |
| 22 | Mercury Vapor | RATE B (30 Foot pole) | 200W | CLS 11 | | 73 | 12.02 | | 12.02 | - | 0.05 | 0.06 | (0.03) | 0.03 | 12.13 | 22 |
| 23 | Mercury Vapor | RATE B (30 Foot pole) | 200W | CLS 13 | | 165 | 11.77 | | 11.77 | - | 0.11 | 0.14 | (0.06) | 0.06 | 12.02 | 23 |
| 24 | Mercury Vapor | RATE B (30 Foot pole) | 200W | CLS 13 | | 165 | 11.77 | | 11.77 | - | 0.11 | 0.14 | (0.06) | 0.06 | 12.02 | 24 |
| 25 | High Pressure | RATE B (30 Foot pole) | 100W | CLS 16 | | 42 | 12.13 | | 12.13 | - | 0.03 | 0.04 | (0.02) | 0.02 | 12.20 | 25 |
| 26 | High Pressure | RATE B (30 Foot pole) | 200W | CLS 17 | | 83 | 12.09 | | 12.09 | - | 0.06 | 0.07 | (0.03) | 0.03 | 12.22 | 26 |
| 27 | High Pressure | RATE B (30 Foot pole) | 200W | CLS 17 | | 83 | 12.09 | | 12.09 | - | 0.06 | 0.07 | (0.03) | 0.03 | 12.22 | 27 |
| 28 | LED | RATE A (Existing pole) | 200W | CLS 10 | | 70 | 4.79 | | 4.79 | - | 0.05 | 0.06 | (0.03) | 0.03 | 4.90 | 28 |
| 29 | LED | RATE A (Existing pole) | 200W | CLS 12 | | 70 | 3.01 | | 3.01 | - | 0.05 | 0.06 | (0.03) | 0.03 | 3.12 | 29 |
| 30 | LED | RATE A (Existing pole) | 100W | CLS 14 | | 35 | 4.71 | | 4.71 | - | 0.02 | 0.03 | (0.01) | 0.01 | 4.76 | 30 |
| 31 | LED | RATE A (Existing pole) | 200W | CLS 15 | | 70 | 4.61 | | 4.61 | - | 0.05 | 0.06 | (0.03) | 0.03 | 4.72 | 31 |
| 32 | LED | RATE A (Existing pole) | 200W | CLS 88 | | 70 | 3.00 | | 3.00 | - | 0.05 | 0.06 | (0.03) | 0.03 | 3.11 | 32 |
| 33 | LED | RATE B (30 Foot pole) | 200W | CLS 11 | | 70 | 11.95 | | 11.95 | - | 0.05 | 0.06 | (0.03) | 0.03 | 12.06 | 33 |
| 34 | LED | RATE B (30 Foot pole) | 200W | CLS 13 | | 70 | 9.76 | | 9.76 | - | 0.05 | 0.06 | (0.03) | 0.03 | 9.87 | 34 |
| 35 | LED | RATE B (30 Foot pole) | 100W | CLS 16 | | 35 | 11.93 | | 11.93 | - | 0.02 | 0.03 | (0.01) | 0.01 | 11.98 | 35 |
| 36 | LED | RATE B (30 Foot pole) | 200W | CLS 17 | | 70 | 11.77 | | 11.77 | - | 0.05 | 0.06 | (0.03) | 0.03 | 11.88 | 36 |
| 37 | | | | | | | | | | | | | | | | 37 |
| 38 | | | | | | | | | | | | | | | | 38 |

Proposed Standby Rates

| Line No. | Class | | Distribution Charges: Distribution Charge, per Cust | Additional Meter/ Generation Meter Charge[8] | Facilities Charge, per customer for SS-I and II, per kW for LSR and SSR-III[3] | Facilities Charge, per kW[2,3] | Contract Demand Charges, contract kW[4]: Sum On Peak: | Sum Mid Peak: | Other: | Backup Service Variable T&G Demand Charges, metered kW: Sum On Peak: | Sum Mid Peak: | Other: | BTGR Energy, per kWh (including interclass rate rebalancing)[5,6]: Sum On Peak: | Sum Mid Peak: | Sum Off Peak: | Other: | Maintenance Back-up Service[7]: Set @ 50% of Summer On-peak Variable T&G Demand Charges | BTER Energy, per kWh | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | SSR II | SS-II GS | 25.50 | 2.50 | 4.74 | | | | | | | | | | | 0.01072 | | | 9 |
| 10 | SSR III | LGS-1 | 15.80 | 6.25 | 3.68 | $ 3.68 | | | $ 1.00 | | | $ 3.01 | | | | 0.01522 | $ 1.51 | | 10 |
| 11 | LSR I | LGS-2S | 122.40 | 9.75 | 2.68 | 2.68 | $ 3.20 | $ 0.66 | 0.15 | $ 9.61 | $ 1.99 | 0.45 | $ 0.03242 | $ 0.01573 | $ 0.00053 | 0.00572 | 4.81 | | 11 |
| 12 | LSR I | LGS-2P | 207.70 | 65.00 | 2.34 | 2.34 | 2.65 | 0.62 | 0.15 | 7.94 | 1.85 | 0.45 | 0.03817 | 0.01763 | 0.00107 | 0.00464 | 3.97 | | 12 |
| 13 | LSR I | LGS-2T | 182.00 | 23.00 | CSF | 0.61 | 2.87 | 0.67 | 0.19 | 8.59 | 2.00 | 0.56 | 0.04425 | 0.00766 | 0.00001 | 0.00066 | 4.30 | | 13 |
| 14 | LSR II | LGS-3S | 122.00 | 3.00 | 2.82 | 2.82 | 3.11 | 0.75 | 0.20 | 9.33 | 2.25 | 0.60 | 0.03591 | 0.01718 | 0.00130 | 0.00483 | 4.67 | | 14 |
| 15 | LSR II | LGS-3P | 214.10 | 76.25 | 2.73 | 2.73 | 3.40 | 0.84 | 0.21 | 10.21 | 2.52 | 0.64 | 0.03856 | 0.01300 | 0.00116 | 0.00279 | 5.11 | | 15 |
| 16 | LSR II[2] | LGS-3T | 182.00 | 23.00 | CSF | 0.61 | 2.87 | 0.67 | 0.19 | 8.59 | 2.00 | 0.56 | 0.04425 | 0.00766 | 0.00001 | 0.00066 | 4.30 | | 16 |
| 17 | LSR III[9] | LGS-XS | 4,743.00 | 20.52 | 0.91 | 0.91 | 3.11 | 0.75 | 0.20 | 9.33 | 2.25 | 0.60 | 0.03591 | 0.01718 | 0.00130 | 0.00483 | 4.67 | | 17 |
| 18 | LSR III[9] | LGS-XP | 4,743.00 | 86.85 | 1.63 | 1.63 | 3.40 | 0.84 | 0.21 | 10.21 | 2.52 | 0.64 | 0.03856 | 0.01300 | 0.00116 | 0.00279 | 5.11 | | 18 |
| 19 | LSR III[1,9] | LGS-XT | 4,743.00 | 139.05 | CSF | - | 2.87 | 0.67 | 0.19 | 8.59 | 2.00 | 0.56 | 0.04425 | 0.00766 | 0.00001 | 0.00066 | 4.30 | | 19 |
| 20 | LSR I WP | LGS-2-WPS | 128.70 | 9.75 | 0.80 | 0.80 | 3.87 | 3.87 | 0.15 | 11.59 | 11.59 | 0.45 | 0.00010 | 0.00010 | 0.00001 | 0.00002 | 5.80 | | 20 |
| 21 | LSR I WP | LGS-2-WPP | 208.60 | 65.00 | 1.17 | 1.17 | 3.27 | 3.27 | 0.15 | 9.79 | 9.79 | 0.45 | 0.05587 | 0.09974 | 0.00104 | 0.00105 | 4.90 | | 21 |
| 22 | LSR I WP | LGS-2-WPT | 169.10 | - | CSF | 0.61 | 3.53 | 3.53 | 0.19 | 10.60 | 10.60 | 0.56 | 0.05435 | 0.10098 | 0.00117 | 0.00117 | 5.30 | | 22 |
| 23 | LSR II WP | LGS-3-WPS | 149.90 | 3.00 | 0.45 | 0.45 | 3.86 | 3.86 | 0.20 | 11.58 | 11.58 | 0.60 | 0.00010 | 0.00010 | 0.00001 | 0.00002 | 5.79 | | 23 |
| 24 | LSR II WP | LGS-3-WPP | 234.20 | 76.25 | 0.92 | 0.92 | 4.24 | 4.24 | 0.21 | 12.73 | 12.73 | 0.64 | 0.03723 | 0.06984 | 0.00080 | 0.00081 | 6.37 | | 24 |
| 25 | LSR II WP | LGS-3-WPT | 189.10 | 23.00 | CSF | 0.61 | 4.35 | 4.35 | 0.21 | 13.07 | 13.07 | 0.64 | 0.03622 | 0.07071 | 0.00089 | 0.00090 | 6.53 | | 25 |
| 26 | | | | | | | | | | | | | | | | | | | 26 |

27 note: while not shown in this table, DEAA is applicable to standby service.

28

29 1. CSF = customer specific facilities charges.

30 2. The facilities charge for SSR-I includes all of the cost-based Rule 9 facilities costs not recovered in the applicable customer charge and 10 percent of the cost-based primary distribution costs. SSR-II facilities recover the balance of the cost-based

31 primary distribution costs not recovered in the applicable basic service charge. For SSR-III, LSR-I, LSR-II and LSR-III the facilities charge, if applicable, is the cost-based charge under the otherwise applicable rate schedule (OAS), or the CSF

32 (see note 1 above). For most transmission-level customers, facilities charges do not apply, as they have no primary distribution costs and have typically funded their (Rule 9) extension costs. If facilities costs do apply, then they are custome

33 3. This is a lower, alternative facilities charge which recovers only the cost based (primary) distribution facilities costs applicable under the OAS. This lower charge is applicable when the customer has paid for the all of the costs of their interconnection

34 facilities. This alternative facilities charge is not applicable to SSR I and SSR II, and is not applicable when a CSF charge applies instead.

35 4. The contract demand charge is set at 25% of current tariff demand charges in each rating period, reflecting the 3-year average diversity factor of all standby customers.

36 5. The BTGR for SSR-1 and SSR-II is adjusted downward from the BTGR charge of the OAS because a greater portion of facilities costs are being recovered from these customers on a per customer basis than is being recovered in the OAS. See note

37 6. Other than as explained in note 5, the BTGR rates are those of the otherwise applicable class including the IRR.

38 7. Energy rates in maintenance periods are the same as those during non-maintenance periods — see BTGR and BTER columns for applicable rates.

39 8. SSR-I and SSR-II charges are the incremental cost based customer and meter charges associated with this standby service. For all other classes the charge is a per meter charge and recovers the cost-based meter costs and other associated cost

40 9. For the LGS-XS and LGS-XP customers, in addition to the per kW charges shown, they will also continue to pay the CSF charges that are currently applicable under the otherwise applicable LGS-X schedule. For the LGS-XT class, only CSF charge

Proposed Distribution Only Service (DOS) Rates

| Line No. | Class | Note | Distribution Charge, per Customer | Total Facilities Charge, per kW [1] | Additional Meter Charge, per Meter | LGSX CSF Charges (monthly dollar charge for entire class) | Non-Bypassable Energy Charges Interclass Rate Rebalancing (IRR) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 8 | GS | 1 | $ 25.50 | | $ 2.50 | | $ 0.01131 | 8 |
| 9 | LGS-1 | 1 | 15.80 | $ 3.68 | 6.25 | | 0.00178 | 9 |
| 10 | LGS-2S | | 122.40 | 2.68 | 9.75 | | 0.00110 | 10 |
| 11 | LGS-2P | | 207.70 | 2.34 | 65.00 | | 0.00001 | 11 |
| 12 | LGS-2T | 2 | 182.00 | 0.61 | 23.00 | | 0.00178 | 12 |
| 13 | LGS-3S | | 122.00 | 2.82 | 3.00 | | 0.00066 | 13 |
| 14 | LGS-3P | | 214.10 | 2.73 | 76.25 | | 0.00001 | 14 |
| 15 | LGS-3T | 2 | 182.00 | 0.61 | 23.00 | | 0.00001 | 15 |
| 16 | LGS-XS | 3 | 4,743.00 | 0.91 | 20.52 | $ 1,608.00 | 0.00001 | 16 |
| 17 | LGS-XP | 3 | 4,743.00 | 1.63 | 86.85 | $ 49,797.00 | 0.00131 | 17 |
| 18 | LGS-XT | 3 | 4,743.00 | - | 139.05 | $ 29,105.00 | 0.00090 | 18 |
| 19 | LGS-2S-WP | | 128.70 | 0.80 | 9.75 | | 0.00001 | 19 |
| 20 | LGS-2P-WP | | 208.60 | 1.17 | 65.00 | | 0.00001 | 20 |
| 21 | LGS-2T-WP | 2 | 169.10 | 0.61 | - | | 0.00001 | 21 |
| 22 | LGS-3S-WP | | 149.90 | 0.45 | 3.00 | | 0.00001 | 22 |
| 23 | LGS-3P-WP | | 234.20 | 0.92 | 76.25 | | 0.00001 | 23 |
| 24 | LGS-3T-WP | 2 | 189.10 | 0.61 | 23.00 | | 0.00001 | 24 |
| 25 | SL | 4 | | | | | | 25 |
| 26 | GS-Pal | 4 | | | | | | 26 |

| | | | | |
|---|---|---|---|---|
| 27 | | | | 27 |
| 28 | Additional Charges: | | | 28 |
| 29 | Separate Billing | | | 29 |
| 30 | DOS LGS-X & LGS-WP-X: | $ 93.50 | Per additional bill | 30 |
| 31 | Power Factor Charges ($/kVarh)[5]: | | | 31 |
| 32 | Summer: | $ 0.00200 | $/kVarh | 32 |
| 33 | Winter: | 0.00100 | $/kVarh | 33 |
| 34 | Non-X class Customer Specific Facilities: | 0.00313 | Per $ of Utility Investment | 34 |
| 35 | | 0.00057 | $ per Customer Contributed Investment | 35 |
| 36 | R-BTER - 2016 charge ($/kWh)[6]: | - | | 36 |
| 37 | R-BTER - 2017 charge ($/kWh)[6]: | - | | 37 |

38 (1) The facilities charge is included in the per customer charge for the GS classes. For LGS-1, the charge is based on the kW monthly demand per meter. For all other customers, it is based on the highest measured demand in the billing period and the prior twelve billing periods. For non-transmission level customers and the non-LGSX customers, the facilities charges recover both the Rule 9 facility and primary distribution facilities costs.

41 (2) The non-LGSX transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facility calculations be incomplete at the start of service. All new, permanent customers served under these tariffs will be placed on a CSF charges as soon as reasonably practical.

45 (3) As in present rates, for the LGS-X class, the per kW distribution facility charge applies to only the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the facilities identified to serve them.

47 (4) RS-Pal is not eligible for DOS service. The Streetlights and GS-PAL proposed DOS rates are shown on pages 14 and 16 of Statement O.

48 (5) This charge is per kvarh in excess of 90% Power Factor (PF) for all classes except OLGS-3P HLF and LGS-X, which uses a 95% threshold. For all other classes the PF threshold is 90%.

49 (6) Rates do not apply to all DOS customers and are charged only to applicable customers.

Summary of Incremental Price (IP) Generation Capacity Rates

| Line No. | Class[1] | Sales (kWh) | Marginal Generation Revenue | Reconciled Generation Cost per kWh[2] | Line No. |
|---|---|---|---|---|---|
| 8 | **Bundled Service** | | | | 8 |
| 9 | GS | 584,168,954 | $ 11,425,330 | $ 0.01956 | 9 |
| 10 | LGS-1 | 3,897,463,666 | 85,606,862 | 0.02196 | 10 |
| 11 | LGS-2S | 2,365,736,287 | 46,945,234 | 0.01984 | 11 |
| 12 | LGS-2P | 67,742,230 | 1,239,007 | 0.01829 | 12 |
| 13 | LGS-2T | no customers | (set @ LGS-3T) | 0.02373 | 13 |
| 14 | LGS-3S | 800,640,755 | 15,055,569 | 0.01880 | 14 |
| 15 | LGS-3P | 1,296,176,562 | 30,830,553 | 0.02379 | 15 |
| 16 | LGS-3T | 291,915,629 | 6,926,167 | 0.02373 | 16 |
| 17 | LGS-XS | 0 | (set @ LGS-3S) | 0.01880 | 17 |
| 18 | LGS-XP | 0 | (set @ LGS-3P) | 0.02379 | 18 |
| 19 | LGS-XT | 0 | (set @ LGS-3T) | 0.02373 | 19 |
| 20 | LGS-2S-WP | 6,831,160 | 161,762 | 0.02368 | 20 |
| 21 | LGS-2P-WP | 12,228,600 | 167,973 | 0.01374 | 21 |
| 22 | LGS-2T-WP | no customers | (set @ LGS-3T) | 0.02373 | 22 |
| 23 | LGS-3S-WP | 5,751,817 | 20,520 | 0.00357 | 23 |
| 24 | LGS-3P-WP | 17,504,868 | 188,297 | 0.01076 | 24 |
| 25 | LGS-3T-WP | no customers | (set @ LGS-3T) | 0.02373 | 25 |
| 26 | SL | 150,361,312 | 1,894,319 | 0.01260 | 26 |
| 27 | GS-Pal | 2,337,372 | 27,312 | 0.01168 | 27 |
| 28 | IAIWP | no customers | (set @ LGS-3S) | 0.02196 | 28 |
| 29 | | | | | 29 |
| 30 | **Current LSR & Optional/Trial TOU Classes with Customers:** | | | | 30 |
| 31 | LSR-1: LGS-2S | | (set @ LGS-2S) | 0.01984 | 31 |
| 32 | LSR-1: LGS-2P | | (set @ LGS-2P) | 0.01829 | 32 |
| 33 | LSR-1: LGS-2T | | (set @ LGS-2T) | 0.02373 | 33 |
| 34 | LSR-2: LGS-3P | | (set @ LGS-3P) | 0.01880 | 34 |
| 35 | LSR-2: LGS-3T | | (set @ LGS-3T) | 0.02373 | 35 |
| 36 | LSR-2: LGS-3S-WP | | (set @ LGS-3S-WP) | 0.00357 | 36 |
| 37 | LSR-2: LGS-3P-WP | | (set @ LGS-3P) | 0.01076 | 37 |
| 38 | LSR-2: LGS-2S-WP | | (set @ LGS-2S) | 0.02368 | 38 |
| 39 | OGS-TOU | | (set @ GS) | 0.01956 | 39 |
| 40 | OLGS-1-TOU | | (set @ LGS-1) | 0.02196 | 40 |
| 41 | | | | | 41 |
| 42 | **DOS Classes:** | | | | 42 |
| 43 | DOS: GS | | (set @ GS) | 0.01956 | 43 |
| 44 | DOS: LGS-1 | | (set @ LGS-1) | 0.02196 | 44 |
| 45 | DOS: LGS-2S | | (set @ LGS-2S) | 0.01984 | 45 |
| 46 | DOS: LGS-3S | | (set @ LGS-3S) | 0.01880 | 46 |
| 47 | DOS: LGS-3P | | (set @ LGS-3P) | 0.02379 | 47 |
| 48 | DOS: LGS-3T | | (set @ LGS-3T) | 0.02373 | 48 |
| 49 | DOS: LGS-2S-WP | | (set @ LGS-2S-WP) | 0.02368 | 49 |
| 50 | DOS: LGS-2T-WP | | (set @ LGS-2T-WP) | 0.02373 | 50 |
| 51 | DOS: LGS-3S-WP | | (set @ LGS-3S-WP) | 0.00357 | 51 |
| 52 | DOS: LGS-3P-WP | | (set @ LGS-3P-WP) | 0.01076 | 52 |
| 53 | DOS: LGS-3T-WP | | (set @ LGS-3T-WP) | 0.02373 | 53 |
| 54 | | | | | 54 |

55 1. Rates are shown only for classes containing customers with the potential of going open access under AB 661 or SB 211 provisions.
56 For customer served under DOS, LSR, OGS-TOU and OLGS-1-TOU, the applicable generation capacity rates will be set at those of an otherwise
57 applicable schedule (OAS). For these classes that presently have customers served, the applicable OAS is shown in the table.
58 2. This rate is the marginal generation cost reconciled to the generation revenue requirement stated on a per kWh basis for the class.
59 Reconcillation factor is: 100.0%

Calculation of Customer Specific Facilities Charges

| Line No. | Customer Specific Facility Investment & Revenue Requirement | | | | | | | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|
| 7 | Investment Cost for all Transmission level customers | | | | | $ 34,982,146 | | | | 7 |
| 8 | Total Annual Marginal Cost Revenue Requirement associated with the T-level customer specific investment | | | | | $ 1,155,018 | | | | 8 |
| 9 | Marginal Cost: $ of Revenue Req. per $ of Marginal Investment (line 8/line 7) | | | | | $ 0.03302 | | | | 9 |
| 10 | Distribution Reconciliation Factor | | | | | 100.0% | | | | 10 |
| 11 | Reconciled: Annual $ of Reconciled Revenue Req. per $ of Investment (line 9 * line 10) | | | | | $ 0.03754 | | | | 11 |
| 12 | | | | | | | | | | 12 |
| 13 | CSF Charges By Customer Per Dollar of Facilities Investment Factor Developed above | | | | | | | | | 13 |
| 14 | | | | | Annual | | Monthly | Monthly Fac | | 14 |
| 15 | | | | NVE | $ Per $ of Facility | Annual Fac Rev | Per $ of Fac | Revenue | | 15 |
| 16 | Individual CSFC | Class | Group | Investment | Investment | By Customer | Invest. Factor | By Customer | | 16 |
| 17 | LHOIST | LGS-3T | Bundled | $ 683,793 | $ 0.03754 | $ 25,683 | $ 0.00313 | $ 2,140.27 | | 17 |
| 18 | SA RECYCLING | LGS-3T | Bundled | 1,255,444 | 0.03754 | 47,154 | 0.00313 | 3,929.54 | | 18 |
| 19 | VENETIAN | LGS-3T | Bundled | 6,070,698 | 0.03754 | 228,015 | 0.00313 | 19,001.28 | | 19 |
| 20 | HOLDER | LGS-3T | Bundled | 168,370 | 0.03754 | 6,324 | 0.00313 | 527.00 | | 20 |
| 21 | SNWA LAMB | LGS-3T | DOS | 226,610 | 0.03754 | 8,511 | 0.00313 | 709.29 | | 21 |
| 22 | SNWA LAMB | LGS-3T | DOS | 226,610 | 0.03754 | 8,511 | 0.00313 | 709.29 | | 22 |
| 23 | SNWA SLOAN | LGS-3T | DOS | 573,573 | 0.03754 | 21,543 | 0.00313 | 1,795.28 | | 23 |
| 24 | CITY OF HENDERSON2 | LGS-3T | DOS | 474,810 | 0.03754 | 17,834 | 0.00313 | 1,486.16 | | 24 |
| 25 | CITY OF HENDERSON2 | LGS-3T | DOS | 474,810 | 0.03754 | 17,834 | 0.00313 | 1,486.16 | | 25 |
| 26 | CCWRD2 | LGS-3T | DOS | 71,248 | 0.03754 | 2,676 | 0.00313 | 223.01 | | 26 |
| 27 | CCWRD2 | LGS-3T | DOS | 40,278 | 0.03754 | 1,513 | 0.00313 | 126.07 | | 27 |
| 28 | CCWRD2 | LGS-3T | DOS | 446,751 | 0.03754 | 16,780 | 0.00313 | 1,398.33 | | 28 |
| 29 | MGM | LGS-3T | DOS | 19,417,260 | 0.03754 | 729,312 | 0.00313 | 60,776.02 | | 29 |
| 30 | MGM | LGS-3T | DOS | 1,317,659 | 0.03754 | 49,491 | 0.00313 | 4,124.27 | | 30 |
| 31 | CAESAR'S | LGS-3T | DOS | 942,390 | 0.03754 | 35,396 | 0.00313 | 2,949.68 | | 31 |
| 32 | SNWA PP4 | LGS-3T-WP | DOS | 27,742 | 0.03754 | 1,042 | 0.00313 | 86.83 | | 32 |
| 33 | SNWA PP5 | LGS-3T-WP | DOS | 1,259,170 | 0.03754 | 47,294 | 0.00313 | 3,941.20 | | 33 |
| 34 | SNWA PP6 | LGS-3T-WP | DOS | 617,642 | 0.03754 | 23,199 | 0.00313 | 1,933.22 | | 34 |
| 35 | SNWA HACIENDA | LGS-3T-WP | DOS | 300,574 | 0.03754 | 11,290 | 0.00313 | 940.80 | | 35 |
| 36 | SNWA PP3 | LGS-2T-WP | DOS | 386,714 | 0.03754 | 14,525 | 0.00313 | 1,210.41 | | 36 |
| 37 | CLEARWATER PAPER CORPORATION | OLGS-3P HLF | Bundled | 1,478,462 | 0.03754 | 55,531 | 0.00313 | 4,627.59 | | 37 |
| 38 | NP RED ROCK LLC | OLGS-3P HLF | Bundled | 636,335 | 0.03754 | 23,901 | 0.00313 | 1,991.73 | | 38 |
| 39 | POLY-WEST INC | OLGS-3P HLF | Bundled | 204,283 | 0.03754 | 7,673 | 0.00313 | 639.41 | | 39 |
| 40 | STATION GVR ACQUISITION LLC | OLGS-3P HLF | Bundled | 288,821 | 0.03754 | 10,848 | 0.00313 | 904.01 | | 40 |
| 41 | TRUMP RUFFIN COMMERCIAL LLC | OLGS-3P HLF | Bundled | 921,045 | 0.03754 | 34,594 | 0.00313 | 2,882.87 | | 41 |
| 42 | SUNSET STATION 1641830 | OLGS-3P HLF | Bundled | 398,394 | 0.03754 | 14,964 | 0.00313 | 1,246.97 | | 42 |
| 43 | STRATOSPHERE CORPORATION | OLGS-3P HLF | Bundled | 538,517 | 0.03754 | 20,227 | 0.00313 | 1,685.56 | | 43 |
| 44 | STRATOSPHERE CORPORATION | OLGS-3P HLF | Bundled | 447,097 | 0.03754 | 16,793 | 0.00313 | 1,399.42 | | 44 |
| 45 | POLY-WEST 2089379 | OLGS-3P HLF | Bundled | 204,283 | 0.03754 | 7,673 | 0.00313 | 639.41 | | 45 |
| 46 | | | | | | | | | | 48 |
| 47 | | | | | | | | | | 47 |
| 48 | | | | | | | | | | 48 |
| 49 | | | | | | | | | | 49 |
| 50 | Subtotals by Class and Service | | | | | | | | | 50 |
| 51 | LGS-3T - Bundled | LGS-3T | Bundled | $ 8,178,305 | 0.03754 | 307,177 | 0.00313 | 25,598 | | 51 |
| 52 | LGS-3T - DOS | LGS-3T | DOS | 24,211,999 | 0.03754 | 909,403 | 0.00313 | 75,784 | | 52 |
| 53 | LGS-2T-WP - Bundled | LGS-2T-WP | Bundled | - | 0.03754 | - | 0.00313 | - | | 53 |
| 54 | LGS-2T-WP - DOS | LGS-2T-WP | DOS | 386,714 | 0.03754 | 14,525 | 0.00313 | 1,210 | | 54 |
| 55 | LGS-3T-WP - Bundled | LGS-3T-WP | Bundled | - | 0.03754 | - | 0.00313 | - | | 55 |
| 56 | LGS-3T-WP - DOS | LGS-3T-WP | DOS | 2,205,128 | 0.03754 | 82,825 | 0.00313 | 6,902 | | 56 |
| 57 | OLGS-3P-HLF Bundled | OLGS-3P HLF | Bundled | 5,117,238 | 0.03754 | 192,203 | 0.00313 | 16,017 | | 57 |
| 58 | | | | | avg. | | avg. | | | 58 |
| 59 | Total | | | $ 40,099,384 | 0.03756 | $ 1,506,133 | 0.00313 | $ 125,511 | | 59 |
| 60 | | | | | rounding>> | $ 0 | | $ 0 | | 60 |
| 61 | Temporary Transmission level per kW Facility Charge (Charged until CSF charge is developed) | | | | | | ^^^^^^^^^^^ | | | 61 |
| 62 | | | | | | | Proposed | | | 62 |
| 63 | Investment Cost for Transmission level customers: | | | | | $ 34,982,146 | Tariff Recovery | | | 63 |
| 64 | Total Annual Marginal Cost Revenue Requirement associated with the customer specific investment (line 63 * line 11): | | | | | $ 1,155,018 | Rate per Dollar | | | 64 |
| 65 | Distribution Reconciliation Factor (line 11): | | | | | 100.0% | of Facility | | | 65 |
| 66 | Reconciled Investment Cost (line 65 * line 64): | | | | | $ 1,155,018 | Investment | | | 66 |
| 67 | Annual facility kW determinants | | | | | 1,560,404 | | | | 67 |
| 68 | Per kW facilty rate (line 66 / Line 67) | | | | | $ 0.61 | | | | 68 |

Calculation of Transmission Level Customer Specific Facilities O&M and A/G Customer Specific Rates Relating to Contributed (CIAC) Investment

**Development of Annual & Monthly Per Dollar of Investment Recovery Rate**

| | (a) | (b) | | (c) |
|---|---|---|---|---|
| Annual: Dist Reconciliation Factor | X | Dollar O&M/A&G Recovery Per Dollar of Contributed Investment | | |
| 100.0% | x | $0.00992 | = | $ 0.00992 |
| Monthly: (annual rate divided by 12) | | | = | $ 0.00057 |

**CIAC Investment & O&M and A&G Revenue Requirement**

| Customer | Class | Group | Contributed Investment | Annual Revenue Requirement | Dollar Per Dollar of Investment $ (cost based – before reconciliation) [(b) / (a)] | Per Dollar O&M/A&G Recovery Per Dollar of CIAC'd Facility Investment & Charges by Customer: Original CIAC Investment | Monthly Per $ of CIAC'd Investment | Monthly Payment [ (d) * (e) ] | Annual Payment |
|---|---|---|---|---|---|---|---|---|---|
| LHOIST | LGS-3T | Bundled | $ - | $ - | $0.00992 | $ - | $ 0.00057 | $ - | $ - |
| SA RECYCLING | LGS-3T | Bundled | - | - | $0.00992 | - | 0.00057 | - | - |
| VENETIAN | LGS-3T | Bundled | - | - | $0.00992 | - | 0.00057 | - | - |
| HOLDER | LGS-3T | Bundled | 11,791,553 | 117,025 | $0.00992 | 11,791,553 | 0.00057 | 6,721.19 | 80,654.28 |
| SNWA LAMB | LGS-3T | DOS | 453,810 | 4,504 | $0.00992 | 453,810 | 0.00057 | 258.67 | 3,104.04 |
| SNWA LAMB | LGS-3T | DOS | 453,810 | 4,504 | $0.00992 | 453,810 | 0.00057 | 258.67 | 3,104.04 |
| SNWA SLOAN | LGS-3T | DOS | 826,580 | 8,203 | $0.00992 | 826,580 | 0.00057 | 471.15 | 5,653.80 |
| CITY OF HENDERSON2 | LGS-3T | DOS | 1,191,000 | 11,820 | $0.00992 | 1,191,000 | 0.00057 | 678.87 | 8,146.44 |
| CITY OF HENDERSON2 | LGS-3T | DOS | 1,191,000 | 11,820 | $0.00992 | 1,191,000 | 0.00057 | 678.87 | 8,146.44 |
| CCWRD2 | LGS-3T | DOS | 374,615 | 3,718 | $0.00992 | 374,615 | 0.00057 | 213.53 | 2,562.36 |
| CCWRD2 | LGS-3T | DOS | 211,779 | 2,102 | $0.00992 | 211,779 | 0.00057 | 120.71 | 1,448.52 |
| CCWRD2 | LGS-3T | DOS | 2,348,976 | 23,312 | $0.00992 | 2,348,976 | 0.00057 | 1,338.92 | 16,067.04 |
| MGM | LGS-3T | DOS | - | - | $0.00992 | - | 0.00057 | - | - |
| MGM | LGS-3T | DOS | - | - | $0.00992 | - | 0.00057 | - | - |
| CAESAR'S | LGS-3T | DOS | - | - | $0.00992 | - | 0.00057 | - | - |
| SNWA PP4 | LGS-3T-WP | DOS | - | - | $0.00992 | - | 0.00057 | - | - |
| SNWA PP5 | LGS-3T-WP | DOS | - | - | $0.00992 | - | 0.00057 | - | - |
| SNWA PP6 | LGS-3T-WP | DOS | - | - | $0.00992 | - | 0.00057 | - | - |
| SNWA HACIENDA | LGS-3T-WP | DOS | - | - | $0.00992 | - | 0.00057 | - | - |
| SNWA PP3 | LGS-2T-WP | DOS | - | - | $0.00992 | - | 0.00057 | - | - |
| CLEARWATER PAPER CORPORATION | OLGS-3P HLF | Bundled | - | - | $0.00992 | - | 0.00057 | - | - |
| NP RED ROCK LLC | OLGS-3P HLF | Bundled | - | - | $0.00992 | - | 0.00057 | - | - |
| POLY-WEST INC | OLGS-3P HLF | Bundled | 51,773 | 514 | $0.00992 | 51,773 | 0.00057 | 29.51 | 354.12 |
| STATION GVR ACQUISITION LLC | OLGS-3P HLF | Bundled | - | - | $0.00992 | - | 0.00057 | - | - |
| TRUMP RUFFIN COMMERCIAL LLC | OLGS-3P HLF | Bundled | - | - | $0.00992 | - | 0.00057 | - | - |
| SUNSET STATION 1641830 | OLGS-3P HLF | Bundled | - | - | $0.00992 | - | 0.00057 | - | - |
| STRATOSPHERE CORPORATION | OLGS-3P HLF | Bundled | - | - | $0.00992 | - | 0.00057 | - | - |
| STRATOSPHERE CORPORATION | OLGS-3P HLF | Bundled | - | - | $0.00992 | - | 0.00057 | - | - |
| POLY-WEST 2089379 | OLGS-3P HLF | Bundled | 51,773 | 514 | $0.00992 | 51,773 | 0.00057 | 29.51 | 354.12 |
| **Subtotals by Class and Service** | | | | | | | | | |
| LGS-3T - Bundled | LGS-3T | Bundled | 11,791,553 | 117,025 | $0.00992 | 11,791,553 | 0.00057 | 6,721.19 | 80,654.28 |
| LGS-3T - DOS | LGS-3T | DOS | 7,051,570 | 69,983 | $0.00992 | 7,051,570 | 0.00057 | 4,019.39 | 48,232.68 |
| LGS-2T-WP - Bundled | LGS-2T-WP | Bundled | - | - | $0.00992 | - | 0.00057 | - | - |
| LGS-2T-WP - DOS | LGS-2T-WP | DOS | - | - | $0.00992 | - | 0.00057 | - | - |
| LGS-3T-WP - Bundled | LGS-3T-WP | Bundled | - | - | $0.00992 | - | 0.00057 | - | - |
| LGS-3T-WP - DOS | LGS-3T-WP | DOS | - | - | $0.00992 | - | 0.00057 | - | - |
| OLGS-3P-HLF Bundled | OLGS-3P HLF | Bundled | 103,546 | 1,028 | $0.00992 | 103,546 | 0.00057 | 59.02 | 708.24 |
| Total | | | $ 18,946,669 | $ 188,036 | $0.00992 | $ 37,893,338 | | $ 10,799.60 | $ 129,595.20 |
| | | | | | Marginal O&M from MCS | | | | |
| | | | | | $188,036 | | | | |

## Calculation of LGS-X Specific Charges

**Basic Service, Additional Meter and Separate Billing Charges**

| | Basic Service Charge | | | Additional Meter Charge | | | Separate Bill | | |
|---|---|---|---|---|---|---|---|---|---|
| | Billing Units | Cost-Based Revenue | Rate | Billing Units | Cost-Based Revenue | Rate | Billing Units | Cost-Based Revenue | Rate |
| LGS-XS | - | $ - | | 60 | $ 1,362.75 | $ 22.70 | - | $ - | |
| LGS-XP | 24 | $ 1,244,282.46 | $ 51,845.10 | 156 | $ 6,262.71 | $ 40.10 | 24 | $ 630.43 | $26.27 |
| LGS-XT | 12 | $ 363,617.42 | $ 30,301.45 | 36 | $ 756.91 | $ 21.00 | 12 | $ 157.61 | $13.13 |
| Total | 36 | $ 1,607,899.88 | **$4,743.00** | 252 | $ 8,382.37 | **$33.30** | 36 | $ 788.03 | **$93.50** |
| | | Present DOS Rate: | $5,580.00 | | | | | Present Rate: | $110.00 |
| | | Percent Change: | -15.0% | | | | | Percent Change: | -15.0% |

**LGS-X Customer Specific Facilities**

| | | | Current Charges | | | Proposed Charges | | |
|---|---|---|---|---|---|---|---|---|
| Customer | Premise | Rate Schedule | Monthly Facilities Charge | Annual Facilities Revenue | Investment | Monthly Facilities Charge | Annual Facilities Revenue | Investment |
| Bally | 1231089 | LGS-XP DOS | $ 4,228 | $ 50,736 | | $ 3,740 | $ 44,880 | |
| Bally | 1231091 | LGS-XS DOS | 1,818 | 21,816 | | 1,608 | 19,296 | |
| Paris | 1735149 | LGS-XP DOS | 5,729 | 68,748 | | 5,068 | 60,816 | |
| Paris | 1735152 | LGS-XP DOS | 5,729 | 68,748 | | 5,068 | 60,816 | |
| | | | $ 17,504 | $ 210,048 | $ 2,020,383 | $ 15,484 | $ 185,808 | $ 2,066,291 |
| New Castle Corp (Excalibur) | 1396169 | LGS-XP DOS | $ 5,257 | $ 63,084 | | $ 4,710 | $ 56,520 | |
| New Castle Corp (Excalibur) | 1396170 | LGS-XP DOS | 5,232 | 62,784 | | 4,687 | 56,244 | |
| New Castle Corp (Excalibur) | 1415346 | LGS-XS DOS | - | - | | - | - | |
| New Castle Corp (Excalibur) | 1415347 | LGS-XS DOS | - | - | | - | - | |
| Luxor | 1500684 | LGS-XP DOS | 6,295 | 75,540 | | 5,640 | 67,680 | |
| Luxor | 1500685 | LGS-XP DOS | 7,820 | 93,840 | | 7,006 | 84,072 | |
| Luxor | 1511139 | LGS-XS DOS | - | - | | - | - | |
| Luxor | 1652129 | LGS-XP DOS | 1,895 | 22,740 | | 1,698 | 20,376 | |
| Mandalay Bay | 1714502 | LGS-XP DOS | 6,798 | 81,576 | | 6,090 | 73,080 | |
| Mandalay Bay | 1714503 | LGS-XP DOS | 6,798 | 81,576 | | 6,090 | 73,080 | |
| New Castle Corp (Excalibur) | 1758368 | LGS-XP DOS | - | - | | - | - | |
| | | | $ 40,095 | $ 481,140 | $ 4,885,159 | $ 35,921 | $ 431,052 | $ 4,885,159 |
| Monte Carlo | 1607748 | LGS-XT DOS | $ - | $ - | | $ - | $ - | |
| Monte Carlo | 1607750 | LGS-XT DOS | 10,739 | 128,868 | | 9,790 | 117,480 | |
| Bellagio | 1656755 | LGS-XP DOS | - | - | | - | - | |
| Bellagio | 1656777 | LGS-XP DOS | - | - | | - | - | |
| Bellagio | 1693991 | LGS-XT DOS | 21,186 | 254,232 | | 19,315 | 231,780 | |
| Monte Carlo | 1782548 | LGS-XP DOS | - | - | | - | - | |
| | | | $ 31,925 | $ 383,100 | $ 3,727,626 | $ 29,105 | $ 349,260 | $ 3,727,626 |
| Subtotals by Class and Service | | LGS-XS | $ - | $ - | $ - | $ - | $ - | $ - |
| | | LGS-XP | - | - | - | - | - | - |
| | | LGS-XT | - | - | - | - | - | - |
| | | LGS-XS DOS | **1,818** | **21,816** | - | **1,608** | **19,296** | - |
| | | LGS-XP DOS | **55,781** | **669,372** | - | **49,797** | **597,564** | - |
| | | LGS-XT DOS | **31,925** | **383,100** | - | **29,105** | **349,260** | - |
| | | Total for Class | $ 89,524 | $ 1,074,288 | $ - | $ 80,510 | $ 966,120 | $ - |

Note: The allocation of CSFC's among accounts was done by keeping the Transmission & Secondary charges the same as Current (Since the underlying investment has remained the same), and allocating the Primary Charges in proportion to the current Primary charges.

FILED WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA - 9/24/2020

NVEnergy

September 24, 2020

Ms. Trisha Osborne, Assistant Commission Secretary
Public Utilities Commission of Nevada
Capitol Plaza
1150 East William Street
Carson City, Nevada 89701-3109

RE: Docket No. 20-06003: Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.

Dear Ms. Osborne:

Pursuant to the filing made this afternoon by Nevada Power Company d/b/a NV Energy, attached is Mr. Lucas Foletta's signature page.

Should you have any questions regarding this filing, please contact me at (775) 834-4261 or ldinnocenti@nvenergy.com.

Respectfully submitted,

*/s/Lynn D'Innocenti*
Lynn D'Innocenti
Sr. Legal Administrative Assistant

This Stipulation is entered into by each Signatory as of the date entered below:

NEVADA POWER COMPANY
d/b/a NV ENERGY

Date

By: Michael Greene, Esq.
Deputy General Counsel

REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA

Date

By: Shelly Cassity, Esq.
Assistant Staff Counsel
Jesse Panoff, Esq.
Assistant Staff Counsel

BUREAU OF CONSUMER PROTECTION

Date

By: Michael Saunders, Esq.
Senior Deputy Attorney General

MGM RESORTS INTERNATIONAL

9-24-20
Date

Fred Schmidt
By: Fred Schmidt, Esq.
Austin Jensen, Esq.

CAESARS ENTERPRISE SERVICES

9-24-20
Date

Fred Schmidt
By: Fred Schmidt, Esq.
Austin Jensen, Esq.

SOUTHERN NEVADA GAMING GROUP

9-24-20
Date

By: Lucas Foletta, Esq.

# Appendix D

## Permit Application Forms

# Authority to Construct Permit Application for a 40 CFR Part 70 Source

## Clark County Department of Environment & Sustainability Division of Air Quality

**Submit Application and Payment to:**
**Division of Air Quality**
**4701 W. Russell Road, Suite 200**
**Las Vegas NV 89118**

**For DAQ Use Only**

**Invoice No.:**

**Date:**

## Section A: Permit Application Type (check one):

- ☐ ATC with PSD Review (AQR 12.2)
- ☐ ATC with Nonattainment Review (AQR 12.3)
- ■ ATC (AQR 12.4; not subject to AQR 12.2 or 12.3)
- ☐ ATC as part of a Part 70 OP Significant Revision (AQR 12.4.3.2(d))
- ☐ ATC as part of a Part 70 OP Minor Revision (AQR 12.4.3.2(e))
- ☐ Administrative Revision of Existing ATC (AQR 12.4.4.1(b))
- ☐ Significant Revision of Existing ATC (AQR 12.4.4.1(c))

***Application Description:*** Describe the action being proposed, e.g., new process, change to equipment, change to permit conditions, Voluntarily Accepted Emission Limit (VAEL), etc.

Title V Permit modification to reflect Reasonably Available Control Technology (RACT) requirements for NOx per AQR Section 120

**Applications for a Part 70 source ATC shall include the information requested in Sections B–F.**

***Complete the fields in Sections B–F even if there is no change from the previous application.***

## Section B: Source Information

Source ID No (existing permits only): 00329

Source Name (as listed on Clark County/State of Nevada business license):
Las Vegas Generating Station

City/County Business License #:

**Source Location Information**

| Number: | Direction: | Street Name: | Cross Streets: |
|---|---|---|---|
| 1701 | East | Alexander Road | |

City: North Las Vegas | State: NV | ZIP: 89030

**Phone Numbers**

Office: (702) 402-8225 | Fax:

**North American Industry Classification System (NAICS) / Source Industry Classification Code**

Primary NAICS: 221112 | Additional NAICS:

***Source Description:*** Describe the nature of your business, including processes and products.

Fossil fuel-fired electric power generation

## Section C: Company Information (AS LISTED ON THE SECRETARY OF STATE'S BUSINESS CERTIFICATE/FILING)

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**
If YES, submit the Transfer of Ownership/Change of Name form and fee (SS-PER-020-01).

Company Name: Nevada Power Company, dba NV Energy

Nevada Secretary of State Business Certificate/Filing No.:

If this is a new source, attach a printout of your company's business listing on the Nevada Secretary of State website or other formal documentation that includes your company's full legal name.

**Company Location Information**

**Physical Address**

| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| 6226 | West | Sahara Avenue | | | |
| City: Las Vegas | | | State: NV | ZIP: 89146 | |

**Mailing Address**

| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| 6226 | West | Sahara Avenue | | | |
| City: Las Vegas | | | State: NV | ZIP: 89146 | |

**Phone Numbers**

| Office: (702) 402-8225 | Fax: |
|---|---|

## Section D: Responsible Official (RO) Information

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**
If YES, submit separately the Declaration of Responsible Official form (RO-PER-003). See AQR 12.4.2(h)) for the applicable definition of an RO.

| Name: Jason Hammons | | Title: Vice President, Generation | | | |
|---|---|---|---|---|---|
| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
| 6226 | West | Sahara Avenue | | | |
| City: Las Vegas | | | State: NV | ZIP: 89146 | |
| Email: jasonhammons@NVEnergy.com | | Primary Communication Method: ■ Email ☐ USPS | | | |

**Phone Numbers**

| Office: (702) 402-8225 | Extension: | Cell: | Fax: |
|---|---|---|---|

## Section E: Plant Manager/Environmental Representative Information (Optional)

| Name: Ted Gretz | | Title: Plant Director | | | |
|---|---|---|---|---|---|
| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
| 1701 | East | Alexander Road | | | |
| City: North Las Vegas | | | State: NV | ZIP: 89030 | |
| Email: ted.gretz@NVEnergy.com | | Primary Communication Method: ■ Email ☐ USPS | | | |

**Phone Numbers**

| Office: (702) 402-5783 | Extension: | Cell: | Fax: |
|---|---|---|---|

## Section F: Billing Contact (Accounts Payable) Information (Optional)

| Name: | Title: |
|---|---|
| Email: | Primary Communication Method: ☐ Email ☐ USPS |

**Phone Numbers**

| Office: | Extension: | Cell: | Fax: |
|---|---|---|---|

## Section G: Application Instructions

1. An owner or operator of an existing or new Part 70 source shall obtain an Authority to Construct (ATC) Permit from the Control Officer before beginning actual construction or continuing with any of the following:
   a. Operating a new Part 70 source;
   b. "Major modification," as defined in AQR 12.2 or 12.3;
   c. Modification that increases the Part 70 source's potential to emit (PTE) by an amount equal to or greater than the minor New Source Review (NSR) significant level in AQR 12.4.2.1;
   d. Construction, modification, or reconstruction of an affected facility that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 60;
   e. Construction or reconstruction of a new source or of an affected source that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 63, including, but not limited to, construction or modification that requires preconstruction review under 40 CFR Part 63.5; or
   f. Modification to a solid waste incinerator unit, as defined by an applicable standard under 40 CFR Part 60.
2. When the owner or operator of a Part 70 source must revise the existing Part 70 Operating Permit before construction, modification, or reconstruction, as specified in AQR 12.4.1.1(c), the Control Officer shall follow AQR 12.5.2.13 or 12.5.2.14, as applicable, to process the ATC Permit application and revise the Part 70 Operating Permit.
3. For construction, modification, or reconstruction that meets the AQR 12.5.2.14(c)(1) criteria for a significant permit revision, the owner or operator may submit an ATC Permit application that fulfills both AQR 12.4.3.1(a) requirements and the requirements for an application for a significant revision to an existing Part 70 Operating Permit in AQR 12.5.2.14(c)(2). The owner or operator and the Control Officer may then follow the AQR 12.5.2.14(c) process for significant permit revisions to obtain authorization to construct and operate under a revised Part 70 Operating Permit and/or an ATC Permit.
4. For modifications that increase the Part 70 source's PTE by an amount less than the minor NSR significance level defined in AQR 12.4.2.1 and meet the AQR 12.5.2.14(a)(1) criteria for a minor permit revision:
   a. The owner or operator may submit an application for an ATC Permit that fulfills both the AQR 12.4.3.1(a) requirements and the requirements for an application for a minor permit revision in AQR 12.5.2.14(a)(3). The owner or operator may then begin actual construction and operate under the authority provided by AQR 12.5.2.14(a)(6), and the Control Officer may follow the AQR 12.5.2.14 minor permit revision process to issue an authorization to construct and operate under a revised Part 70 Operating Permit and/or an ATC Permit.
   b. An authorization to construct and operate per AQR 12.5.2.14(a)(6) remains in effect until the Control Officer takes final action on the minor permit revision application under AQR 12.5.2.14(a)(5)(A), (B), or (C), or issues a separate ATC Permit.
   c. The Control Officer may modify the AQR 12.5.2.14(a)(6) authorization to construct and operate before taking final action on the minor permit revision application by revising the draft minor permit revision under AQR 12.5.2.14(a)(5)(D).
5. When an owner or operator and the Control Officer follow the procedures in G.2, G.3, or G.4 then, in accordance with AQR 12.4.5.2(b), the revised Part 70 Operating Permit serves as both the Operating Permit and the ATC Permit for the affected and constructed emission units at the source when the Control Officer does not issue a separate ATC Permit.

## Section H: Application Supplemental Documents

*Information worksheets for common source types and emission units are posted on the DES website under **Applications/Forms → Stationary Source Permitting Forms → Emission Unit/Control Device Worksheets & Tools**. Applicants can use these documents to provide some of the technical information requested below.*

1. To complete this application, provide the following information related to the construction or project, as set forth in AQR 12.4.3.1:
   a. Description of all emissions of regulated air pollutants from all affected and construction emission units, and a projected operating schedule for each unit;

b. Identification and description of all emission units, including, but not limited to, the manufacturer, model number, serial number, rating, and Source Classification Code (SCC) of each unit in sufficient detail to establish applicable requirements;

c. Identification and description of all points of emissions, and a process description of all activities (including design capacity) that may generate emissions of regulated air pollutants in sufficient detail to establish the basis for applicability of standards and fees;

d. Emission rates of all regulated air pollutants for each emission unit modified by this action, including fugitive emission rates, described in tons per year and for such shorter-term averages as needed to establish compliance using the applicable standard reference test method or other methodology;

e. Calculations on which the information in Section H.1.d above is based, including fuel descriptions and specifications (this shall include facility-wide PTE calculations);

f. Descriptions of any new or modified air pollution control equipment to be operated at the stationary source;

g. Citations to and descriptions of all applicable requirements;

h. The applicable reference test method or other methodology used for determining compliance with each applicable requirement, including monitoring criteria;

i. Reasonably available control technology (RACT) demonstration for pollutant(s) exceeding the minor NSR significant level(s) defined in AQR 12.4.2.1(d), including a description of how the owner/operator determined RACT and will measure compliance, as well as material usage limits, performance testing, and continuous emissions monitoring.

   i. This includes any existing emission limitation(s) increased or removed if, without those limitation(s), an emissions unit would have been subject to the RACT demonstration requirement in a previous ATC application, and for which the Control Officer issued an ATC within the last five years without requiring the unit to comply with RACT.

j. If applicable, a description of how performance testing will be conducted, including test methods and testing protocols;

k. If applicable, the basic design parameter(s) of the source, emission units, or processes being permitted, as applicable;

l. If applicable, a description of how the permittee proposes to comply with the compliance assurance monitoring requirements in 40 CFR Part 64, including a plan describing how the applicant will comply with the monitoring design criteria in 40 CFR Part 64.3;

m. If any information or data in the application is proposed to be treated as confidential, a demonstration of compliance with the Certification of Confidentiality procedures in AQR 12.6.1;

n. If the applicant wishes to be subject to the enhanced public participation procedures in AQR 12.2.16.6, a declaration to that effect; and

o. For construction, modification, or reconstruction that increases the source's PTE by an amount equal to or greater than the minor NSR significant level defined in AQR 12.4.2.1(d) for a regulated air pollutant, but less than the major source or major modification threshold in AQRs 12.2 or 12.3, a demonstration that the construction will not cause an exceedance of the National Ambient Air Quality Standards (NAAQS), as defined in AQR 0, or an exceedance of the ambient air increments specified in AQR 12.2.3.

2. If the new or modified Part 70 source is subject to the Prevention of Significant Deterioration preconstruction review provisions of AQR 12.2, the application shall also contain the following:

   a. The control technology review required by AQR 12.2.9;

   b. The source impact analysis required by AQR 12.2.10;

   c. The air quality analysis required by AQR 12.2.12;

   d. The source information required by AQR 12.2.13;

   e. The additional impact analyses required by AQR 12.2.14; and

   f. Any other information that the Control Officer determines is necessary to process the application in accordance with AQRs 12.2 or 12.3.

3. If the new or modified Part 70 source is subject to the nonattainment area preconstruction review provisions of

AQR 12.3, the application shall also contain the following:

a. The statewide compliance demonstration required by AQR 12.3.3;

b. The alternatives analysis required by AQR 12.3.4;

c. The LAER demonstration and draft permit conditions required by AQR 12.3.5.2;

d. An air impact analysis, including dispersion modeling;

e. The information necessary to demonstrate that the applicant has satisfied or will satisfy the emissions offset requirements in AQR 12.3.6; and

f. Any other information that the Control Officer determines is necessary to process the application in accordance with AQR 12.2 or 12.3.

4. A justification for any exemption sought from any otherwise applicable requirement.

5. In addition to any other application requirements, if the construction of a new Part 70 source—or the construction or reconstruction of an existing Part 70 source—creates a "new affected source" or "reconstructed affected source" that is a major source under 40 CFR Part 63, the owner or operator shall comply with the application requirements under 40 CFR Part 63.5 and Section G.1. The ATC Permit for the source shall comply with 40 CFR Part 63.5(e) requirements.

## Section I: Fees and Payments

Air Quality Program Fees: AQR 18, "Permit and Technical Service Fees," describes all fees related to this application and the resulting permit: https://www.clarkcountynv.gov/government/departments/environment_and_sustainability/division_of_air_quality/fees_and_payments/fees_page.php.

Application Filing Fee: The application fee invoice must be paid in full before the application will be processed.

Permit Issuance: All outstanding invoices for the source and associated with the parent company of the source must be paid in full; otherwise, DAQ cannot issue the source any permits. This includes the invoice for the permit fees resulting from this application.

Payment: Invoices must be paid by check, money order, or credit card. Make checks and money orders payable to **Division of Air Quality** or **DAQ**. Credit card payments may be made in person at DAQ's main office or online at https://www.clarkcountynv.gov/government/departments/environment_and_sustainability/division_of_air_quality/ fees_and_payments/page_payments.php.

## Section J: Grant of Authority

I authorize DAQ to transmit all communications, permits, and billing invoices by the primary communication method selected in Section D of this application. I acknowledge that if I select "Email," DAQ will transmit all listed items electronically. I further acknowledge that if I select "U.S. Postal Service," I may incur applicable postage fees.

## Section K: Certification of Truth, Accuracy, and Completeness

As the Responsible Official, I declare, under penalty of perjury under the laws of the state of Nevada, that the statements and information in this application and the attached supplemental documents and worksheets are true, accurate, and complete. My signature acknowledges that I am subject to liability for perjury under NRS Chapter 199.145.

Responsible Official Certification (original "wet" signature) — Date: 7/24/2025

Jason Hammons

Printed Name of Responsible Official

**If this application is being submitted for an existing permit holder, it must be signed by an RO on file for this source.**

# Emission Units Subject to RACT

| EU | Description | Rating | Make | Model No. | Serial No. | NOx Controls | CO Controls |
|---|---|---|---|---|---|---|---|
| A01 | Combustion Turbine Generator Package Unit 1, natural gas fired | Heat Input: 480 MMBtu/hr Output: 44 MW | General Electric | LM-6000 | 260245 | Water injection, Selective Catalytic Reduction | Oxidation Catalyst |
| A03 | Combustion Turbine Generator Package Unit 2, natural gas fired | Heat Input: 480 MMBtu/hr Output: 44 MW | General Electric | LM-6000 | 310891 | Water injection, Selective Catalytic Reduction | Oxidation Catalyst |
| A04 | Combustion Turbine Generator Package Unit 3, natural gas fired | Heat Input: 480 MMBtu/hr Output: 44 MW | General Electric | LM-6000 | 311668 | Water injection, Selective Catalytic Reduction | Oxidation Catalyst |
| A05 | Combustion Turbine Generator Package Unit 4, natural gas fired | Heat Input: 480 MMBtu/hr Output: 44 MW | General Electric | LM-6000 | 311724 | Water injection, Selective Catalytic Reduction | Oxidation Catalyst |
| A05 | Combustion Turbine Generator Package Unit 5, natural gas fired | Heat Input: 480 MMBtu/hr Output: 44 MW | General Electric | LM-6000 | 312189 | Water injection, Selective Catalytic Reduction | Oxidation Catalyst |

# Combustion Turbine Emission Calculations

*Emissions Calculation Methodology*

Combustion Turbines

*Emission Units A01 and A03 through A06*

Criteria pollutant emissions for Unit 1 are based on emission guarantees at the time of permitting in 1992. For Units 2-5, the hourly emissions of $PM_{10}$, $PM_{2.5}$, $SO_2$, and VOC are based on emission guarantees at the time of permitting in 1999. $NO_X$ and CO are also based on manufacturer's data provided at three different operating temperatures. The worst-case emission parameters are based on the data at 36°F, the annual emissions are based on the data at 66°F, and the data at 115°F is considered representative of emissions during the summertime.

Units 2 through 5 are subject to a group cap of 30,480 hours/year, therefore emissions are calculated as follows:

$$Pollutant\frac{lb}{hr} \times 30{,}480\frac{hr}{yr} \div 2000\frac{lb}{ton} = Pollutant\frac{ton}{yr}$$

The control efficiency (CE) is assumed to be 50 percent due to estimated emissions reduction from the oxidation catalyst used for controlling CO emissions.

HAP emissions are calculated as follows:

$$EF\frac{lb}{mmBtu} \times 480\frac{mmBtu}{hr} \times (1 - CE) = HAP\frac{lb}{hr}$$

$$HAP\frac{lb}{hr} \times 8760\frac{hr}{yr} \div 2000\frac{lb}{ton} = HAP\frac{ton}{yr}$$

Emission factors for HAPs from AP-42 Section 3.1, Table 3.1-3.

## *Combustion Turbine Emission Calculations*

| Stack Gas Parameters | | | |
|---|---|---|---|
| **Ambient Temp (F)** | **115** | **66** | **36** |
| Stack $O_2$ % | 15.07 | 14.84 | 14.72 |
| Flowrate (dscfm) | 194276 | 203862 | 210182 |
| Raw $NO_X$ (ppm) | 1.98 | 2.05 | 2.09 |
| Raw CO (ppm) | 1.98 | 2.05 | 2.09 |

| Emission Limits (ppm) | | |
|---|---|---|
| | **$NO_X$** | **CO** |
| Unit 1 | 10 | 10 |
| Unit 2-5 | 2 | 2 |
| Corrected to: | 15 | % $O_2$ |

| HAP Emission Factors | (lb/mmBtu) |
|---|---|
| 1,3-Butadiene | 4.30E-07 |
| Acetaldehyde | 4.00E-05 |
| Acrolein | 6.40E-06 |
| Benzene | 1.20E-05 |
| Ethylbenzene | 3.20E-05 |
| Formaldehyde | 7.10E-04 |
| Naphthalene | 1.30E-06 |
| PAH | 2.20E-06 |
| Propylene Oxide | 2.90E-05 |
| Toluene | 1.30E-04 |
| Xylenes | 6.40E-05 |

Emission Factor Source: AP-42 Section 3.1 Table 3.1-3 with 50% emission control efficiency from oxidation catalyst

| *EU: A01 Unit #1 Emission Rates* | | |
|---|---|---|
| **Pollutant** | **lb/hr** | **ton/yr** |
| $PM_{10}$ | 3.00 | 7.70 |
| $PM_{2.5}$ | 3.00 | 7.70 |
| $NO_X$ | 14.00 | 48.00 |
| CO | 9.00 | 22.00 |
| $SO_2$ | 0.30 | 0.80 |
| VOC | 2.00 | 5.00 |
| *Hazardous Air Pollutants* | | |
| 1,3-Butadiene | 1.03E-04 | 4.52E-04 |
| Acetaldehyde | 9.60E-03 | 4.20E-02 |
| Acrolein | 1.54E-03 | 6.73E-03 |
| Benzene | 2.88E-03 | 1.26E-02 |
| Ethylbenzene | 7.68E-03 | 3.36E-02 |
| Formaldehyde | 1.70E-01 | 7.46E-01 |
| Naphthalene | 3.12E-04 | 1.37E-03 |
| PAH | 5.28E-04 | 2.31E-03 |
| Propylene Oxide | 6.96E-03 | 3.05E-02 |
| Toluene | 3.12E-02 | 1.37E-01 |
| Xylenes | 1.54E-02 | 6.73E-02 |
| TOTAL HAPs | 0.25 | 1.08 |

Turbine heat input rating: 480 mmBtu/hr
Annual HAP emissions calculated using 8,760 hour per year

## *Combustion Turbine Emission Calculations* continued

| ***EU: A03-A06 Units #2-5 Short Term Emission Rates (lb/hr)*** | | | | |
|---|---|---|---|---|
| | **Temp (F)** | | | **Worst-** |
| **Pollutant** | **115** | **66** | **36** | **Case** |
| $PM_{10}$ | 2.50 | 2.50 | 2.50 | 2.50 |
| $PM_{2.5}$ | 2.50 | 2.50 | 2.50 | 2.50 |
| $NO_X$ | 2.75 | 3.00 | 3.15 | 3.15 |
| CO | 1.67 | 1.83 | 1.92 | 1.92 |
| $SO_2$ | 0.30 | 0.30 | 0.30 | 0.30 |
| VOC | 2.00 | 2.00 | 2.00 | 2.00 |
| *Hazardous Air Pollutants* | | | | |
| 1,3-Butadiene | 1.03E-04 | 1.03E-04 | 1.03E-04 | 1.03E-04 |
| Acetaldehyde | 9.60E-03 | 9.60E-03 | 9.60E-03 | 9.60E-03 |
| Acrolein | 1.54E-03 | 1.54E-03 | 1.54E-03 | 1.54E-03 |
| Benzene | 2.88E-03 | 2.88E-03 | 2.88E-03 | 2.88E-03 |
| Ethylbenzene | 7.68E-03 | 7.68E-03 | 7.68E-03 | 7.68E-03 |
| Formaldehyde | 1.70E-01 | 1.70E-01 | 1.70E-01 | 1.70E-01 |
| Naphthalene | 3.12E-04 | 3.12E-04 | 3.12E-04 | 3.12E-04 |
| PAH | 5.28E-04 | 5.28E-04 | 5.28E-04 | 5.28E-04 |
| Propylene Oxide | 6.96E-03 | 6.96E-03 | 6.96E-03 | 6.96E-03 |
| Toluene | 3.12E-02 | 3.12E-02 | 3.12E-02 | 3.12E-02 |
| Xylenes | 1.54E-02 | 1.54E-02 | 1.54E-02 | 1.54E-02 |
| TOTAL HAPs | 0.25 | 0.25 | 0.25 | 0.25 |

Emission rates do not include SU/SD emissions

Turbine heat input rating: 480 mmBtu/hr

| **Annual Emissions (ton/yr) - maximum rate single unit @ 8760 hr/year** | | | **Annual emissions @ 8760 hr/yr *** | **Capped emissions @ 30,480 hr/yr *** |
|---|---|---|---|---|
| | Unit 1 | Unit 2-5 | Unit 1 | Unit 2-5 |
| $PM_{10}$ | 7.70 | 10.95 | 7.70 | 38.10 |
| $PM_{2.5}$ | 7.70 | 10.95 | 7.70 | 38.10 |
| $NO_X$ | 48.00 | 13.14 | 48.00 | 45.72 |
| CO | 22.00 | 8.00 | 22.00 | 27.83 |
| $SO_2$ | 0.80 | 1.31 | 0.80 | 4.57 |
| VOC | 5.00 | 8.76 | 5.00 | 30.48 |
| *Hazardous Air Pollutants* | | | | |
| 1,3-Butadiene | 4.52E-04 | 4.52E-04 | 4.52E-04 | 1.57E-03 |
| Acetaldehyde | 0.04 | 0.04 | 0.04 | 0.15 |
| Acrolein | 0.01 | 0.01 | 0.01 | 0.02 |
| Benzene | 0.01 | 0.01 | 0.01 | 0.04 |
| Ethylbenzene | 0.03 | 0.03 | 0.03 | 0.12 |
| Formaldehyde | 0.75 | 0.75 | 0.75 | 2.60 |
| Naphthalene | 1.37E-03 | 1.37E-03 | 1.37E-03 | 4.75E-03 |
| PAH | 2.31E-03 | 2.31E-03 | 2.31E-03 | 8.05E-03 |
| Propylene Oxide | 0.03 | 0.03 | 0.03 | 0.11 |
| Toluene | 0.14 | 0.14 | 0.14 | 0.48 |
| Xylenes | 0.07 | 0.07 | 0.07 | 0.23 |
| TOTAL HAPs | 1.08 | 1.08 | 1.08 | 3.76 |

*Indicates values that include SU/SD emissions

# Applicable Requirements

| Citation | Title | Applicability | Compliance Method/ Applicable Test Method | Compliance Status |
|---|---|---|---|---|
| AQR Section 00 | Definitions | Applicable – The facility must use the definitions in this section when applying the AQR rules for the facility. | The facility will meet applicable compliance and test methods should new definitions apply. | The Facility complies with applicable requirements. |
| AQR Section 04 | Control Officer | Applicable – The Control Officer or designated representative may enter into the Facility property, with or without prior notice, at any reasonable time for purpose of establishing compliance with permit regulations | NV Energy will allow Control Officer to enter the Facility property as required. | The Facility complies with applicable requirements. |
| AQR Section 05 | Interference with Control Officer | Applicable – NV Energy shall not hinder, obstruct, delay, resist, interfere with, or attempt to interfere with the Control Officer. | NV Energy will allow Control Officer to operate as needed. | The Facility complies with applicable requirements. |
| AQR Section 08 | Persons Liable for Penalties-Punishment Defense | Applicable – NV Energy and employees will be individually and collectively liable to any penalty or punishment from AQR. | NV Energy will adhere to the rules stipulated in applicable AQR regulations. | The Facility complies with applicable requirements. |
| AQR Section 09 | Civil Penalties | Applicable – The facility as a whole is subject to rule. The rule stipulates penalties for AQR violations. | NV Energy will adhere to the rules stipulated in applicable AQR regulations. | The Facility complies with applicable requirements. |
| AQR Section 10 | Compliance Schedule | Not applicable | Compliance schedule standards repealed in 2019. | Not applicable |
| AQR Section 11 | Ambient Air Quality Standards | Not applicable | Ambient air quality standards repealed 2014. | Not applicable |
| AQR Section 12.0 | Applicability and General Requirements | Applicable- The facility is subject to these requirements. Rule outlines source applicability, requirement for a source to obtain a permit, and transition for sources that received permit prior to rulemaking | The facility applied for and received ATC permits from DAQ prior to commercial operations. NV Energy will comply with the requirements for ATCs. | The facility complies with applicable requirements. |
| AQR Section 12.2 | Permit Requirements For Major Sources In Attainment Areas (Prevention Of Significant Deterioration) | Not applicable – The facility is a synthetic minor source for $PM_{10}$ and $NO_X$ and is a minor source of other priority pollutants. | Not applicable<br>The facility complies with the applicable regulations of the Section and with the requirements of 40 CFR §52.21. The Part 70 permit has relevant compliance, recordkeeping and reporting requirements. BACT analysis, air quality analysis, and visibility and additional impact analysis was performed for original ATC permits. | The facility complies with applicable requirements. |
| AQR Section 12.3 | Permit Requirements For Major Sources In Nonattainment Areas | Not Applicable – The facility is not located in a non-attainment area. Clark County is designated as Attainment or Unclassifiable for applicable NAAQS. | Not applicable. | Not applicable |
| AQR Section 12.4 | Authority to Construct Application And Permit Requirements For Part 70 Sources | Applicable – The facility is subject to the ATC requirements. The facility has applied for ATC permits from DAQ. | The facility has applied for and received ATC permits from DAQ as required. NV Energy will continue to comply with the requirements for ATCs. | The facility complies with applicable requirements. |
| AQR Section 12.5 | Part 70 Operating Permit Requirements | Applicable – The facility is subject to the Title V Operating Permit requirements. This | NV Energy complies with the requirements for Title V Permits outlined in this AQR Section and with the current Title V permit. This application is being | The facility complies with |

| Citation | Title | Applicability | Compliance Method/ Applicable Test Method | Compliance Status |
|---|---|---|---|---|
| | | section is both federally and locally enforceable. | submitted within 18 months and 6 months of the expiration date of the current permit. | applicable requirements. |
| AQR Section 12.9 | Annual Emissions Statement and Inventory Requirement | Applicable – Every major stationary source shall complete and submit an annual emissions inventory and annual emissions statement. | Annual emissions inventory and emissions statement is submitted by March 31st each year. | The facility complies with applicable requirements. |
| AQR Section 12.10 | Continuous Monitoring Requirements | Applicable - The Control Officer may require any source of regulated air pollutants, to monitor, sample or perform other studies to quantify emissions or the levels of air pollution that may be reasonably attributable to such source. | LVGS is subject to continuous monitoring requirements in 40 CFR 60 and 40 CFR 75. $NO_X$ and CO CEMS have been installed on the turbine stacks. All required protocols and test plans have been submitted. | In compliance |
| AQR Section 13 | National Emission Standards for Hazardous Air Pollutants | Applicable – Requirements of 40 CFR 61 and 40 CFR 63 are incorporated by reference. LVGS is subject to Subpart ZZZZ NESHAP regulations for Stationary Reciprocating Internal Combustion Engines. | The facility complies with the applicable requirements of 40 CFR Part 61 and 40 CFR Part 63 subpart ZZZZ for emergency diesel engines and fire pumps through compliance with the relevant permit conditions. | In compliance |
| AQR Section 14 | New Source Performance Standards | Applicable – Requirements of 40 CFR 60 are incorporated by reference. LVGS is subject to NSPS regulations Subpart GG - Standards of Performance for Stationary Gas and Combustion Turbines. | LVGS complies with all applicable requirements in 40 CFR 60 through compliance with the relevant permit conditions. | In compliance |
| AQR Section 18 | Permit and Technical Service Fees | Applicable – LVGS will be required to pay all applicable permit and technical service fees. | All applicable fees have been paid. | In compliance |
| AQR Section 21 | Acid Rain Continuous Emission Monitoring | Applicable – The facility is an affected facility and is required to meet the requirements for the monitoring, recordkeeping, and reporting of SO2, NOx, and CO2 emissions. | CEMS have been installed and certified as required by DAQ and EPA. NV Energy has submitted required CEMS plans, test protocols, and CEMS certifications to DAQ and EPA CAMD. | The facility complies with applicable requirements. |
| AQR Section 22 | Affirmative Defense for Excess Emissions due to Malfunctions, Startup, and Shutdown | Applicable – Any upset, breakdown, emergency condition, or malfunction which causes emissions of regulated pollutants in excess of permit limits must be reported to Control Officer. | Any upset, breakdown, or malfunction in which emissions exceed any permit limit shall be reported to the Control Officer per AQR Section 25 requirements included in the permit. | The facility complies with applicable requirements. |
| AQR Section 25 | Emission of Visible Air Contaminants | Applicable – Opacity for the facility must not exceed an average of 20 percent for more than 6 consecutive minutes. | Compliance determined by quarterly visible emission checks and corrective actions to minimize emissions if visible emissions are observed. | The facility complies with applicable requirements. |
| AQR Section 26 | Fuel Burning Equipment | Applicable – The PM emission rates are well below those established based on Section 28 requirements. | Compliance with permit emission limits. | The facility complies with applicable requirements. |
| AQR Section 28 | Prohibition of Nuisance Conditions | Applicable – No person shall cause, suffer or allow the discharge from any source whatsoever such quantities of air contaminants or other material which causes a nuisance. | The facility air contaminant emissions are controlled by pollution control devices or good combustion practices and will not cause a nuisance. The facility also implements dust control measures at the site. | The facility complies with applicable requirements. |

| Citation | Title | Applicability | Compliance Method/ Applicable Test Method | Compliance Status |
|---|---|---|---|---|
| AQR Section 40 | Acid Rain Continuous Emission Monitoring | Applicable – The facility is an affected facility and is required to meet the requirements for the monitoring, recordkeeping, and reporting of SO2, NOx, and CO2 emissions. | CEMS have been installed and certified as required by DAQ and EPA. NV Energy has submitted required CEMS plans, test protocols, and CEMS certifications to DAQ and EPA CAMD. | The facility complies with applicable requirements. |
| AQR Section 41 | Fugitive Dust | Applicable – The facility shall take necessary actions to abate fugitive dust and prevent from becoming airborne. | The facility utilizes appropriate best practices to not allow airborne fugitive dust. | The facility complies with applicable requirements. |
| AQR Section 42 | Open Burning | Applicable – Facility will obtain approved by Control Officer in advance of any open burning. | The facility will contact the DAQ and obtain approval in advance for applicable burning activities as identified in the rule. | The facility complies with applicable requirements. |
| AQR Section 43 | Odors in the Ambient Air | Applicable – An odor occurrence is a violation if the Control Officer is able to detect the odor twice within the period of an hour, if the odor causes a nuisance, and if the detection of odors is separated by at least 15 minutes. | The facility is a predominately natural gas-fired facility and is not expected to cause odors. | The facility complies with applicable requirements. |
| AQR Section 70 | Emergency Procedures | Applicable – The facility submitted an emergency standby plan for reducing or eliminating air pollutant emissions. | The facility has previously submitted an emergency standby plan and received the Part 70 Operating Permit. An updated emergency standby plan is being submitted with this application as **Appendix E**. | The facility complies with applicable requirements. |
| AQR Section 80 | Circumvention | Applicable – The facility as a whole is subject. Rule stipulates that NV Energy will not conceal emissions in any way at the facility. | NV Energy will disclose all emissions as required by state and federal regulations. | The facility complies with applicable requirements. |
| AQR Section 94 | Permitting and Dust Control for Construction and Temporary Commercial Activities | Applicable - The facility will need to apply for dust control permit in the event of construction activity greater than 1/4 acre or trench at least 100 ft in length (and aggregate greater than 1/4 acre). | The facility complied during initial construction and will continue to do so in the future as applicable. | The facility complies with applicable requirements. |
| AQR Section 120 | Reasonably Available Control Technology Demonstration and Determination Requirements for Major Stationary Sources in Ozone Nonattainment Areas | Applicable – Hydrographic Area 212 is classified as serious nonattainment. The facility has 50 tons or more potential to emit NOx and requires a RACT demonstration. | Submittal of this permit application and RACT analysis by August 1, 2025. | The facility complies with applicable requirements. |
| NRS Chapter 445B | Nevada Revised Statutes, Air Pollution | Applicable – The facility as a whole is subject to these requirements. | The facility will continue to comply with applicable regulations. | The facility complies with applicable requirements. |
| 42 USC §7401, et seq. | Clean Air Act | Applicable – The facility as a whole is subject to these requirements. | The facility will continue to comply with applicable regulations. | The facility complies with applicable requirements. |

| Citation | Title | Applicability | Compliance Method/ Applicable Test Method | Compliance Status |
|---|---|---|---|---|
| 40 CFR 52.21 | Prevention of Significant Deterioration (PSD) | Applicable – The facility is major source and is listed as one of the 28 source categories. Therefore, the facility is a major source for PSD. | The facility complies with the applicable regulations of the Section and with the requirements of AQR 12.2. BACT analysis, air quality analysis, and visibility and additional impact analysis was performed for original ATC permits. | The facility complies with applicable requirements. |
| 40 CFR 52 Subpart DD | Nevada SIP Rules | Applicable – LVGS is classified as a Title V source and is subject to the State Implementation Plan (SIP) for Nevada. | LVGS will continue to comply with the federally enforceable monitoring, testing, recordkeeping, and reporting requirements stipulated in the SIP. | The facility complies with applicable requirements. |
| 40 CFR 60 Subpart A | Standards of Performance for New Stationary Sources (NSPS) – General Provisions | Applicable – LVGS is subject to the NSPS requirements of 40 CFR 60 Subpart GG. | LVGS will continue to adhere to applicable monitoring, testing, recordkeeping, and reporting regulations. | In compliance |
| 40 CFR 60 Subpart GG | Standards of Performance for New Stationary Sources (NSPS) – Stationary Gas Turbines | Applicable – The Turbine Units (EUs:A01 and A03-A05) are subject to subpart GG. | The facility will continue to adhere to applicable monitoring, testing, recordkeeping, and reporting requirements. | The facility complies with applicable requirements. |
| 40 CFR 63 Subpart ZZZZ | National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines | Applicable – The diesel emergency fire pump engine is subject to this regulation as it is classified as an existing ICE located at an area source of HAP. | LVGS will continue to comply with the applicable work practices standards, emission limitations, operating and maintenance requirements, continuous compliance requirements, recordkeeping, reporting, and general provisions. | The facility complies with applicable requirements. |
| 40 CFR 64 | Compliance Assurance Monitoring | Not Applicable – The sources are exempt from the regulation. | Not applicable – refer to **Section 6** of this application for a detailed explanation. | Not applicable |
| 40 CFR 70 | Federally Mandated Operating Permits | Applicable – The regulations in this part provide for the establishment of comprehensive State air quality permitting systems consistent with the requirements of title V of the Clean Air Act (Act) (42 U.S.C. 7401, et seq.). | The facility complies with this regulation by maintaining a comprehensive, updated Title V Federal Operating Permit. | The facility complies with applicable requirements. |
| 40 CFR 72 | Acid Rain Permits Regulation | Applicable – The facility is an affected source. The turbines are applicable units. The regulations in this part identify affected sources and establish regulations for the Acid Rain Program, pursuant to title IV of the Clean Air Act, 42 U.S.C. 7401, et seq. | NV Energy complies with all the applicable requirements of the Acid Rain Permit Application located in **Appendix D** of this application. The facility has included a renewal application for the acid rain permit with this Title V renewal application. | The facility complies with applicable requirements. |
| 40 CFR 73 | Acid Rain Sulfur Dioxide Allowance System | Applicable – The facility is an affected source. The regulations in this part outline the stipulations for the allocation, exchange, etc. of acid rain $SO_2$ allowances. | NV Energy complies with all the applicable requirements of the Acid Rain $SO_2$ Allowance System. | The facility complies with applicable requirements. |
| 40 CFR 75 | Acid Rain Continuous Emission Monitoring | Applicable – The facility is an affected facility and is required to meet the requirements for the monitoring, recordkeeping and reporting of flow rate, $SO_2$, $NO_x$, and $CO_2$ emissions. | The facility will continue to adhere to the CEMS requirements stipulated in the rule including monitoring, recordkeeping, and reporting. | The facility complies with applicable requirements. |
| 40 CFR 82 | Protection of Stratospheric Ozone | Applicable – The facility as a whole is subject to the applicable rules regarding protection of the stratospheric ozone. | NV Energy complies with this regulation by keeping applicable records onsite. | The facility complies with applicable requirements. |

| Citation | Title | Applicability | Compliance Method/ Applicable Test Method | Compliance Status |
|---|---|---|---|---|
| 40 CFR Part 1068, Subpart A | General Compliance Provisions for Highway, Stationary, and Nonroad Programs | Applicable – LVGS is subject to the applicable rules regarding engines operate at the facility. | Records of location changes for portable or transportable nonroad engines are maintained and available to the Control Officer upon request. | In compliance |

NOTES:

1. The emission units at the Las Vegas Generating Station have the potential to emit greenhouse gases (GHG) greater than the $CO_2e$ thresholds specified in the GHG Tailoring rule. In addition, Las Vegas Generating Station is subject to the EPA GHG Mandatory Reporting Rule (MRR) in 40 CFR Part 98. Based on both federal definitions and the definitions in AQR Section 00, MRR is not considered an applicable requirement. Although Las Vegas Generating Station has a GHG PTE greater than the $CO_2e$ thresholds and is subject to MRR, there are no applicable requirements for GHG emissions, as specified in the GHG Tailoring Rule and defines in AQR Section 00, for inclusion in the Title V permit.
2. Abbreviations used in this table: AQR – Clark County Air Quality Regulations; CFR – Code of Federal Regulations; NRS – Nevada Revised Statutes; USC – United States Code

# ATTACHMENT 7B: NV Energy Clark Generating Station RACT

NVEnergy

RECEIVED CC DAQ
2025 JUL 28 PM4:03

July 24, 2025

Theodore Lendis
Planning Manager
Clark County Department of Environment and Sustainability
Division of Air Quality
4701 W. Russell Road
Las Vegas, NV 89118

Re: Response to Regulatory Notification – Major Stationary Source RACT Requirements
Letter Dated April 3, 2025

Dear Mr. Lendis:

Nevada Power Company, d/b/a, NV Energy (NVE) owns and operates Clark (Source 7), Sun Peak (Source 423) and Las Vegas (Source 329) Generating Stations, electrical power generating stations located in Hydrographic Area 212 within Clark County, Nevada. Per your letter dated April 3, 2025, the Division of Air Quality (DAQ) has informed NV Energy that compliance with applicable requirements of Air Quality Regulation (AQR) Section 120 is due on or before August 1, 2025, which is within 120 days after the Control Officer issues the written notice.

Reasonably Available Control Technology (RACT) applies to major stationary sources of nitrogen oxide (NOx) or volatile organic compounds (VOC). Major stationary sources defined in the Clean Air Act (CAA) Section §302(j) are any stationary facility or source of air pollutants which directly emits, or has the potential to emit, one hundred tons per year or more of any air pollutant. CAA Section 182(b) and (c) classifies major stationary source thresholds for NOx and VOC in moderate and serious nonattainment areas if the source emits or has the potential to emit 100 or 50 tons or more respectively. Clark Generating Station is a major source for both NOx and VOC while Sun Peak Generating Station is only major for NOx emissions under the moderate nonattainment designation.

On January 21, 2025, Hydrographic Area 212 within Clark County, Nevada received a serious nonattainment designation (Federal Register dated December 9, 2024). Consequently, the Las Vegas Generating Station underwent a RACT evaluation, as it qualifies as a major source of NOx under this designation. Las Vegas Generating Station is only major for NOx under the serious nonattainment designation.

Per the referenced letter and your email dated April 30, 2025, included below, and attached are:

- Applicable sections of the final "Case-By-Case RACT for Major VOC and NOx Sources in Hydrographic Area 212", prepared for Clark County Department of Environment and

Sustainability by RTP Environmental Associates, dated October 19, 2023, for Clark and Sun Peak Generating Stations.

- The required verbiage as stated in AQR Section 120.5(c) attesting that the RACT determination remains RACT for Clark and Sun Peak Generating Stations.

- A RACT evaluation and permit application as required in AQR Section 120 for Las Vegas Generating Station.

*I certify the basis of the Clark and Sun Peak RACT determinations continue to be RACT because there are no relevant changes to the available control technologies, technical feasibility, control effectiveness, cost effectiveness, or environmental, energy, and other impacts since the determinations were initially performed.*

If you have any questions or comments about the information presented in this letter, please do not hesitate to contact me at Mathew.Johns@nvenergy.com.

Sincerely,

Jason Hammons
Vice President, Generation
Responsible Official
NV Energy

cc: Matt Johns, NV Energy
Jason Reed, NV Energy
Chris Heintz, NV Energy

Clark (Source ID: 7) and

Sun Peak Generating Stations (Source ID: 423)

# Case-By-Case RACT for Major VOC and $NO_x$ Sources in Hydrographic Area 212

Prepared For:
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**October 19, 2023**

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Acceptable catalyst operating temperatures range from 400–1,250°F, with an optimum temperature range of 850–1,100°F. Below approximately 400°F, catalyst activity (and oxidation potential) is negligible. This temperature range is generally achievable with simple cycle GTs except at low-load startup and shutdown conditions. Oxidation catalysts have the potential to achieve approximately 90% reductions in "uncontrolled" emissions at steady-state operation.

#### 6.2.2.2 Dry Low $NO_x$ Combustion

The installation of DLNC is not generally considered an effective VOC control option, since the reduction in combustion temperature typically increases both CO and VOC emissions. However, a DLNC retrofit may reduce $NO_x$, CO, and VOC on some older turbines due to increased combustion efficiency.

#### 6.2.2.3 Good Combustion Practices/Good Maintenance Practices

GCP and GMP involve operating the turbine to maximize energy output or thermal efficiency while maintaining optimized oxygen levels to assure complete combustion. GCP can also involve running the equipment in accordance with the manufacturer's recommended settings and preventative maintenance schedules (Appendix 4, p. 2-2; Appendix 5, p. 2-3).

## 6.3 CLARK GENERATING STATION

### 6.3.1 Background

NV Energy owns and operates the CGS (Source ID: 7) in Whitney, NV. CGS is an electric power generating facility (SIC code 4911, NAICS code 221112) consisting of four natural gas-fired combined cycle combustion turbines (no supplemental firing)[202] and thirteen natural-gas fired simple cycle combustion turbines. Other emissions sources include two cooling towers, a diesel-powered emergency generator, a diesel-powered emergency fire pump, and gasoline dispensing operations. Table 6.3-1 summarizes affected units, current control equipment, and $NO_x$ and VOC emission limits.

[202] Turbine vintage is approximately 1980.

**Table 6.3-1. CGS RACT-Affected Units**

| Emission unit | | Description | Date of Commercial Operation | Control(s) | Emission Limits | |
|---|---|---|---|---|---|---|
| | | | | | $NO_x$ | VOC |
| A00704D (Unit 4) | | Natural gas-fired CT (60 MW) | 1973 | None | 1732.6 tpy | None |
| Unit 10 | A00701A (Unit 5) | Natural gas-fired CCU (85 MW) | ~1980 | LNB | 360 tpy<br>5 ppm@15% $O_2$<br>(1-hour)<br>19.11 lb/hr | |
| | A00702B (Unit 6) | | | | | |
| Unit 9 | A00705 (Unit 7) | Natural gas-fired CCU (85 MW) | ~1980 | LNB | | |
| | A00708 (Unit 8) | | | | | |
| A27–A38 (Units 11–22) | | Natural gas-fired CTs (57.9 MW) | 2008 | SCR/water injection<br>Oxidation catalyst | 30.96 tpy<br>5 ppm @ 15% $O_2$<br>(1-hour)<br>11.01 lb/hr | |

CGS currently operates as a major source under the conditions in its Title V OP (Source ID: 257), issued by DAQ. Since the 40 CFR Part 70 major-source classification is the same as the moderate attainment area major-source classification, RACT is required only if the permitted PTE for either VOC or $NO_x$ exceeds the Part 70 major source threshold. According to the source PTE summary in its current Title V OP, the facility's $NO_x$ PTE is 2,467 tpy and its VOC PTE is 217 tpy. The only units with a VOC PTE greater than 5 tpy are Units 4 and Units 5–8; the only units with a $NO_x$ PTE greater than 5 tpy are Units 4, 5–8, and 11–22 (all CTs/CCUs). The PTE for both $NO_x$ and VOC for all other sources is below 5 tpy. CGS is therefore subject to RACT for $NO_x$ for all turbines and VOC for Units 4 and 5–8.

### 6.3.2 RACT Analysis

DAQ conducted the following RACT analysis for $NO_x$ and VOC using data and information provided by NV Energy[203] as noted and where applicable.

#### 6.3.2.1 $NO_x$ RACT Analysis

##### *6.3.2.1.1 Baseline Emissions*

Baseline emissions establish the basis for the cost-effectiveness of each control option. DAQ used emissions data provided by NV Energy in this determination. For Unit 4, the baseline emissions were selected as the highest two-year average in the 2017–2021 period.[204] Because Units 5–8 are identical units with similar dispatch, the baseline emissions for these were selected as the highest two-year average in the 2017–2021 period for a single unit.[205] The baseline emissions for Units 11–22 also were selected as the highest two-year average in the 2017–2021 period for a

[203] Appendix 7

[204] The highest two-year average $NO_x$ emissions for Unit 4 is 37.65 tpy (2020–2021).

[205] The highest two-year average $NO_x$ emissions for Units 5–8 is 14.30 tpy (Unit 7, 2020–2021).

single unit.[206, 207] Actual emissions data were used for the cost evaluation of all units because total emissions for the facility were well below 70% of PTE.

#### *6.3.2.1.2 Potential Control Technologies*

Table 6.3-2 lists the potential control technologies considered for each unit. These technologies are consistent with the potential retrofit options in EPA guidance for combustion turbines.[208] Certain technologies were not considered technically feasible so were eliminated from consideration, as discussed below.

**Table 6.3-2. Technical Feasibility of $NO_x$ Control Technologies (CGS)**

| Control Technology | Unit 4 | Units 5–8 | Units 11–22 |
|---|---|---|---|
| SCR | Yes | Yes | Already equipped; increased ammonia injection is not technically feasible |
| DLNC | No | Already equipped | Yes |
| Water Injection | Possibly | No | Already equipped; increased water injection is not technically feasible |
| GCP | Yes | Yes | Yes |

For Unit 4, DLNC was eliminated from consideration because the vendor indicated[209] that the only retrofit option (GE 7B DLN1+) for this unit has never been implemented on this turbine frame. The addition of water injection was considered technically feasible for this evaluation, although further investigation would be required to confirm whether the retrofit has been demonstrated in practice on similar turbines.[210]

For Units 5–8, the addition of water injection was eliminated from consideration because the existing combustors were not designed for water injection and would have to be replaced.[211]

For Units 11–22, the use of increased ammonia injection rates with the existing SCR configuration was eliminated from consideration. The vendor indicated that adding ammonia beyond current design specifications would flood the catalyst with ammonia and reduce $NO_x$ removal.[212] Installation of DLNC is considered a feasible retrofit option, although the new combustor would not incorporate WSI.

---

[206] The highest two-year average $NO_x$ emission for Units 11–22 is 4.37 tpy (Unit 14, 2017–2018).

[207] DAQ also reviewed the 10-year forecasted dispatch of each unit and compared that to the highest two-year average operation in the preceding five years (2017–2021) using data provided by NV Energy. Because forecasted operation is significantly less than the maximum two-year annual average for each unit, use of the maximum two-year annual average $NO_x$ emissions is a conservative assumption (Appendix 7).

[208] "Alternative Control Techniques Document–$NO_x$ Emissions from Stationary Gas Turbines," January 1993. EPA.

[209] Appendix 7

[210] GE provides a water injection kit for MS7001B (Frame 7B) turbines, but more information is needed to determine whether it has been successfully installed and operated on other turbines.

[211] Appendix 7b

[212] Appendix 7b

#### 6.3.2.1.3 Control Equipment Costs

All control equipment costs are based on vendor estimates provided by NV Energy except as noted. Estimates have been modified as follows to provide consistency between RACT determinations for the various units:

- Total capital investment (TCI) includes initial capital investment (equipment cost only) and direct costs (direct installation cost only).
- Annualized TCI is calculated using the estimated equipment life of the various control options as specified in EPA's Cost Strategy Tool (CoST).[213] DAQ assumed an interest rate of 7.14% based on justification provided by NV Energy.[214]
- Annual operating costs include catalyst replacement cost only (for SCR options).

Potential energy impacts for certain upgrade options and several of the cost components described in the *EPA Air Pollution Control Cost Manual* were not included in order to simplify the analysis. Estimated costs are thus considered conservative and likely understate the actual costs associated with each control option; see Appendix 9 for detailed cost-effectiveness calculations.

For Unit 4, the SCR equipment, installation, and catalyst costs are based on a vendor estimate provided by NV Energy.[215] Estimated costs for a water injection retrofit are based on CoST,[216] adjusted for inflation. No additional costs are associated with the implementation of GCP.

For Units 5–8, SCR equipment, installation, and catalyst costs are based on the Unit 4 SCR cost estimate, scaled according to the "six-tenths factor" methodology.[217]

For Units 11–22, total installed LNB costs were estimated based on a vendor cost estimate for Unit 4 provided by NV Energy.

#### 6.3.2.1.4 Control Equipment Performance

For Unit 4, the achievable emissions level for the SCR retrofit option (4 ppm @ 15% $O_2$) is based on vendor data provided by NV Energy. The achievable emissions level for installation of water injection is based on the lowest RBLC determination for a similarly equipped unit (25 ppm @ 15% $O_2$).[218] The achievable emissions level for GCP assumes the current level of emissions will be maintained (~120 ppm @ 15% $O_2$).

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[213] CoST version 4.1

[214] Appendix 7

[215] Appendix 9

[216] EPA CoST version 4.1

[217] The rule of 'six-tenths' refers to a cost scaling method that can be used to estimate the cost of a similar item of different size or capacity based on the equation: $Cost_1/Cost_2 = (MW_1/MW_2)^{0.6}$

[218] The lowest RBLC determination for the period 2012–2022 for CTs equipped with water injection is 25 ppm@15% $O_2$ (see Appendix 10). Further investigation would be required to determine if this level of performance has been achieved on a similar turbine retrofit.

For Units 5–8, the achievable emissions level for the addition of SCR with the existing DLNC (DLNC/SCR) is based on the lowest RBLC determination (2 ppm at 15% $O_2$) for a similarly equipped unit.[219]

For Units 11–22, the achievable emissions level for the installation of DLNC with the existing SCR system (DLNC/SCR) is based on the lowest RBLC determination (2 ppm at 15% $O_2$) for a similarly equipped unit.[220]

*6.3.2.1.5 Benefits/Disbenefits*

**SCR.** SCR converts $NO_x$ (NO and $NO_2$) to nitrogen and oxygen by reacting the $NO_x$ compounds with ammonia in the presence of a catalyst. However, excess ammonia ("ammonia slip") is required to account for non-uniform distribution of gases across the catalyst bed. The amount of slip required to maintain $NO_x$ removal efficiency also increases over time due to catalyst deactivation. Because ammonia is a contributor to atmospheric fine particle formation, excess ammonia presents an adverse environmental impact. Other environmental concerns include accidental release of stored ammonia and the disposal of spent catalyst, which contains vanadium and/or titanium. SCR also presents an adverse energy impact, as the increased pressure drop across the catalyst bed reduces turbine efficiency.

**DLNC.** Maximum reduction in $NO_x$ is typically achievable only at higher load conditions with premixed operation (< 75% load). A significant lack of turn-down capability may be an issue for peaking units or units with variable demand. In addition, decreasing the firing temperature may increase CO and VOC emissions.

DLNCs have a lower combustion efficiency than conventional combustors, which adversely affects fuel efficiency for these units. The source would have to purchase additional generating capacity elsewhere to maintain total system generating capacity. Units equipped with water injection would incur an energy penalty due to the loss of power augmentation.[221]

**Water Injection.** Water injection increases power output due to the increased mass flow needed to maintain the turbine inlet temperature. However, it also reduces combustion efficiency, as some of the energy from the combustion gases is needed to overcome the latent heat of vaporization of the water, which can result in emissions increases of CO and VOC. It also causes non-uniform heat release within the combustor, which can create pressure oscillations that induce turbine vibration. Although combustor modifications can reduce the effects of these oscillations, they are not completely eliminated, which may affect equipment life.

[219] RBLC determinations for the period 2012–2022 for CCUs equipped with SCR/DLN range from 2–3 ppm @ 15% $O_2$ (see Appendix 10)

[220] RBLC determinations for the period 2012–2022 for simple cycle CT equipped with SCR/DLN range from 2-3.1 ppm @ 15% $O_2$ (see Appendix 10)

[221] Appendix 7

### *6.3.2.1.6 RACT Determination*

Table 6.3-3 provides a summary of the incremental control efficiency, achievable level of emissions, and cost-effectiveness of each control option used in the RACT determination for each unit. Additional supporting calculations are provided in Appendix 9.

**Table 6.3-3. $NO_x$ RACT Summary (CGS)**

| Control Equipment | Incremental Control Efficiency (%) | Achievable Emissions (ppm@15% $O_2$) | Cost Effectiveness ($/ton) |
|---|---|---|---|
| **Unit 4** | | | |
| SCR | 97% | 4 | $56,000 |
| Water Injection | 79% | 25 | $114,000 |
| GCP | N/A | ~120 | N/A |
| **Unit 5 – 8** | | | |
| SCR/LNB | 60% | 2 | $294,000 |
| LNB (existing controls) | N/A | 5 | N/A |
| **Units 11 – 28** | | | |
| SCR/LNB | 60% | 2 | $803,000 |
| SCR with WSI (existing controls) | N/A | 5 | N/A |

Table 6.3-4 summarizes the RACT determination for each unit. For Unit 4, DAQ determines that the existing use of GCP represents RACT. The annual $NO_x$ limit of 1,732.6 tpy (including startup, shutdown, and testing/tuning operation) does not require any specific control, so by itself does not establish RACT; DAQ has thus determined that RACT for $NO_x$ consists of an emissions limit of 120 ppm @ 15% $O_2$[222] during normal operation, with compliance to be determined by adhering to GCP. RACT during startup, shutdown, and other non-normal operation is also determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. All other technically feasible upgrade options were rejected due to excessive cost ($56,000–$114,000/ ton).

**Table 6.3-4. Proposed RACT-Based $NO_x$ Emission Limitations/Work Practices (CGS)**

| Emission Unit | Emission Limitation/Work Practice | | Monitoring Requirements |
|---|---|---|---|
| | Normal Operation | Startup/Shutdown | |
| Unit 4 | 120 ppm @ 15% $O_2$ GCP | GCP | Follow existing permit conditions |
| Units 5–8 | 5 ppm @ 15% $O_2$ (one-hour average) | GCP | CEMS (follow existing permit conditions) |
| Units 11–22 | | | |

For Units 5–8 and 11–22, DAQ determines that the existing $NO_x$ limits of 5 ppm @ 15% $O_2$ represent RACT for all units (excluding startup and shutdown). All technically feasible upgrade options were rejected due to excessive cost (> $294,000/ton for all units). Compliance shall be

[222] Based on existing PTE of 1,732.6 tpy, heat input limit of 899 MMBtu/hr, and continuous annual operation (8,760 hr/yr).

demonstrated using the existing continuous emission monitoring system (CEMS) on each unit based on a one-hour average. RACT during startup, shutdown, and other non-normal operation is also determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. NV Energy shall also follow the compliance requirements during startup and shutdown operation for each unit outlined in the source's current OP.[223]

Since the current OP does not adequately reflect the monitoring, recordkeeping, and reporting requirements needed to ensure compliance with GCP, the permit will be revised to require that the permittee (1) develop a best operating practices document that includes manufacturer's recommended O&M procedures (or other industry-accepted standards) and (2) provide adequate recordkeeping to ensure the procedures are being implemented.

#### 6.3.2.2 VOC RACT Analysis

The VOC RACT analysis includes Units 4–8, which are not currently equipped with any VOC controls. Units 11–22 are already equipped with oxidation catalyst limiting VOC PTE to less than 5 tpy and have therefore been excluded from the analysis.

##### *6.3.2.2.1 Baseline Emissions*

DAQ applied the same approach as the $NO_x$ RACT evaluation to establish baseline emissions.[224] For Unit 4, the baseline emissions were selected as the highest two-year average in the 2017–2021 period.[225] Because Units 5–8 are identical units with similar dispatch, the baseline emissions for these were selected as the highest two-year average in the 2017–2021 period for a single unit.[226] The baseline emissions for Units 11–22 also were selected as the highest two-year average in the 2017–2021 period for a single unit.[227, 228] Actual emissions data were used for the cost evaluation of all units because total emissions for the facility were well below 70% of PTE.

##### *6.3.2.2.2 Potential Control Technologies*

Table 6.3-5 lists the potential control technologies considered for each unit. These technologies are consistent with the potential retrofit options identified in EPA guidance for combustion turbines.[229] Certain technologies were not considered technically feasible and eliminated from consideration, as discussed below.

---

[223] Part 70 Operating Permit, Source ID 7, Clark Generating Station, Issued on October 5, 2020.

[224] Appendix 7

[225] The highest two-year average VOC emissions for Unit 4 is 2.05 tpy (2020-2021).

[226] The highest two-year average VOC emissions for Units 5–8 is 4.57 tpy (Unit 7 - 2020-2021).

[227] The highest two-year average VOC emissions for Units 11–22 is 0.48 tpy (Unit 14 - 2017-2018).

[228] DAQ also reviewed the 10-year forecasted dispatch of each unit and compared that to the highest two-year average operation in the preceding five years (2017–2021) using data provided by NV Energy. Because forecasted operation is significantly less than the maximum two-year annual average for each unit, the use of the maximum two-year annual average $NO_x$ emissions is a conservative assumption (see Appendix 7).

[229] *Air Pollution Control Cost Manual (6th edition)*, Chapter 3.2 (VOC Destruction Controls). January 2002, EPA.

**Table 6.3-5. Technical Feasibility of VOC Control Technologies (CGS)**

| Control Technology | Unit 4 | Units 5–8 |
|---|---|---|
| DLNC | No | Already equipped |
| OC | Yes | Yes |
| GCP | Yes | Yes |

The only option considered technically infeasible was a DLNC upgrade for Unit 4. Improved combustion efficiency may reduce VOC emissions, although (as discussed above) a DLNC retrofit for this turbine frame has not been demonstrated in practice.

*6.3.2.2.3 Control Equipment Costs*

DAQ applied the same methodology for estimating costs as the $NO_x$ RACT analysis. As noted above (Section 6.3.2.1.3), energy impacts and certain cost components described in the *EPA Air Pollution Control Cost Manual* were not included in order to simplify the analysis, which may understate actual costs associated with each control option (Appendix 9).

For Units 5–8, equipment, installation, and catalyst costs are based on a vendor estimate provided by NV Energy.[230] For Unit 4, oxidation catalyst (OC) costs are based on the Unit 4 vendor estimate and scaled using the "six-tenths factor" methodology. No additional costs are associated with the implementation of GCP.

*6.3.2.2.4 Control Equipment Performance*

For Unit 4, OC control effectiveness is based on a vendor estimate of 80% removal efficiency provided by NV Energy. For Units 5–8, OC control effectiveness is based on a vendor estimate of 2 ppm @ 15% $O_2$ provided by NV Energy.[231] Control effectiveness resulting from implementation of GCP is based on maintaining the current level of VOC emissions.

*6.3.2.2.5 Benefits/Disbenefits*

**Oxidation Catalysts.** The environmental impact of OC use includes potential increases of $NO_x$ from oxidation of NO and $SO_3$ formation resulting from oxidation of $SO_2$, both of which are precursors to formation of acid rain. Energy impacts include a reduction in turbine efficiency caused by an increase in exhaust back pressure across the catalyst bed.

*6.3.2.2.6 RACT Determination*

Table 6.3-6 provides a summary of the incremental control efficiency, achievable level of emissions, and cost-effectiveness of each control option used in the RACT determination for each unit. Additional supporting calculations can be found in Appendix 9.

[230] Appendix 7a

[231] See Appendix 7b. DAQ considered applying a more conservative removal efficiency assumption of 95% for Units 4–8, although cost effectiveness would be well above the acceptable cost threshold. The vendor would have to provide further justification of the feasibility of achieving such levels of emissions reduction.

**Table 6.3-6. CGS VOC RACT Summary**

| Control Equipment | Incremental Control Efficiency (%) | Achievable Emissions (tpy) | Cost Effectiveness ($/ton) |
|---|---|---|---|
| **Unit 4** | | | |
| Oxidation Catalyst | 80% | 0.41 | $318,000 |
| Good Combustion Practices | N/A | 2.05 | N/A |
| **Units 5 – 8** | | | |
| Oxidation Catalyst | 88% | 0.57 | $143,000 |
| Good Combustion Practices | N/A | 4.57 | N/A |

Table 6.3-7 summarizes the RACT determination for each unit. For Unit 4, DAQ determines that the existing requirement to use GCP represents RACT. The VOC limit of 94.5 tpy (including startup, shutdown, and testing/tuning operation) does not require any specific control, so by itself does not establish RACT. DAQ has thus determined that RACT for VOC consists of an emissions limit of 21.6 lb/hr[232] during normal operation, with compliance to be determined by adhering to GCP. RACT during startup, shutdown, and other non-normal operation is also determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. The use of oxidation catalyst has been eliminated due to excessive cost (~$318,000/ton).

**Table 6.3-7. Proposed RACT-Based VOC Emission Limitations (CGS)**

| Emission unit | Emission Limitation/Work Practice | | Monitoring Requirements |
|---|---|---|---|
| | Normal Operation | Startup/Shutdown | |
| Unit 4 | 21.6 lb/hr GCP | | Unit 4 |
| Units 5–8 | 5.01 lb/hr GCP | GCP | |

For Units 5–8, DAQ determines that the existing VOC limit of 5.01 lb/hr (excluding startup, shutdown, and testing/tuning operation) represents RACT based on the application of GCP. OC use was eliminated due to excessive cost (> $143,000/ton for all units). RACT during startup, shutdown, and other non-normal operation is also determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. NV Energy shall also follow the compliance requirements during startup and shutdown operation for each unit outlined in the source's current OP.[233]

Since the current OP does not adequately reflect the monitoring, recordkeeping, and reporting requirements needed to ensure compliance with GCP, the permit will be revised to require that the permittee (1) develop a best operating practices document that includes manufacturer's recommended O&M procedures (or other industry-accepted standards) and (2) provide adequate recordkeeping to ensure the procedures are being implemented.

[232] Based on existing PTE of 94.5 tpy continuous annual operation (8,760 hr/yr).

[233] Title V OP, issued October 5, 2020.

11. The Parties agree that NPC's rate design will use Generation Allocators, not Generation & Energy Allocators, which the Commission adopted to allocate generation demand costs in SPPC's 2019 rate case. (*Id.*)

12. The Parties agree that NPC's rate design will not include energy costs (Base Tariff Energy Rate ("BTER")) in adjusting class revenue requirement for policy considerations in Statement O, Tab "Passes." More broadly, while it is acceptable to list energy costs (BTER) in Cost of Service Study and Statement O, they should not be used in any BTGR calculations or "Interclass Revenue Adjustments." (*Id.* at 8.)

13. The Parties agree that NPC's rate design will not shift all claimed net energy metering ("NEM") revenue shortfalls to the corresponding otherwise applicable class (e.g., NMR schedules to RS schedule), which inflates NPC's calculated subsidy for the corresponding otherwise applicable class (e.g., RS). (*Id.*)

14. The Parties agree that NPC's rate design will use Exhibit Pollard Cert-20, Statement O-ECS-E Proposed Revenue Requirement-Proposed Rates, as adjusted and proposed in Exhibit 3 attached to the Stipulation ("Settlement Statement O"). In the event of any ambiguity or perceived divergence between the language of this Stipulation and the rates identified in Settlement Statement O, Settlement Statement O will control. (*Id.*)

15. The Parties agree to accept the rates contained in Settlement Statement O as the tariffed rates effective January 1, 2021. (*Id.*)

16. The Parties agree that when the claimed NEM revenue shortfalls are placed back to their appropriate rate classes (e.g., from RS to RS-NEM and RM to RM-NEM), Settlement Statement O shows that there is no subsidy for non-NEM residential customers. (*Id.*)

# ATTACHMENT 7C: NV Energy Sun Peak Generating Station RACT

NVEnergy

RECEIVED CC DAQ
2025 JUL 28 PM4:03

July 24, 2025

Theodore Lendis
Planning Manager
Clark County Department of Environment and Sustainability
Division of Air Quality
4701 W. Russell Road
Las Vegas, NV 89118

Re: Response to Regulatory Notification – Major Stationary Source RACT Requirements
Letter Dated April 3, 2025

Dear Mr. Lendis:

Nevada Power Company, d/b/a, NV Energy (NVE) owns and operates Clark (Source 7), Sun Peak (Source 423) and Las Vegas (Source 329) Generating Stations, electrical power generating stations located in Hydrographic Area 212 within Clark County, Nevada. Per your letter dated April 3, 2025, the Division of Air Quality (DAQ) has informed NV Energy that compliance with applicable requirements of Air Quality Regulation (AQR) Section 120 is due on or before August 1, 2025, which is within 120 days after the Control Officer issues the written notice.

Reasonably Available Control Technology (RACT) applies to major stationary sources of nitrogen oxide (NOx) or volatile organic compounds (VOC). Major stationary sources defined in the Clean Air Act (CAA) Section §302(j) are any stationary facility or source of air pollutants which directly emits, or has the potential to emit, one hundred tons per year or more of any air pollutant. CAA Section 182(b) and (c) classifies major stationary source thresholds for NOx and VOC in moderate and serious nonattainment areas if the source emits or has the potential to emit 100 or 50 tons or more respectively. Clark Generating Station is a major source for both NOx and VOC while Sun Peak Generating Station is only major for NOx emissions under the moderate nonattainment designation.

On January 21, 2025, Hydrographic Area 212 within Clark County, Nevada received a serious nonattainment designation (Federal Register dated December 9, 2024). Consequently, the Las Vegas Generating Station underwent a RACT evaluation, as it qualifies as a major source of NOx under this designation. Las Vegas Generating Station is only major for NOx under the serious nonattainment designation.

Per the referenced letter and your email dated April 30, 2025, included below, and attached are:

- Applicable sections of the final "Case-By-Case RACT for Major VOC and NOx Sources in Hydrographic Area 212", prepared for Clark County Department of Environment and

Sustainability by RTP Environmental Associates, dated October 19, 2023, for Clark and Sun Peak Generating Stations.

- The required verbiage as stated in AQR Section 120.5(c) attesting that the RACT determination remains RACT for Clark and Sun Peak Generating Stations.

- A RACT evaluation and permit application as required in AQR Section 120 for Las Vegas Generating Station.

*I certify the basis of the Clark and Sun Peak RACT determinations continue to be RACT because there are no relevant changes to the available control technologies, technical feasibility, control effectiveness, cost effectiveness, or environmental, energy, and other impacts since the determinations were initially performed.*

If you have any questions or comments about the information presented in this letter, please do not hesitate to contact me at Mathew.Johns@nvenergy.com.

Sincerely,

Jason Hammons
Vice President, Generation
Responsible Official
NV Energy

cc: Matt Johns, NV Energy
Jason Reed, NV Energy
Chris Heintz, NV Energy

Clark (Source ID: 7) and

Sun Peak Generating Stations (Source ID: 423)

# Case-By-Case RACT for Major VOC and $NO_x$ Sources in Hydrographic Area 212

Prepared For:
Clark County Department of Environment and Sustainability
4701 West Russell Road, Suite 200
Las Vegas, NV 89118
(702) 455-5942

Prepared by:
RTP Environmental Associates ("RTP")
304A West Millbrook Road
Raleigh, North Carolina 27609

**October 19, 2023**

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## 6.4 SUN PEAK GENERATING STATION, LAS VEGAS

### 6.4.1 Background

NV Energy owns and operates the SPGS (Source ID: 423). SPGS is an electric power generating facility (SIC code 4911, NAICS code 221112) consisting of three natural gas-fired simple cycle combustion turbines, and one 81-hp diesel power emergency generator with a diesel storage tank. Table 6.4-1 provides a summary of the affected units, current control equipment, and $NO_x$ and VOC emission limits.

Table 6.4-1. SPGS RACT-Affected Units

| Emission Unit | Description | Date of Commercial Operation | Control(s) | Emission Limits (all 3 units combined) | |
|---|---|---|---|---|---|
| | | | | $NO_x$ | VOC |
| A01 (Unit 3) | Natural gas/oil-fired CT (84.5 MW) | 1991 | Water injection | **Natural Gas**[234] 249.11 tpy 143.00 lb/hr 42 ppmvd@15% $O_2$ **#2 Oil**[235] 249.02 tpy 227.00 lb/hr 65 ppmvd@15% $O_2$ | **Natural Gas**[236] 3.59 tpy 2.06 lb/hr **#2 Oil**[237] 4.94 tpy 4.50 lb/hr |
| A02 (Unit 4) | Natural gas/oil- fired CT (84.5 MW) | 1991 | Water injection | | |
| A03 (Unit 5) | Natural gas/oil-fired CT (84.5 MW) | 1991 | Water injection | | |

SPGS is a Part 70 major stationary source for $NO_x$, a synthetic minor source for $SO_2$, and a minor source for all other pollutants. It currently operates as a major source under the conditions in its Title V OP (Source ID: 423), issued by DAQ. Since the 40 CFR Part 70 major-source classification is the same as the moderate attainment area major-source classification, RACT is required only if the permitted PTE for either VOC or $NO_x$ exceeds the Part 70 major source threshold. According to the source PTE summary in its current Title V OP, the facility's $NO_x$ PTE is 249 tpy (gas- or oil-firing) and its VOC PTE is 7.26 tpy. The source is subject to $NO_x$ or VOC RACT for any emission units whose $NO_x$ or VOC PTE is at least 5 tpy. For the turbines, $NO_x$ PTE is 249 tpy (oil or gas combustion); VOC PTE is 3.59 tpy for natural gas combustion and 4.94 tpy for oil combustion. Therefore, the turbines are subject to $NO_x$ RACT but not VOC RACT. The PTE for both $NO_x$ and VOC for the emergency generator is below 5 tpy, so it is not subject to RACT. SPGS is subject to RACT for $NO_x$ for all turbines only, since $NO_x$ and VOC emissions for all other sources are below the DAQ guidelines for RACT applicability (5 tpy).

### 6.4.2 $NO_x$ RACT Analysis

DAQ conducted the following analysis using data and information in the RACT analysis provided by NV Energy[238] as noted and where applicable.

[234] NSR ATC Modification 1, Revision 2 (04/29/10), AQR 12.5.2.6(b)
[235] NSR ATC Modification 1, Revision 2 (04/29/10), AQR 12.5.2.6(b)
[236] Title V Operating Permit (08/24/22), AQR 12.5.2.6(b)
[237] NSR ATC Modification 1, Revision 2 (04/29/10), AQR 12.5.2.6(b)
[238] Appendix 7

#### 6.4.2.1 Baseline Emissions

Baseline emissions establish the basis for the cost-effectiveness of each control option. DAQ used emission data provided by NV Energy for this determination. Because Units 3–5 are identical units with similar dispatch, the baseline emissions were selected as the highest two-year average in the 2017–2021 period for a single unit.[239] Actual emissions data were used for the cost evaluation because total emissions for the facility were well below 70% of PTE.

#### 6.4.2.2 Potential Control Technologies

Table 6.4-2 lists the potential control technologies considered for each unit. These are consistent with the potential retrofit options identified in EPA guidance for combustion turbines.[240] Certain technologies were not considered technically feasible so were eliminated from consideration, as discussed below.

**Table 6.4-2. Technical Feasibility of $NO_x$ Control Technologies (SPGS)**

| Control Technology | Units 3–5 |
|---|---|
| SCR | Yes |
| DLNC | Yes |
| SCR + DLNC | Yes |
| Increased water injection | No |
| GCP | Yes |

Installation of DLNC is considered a feasible option, but water injection would have to be eliminated because the new burners would not support it. DAQ also considered the use of increased water injection as a relatively inexpensive method of further $NO_x$ reductions, with the possibility of achieving a RACT level of 25 ppmv 15% $O_2$. However, this option was eliminated from consideration based on vendor information indicating these units are not capable of meeting this level of emissions with the current combustors.[241] The combination of DLNC and SCR is considered technically feasible, but it was eliminated from further consideration because the vendor performance estimate for SCR is comparable to the performance of DLNC with SCR based on the lowest RBLC determinations for similar equipped units (see discussion below in Section 6.4.3.2.1).

#### 6.4.2.3 Control Equipment Costs

All control equipment costs are based on vendor estimates provided by NV Energy except as noted. Estimates have been modified as follows to provide consistency between RACT determinations for the various units:

[239] The highest two-year average for $NO_x$ emissions for Units 3–5 is 32.19 tpy (Unit 3, 2020–2021).

[240] "Alternative Control Techniques Document–$NO_x$ Emissions from Stationary Gas Turbines," January 1993. EPA.

[241] Appendix 7b

peaking units or units with variable demand. In addition, decreasing the firing temperature may increase CO and VOC emissions.

DLNC have lower combustion efficiency than conventional combustors, which adversely affects fuel efficiency for these units. The source would need to purchase additional generating capacity elsewhere to maintain total system generating capacity. Units equipped with water injection would incur an energy penalty due to the loss of power augmentation.[247]

### 6.4.3 RACT Determination

Table 6.4-3 lists the incremental control efficiency, achievable level of emissions, and cost-effectiveness of each control option used in the RACT determination for each unit. Additional supporting calculations are in Appendix 9.

**Table 6.4-3. $NO_X$ RACT Summary (SPGS)**

| Control Equipment | Incremental Control Efficiency (%) | Achievable Emissions (ppm @ 15% $O_2$) | Cost Effectiveness ($/ton) |
|---|---|---|---|
| **Units 3-5** | | | |
| SCR | 95% | 2 | 82,700 |
| LNB | 76% | 9 | 47,700 |
| Water Injection (existing controls) | N/A | 42 | N/A |

Table 6.4-4 summarizes the RACT determination for each unit.

**Table 6.4-4. Proposed RACT-Based $NO_X$ Emission Limitations (SPGS)**

| Emission unit | Emission Limitation/Work Practice | | Monitoring Requirements |
|---|---|---|---|
| | Normal Operation | Startup/Shutdown | |
| Unit 3–5 | 42 ppm @ 15% O2 (three-hour average) | GCP | CEMS (follow existing permit requirements) |

DAQ determines that the existing $NO_X$ limit of 42 ppmvd @ 15% $O_2$ (3-hr average) while firing natural gas (excluding startup, shutdown, and testing/tuning operation) represents RACT based on the use of existing $NO_X$ controls. All upgrade options have been eliminated due to excessive cost (> $48,000/ton for all options/units). Compliance shall be demonstrated using CEMS, according to the monitoring and reporting procedures in the source's current OP. RACT during startup, shutdown, and other non-normal operation is also determined to be adherence to GCP during each of those modes of operation; emissions are considered too variable to establish an emissions limit, so the work practice standard of GCP is RACT. NV Energy shall also follow the compliance requirements during startup and shutdown operation for each unit outlined in the source's OP.

Since the current OP does not adequately reflect the monitoring, recordkeeping, and reporting requirements needed to ensure compliance with GCP, the permit will be revised to require that the permittee (1) develop a best operating practices document that includes manufacturer's

[247] See Appendix 7. Energy impacts were not accounted for in DAQ's cost effectiveness calculations.

recommended O&M procedures (or other industry-accepted standards) and (2) provide adequate recordkeeping to ensure the procedures are being implemented.

## 6.5 SAGUARO POWER COMPANY, HENDERSON

### 6.5.1 Background

Saguaro Power Company (SPC) (Source ID: 393) is an electric power generating facility (SIC code 4931, NAICS code 221112) that consists of two natural gas-/oil-fired CCTs (GE PG6541), each equipped with two 25 MMBtu/hr duct burners, two diesel starter engines, two natural gas-fired auxiliary boilers, and a cooling tower.

SPC is a major stationary source for $NO_x$ and a minor source for all other pollutants. SPC operates according to the conditions contained in the Title V OP issued by DAQ. Since the 40 CFR Part 70 major-source classification is the same as the moderate attainment area major-source classification, RACT is required only if the permitted PTE for either VOC or $NO_x$ exceeds the Part 70 major source threshold. According to the source PTE summary contained in the facility's current Title V OP, the facility's $NO_x$ PTE is 163.77 tpy and its VOC PTE is 13.36 tpy. For the turbines, the $NO_x$ PTE is 69.24 tpy and the VOC PTE is 4.29 tpy. Both limits include duct burner operation. The PTE for Auxiliary Boiler #1 is 13.94 tpy for $NO_x$ and 4.47 tpy for VOC. The PTE for Auxiliary Boiler #2 is 9.33 tpy for $NO_x$ and 0.15 tpy for VOC. The PTE for both $NO_x$ and VOC for each diesel starter engine is below 5 tpy.

Based on DAQ's RACT applicability guidelines, SPC is subject to RACT for $NO_x$ for both turbines and the auxiliary boilers. $NO_x$ and VOC emissions for all other sources are below the RACT applicability threshold (5 tpy). Table 6.5-1 provides a summary of the affected units, current control equipment, and $NO_x$ and VOC emission limits.

## Appendix C

## Public Utility Commission Capital Recovery Rate Information

# ATTACHMENT 7D: NV Energy Supplemental

NVEnergy

RECEIVED CC DAQ
2025 SEP 29 PM3:32

September 29, 2025

Michael Rael
Air Quality Supervisor
Clark County Department of Environment and Sustainability
Division of Air Quality
4701 W. Russell Road, Suite 200
Las Vegas, NV 89118

Re: Response to AQR 120 RACT Determination Letters for Clark, Sun Peak, and Las Vegas Generating Stations Dated September 8, 2025

Dear Mr. Rael:

In accordance with Division of Air Quality (DAQ) letter requests dated September 8, 2025, and emails dated September 18 and 23, 2025, for the referenced generating stations, Nevada Power Company, d/b/a NV Energy (NVE) is providing updated cost effectiveness information for combustion turbines EUs: A00704D, A00701A, A00702B, A00705, A00708, and A27-A38 at Clark Generating Station (Source ID: 00007), combustion turbines EUs: A01-A03 at Sun Peak Generating Station (Source ID: 00423) and combustion turbines EUs: A01 and A03-A06 at Las Vegas Generating Station (Source ID: 00329).

For the updated cost effectiveness calculations for Clark and Sun Peak Generating Stations, NVE used DAQ's Cost Effectiveness Calculations 42 through 49 from Appendix 9 of the 2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area document dated November 5, 2024 (PDF pages 1386 – 1393). For the updated calculations for Las Vegas Generating Station, NVE used the same costing information presented in Appendix B of the Response to Regulatory Notification – Major Stationary Source RACT Requirements letter dated April 3, 2025 submitted to DAQ on July 24, 2025. In all cases the baseline emissions data used in the previously submitted cost effectiveness calculations has been updated to reflect each referenced unit's potential to emit.

Review of the attached summary of the updated cost effectiveness and individual cost effectiveness calculations sheets referenced above shows that only Clark Station (Clark) Unit 4 (EU:A00704D) for NOx and Las Vegas Generation Station (LVGS) Unit 1 (EU: A01) for NOx, had cost effectiveness values of less than $5,500/ton removed. As opposed to installing selective catalytic reduction (SCR) pollution control devices on Clark Unit 4 and increasing the removal effectiveness of the SCR on LVGS Unit 1, NVE would propose to accept emission caps to limit the PTE emission rates for each of those two units.

At Clark Unit 4, NVE calculated an emission cap of 385.0 tons of NOx on a 12-month rolling total; at this level the cost effectiveness of further reductions in NOx emissions through the installation of SCR on this unit is just over $5,500/ton removed. An emission cap of 385.0 tons of NOx per year is equivalent to approximately 1,950 hours per year of operation at maximum heat input.

At LVGS Unit 1, NVE calculated an emission cap of 43.0 tons of NOx on a 12-month rolling total; at this level the cost effectiveness of upgrading the unit's existing SCR system to achieve an outlet emissions level of 2 ppm is just over $5,500/ton removed. An emissions cap of 43.0 tons of NOx per year equates to approximately 6,100 hours of operation at the maximum hourly NOx permitted limit of 14.0 lb/hr. For Units 2-5 (EUs: A03-A06) there are no NOx control alternatives available to improve the performance. The current NOx emission controls on these units (use of SCR with an emissions limit of 2 ppmvd @ 15% $O_2$) represent the most stringent NOx control alternative for natural gas-fired combustion turbines, and thus the current NOx controls are concluded to be representative of RACT.

NVE provides the following rationale for LVGS Unit 1 using different metrics (7.14% return on investment (ROI) vs 6.0% and 20 year equipment life vs 30 year equipment life as stated in AQR 120.5(a)(3)) for emission Unit 1 (EU:A01).

- DAQ approved use of this ROI in the 2015 Ozone NAAQS Attainment Plan for the Las Vegas Valley Moderate Nonattainment Area document dated November 5, 2024 (PDF Pages 587, 1,085, 1,092, and 1,134.

- Although "Book Life" for LVGS Unit 1 is shorter than 30 years the RACT analysis has been updated using a 30 year equipment life.

As discussed in the September 18, 2025, email, both Clark Unit 4 (EU:A00704D) and LVGS Unit 1 (EU:A01) hour of operation limitations are not being requested and are not required for compliance. Hour of operation limitations are more restrictive and over controlling as all hours of operation at either unit are not at the maximum heat input.

To show continuous compliance with the NOx limit (12-month rolling total) at Clark Unit 4 NVE suggests use of a parametric monitoring system that logs hourly fuel use, monthly average gross calorific value (GCV) of the fuel from the fuel supplier, hours of operation, and the NOx lb/MMBtu emission factor (0.44) used in the RACT analysis.

LVGS Unit 1 is an Acid Rain unit and has a certified continuous emissions monitoring system (CEMS) with NOx and $O_2$ monitors. Therefore, NVE would suggest requiring the same parametric monitoring information as for Clark Unit 4, except LVGS Unit 1 would use actual NOx/$O_2$ readings to calculate NOx lb/hr and tons to show compliance with the 12-month rolling total.

NV Energy requests that DAQ and NV Energy meet and discuss the results of the revised RACT analysis and suggested monitoring methods before proceeding with final actions. These

two units remain critical to serve customer load and changes in operating requirement based on DAQ review may impact on the proposed approach.

NVE looks forward to working with DAQ in complying with AQR Section 120.

> *I certify based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.*

If you have any questions or comments about the information presented in this letter, please do not hesitate to contact Chris Heintz Christopher.Heintz@nvenergy.com.

Sincerely,

Jason Hammons
Vice President, Generation
Responsible Official
NV Energy

cc: M. Johns, NV Energy
J. Reed, NV Energy
C. Heintz, NV Energy
S. Mathew, permitting Manager, DAQ
S. Jelinek, Stationary Sources Supervisor, DAQ

# Attachments

## Clark, Sun Peak, and Las Vegas Generating Stations

## Cost Effectiveness Calculations Using Potential to Emit

## Summary of Updated Cost Effectiveness Using Potential to Emit

| Facility | Emission Unit | Unit Name | Pollutant and Technology | PTE (NOx) | Capped PTE (NOx) | PTE (VOC) | Capped PTE (VOC) | Reductions (NOx TPY) | Capped Reductions (NOx TPY) | Reductions (VOC TPY) | Capped Reductions (VOC TPY) | Total Annualized Cost (NOx) | Total Annualized Cost (VOC) | Cost Effectiveness (NOx -$/ton) | Cost Effectiveness (VOC -$/ton) | Capped Cost Effectiveness (NOx -$/ton) | Capped Cost Effectiveness (VOC -$/ton) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Clark | A00704D | Unit 4 | NOx/SCR | 1732.6 | 292.0 | -- | -- | 1,674.8 | 282.3 | -- | -- | 2,050,224 | -- | 1,224 | -- | 5,502 | -- |
| | | | NOx/$H_2O$ Inj. | 1732.6 | 292.0 | -- | -- | 1,371.6 | 231.2 | -- | -- | 3,403,512 | -- | 2,481 | -- | 14,723 | -- |
| | | | VOC/Ox. Cat. | -- | -- | 94.5 | -- | -- | -- | 75.6 | -- | 5,536 | 418,501 | -- | 5,536 | -- | -- |
| | A00701A | Unit 5 | NOx/SCR_LNB | 90.0 | -- | -- | -- | 54.0 | -- | -- | -- | 1,914,166 | -- | 35,448 | | -- | -- |
| | | | VOC/Ox. Cat. | -- | -- | 21.90 | -- | -- | -- | 19.2 | -- | -- | 456,900 | -- | 23,843 | -- | -- |
| | A00702B | Unit 6 | NOx/SCR_LNB | 90.0 | -- | -- | -- | 54.0 | -- | -- | -- | 1,914,166 | -- | 35,448 | | -- | -- |
| | | | VOC/Ox. Cat. | -- | -- | 21.90 | -- | -- | -- | 19.2 | -- | -- | 456,900 | -- | 23,843 | -- | -- |
| | A00705 | Unit 7 | NOx/SCR_LNB | 90.0 | -- | -- | -- | 54.0 | -- | -- | -- | 1,914,166 | -- | 35,448 | | -- | -- |
| | | | VOC/Ox. Cat. | -- | -- | 21.90 | -- | -- | -- | 19.2 | -- | -- | 456,900 | -- | 23,843 | -- | -- |
| | A00708 | Unit 8 | NOx/SCR_LNB | 90.0 | -- | -- | -- | 54.0 | -- | -- | -- | 1,914,166 | -- | 35,448 | | -- | -- |
| | | | VOC/Ox. Cat. | -- | -- | 21.90 | -- | -- | -- | 19.2 | -- | -- | 456,900 | -- | 23,843 | -- | -- |
| | *A-27 though 38 | Units 11-22 | NOx/SCR_LNB | 30.96 | -- | -- | -- | 18.6 | -- | -- | -- | 1,552,300 | -- | 83,565 | -- | -- | -- |
| Sun Peak | A01 | Unit 3 | NOx/SCR | 83.04 | -- | -- | -- | 78.5 | -- | -- | -- | 1,908,082 | -- | 24,292 | -- | -- | -- |
| | | | NOx/LNB | 83.04 | -- | -- | -- | 62.8 | -- | -- | -- | 857,850 | -- | 13,652 | -- | -- | -- |
| | A02 | Unit 4 | NOx/SCR | 83.04 | -- | -- | -- | 78.5 | -- | -- | -- | 1,908,082 | -- | 24,292 | -- | -- | -- |
| | | | NOx/LNB | 83.04 | -- | -- | -- | 62.8 | -- | -- | -- | 857,850 | -- | 13,652 | -- | -- | -- |
| | A03 | Unit 5 | NOx/SCR | 83.04 | -- | -- | -- | 78.5 | -- | -- | -- | 1,908,082 | -- | 24,292 | -- | -- | -- |
| | | | NOx/LNB | 83.04 | -- | -- | -- | 62.8 | -- | -- | -- | 857,850 | -- | 13,652 | -- | -- | -- |
| LVGS | A01 | Unit 1 | NOx/SCR | 48.00 | 43.00 | -- | -- | 38.40 | 34.40 | -- | -- | 208,700 | -- | 5,435 | -- | 5,526 | -- |
| | A03-A06 | Units 2-5 | NOx/SCR | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |

* These units already have and SCR. Analysis looks at going from 5 ppm to 2 ppm.

| COST EFFECTIVENESS CALCULATION 42 | | |
|---|---|---|
| CLARK ~~COUNTY~~ GENERATING STATION (~~C~~CGS) | | |
| UNIT 4 (COMBUSTION TURBINE) | | Proposed PTE |
| **Emissions Unit** | 4 | 4 |
| Pollutant | NOx | NOx |
| Control Technology | SCR | SCR |
| Baseline Emissions (ppm@15% O2) | 120 | 120 |
| Controlled Emissions (ppm@15% O2) | 4 | 4 |
| ~~Baseline~~ Potential to Emit Emissions Rate (tpy) | 1732.60 | **292.0** |
| Controlled Emissions (tpy) | 57.753 | 9.733 |
| Emissions Reduction (%) | 97% | 97% |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | 10,100,000 | 10,100,000 |
| Direct & Indirect Costs | 7,000,000 | 7,000,000 |
| Total Capital Investment | 17,100,000 | 17,100,000 |
| Estimated Equipment Life, years | 15 | 30 |
| Interest Rate, % | 7.14 | 7.14 |
| Capital Recovery Factor | 0.111 | 0.082 |
| Annualized Total Capital Investment | 1,894,124 | 1,397,070 |
| | | |
| **Annual Operating Costs** | | |
| Catalyst | 156,100 | 156,100 |
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **2,050,224** | **1,553,170** |
| | | |
| **Cost Effectiveness (CE)** | | |
| Emissions Reduction (tpy) | 1674.8 | 282.3 |
| Cost Effectiveness ($/ton) | **1,224** | **5,502** |
| | | |
| | | |

Notes:

*1. SCR costs provided by NV Energy based on vendor estimate (see Attachment 7)*

*2. Achievable emissions for SCR and oxidation catalyst retrofit is based on vendor data provided by NV Energy (see "PMC Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle CT"*

*3. Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)*

*4. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)*

~~*5. Baseline NOx and VOC emissions (tpy) based on maximum two year annual average for the period 2017-2021 (see Attachment 7)*~~

| COST EFFECTIVENESS CALCULATION 43 | | |
|---|---|---|
| CLARK ~~COUNTY~~ GENERATING STATION (~~CCGS~~) | | |
| UNIT 4 (COMBUSTION TURBINE) | | |
| **Emissions Unit** | 4 | 4 |
| Pollutant | NOx | NOx |
| Control Technology | Water Injection | Water Injection |
| Baseline Emissions (ppm@15% O2) | 120 | 120 |
| Controlled Emissions (ppm@15% O2) | 25 | 25 |
| ~~Baseline~~ Potential to Emit Emissions Rate (tpy) | 1732.60 | 292.0 |
| Controlled Emissions (tpy) | 360.96 | 60.83 |
| Emissions Reduction (%) | 79% | 79% |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | | |
| Direct & Indirect Costs | | |
| Total Capital Investment | | |
| Estimated Equipment Life, years | | |
| Interest Rate, % | | |
| Capital Recovery Factor | | |
| Annualized Total Capital Investment | | |
| | | |
| **Annual Operating Costs** | | |
| | | |
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **3,403,512** | **3,403,512** |
| | | |
| **Cost Effectiveness (CE)** | | |
| Emissions Reduction (tpy) | 1371.6 | 231.2 |
| Cost Effectiveness ($/ton) | **2,481** | **14,723** |
| | | |
| | | |

Notes:

*1. Water injection costs based on EPA CoST Model (version 4.1):*

*Annual Cost (1999$) = annual cost multiplier x design capacity^annual cost exponent + annual base cost*

*Annual Cost (1999$) = 3700.2*600^0.95+0* *$ 1,612,386*

*Design capacity = (60 MW)(1000 kW/MW)(10,000 Btu/kWh)/1000000 = 600 MMBtu/hr*

*2. Present value cost adjustment (2022$) = Cost x CEPCI (2022) / CEPCI (YYYY)*

*CEPCI (8/2022)* *824.5*

*CEPCI (1999)* *390.6*

*3. Achievable emissions for water injection are based on the lowest RBLC determination for similarly equipped unit for 2012-2022 (see RBLC Determinations - Attachment 10). Further investigation may be required to confirm this level of performance.*

*4. Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)*

*5. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)*

*~~6. Baseline NOx and VOC emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 7)~~*

| COST EFFECTIVENESS CALCULATION 44 | |
|---|---|
| CLARK ~~COUNTY~~ GENERATING STATION (~~C~~CGS) | |
| UNIT 4 (COMBUSTION TURBINE) | |
| **Emissions Unit** | **4** |
| Pollutant | VOC |
| Control Technology | Oxidation Catalyst |
| Baseline Emissions (ppm@15% O2) | 85 |
| Controlled Emissions (ppm@15% O2) | 17 |
| ~~Baseline~~ Potential to Emit Emissions Rate (tpy) | 94.5 |
| Controlled Emissions (tpy) | 18.90 |
| Emissions Reduction (%) | 80% |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment | 2,030,000 |
| Direct & Indirect Costs | 1,500,000 |
| Total Capital Investment | 3,530,000 |
| Estimated Equipment Life, years | 30 |
| Interest Rate, % | 7.14 |
| Capital Recovery Factor | 0.082 |
| Annualized Total Capital Investment | 288,401 |
| | |
| **Annual Operating Costs** | |
| Catalyst | 130,100 |
| | |
| | |
| | |
| **Total Annualized Cost** | **418,501** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 75.6 |
| Cost Effectiveness ($/ton) | **5,536** |
| | |
| | |

Notes:

*1. Achievable emissions for SCR and oxidation catolyst retrofit is based on vendor data provided by NV Energy (see "PMC Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle CT"*

*2. Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)*

*3. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)*

*~~4. Baseline NOx and VOC emissions (tpy) based on maximum two year annual average for the period 2017-2021~~*

*5. Oxidation catalyst costs provided by NV Energy based on vendor estimate for Unit 5 and scaled using 'six-tenths factor' methodology (see Attachment 7)*

*6. Baseline emissions concencentration (ppm as propane) provided by NV Energy assuming current emissions 0.024 lb/MMBtu (see Attachment 7)*

| COST EFFECTIVENESS CALCULATION 45 | |
|---|---|
| CLARK ~~COUNTY~~ GENERATING STATION (~~C~~CGS) | |
| UNIT 5 - 8 (COMBINED CYCLE UNITS) | |
| **Emissions Unit** | 7 |
| Pollutant | NOx |
| Control Technology | SCR/LNB |
| Baseline Emissions (ppm@15% O2) | 5 |
| Controlled Emissions (ppm@15% O2) | 2 |
| ~~Baseline~~ Potential to Emit Emissions Rate (tpy) | 90.0 |
| Controlled Emissions (tpy) | 36.00 |
| Emissions Reduction (%) | 60% |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment | 12,447,496 |
| Direct & Indirect Costs | 8,626,977 |
| Total Capital Investment | 21,074,473 |
| Estimated Equipment Life, years | 30 |
| Interest Rate, % | 7.14 |
| Capital Recovery Factor | 0.082 |
| Annualized Total Capital Investment | 1,721,784 |
| | |
| **Annual Operating Costs** | |
| Catalyst | 192,382 |
| | |
| | |
| | |
| **Total Annualized Cost** | **1,914,166** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 54.0 |
| Cost Effectiveness ($/ton) | **35,448** |
| | |
| | |

Notes:

*1. SCR capital, installation, and catalyst cost is based on NV Energy Unit 4 vendor estimate scaled according to generating capacity using 'six-tenths factor' methodology (see Attachment 7):*

$$Cost_1/Cost_2 = (MW_1/MW_2)^{0.6}$$

*2. Achievable emissions for SCR/LNB is based the lowest RBLC determination for a similarly equipped unit (see RBLC Determinations - Attachment 10)*

*3. Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)*

*4. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)*

~~*5. Baseline NOx and VOC emissions (tpy) based on maximum two-year annual average for the period 2017–2021 (see Attachment 7)*~~

~~*6. Unit 7 was selected as representative of all units for the cost effectiveness evaluation because it has the highest baseline emissions.*~~

| COST EFFECTIVENESS CALCULATION 46 | |
|---|---|
| CLARK ~~COUNTY~~ GENERATING STATION (~~C~~CGS) | |
| UNIT 5 - 8 (COMBINED CYCLE UNITS) | |
| **Emissions Unit** | 7 |
| Pollutant | VOC |
| Control Technology | Oxidation Catalyst |
| Baseline Emissions (ppm@15% O2) | 16 |
| Controlled Emissions (ppm@15% O2) | 2 |
| ~~Baseline~~ Potential to Emit Emissions Rate (tpy) | 21.90 |
| Controlled Emissions (tpy) | 2.74 |
| Emissions Reduction (%) | 88% |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment | 2,500,000 |
| Direct & Indirect Costs | 1,500,000 |
| Total Capital Investment | 4,000,000 |
| Estimated Equipment Life, years | 30 |
| Interest Rate, % | 7.14 |
| Capital Recovery Factor | 0.082 |
| Annualized Total Capital Investment | 326,800 |
| | |
| **Annual Operating Costs** | |
| Catalyst | 130,100 |
| | |
| | |
| | |
| **Total Annualized Cost** | **456,900** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 19.2 |
| Cost Effectiveness ($/ton) | **23,843** |
| | |
| | |

Notes:

*According to generating capacity using 'six-tenths factor' methodology (see Attachment 9):*

*$Cost_1/Cast_2 = (MW_1/MW_2)^{0.6}$*

*2. Oxidation catalyst costs provided by NV Energy based on vendor estimate (see Attachment 7)*

*3. Achievable oxidation catalyst retrofit is based on vendor data provided by NV Energy (see "PMC Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle CT"*

*4. Capitol interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)*

*5. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)*

*~~6. Baseline NOx and VOC emissions (tpy) based on maximum two year annual average for the period 2017-2021 (see Attachment 7)~~*

*7. Baseline emissions concencentration (ppm as propane) provided by NV Energy assuming current emissions 0.0046 lb/MMBtu (see Attachment 7)*

*~~8. Unit 7 was selected as representative of all units for the cost effectiveness evaluation because it has the highest baseline emissions.~~*

| COST EFFECTIVENESS CALCULATION 47 | |
|---|---|
| CLARK ~~COUNTY~~ GENERATING STATION (~~C~~CGS) | |
| UNIT 11 - 22 (COMBUSTION TURBINES) | |
| **Emissions Unit** | 14 |
| Pollutant | NOx |
| Control Technology | SCR/LNB |
| Baseline Emissions (ppm@15% O2) | 5 |
| Controlled Emissions (ppm@15% O2) | 2 |
| ~~Baseline~~ Potential to Emit Emissions Rate (tpy) | 30.96 |
| Controlled Emissions (tpy) | 12.384 |
| Emissions Reduction (%) | 60% |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment | |
| Direct & Indirect Costs | |
| Total Capital Investment | 19,000,000 |
| Estimated Equipment Life, years | 30 |
| Interest Rate, % | 7.14 |
| Capital Recovery Factor | 0.082 |
| Annualized Total Capital Investment | 1,552,300 |
| | |
| **Annual Operating Costs** | |
| | |
| | |
| | |
| | |
| **Total Annualized Cost** | **1,552,300** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 18.6 |
| Cost Effectiveness ($/ton) | **83,565** |
| | |
| | |

Notes:

*1. LNB total instolled cost is based on CCGS Unit 4 vendor estimate (see Attachment 7a - RACT Analysis Request*

*2. SCR upgrade costs are based on Saguaro Power Company vendor estimate for 35 MW CCU and scaled*

*0.6*

*3. Achievable emissions for SCR/LNB is based the lowest RBLC determination for a similarly equipped unit*

*4. Capital interest rate based on interest rate for other capital projects approved by the public utility commission*

*5. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)*

*6. Baseline NOx and VOC emissions (tpy) based on maximum two-year annual average for the period 2017-*

*7. Unit 14 was selected as representative of all units for the cost effectiveness evaluation because it has the highest baseline emissions.*

| COST EFFECTIVENESS CALCULATION 48 | |
|---|---|
| SUN PEAK GENERATING STATION (SPGS) | |
| UNITS 3-5 (COMBUSTION TURBINES) | |
| **Emissions Unit** | 3 |
| Pollutant | NOx |
| Control Technology | SCR |
| Baseline Emissions (ppm@15% O2) | 37 |
| Controlled Emissions (ppm@15% O2) | 2 |
| ~~Baseline~~ Potential to Emit Emissions Rate (tpy) | 83.04 |
| Controlled Emissions (tpy) | 4.49 |
| Emissions Reduction (%) | 95% |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment | 12,500,000 |
| Direct & Indirect Costs | 8,500,000 |
| Total Capital Investment | 21,000,000 |
| Estimated Equipment Life, years | 30 |
| Interest Rate, % | 7.14 |
| Capital Recovery Factor | 0.082 |
| Annualized Total Capital Investment | 1,715,700 |
| | |
| **Annual Operating Costs** | |
| Catalyst | 192,382 |
| | |
| | |
| | |
| **Total Annualized Cost** | **1,908,082** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 78.5 |
| Cost Effectiveness ($/ton) | **24,292** |
| | |
| | |

Notes:

*1. SCR total installed cost is based on SPGS vendor estimate (see Attachment 7a - RACT Analysis Request for Supporting Documentation (1/30/2023))*

*2. SCR catalyst cost is based on vendor estimate for ~~E~~CGS Unit 4 (see Attachment 7a - RACT Analysis Request for Supporting Documentation (1/30/2023))*

*3. Achievable emissions for SCR is based on vendor data provided by NV Energy (see Attachment 7a - RACT Analysis Request for Supporting Documentation (1/30/2023))*

*4. Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)*

*5. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)*

*~~6. Baseline NOx (tpy) based on maximum two year annual average for the period 2017-2021 (see Attachment 7 - NV Energy RACT Analysis)~~*

*~~7. Unit 3 was selected as representative of all units for the cost effectiveness evaluation because it has the highest baseline emissions.~~*

| COST EFFECTIVENESS CALCULATION 49 | |
|---|---|
| SUN PEAK GENERATING STATION (SPGS) | |
| UNITS 3-5 (COMBUSTION TURBINES) | |
| **Emissions Unit** | 3 |
| Pollutant | NOx |
| Control Technology | LNB |
| Baseline Emissions (ppm@15% O2) | 37 |
| Controlled Emissions (ppm@15% O2) | 9 |
| ~~Baseline~~ Potential to Emit Emissions Rate (tpy) | 83.04 |
| Controlled Emissions (tpy) | 20.20 |
| Emissions Reduction (%) | 76% |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment | 9,000,000 |
| Direct & Indirect Costs | 1,500,000 |
| Total Capital Investment | 10,500,000 |
| Estimated Equipment Life, years | 30 |
| Interest Rate, % | 7.14 |
| Capital Recovery Factor | 0.082 |
| Annualized Total Capital Investment | 857,850 |
| | |
| **Annual Operating Costs** | |
| | |
| | |
| | |
| | |
| **Total Annualized Cost** | **857,850** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 62.8 |
| Cost Effectiveness ($/ton) | **13,652** |
| | |
| | |

Notes:

1. *Achievable emissions for LNB are based on the vendor estimate (see Attachment 7 - NV Energy RACT Analysis)*

2. *Capital interest rate based on interest rate for other capital projects approved by the public utility commission (see Attachment 7)*
3. *Estimated equipment life for all control options based on EPA CoST Model (version 4.1)*

~~*4. Baseline NOx (tpy) based on maximum two year annual average for the period 2017-2021 (see Attachment 7 - NV Energy RACT Analysis)*~~
~~*5. Unit 3 was selected as representative of all units for the cost effectiveness evaluation because it has the highest baseline emissions.*~~

**LVGS Unit 1**
**SCR System Upgrade**
**Summary of Economic Impact**

| | | =PTE Input | | |
|---|---|---|---|---|
| | | *Basis* | | |
| Baseline Operation (hours/yr) | 1,523.7 | *Highest two-year average in past five years* | | |
| Baseline NOx Emissions Level | | | PTE | Cap (PTE) |
| (tons/yr) | 6.32 | ***Highest two-year average in past five years*** | 48.00 | 43.00 |
| (avg lb/MMBtu) | 0.031 | *Plant data* | 0.031 | 0.031 |
| (ppm @ 15% O2) | 10 | *permit limit* | 10 | 10 |
| Achievable Emissions Level | | | | |
| (ppm @ 15% O2) | 2 | *estimate (permit limit for Units 2 - 5)* | 2 | 2 |
| (tons/yr) | 1.26 | *calculated* | 9.60 | 8.60 |
| Annual Emissions Reduction (tons/yr) | 5.06 | *calculated* | 38.40 | 34.40 |
| Capital Equipment Cost | $880,000 | *Vendor (Environex) capital cost estimate* | $880,000 | $880,000 |
| Sales Tax | $40,480 | *4.6% Nevada sales tax* | $40,480 | $40,480 |
| Direct Installation Cost | - | *Included in capital cost estimate* | - | - |
| Indirect Installation Cost | $322,200 | *35% of capital equipment cost (OAQPS Manual)* | $322,200 | $322,200 |
| Total Capital Cost | **$1,242,680** | | **$1,242,680** | **$1,242,680** |
| Annualized Capital Cost | $101,500 | *30 yr equipment life, 7.14% ROI* | $101,500 | $101,500 |
| O&M Costs | | | | |
| Catalyst changeout | $69,400 | *5 year life, 7.14% ROI, Vendor catalyst cost* | $69,400 | $69,400 |
| Annual maintenance | $6,200 | *0.5% of total capital investment (OAQPS Manual)* | $6,200 | $6,200 |
| NH3 usage | $1,900 | *Estimated additional NH3 consumption at 1.05 lbmol NH3/lbmol NOx removed and $0.69/gal* | $14,500 | $13,000 |
| Total | **$77,500** | | **$90,100** | **$88,600** |
| Total Annualized Cost | **$179,000** | | **$191,600** | **$190,100** |
| **Cost Effectiveness ($/ton)** | **$35,403** | | **$4,990** | **$5,526** |

# ATTACHMENT 8A: Saguaro Power Company RACT

RECEIVED CC DAQ
2025 JUL 17 AM10:51

BROADBENT
8 West Pacific Ave., Henderson, NV 89015
[T] 702-563-0600 [F] 702-563-0610
broadbentinc.com

GREATING SOLUTIONS. BUILDING TRUST.

July 16, 2025

Project No. 05-01-239

Clark County Department of Environment and Sustainability
Division of Air Quality
4701 West Russell Road
Suite 200 – 2nd Floor
Las Vegas, Nevada 89118

**RE: Saguaro Power Company LP – Air Quality Source 393**
**Part 70 Operating Permit Significant Revision Application**

On behalf of Saguaro Power Company LP (Saguaro), Broadbent & Associates, Inc. (Broadbent) is pleased to present the attached Part 70 Operating Permit significant revision application for the above referenced facility. The purpose of the application is for submission of the Reasonably Available Control Technology (RACT) analysis required by AQR Section 120 and to remove all conditions and emissions associated with two permanently shut down emission units (EUs A05 and A06).

Saguaro and Broadbent request that a draft copy of the permit and technical support document be emailed to both the source and the consultant for review prior to issuance. Should you have any questions or concerns regarding this submittal, please feel free to contact me at (702) 563-0600 or rharms@broadbentinc.com.

Sincerely,
Broadbent & Associates, Inc

Russell Harms
Senior Engineer

Reviewed and Approved by:

Scott McNulty
Principal Geologist/Air Quality Division Manager

Attachment: Part 70 Operating Permit Renewal Application

cc: Rob May, Saguaro Power Company, rob.may@camsops.com
Shruti Ramaker, Nightpeak Energy, sramaker@nightpeak.energy

# Title V (Part 70) Permit Application

## Clark County Department of Environment & Sustainability
## Division of Air Quality

**Submit Application to:**
**Division of Air Quality**
**4701 W. Russell Road, Suite 200**
**Las Vegas NV 89118**

**For DAQ Use Only**
RECEIVED CC DAQ
2025 JUL 17 AM10:51

## Section A: Permit Application Basis (check all that apply):

- ☐ Initial Permit
- ☐ Renewal Permit
- ☐ Administrative Revision
- ☐ Minor Revision*
- ■ Significant Revision*

*For all AQR 12.4.3.2 modifications, including Title V permit revisions based on AQR 12.4.3.2(d) and (e), use the Title V ATC application form (see Section G, "Application Instructions").

If applying for a revision: Has an NSR Authority to Construct already been issued? ☐ Yes ■ No

***Application Description:*** Describe the Title V permitting action being proposed, e.g., new process, change to equipment, change to permit conditions, Voluntarily Accepted Emission Limit (VAEL), incorporating ATC, etc.

Significant revision of the Part 70 Operating Permit. The revisions include the submittal of an AQR Section 120 RACT analysis (with conditions) and the removal of two emission units (EUs A05 and A06) and all conditions and emissions related to those emission units.

**Applications for a Part 70 permit shall include the information requested in Sections B–F.**

***Complete the fields in Sections B–F even if there is no change from the previous application.***

## Section B: Source Information

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**

Source ID No: 393

Source Name (as listed on Clark County/State of Nevada business license): Saguaro Power Company LP

Permit Expiration Date (existing permits only): 12/07/2025

City/County Business License #: 1000002.935

**Source Location Information**

| Number: | Direction (E., W.): | Street Name: | Cross Streets: |
|---|---|---|---|
| 435 | | Fourth Street | |

City: Henderson | State: NV | Zip: 89015

**Phone Numbers**

Office: (702) 558-1131 | Fax:

**North American Industry Classification System (NAICS) / Source Industry Classification Code**

Primary NAICS: 221112 | Additional NAICS (optional):

***Source Description:*** Describe the nature of your business, including processes and products.

Electric power generation.

## Section C: Company Information (AS LISTED ON THE SECRETARY OF STATE'S BUSINESS CERTIFICATE/FILING)

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**
If company ownership and/or name has changed, separately submit a Transfer of Ownership / Change of Name form+ fee (SS-PER-020-01).

Company Name: Saguaro Power Company

**Location Information**

| Number: | Direction (W., E.): | Street Name: | Street Type (Rd., Ave.): | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| 435 | | Fourth | St | | |
| City: Henderson | | | State: NV | ZIP: 89015 | |

***Proof of Company Name:*** Have you selected "New Permit" for the action type above? ☐ YES ■ NO

If YES, attach a printout of your company's business listing on the Nevada Secretary of State website, or other formal documentation that includes your company's full legal name.

**Phone Numbers**

| Office: (702) 558-1131 | Fax: |
|---|---|

**Type of Organization**

☐ Corporation ☐ Individual Owner ■ Partnership ☐ Government Entity ☐ Other

## Section D: Responsible Official (RO) Information

Has any of this information changed since the previous application? ☐ YES ■ NO **(Existing Permit Holders Only)**
If the RO has changed, separately submit a Declaration of Responsible Official form (RO-PER-003).

| Name: Rob May | Title: Site Manager |
|---|---|

**Location Information**

| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| 435 | | Fourth | ST | | |
| City: Henderson | | | State: NV | Zip: 89015 | |
| Email: rob.may@camsops.com | | | Primary Communication Method: ■ Email ☐ U.S. Postal | | |

**Phone Numbers**

| Office: (702) 558-1131 | Extension: | Cell: (702) 300-8181 | Fax: |
|---|---|---|---|

## Section E: Plant Manager/Environmental Representative Contact Information

| Name: Rob May | Title: Site Manager |
|---|---|

**Location Information**

| Number: | Direction: | Street Name: | Street Type: | Suite: | P.O. Box: |
|---|---|---|---|---|---|
| 435 | | Fourth | ST | | |
| City: Henderson | | | State: NV | Zip: 89015 | |
| Email: rob.may@camsops.com | | | Primary Communication Method: ■ Email ☐ U.S. Postal | | |

**Phone Numbers**

| Office: (702) 558-1131 | Extension: | Cell: (702) 300-8181 | Fax: |
|---|---|---|---|

## Section F: Billing Contact (Accounts Payable) Information (Optional)

| Name: | Title: |
|---|---|
| Email: | Primary Communication Method: ☐ Email ☐ U.S. Postal |

**Phone Numbers**

| Office: | Extension: | Cell: | Fax: |
|---|---|---|---|

## Section G: Application Instructions

1. For all construction, modification, or reconstruction, the owner or operator shall use the Title V ATC Application Form instead of this Title V Application Form.
2. An owner or operator of an existing or new Part 70 source shall obtain an Authority to Construct (ATC) Permit from the Control Officer before beginning actual construction or continuing with any of the following:
   a. Operating a new Part 70 source;
   b. "Major modification," as defined in AQR 12.2 or 12.3;
   c. Modification that increases the Part 70 source's potential to emit (PTE) by an amount equal to or greater than the minor New Source Review (NSR) significant level in AQR 12.4.2.1;
   d. Construction, modification, or reconstruction of an affected facility that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 60;
   e. Construction or reconstruction of a new source or of an affected source that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 63, including, but not limited to, construction or modification that requires preconstruction review under 40 CFR Part 63.5; or
   f. Modification to a solid waste incinerator unit, as defined by an applicable standard under 40 CFR Part 60.
3. For each Part 70 source, the owner or operator shall submit a timely and complete permit application in accordance with AQR 12.5.2.1.
4. Claims of confidentiality as to information submitted to EPA shall be made pursuant to applicable federal requirements in 40 CFR Part 2. Claims of confidentiality as to information submitted to the department shall be made pursuant to AQR 12.6.

## Section H: Application Supplemental Documents

*Information worksheets for common source types and emission units are posted on the DES website under **Applications/Forms → Stationary Source Permitting Forms → Emission Unit/Control Device Worksheets & Tools**. Applicants can use these documents to provide some of the technical information requested below.*

1. To comply with the requirements of AQR 12.5, the applicant shall submit all of the following information for initial and renewal Title V permit applications. For all other applications, the applicant may omit information that is not related to the proposed changes.
   A. Process description, including any alternative operating scenarios or federally enforceable emissions caps. Emission unit descriptions, including material/fuel usage and/or operating schedules.
   B. Emissions information with supporting calculations for all regulated air pollutants and HAPs, including fugitive emission rates, which shall include calculations of emission rates, short-term limits, hourly rates and tons per year emissions of each emission unit..
   C. Emission information in tons per year for each emission unit and the entire source.
   D. Description of all applicable requirements and/or exemptions, including Voluntarily Accepted Emission Limits (VAEL) and/or Plant-wide Applicability Limits (PAL).
   E. Air pollution control information with associated monitoring and testing requirements (example: for a baghouse, opacity test, pressure drop range and periodic inspections).
   F. Information related to stack height limitations and stack parameters.
   G. An explanation of any proposed exemptions from otherwise applicable requirements.
   H. Any alternative operating scenarios that are proposed in the application pursuant to paragraph (j) of Section 12.5.2.6, such information as is necessary for the Control Officer to define those scenarios and determine the applicable requirements for each proposed scenario.
   I. Compliance plan for all applicable requirements, as set forth in AQR 12.5.2.3(j).
   J. Compliance certification, as set forth in AQR 12.5.2.3(k).
   K. Compliance Assurance Monitoring plan, if determined to be applicable.
   L. Acid rain application, if applicable.

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M. Permit shield (optional).

N. Other information that may be necessary to implement and enforce other requirements of the Clean Air Act or determine the applicability of such requirements.

2. In addition to the requirements above, an application for a minor revision shall include the following:

   A. A description of the change, the emissions estimated to result from the change, and any new applicable requirements that will apply if the change occurs.

   B. Suggested draft permit conditions from the source, including a markup of the operating permit with the changes.

   C. Justification that the proposed modifications meet the criteria for use of minor revision procedures.

   D. All relevant forms, completed, for the Control Officer to submit to EPA and affected states or tribes.

## Section I: Application Advisories

**Permit Applications: Duty to Supplement or Correct (AQR 12.5.2.2).** When an applicant learns of missing or incorrect information in its permit application, it must provide or correct the information as soon as practicable. If additional requirements are deemed to apply after an applicant files a complete application but before the draft permit is released, the applicant must furnish all information needed to address them. The applicant's Responsible Official shall certify the additional information consistent with the requirements of Section 12.5.2.4.

1. **Small Business Assistance.** A DAQ program that offers free assistance on permitting and compliance matters to small businesses (100 employees or fewer). Please ask for an SBA representative at our front counter or call (702) 455-5942 to schedule an appointment.

2. **Fees and Payments.**

   A. Application Filing Fee: There is no application filing fee for Title V permits.

   B. Permit Issuance: All outstanding invoices for the source and associated with the parent company of the source must be paid in full; otherwise, DAQ cannot issue the source any permits. This includes the invoice for the permit fees resulting from this application.

   C. Payment: Invoices must be paid by check, money order, or credit card. Make checks and money orders payable to Division of Air Quality or DAQ. Credit card payments must be made in person at DAQ's main office.

## Section J: Grant of Authority

I authorize DAQ to transmit all communications, permits, and billing invoices by the primary communication method selected in Section D of this application. I acknowledge that if I select "Email," DAQ will transmit all listed items electronically. I further acknowledge that if I select "U.S. Postal Service," I may incur applicable postage fees.

## Section K: Certification of Truth, Accuracy, and Completeness

As the Responsible Official, I declare, under penalty of perjury under the laws of the state of Nevada, that the statements and information in this application and the attached supplemental documents and worksheets are true and correct. My signature acknowledges that I am subject to liability for perjury under NRS Chapter 199.145.

Responsible Official Certification (original "wet" signature) — Date: 7/16/25

Rob May

Printed Name of Responsible Official

**If this application is being submitted for an existing permit holder, it must be signed by an RO on file for this source.**

**Part 70 Permit Significant Revision Application**
**Saguaro Power Company**
**Source ID No. 393**
**July 16, 2025**

## 1.0 Purpose of Application

The purpose of this Part 70 Permit significant revision application is for submission of the Reasonably Available Control Technology (RACT) analysis required by AQR Section 120 and to remove all conditions and emissions associated with two permanently shut down emission units (EUs A05 and A06). The boilers were permanently shutdown in 2022 and the removal was also requested in a recent AQR section 12.4 application.

No other changes to the current Part 70 Permit are being proposed with this significant revision application.

## 2.0 Process Description

Saguaro Power Company (Saguaro) is an electricity and steam generating operation located at 435 Fourth Street, Henderson, Nevada 89015, which is in Hydrographic Area 212 (the Las Vegas Valley). Hydrographic Area 212 is designated serious nonattainment for the 2015 ozone NAAQS and attainment for the remaining regulated air pollutants. All generating and support processes at the site are grouped under SIC code 4931, "Electric and Other Services," and NAICS code 221112, "Fossil Fuel Electric Power Generation."

The facility operates two General Electric (GE) natural gas-combustion turbines (EUs: A01 and A02) each capable of producing 35 MW of electric power. Each turbine exhaust system is equipped with a heat recovery steam generator (HRSG) that uses the heat from exhaust gases to produce steam. Supplemental heat for this purpose is provided by natural gas fired duct burners (EUs: F05, F05a, F06, and F06a). The steam is then diverted to the turbines for $NO_x$ control and a steam turbine generator rated at 29.1 MW. Each HRSG includes an integrated Selective Catalytic Reduction (SCR) system for additional $NO_x$ control. Both turbines are permitted to operate 8,760 hours per year on natural gas and are subject to Acid Rain Permit requirements.

Two 520-hp Detroit diesel starter engines (EUs: A03 and A04) provide a means for starting up the turbines. The starter engines are employed only during startups, and each engine is permitted for 125 hours per year of run time.

In addition, there are two natural gas-fired boilers onsite. These are Indeck/Volcano and Nebraska boilers (EUs: A05 and A06). In the current permit, the Indeck/Volcano and Nebraska boilers are permitted to operate 8,760 hours per year and 6,000 hours per year, respectively.

The source also includes a cooling tower with three cells (EUs: A09a-A09c). This tower is permitted to operate 8,760 hours per year.

Figure 1 shows the processes described above. Table 1 lists all the emission units identified in the current Part 70 operating permit.

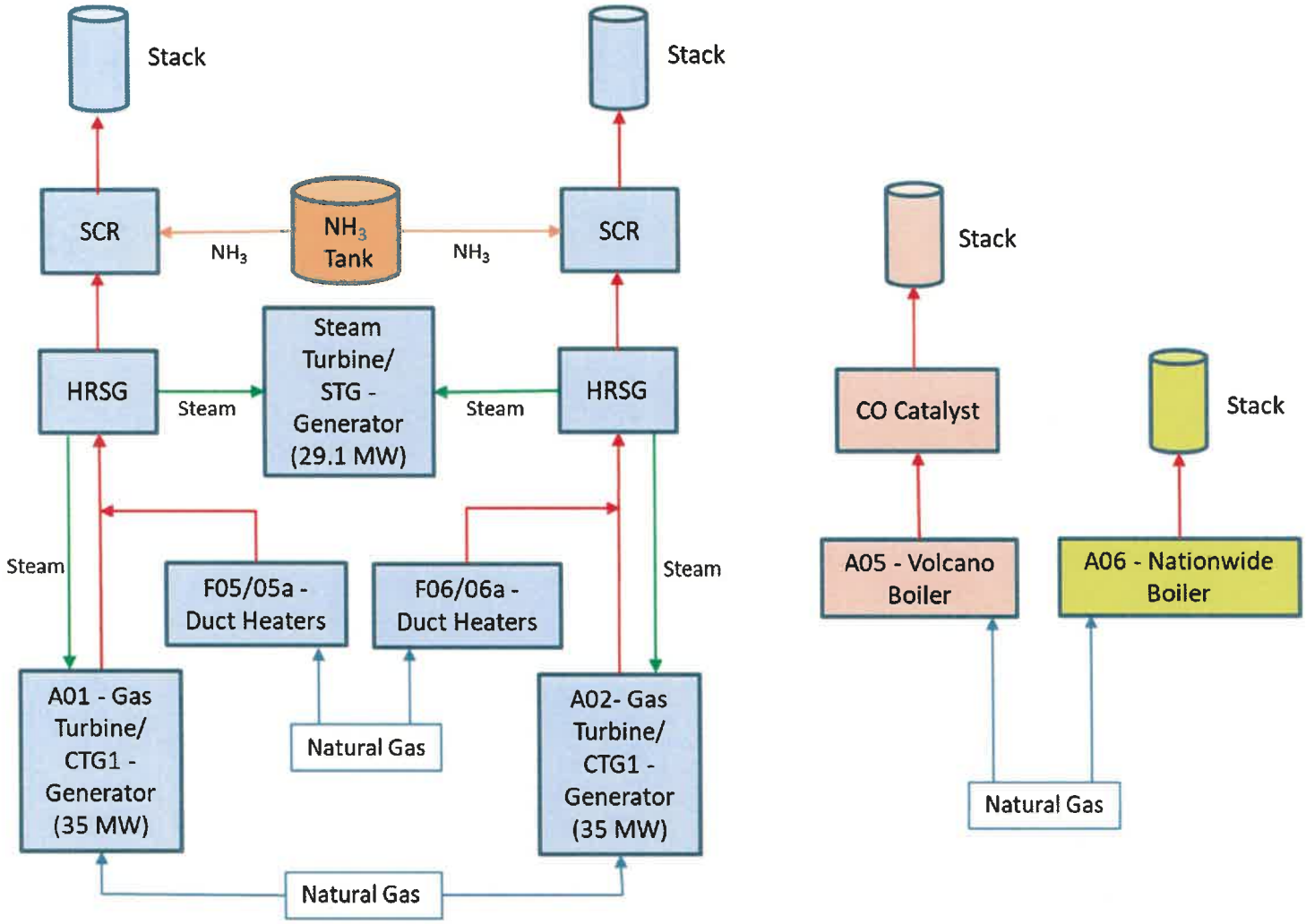



**Figure 1 - Saguaro Power Company Process Flow Diagram**

**Table 1 - List of Current Emission Units**

| EU | Rating | Description | Make | Model No. | Serial No. |
|---|---|---|---|---|---|
| A01 | 35 MW | Combustion Turbine Generator #1 with a fired HRSG | GE | PG6541B | 295525 |
| A02 | 35 MW | Combustion Turbine Generator #2 with a fired HRSG | GE | PG6541B | 295524 |
| A03 | 520 hp | Detroit Diesel Starter Engine, Combustion Turbine Generator #1 | Detroit | 71237300 | 12VA083956 |
| A04 | 520 hp | Detroit Diesel Starter Engine, Combustion Turbine Generator #2 | Detroit | 71237300 | 12VA083901 |
| A05 | 218 MMBtu/h | Auxiliary Boiler #1 | Indeck/ Volcano | 0-7-2000 | |
| A06 | 86 MMBtu/hr | Auxiliary Boiler #2 | Nebraska | NOS 2A/S- 55 | 032-88 |
| A09a | 7,666 gpm each | Cooling Tower, 3 cells | Thermal-Dynamics Towers Inc. | TD-3030-3- 2424CF | |
| A09b | | | | | |
| A09c | | | | | |
| F05 | 25 MMBtu/hr | Supplemental Duct Burner, Skid #1 | John Zink | LDR-11-LE | S82733 |
| F05a | 25 MMBtu/hr | Supplemental Duct Burner, Skid #1 | John Zink | LDR-11-LE | S82733 |
| F06 | 25 MMBtu/hr | Supplemental Duct Burner, Skid #2 | John Zink | LDR-11-LE | S82733 |
| F06a | 25 MMBtu/hr | Supplemental Duct Burner, Skid #2 | John Zink | LDR-11-LE | S82733 |

## 3.0 Applicable Regulations (AQR Section 120)

AQR Section 120 establishes and implements RACT requirements for major stationary sources of $NO_x$ and/or VOCs in areas of serious nonattainment for ozone, including Hydrographic Area 212. According to the regulation, owners and operators of existing stationary sources affected by the regulation must submit a major source RACT demonstration for all affected units by applying for a new stationary source permit or a significant permit revision. In addition to the definition in Section 120.3, DAQ has specified that affected units are individual emission units located at the major stationary source with a PTE for $NO_x$ or VOC that is equal to, or greater than five tons per year. This application must comply with the submittal requirements outlined in AQR Sections 12.4 and/or 12.5. Even if the demonstration does not result in additional control requirements, sources still must submit a complete application to the Control Officer. Compliance with the application requirements of AQR Section 120 is due on or before August 1, 2025, which is within 120 days after the Control Officer issued a written notice dated April 3, 2025.

Saguaro has prepared the required RACT analysis and has included the analysis with this application as required. The analysis provides details regarding the applicability of AQR Section 120 requirements, which emission unit are affected and the RACT assessment methodology and results. Since the results of the RACT analysis did not result in any requirements to add or modify existing controls, an AQR Section 12.4

application is not necessary. The analysis includes the specific RACT control, monitoring, testing, recordkeeping and reporting conditions necessary to ensure compliance with AQR Section 120.

## 4.0 Required Revisions to Permit

The required revisions to the permit pertain only to the removal emissions and conditions related to the permanently shut down auxiliary boilers and incorporation of the AQR Section 120 RACT conditions for affected emission units.

### *4.1 Removal of Boilers*

Removal of the boilers requires revisions to the permitted Source-wide Potential to Emit (PTE) as well as the Executive Summary, Equipment, Controls, Limitations and Standards, Compliance Demonstration Requirements, and Permit Shield sections of the permit. The specific revisions required are discussed for each section below.

Executive Summary

1. The second paragraph of this section should be revised to delete the reference to "two auxiliary natural gas-fired boilers."

2. Table 1: Source-wide PTE should be revised as shown below.

| Pollutant | $PM_{10}$ | $PM_{2.5}$ | $NO_x$ | CO | $SO_2$ | VOC | HAPs | GHG[1] |
|---|---|---|---|---|---|---|---|---|
| Existing Permit (tons/year) | 31.79 | 31.07 | 158.45 | 90.13 | 3.10 | 12.84 | 9.00 | 544,827[2] |
| Revised Permit (tons/year) | 23.84 | 23.12 | 135.18 | 79.28 | 2.38 | 8.22 | 4.04 | 415,988 |
| PTE Change (tons/year) | -7.95 | -7.95 | -23.27 | -10.85 | -0.72 | -4.62 | -4.96 | -128,839 |
| AQR Section 12.5 Minor NSR Significant Levels (tons/year) | 7.5 | 5.0 | 20 | 50 | 20 | 20 | NA | NA |

[1] GHG is greenhouse gas pollutants, emissions are in metric tons per year of $CO_2$ equivalent.

[2] Revised in renewal application.

The change in PTE is due to the removal of EUs A05 and A06 which have permitted PTEs as shown below.

| Emission Unit | $PM_{10}$ | $PM_{2.5}$ | $NO_x$ | CO | $SO_2$ | VOC | HAPs | GHG[1] |
|---|---|---|---|---|---|---|---|---|
| A05 (tons/year) | 6.66 | 6.66 | 13.94 | 0.86 | 0.57 | 4.47 | 4.47 | 101,432[2] |
| A06 (tons/year) | 1.29 | 1.29 | 9.33 | 9.99 | 0.15 | 0.15 | 0.49 | 27,407 |
| Total (tons/year) | 7.95 | 7.95 | 23.27 | 10.85 | 0.72 | 4.62 | 4.96 | 128,839 |

[1] GHG is greenhouse gas pollutants, emissions are in metric tons per year of $CO_2$ equivalent.

[2] Revised in renewal application.

No additional AQR Section 12.5 requirements are triggered by this change as shown above.

Equipment (Section 1.0)

1. Remove EUs A05 and A06 from Table 1-1: List of Emission Units.

Controls (Section 2.0)

1. Remove Conditions 2.2.10-12 pertaining to the boilers.

Limitations and Standards (Section 3.0)

1. Remove EUs A05 and A06 from Table 3-1: Fuel Limitations for Combustion Equipment.

2. Remove Conditions 3.1.9-14 pertaining to the boilers.

3. Remove EUs A05 and A06 from Table 3-2: Emission Unit PTE, Including Startup and Shutdowns (tons per year).

4. Remove EUs A05 and A06 from Table 3-3: Emission Rate (pounds per hour) Limitations, Excluding Startup and Shutdowns.

5. Remove EUs A05 and A06 from Table 3-4: Emission Concentration (ppmvd) Limitations, Excluding Startup and Shutdowns.

6. Remove Conditions 3.2.6-10 pertaining to the boilers.

7. Remove references to EUs A05 and A06 in Condition 3.2.11.

Compliance Demonstration Requirements (Section 4.0)

1. Remove Condition 4.1.7 pertaining to EU A05.

2. Remove reference to EU A05 in Conditions 4.1.9-11.

3. Remove Conditions 4.1.12-18. pertaining to the boilers.

4. Remove references to Subparts Db and Dc in Condition 4.2.5.

5. Remove Conditions 4.2.8-14. pertaining to the boilers.

6. Remove references to Subparts Db and Dc in Condition 4.3.2

7. Remove Conditions 4.3.1.2 d-f. pertaining to the boilers.

8. Remove reference to EU A05 in Conditions 4.3.1.2 h and j.

9. Remove references to EUs A05 and A06 in Condition 4.3.1.2 k.

10. Remove Conditions 4.3.1.3 d-g. pertaining to the boilers.

11. Remove reference to EU A05 in Condition 4.3.1.3 i.

12. Remove reference to EU A06 in Condition 4.3.1.3 n.

13. Remove references to Subparts Db and Dc in Condition 4.4.12.

Permit Shield (Section 5.0)

1. Remove references to Subparts Db and Dc in table 5-1: Applicable Requirements Related to Permit Shield.

2. Remove references to Subparts Db and Dc in table 5-2: Permit Shield.

*4.2 AQR Section 120 RACT requirements*

Revisions required to address AQR Section 120 RACT requirements are detailed in the attached AQR Section 120 Reasonably Available Control Technology Analysis. Since the boilers have been permanently shut down since 2022, a proposal for interim emissions limitations and a shutdown date per AQR Section 12.6 (b) is not required.

# AQR Section 120 Reasonably Available Control Technology Analysis

# AQR Section 120 Reasonably Available Control Technology Analysis

## Clark County Department of Environment and Sustainability
## Division of Air Quality

Saguaro Power Company LP
435 Fourth Street
Henderson, NV 89015

Source ID 393

July 16 , 2025

Prepared by:

Broadbent & Associates, Inc.
8 W. Pacific Avenue
Henderson, Nevada 89015

Project No. 05-01-239

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**Attachments**

Attachment A - Cost Effectiveness Calculations

## 1.0 Background

On December 19, 2024, EPA advanced the Clark County HA 212 (Las Vegas Valley) airshed classification to the serious nonattainment category under the 2015 ozone National Ambient Air Quality Standards (NAAQS) for failing to comply with the standard by August 2024. This reclassification became effective on January 21, 2025, and brought the following changes to permit requirements for existing, new, and modified sources of ozone precursors, including volatile organic compounds (VOCs) and nitrogen oxides ($NO_x$) [40 CFR Part 51, Appendix S]:

- The major source threshold for VOC and $NO_x$ emissions, previously a potential to emit (PTE) of 100 tons per year (tpy) under the "moderate" classification, is lowered to 50 tpy.
- The significant emissions increase threshold, which determines whether a modification is subject to Nonattainment New Source Review (NNSR), is lowered from 40 to 25 tpy of VOC and/or $NO_x$.
- The Non-attainment New Source Review (NNNSR) emissions offset ratio, which was 1.15:1 under moderate nonattainment, is raised to 1.2:1 under serious nonattainment and will apply to all NNSR for new major sources and major modifications to existing major sources.

In an anticipatory response to this EPA action, the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) adopted AQR Section 120 - Reasonably Available Control Technology Demonstration and Determination Requirements for Major Stationary Sources in Ozone Nonattainment Areas effective on December 3, 2024. AQR Section 120 establishes and implements RACT requirements for major stationary sources of $NO_x$ and/or VOCs in areas of serious nonattainment for ozone, including HA 212. According to the regulation, owners and operators of existing stationary sources affected by the regulation must submit a major source RACT demonstration for all affected units by applying for a new stationary source permit or a significant permit revision. In addition to the definition in Section 120.3, DAQ has specified that affected units are individual emission units located at the major stationary source with a PTE for $NO_x$ or VOC that is equal to, or greater than five tons per year. This application must comply with the submittal requirements outlined in AQR Sections 12.4 and/or 12.5. Even if the demonstration does not result in additional control requirements, sources still must submit a complete application to the Control Officer. Compliance with the application requirements of AQR Section 120 is due on or before August 1, 2025, which is within 120 days after the Control Officer issued a written notice dated April 3, 2025. In lieu of submitting a major source RACT analysis, owners and operators of existing stationary sources affected by the regulation may request voluntary emission limitations that reduce the source's or individual emission unit's $NO_x$ and/or VOC PTE below the major source or affected units thresholds.

According to AQR Section 120.5(c) sources that were subject to a major source RACT determination that meets the requirements of AQR Section 120 within the past 36 months and the basis of that determination is still relevant, the owner or operator may provide a copy of that prior determination along with a sworn certification that it continues to be RACT because there are no changes to the available control technologies, technical feasibility, control effectiveness, cost-effectiveness, or environmental, energy, and other impacts since that determination was initially performed. Saguaro Power Company LP (Saguaro) submitted a major source RACT determination analysis in October 2022 in response to the anticipated January 5, 2023 EPA rulemaking determining that the Las Vegas Valley failed to attain the 2015 $O_3$ NAAQS by the applicable marginal nonattainment deadline and reclassifying the area as a moderate nonattainment area. The RACT analysis submitted at that time was approved and subsequently

incorporated as part of AQR Section 121. AQR Section 121 was adopted February 4, 2025. AQR Section 121.9 contains the RACT Control Requirements, RACT Monitoring Requirements, RACT Testing Requirements and RACT Recordkeeping and Reporting Requirements that were approved specifically for Saguaro. As noted above, AQR Section 120 would allow the use of this RACT determination if it meets the requirements of AQR Section 120 within the past 36 months and the basis of that determination is still relevant. However, since certain aspects of the analysis performed in 2022 did not meet certain requirements in AQR Section 120, Saguaro is not able to use the currently approved AQR Section 121 RACT determination to satisfy AQR Section 120. As is the case for many of the other facilities included in AQR Section 121, the only requirement of AQR Section 120 that the 2022 RACT determination did not meet is the requirement that the baseline for cost-effectiveness analyses be based on each emission unit's PTE. This is because, under certain circumstances, DAQ allowed the use of actual emissions for the baseline for the moderate nonattainment classification RACT analyses that were performed. The cost-effectiveness calculations that were included in the RACT analysis performed by Saguaro at that time used the actual emissions as the baseline.

This report summarizes the AQR Section 120 required revised RACT analysis performed by Saguaro that includes the requirement for use of PTE as the baseline for emissions and contains its source specific recommendations for RACT.

## 2.0 RACT Applicability

Saguaro's Henderson facility is an electricity and steam generating operation located in HA 212. It currently operates as a Part 70 major stationary source according to the conditions contained in the Part 70 Operating Permit Source ID 393 issued by DAQ. The current permit includes two 35-MW natural gas combined cycle combustion turbine generators (CTGs); two diesel starter engines; two auxiliary natural gas-fired boilers; a three-celled cooling tower; and four 25 MMBtu/hr supplemental-firing duct burners. In addition, the permit includes a 29.1 MW extraction/condensing steam turbine generator system and an ammonia storage and injection system as insignificant activities. RACT is required only if the permitted PTE for either VOC or $NO_x$ exceeds the serious area major source thresholds (50 tons per year for both VOC and NOx). According to Table 1 contained in the facility's current Part 70 operating permit, the PTE for $NO_x$ emissions is 158.45 tons per year and the PTE for VOC emissions is 12.84 tons per year. Therefore, based on the current permit, only $NO_x$ emissions exceed the serious area major source thresholds and the analysis can be limited to $NO_x$ emissions. In May 2025, Saguaro submitted an AQR Section 12.4 Authority to Construct Application that included the permanent shutdown of the two auxiliary natural gas-fired boilers. Since the combined $NO_x$ PTE for these emissions units is only 23.27 tons per year, the total facility PTE for $NO_x$ still exceeds the serious area major source threshold when excluding these emissions.

## 3.0 Affected Emission Units Subject to RACT

DAQ delineated the emission unit applicability requirement to a so-called "affected unit" that includes only those individual emission units at the major stationary source with a PTE that exceeds 5 tons per year. Table 1 lists the emission units in the current permit that exceed this threshold for $NO_x$. Although the $NO_x$ PTE for each of the two auxiliary boilers exceeds 5 tons per year, these emission units are not included in Table 1 since, as explained above, Saguaro has requested the permanent shutdown of these emission units.

**Table 1 – Affected Emission Units Subject to RACT**

| Emission Unit ID[1] | Description | Maximum Rating | Manufacturer | Model | Fuel Type | $NO_x$ PTE[2] (tons per year) |
|---|---|---|---|---|---|---|
| A01 | Combustion Turbine Generator #1 with a fired HRSG[3] | 35 MW | General Electric | PG6541B | Natural gas | 66.58[4] |
| F05 | Supplemental Duct Burner, Skid #1 | 25 MMBtu/hr | John Zink | LDR-11-LE | Natural gas | |
| F05a | Supplemental Duct Burner, Skid #1 | 25 MMBtu/hr | John Zink | LDR-11-LE | Natural gas | |
| A02 | Combustion Turbine Generator #2 with a fired HRSG[3] | 35 MW | General Electric | PG6541B | Natural gas | 66.58[4] |
| F06 | Supplemental Duct Burner, Skid #2 | 25 MMBtu/hr | John Zink | LDR-11-LE | Natural gas | |
| F06a | Supplemental Duct Burner, Skid #2 | 25 MMBtu/hr | John Zink | LDR-11-LE | Natural gas | |

Notes: [1] Emission Unit ID from Part 70 Operating Permit Table II-A-1: List of Emission Units.
[2] PTE from Part 70 Operating Permit Table II-D-1: Emission Unit PTE, Including Startup and Shutdowns (tons per year).
[3] Emission units F05, F05a, F06 and F06a make up the fired HRSG.
[4] Emissions based on 8,760 hours per year operation.

In addition, each emission unit listed in Table 1 has emission limits in pounds per hour and exhaust gas $NO_x$ concentrations in ppm as well as limitations on the amount of fuel burned annually. These additional limitations are summarized in Tables 2 and 3.

**Table 2 – Emission Unit Emissions Limitations**

| Emission Unit ID | Fuel Type | $NO_x$ Emission Rate (lb/hr) | $NO_x$ Concentration (ppm) |
|---|---|---|---|
| A01, F05, F05a | Natural gas | 15.20 | 10 @ 15% $O_2$ |
| A02, F06, F06a | Natural gas | 15.20 | 10 @ 15% $O_2$ |

**Table 3 - Emission Unit Throughput Limitations**

| Emission Unit ID | Fuel Type | Fuel Use | |
|---|---|---|---|
| | | Hourly | Annual |
| A01 | Natural gas | 447 MMBtu | 3,915,720 MMBtu |
| A02 | Natural gas | 447 MMBtu | 3,915,720 MMBtu |
| F05, F05a | Natural gas | 25 MMBtu | 219,000 MMBtu |
| F06, F06a | Natural gas | 25 MMBtu | 219,000 MMBtu |

## 4.0 RACT Analysis

The RACT analysis consists of various steps:

- Identification of existing equipment and baseline emissions
- Identification of available control options
- Elimination of technically infeasible control options
- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options
- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping and reporting requirements

RACT emissions limitations can take various forms depending on the type of source and as long as the emissions limitations achieve the required emissions reductions and are legally and practically enforceable through appropriate monitoring, recordkeeping and reporting requirements. In addition, RACT is a continuous emissions reduction requirement and must apply over the range of operations [steady-state, startup, shutdown, and malfunctions (SSM)]; however RACT can include alternative emissions limitations or work practices for SSM.

For uniformity of comparison, AQR Section 120 requires major sources to use a 6% interest rate to compute annualized costs. This rate was used in all cost analyses contained in this report. In addition, AQR Section 120 requires sources to use each emissions units permitted PTE as the base case for determining potential emission reductions associated with any control measures being evaluated for RACT. A cost-effectiveness threshold of $5,500/ton was used for this review, which is consistent with the October 19, 2023 DAQ RACT review report prepared for the ozone moderate nonattainment implementation plan.

## 5.0 $NO_x$ RACT Assessment

This RACT analysis follows the same procedures and incorporates many of the same assumptions that were used in the 2022 analysis. Although the heat recovery steam generator portion of each turbine includes supplemental duct burners (EUs F05, F05a, F06 and F06a), these are not included in this analysis since, as explained in the 2022 analysis, current normal operation does not include their operation. This also results in a more conservative analysis for the gas turbines. Since both emission units A01 and A02 are identical with identical emission and operating limitations, an individual analysis for each emission unit is unnecessary.

### 5.1 Baseline Emissions

As noted above, the baseline emissions used for an AQR Section 120 RACT analysis are required to be equal to the permitted PTE for each emission unit evaluated. The permitted $NO_x$ PTE used is therefore that presented in Table 1 above (66.58 tons per year).

### 5.2 Identification of Available Controls

Each turbine is currently equipped with steam injection and Selective Catalytic Reduction (SCR) for $NO_x$ control. Potential control technologies that were evaluated included Dry Low $NO_x$ Burners (DLNB) with SCR and SCR catalyst replacement. Other potential control technologies were evaluated in the 2022 analysis but were eliminated as technically infeasible. These other technologies included Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (NSCR).

The calculation of the potential emissions reductions associated with the control technologies evaluated assumes that the catalyst replacement option would be capable of reducing current $NO_x$ emissions from 10 ppm to 3 ppm (70 % reduction) and the DLNB + SCR option would be capable of reducing current $NO_x$ emissions from 10 ppm to 2 ppm (80% reduction). The most stringent control level of 2 ppm used is consistent with the 2022 analysis conducted and a review of the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) summary of determinations provided in the October 19, 2023 *Case-By-Case RACT for Major VOC and NOx Sources in Hydrographic Area 212*. In addition, the RBLC was searched for any more recent determinations with a more stringent limitation, but none were found. It should be noted that the level of control assumed for the catalyst replacement option is consistent with the 2022 evaluation but is very conservative since it compares a complete new installation to one that involves a retrofit of SCR in an existing HRSG.

### 5.3 Cost Effectiveness of Controls

In order to determine the cost-effectiveness of each control option, the total annualized capital and operating costs are compared to the potential emissions reduction to derive a value of cost per ton of pollutant removed ($/ton). The total annualized capital cost is calculated by applying a capital recovery factor to the total capital investment which includes both the initial capital investment and any direct and indirect costs. The capital recovery factor is based on the estimated equipment life in years and the applicable investment interest rate.

For the purposes of this analysis, the same initial capital investment amounts as used in the 2022 analysis were used. For both control options, these amounts include both the initial capital investment and any direct and indirect costs. In addition, the same cost of ammonia was added to both analyses to reflect the anticipated increase in ammonia use associated with each option. These costs are not expected to be significantly different in present day dollars since the Chemical Engineering Plant Cost Index has not changed significantly since the 2022 analysis was performed.

As noted in Section 4, an interest rate of 6% was used in the calculation of the capital recovery factor. An estimated equipment life of 5 years was used for the catalyst replacement option reflecting the estimated useful life of the catalyst and an estimated equipment life of 15 years was used for the DLNB + SCR option reflecting the estimated useful life of the existing turbines. Both of these equipment life estimates are consistent with those used for the 2022 analysis.

The detailed cost effectiveness calculations for each control option are provided in Attachment A. A summary of the results is provided in Table 4 below.

**Table 4 – Cost-effectiveness Calculation Summary**

| Control Option | Emission Reduction (tons per year) | Total Annualized Cost ($) | Cost-effectiveness ($/ton) |
|---|---|---|---|
| Catalyst replacement | 46.61 | 351,718 | 7,547 |
| DLNB + SCR | 53.26 | 598,038 | 11,228 |

As shown above, the calculated cost-effectiveness of each option analyzed exceeds the RACT threshold of $5,500.

### 5.4 Evaluation of the Benefits and Disadvantages

Evaluation of the benefits and disadvantages includes an evaluation of any additional environmental, energy and economic impacts associated with the control technologies evaluated for RACT. These additional impacts are discussed in this section.

Environmental Impacts

SCR as a control device presents a negative environmental impact due to the released ammonia during its operation. This process is known as Ammonia Slip. Higher NOX control associated with an SCR system corresponds to higher overall ammonia emissions associated with ammonia slip. An additional environmental impact associated with using SCR comes from ammonia transportation and storage. Ammonia is considered a toxic chemical substance and in the event of spill or fire, presents an enormous environmental liability in the form of air, soil and groundwater contamination, and employee injuries. Any SCR system will incorporate these additional impacts to some extent regardless of final NOX control efficiency.

Energy Impacts

There are additional power requirements associated with SCR operation due to running the pumps electrical motors associated with the system. However, since the existing baseline operation utilizes SCR, no significant energy impact is associated with implementation of this enhanced technology. No significant energy impacts have been identified for the implementation of DLN technology implementation other than that it would require the power station to be offline for several months in order to reconfigure/overhaul the turbines resulting in a loss of power production for the community during that time period.

Economic Impacts

Installation of either control option on the existing combustion turbine units at Saguaro would entail significant capital costs. As shown above in Section 5.3, the cost-effectiveness of the control options evaluated exceeds the RACT threshold of $5,500 per ton.

### 5.5 $NO_x$ RACT Determination

After reviewing similar facilities for emission control technologies, eliminating technically infeasible options and evaluating the remaining technologies for environmental, energy, and economic impacts it is determined that the existing SCR and steam injection controls satisfy RACT for compliance with AQR Section 120.

The specific RACT control, monitoring, testing, recordkeeping and reporting conditions necessary to ensure compliance are described below.

RACT Control Requirements

For the turbine generators (EUs: A01 and A02), including duct burners (EUs: F05, F05a, F06, and F06a):

(1) Limit $NO_x$ emissions to 10 ppmvd at 15% O2, excluding startup and shutdown;
(2) Limit $NO_x$ emissions to an emissions rate of 66 lb/hr during startup and shutdown; and
(3) Operate and maintain the units using Good Combustion Practices during startup, shut-down, and other non-normal operations, to include operating the units in accordance with the manufacturer's O&M manual.

RACT Monitoring Requirements

For the turbine generators (EUs: A01–A02):

(1) Install, calibrate, maintain, operate, and certify CEMS for $NO_x$;
(2) Require periodic audit procedures and QA/AC procedures for the CEMS;
(3) Conduct RATA of the $NO_x$ CEMS;
(4) Monitor CEMS $NO_x$ data;
(5) Monitor the occurrences and durations of startup/shutdown cycles; and
(6) Demonstrate compliance with NOx emissions limits.

RACT Testing Requirements

No additional testing requirements were identified.

RACT Recordkeeping and Reporting Requirements

For the turbine generators (EUs: A01–A02):

(1) Maintain records of required reporting, including records of all inspections, maintenance, and repairs;
(2) Maintain records of the date, time, and duration of each startup and shut-down cycle of each turbine;
(3) Maintain records of QA/QC procedures;
(4) Maintain records of CEMS audit and calibration results, along with any corrective actions taken;
(5) Maintain records of the time, duration, nature, and probable cause of any CEMS downtown, and of any corrective actions taken; and
(6) Maintain records of CEMS VOC and $NO_x$ data.
(7) Submit performance test reports;

(8) Submit an annual emissions inventory report; and
(9) Submit an annual compliance certification.

# Attachment A - Cost Effectiveness Calculations

| COST EFFECTIVENESS CALCULATION | |
|---|---|
| SAGUARO POWER COMPANY | |
| CTG 1 AND CTG2 (COMBINED CYCLE UNITS) | |
| **Emissions Unit** | A01/A02 |
| Pollutant | $NO_x$ |
| Control Technology | DLNB+SCR |
| Baseline Emissions (ppm@15% O2) | 10 |
| Controlled Emissions (ppm@15% O2) | 2 |
| Baseline Emissions Rate (tpy) | 66.58 |
| Controlled Emissions (tpy) | 13.32 |
| Emissions Reduction (%) | 80% |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment | 3,793,000 |
| Direct & Indirect Costs | |
| Total Capital Investment | 3,793,000 |
| Estimated Equipment Life, years | 15 |
| Interest Rate, % | 6.00% |
| Capital Recovery Factor | 0.103 |
| Annualized Total Capital Investment | 390,538 |
| | |
| **Annual Operating Costs** | |
| Ammonia | 207,500 |
| | |
| | |
| | |
| **Total Annualized Cost** | **598,038** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 53.26 |
| Cost Effectiveness ($/ton) | **11,228** |

Capitol Recovery Factor = $r(1 + r)^n / ((1 + r)^n - 1)$, where r is the interest rate and n is the equipment life in years
Annualized Total Capital Investment = Total Capital Investment x Capital Recovery Factor

| COST EFFECTIVENESS CALCULATION | |
|---|---|
| SAGUARO POWER COMPANY | |
| CTG 1 AND CTG2 (COMBINED CYCLE UNITS) | |
| **Emissions Unit** | A01/A02 |
| Pollutant | $NO_x$ |
| Control Technology | Replace Catalyst on Existing SCRs |
| Baseline Emissions (ppm@15% O2) | 10 |
| Controlled Emissions (ppm@15% O2) | 3 |
| Baseline Emissions Rate (tpy) | 66.58 |
| Controlled Emissions (tpy) | 19.97 |
| Emissions Reduction (%) | 70% |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment | 607,500 |
| Direct & Indirect Costs | |
| Total Capital Investment | 607,500 |
| Estimated Equipment Life, years | 5 |
| Interest Rate, % | 6.00% |
| Capital Recovery Factor | 0.237 |
| Annualized Total Capital Investment | 144,218 |
| | |
| **Annual Operating Costs** | |
| Ammonia | 207,500 |
| | |
| | |
| | |
| **Total Annualized Cost** | **351,718** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 46.61 |
| Cost Effectiveness ($/ton) | **7,547** |

Capitol Recovery Factor = $r(1 + r)^n / ((1 + r)^n - 1)$, where r is the interest rate and n is the equipment life in years
Annualized Total Capital Investment = Total Capital Investment x Capital Recovery Factor

# ATTACHMENT 8B: Saguaro Power Company RACT Supplemental

SAGUARO POWER COMPANY

RECEIVED CC DAQ
2025 SEP 22 AM10:02

September 19, 2025

Permitting Supervisor
Clark County Department of Environment and Sustainability
Division of Air Quality
4701 West Russell Road
Suite 200 – 2nd Floor
Las Vegas, Nevada 89118

**Re: AQR 120 RACT Determination**
**Saguaro Power Company LP Source ID 393**

This is in response to the September 8, 2025 letter from Michael Rael requesting additional information regarding the Reasonably Available Control Technology (RACT) analysis submitted in the permit application dated July 16, 2025. In that letter, the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) requested the following:

***1. Update the capital and annual cost calculations in accordance with Section 120.5(a)(3), which require using a 30-year life expectancy, or provide a rationale for using different metrics, which must be approved by the Control Officer.***

In response, Saguaro Power Company LP (Saguaro) has revised the cost-effective calculations and metric rational discussion in the RACT analysis according to DAQ's request. A copy of the revised analysis is attached.

If you have any questions, or require additional information, please do not hesitate to contact me at 702-558-1131 or rob.may@camsops.com.

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in this document and attachments are true, accurate, and complete.

Sincerely,

Rob May
Plant Manager

Attachment - AQR Section 120 Reasonably Available Control Technology Analysis

P.O. Box 90849
Henderson, Nevada 89009-0849

Telephone: (702) 558-1100
Fax: (702) 564-2753

RECEIVED CC DAQ
2025 SEP 22 AM10:02

# AQR Section 120 Reasonably Available Control Technology Analysis

**Clark County Department of Environment and Sustainability**
**Division of Air Quality**

Saguaro Power Company LP
435 Fourth Street
Henderson, NV 89015

Source ID 393

July 16 , 2025
Revised September 17, 2025

Prepared by:

Broadbent & Associates, Inc.
8 W. Pacific Avenue
Henderson, Nevada 89015

Project No. 05-01-239

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**3.0 Affected Emission Units Subject to RACT** ..... 2
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**Attachments**

Attachment A - Cost Effectiveness Calculations

## 1.0 Background

On December 19, 2024, EPA advanced the Clark County HA 212 (Las Vegas Valley) airshed classification to the serious nonattainment category under the 2015 ozone National Ambient Air Quality Standards (NAAQS) for failing to comply with the standard by August 2024. This reclassification became effective on January 21, 2025, and brought the following changes to permit requirements for existing, new, and modified sources of ozone precursors, including volatile organic compounds (VOCs) and nitrogen oxides ($NO_x$) [40 CFR Part 51, Appendix S]:

- The major source threshold for VOC and $NO_x$ emissions, previously a potential to emit (PTE) of 100 tons per year (tpy) under the "moderate" classification, is lowered to 50 tpy.
- The significant emissions increase threshold, which determines whether a modification is subject to Nonattainment New Source Review (NNSR), is lowered from 40 to 25 tpy of VOC and/or $NO_x$.
- The Non-attainment New Source Review (NNNSR) emissions offset ratio, which was 1.15:1 under moderate nonattainment, is raised to 1.2:1 under serious nonattainment and will apply to all NNSR for new major sources and major modifications to existing major sources.

In an anticipatory response to this EPA action, the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) adopted AQR Section 120 - Reasonably Available Control Technology Demonstration and Determination Requirements for Major Stationary Sources in Ozone Nonattainment Areas effective on December 3, 2024. AQR Section 120 establishes and implements RACT requirements for major stationary sources of $NO_x$ and/or VOCs in areas of serious nonattainment for ozone, including HA 212. According to the regulation, owners and operators of existing stationary sources affected by the regulation must submit a major source RACT demonstration for all affected units by applying for a new stationary source permit or a significant permit revision. In addition to the definition in Section 120.3, DAQ has specified that affected units are individual emission units located at the major stationary source with a PTE for $NO_x$ or VOC that is equal to, or greater than five tons per year. This application must comply with the submittal requirements outlined in AQR Sections 12.4 and/or 12.5. Even if the demonstration does not result in additional control requirements, sources still must submit a complete application to the Control Officer. Compliance with the application requirements of AQR Section 120 is due on or before August 1, 2025, which is within 120 days after the Control Officer issued a written notice dated April 3, 2025. In lieu of submitting a major source RACT analysis, owners and operators of existing stationary sources affected by the regulation may request voluntary emission limitations that reduce the source's or individual emission unit's $NO_x$ and/or VOC PTE below the major source or affected units thresholds.

According to AQR Section 120.5(c) sources that were subject to a major source RACT determination that meets the requirements of AQR Section 120 within the past 36 months and the basis of that determination is still relevant, the owner or operator may provide a copy of that prior determination along with a sworn certification that it continues to be RACT because there are no changes to the available control technologies, technical feasibility, control effectiveness, cost-effectiveness, or environmental, energy, and other impacts since that determination was initially performed. Saguaro Power Company LP (Saguaro) submitted a major source RACT determination analysis in October 2022 in response to the anticipated January 5, 2023 EPA rulemaking determining that the Las Vegas Valley failed to attain the 2015 $O_3$ NAAQS by the applicable marginal nonattainment deadline and reclassifying the area as a moderate nonattainment area. The RACT analysis submitted at that time was approved and subsequently

incorporated as part of AQR Section 121. AQR Section 121 was adopted February 4, 2025. AQR Section 121.9 contains the RACT Control Requirements, RACT Monitoring Requirements, RACT Testing Requirements and RACT Recordkeeping and Reporting Requirements that were approved specifically for Saguaro. As noted above, AQR Section 120 would allow the use of this RACT determination if it meets the requirements of AQR Section 120 within the past 36 months and the basis of that determination is still relevant. However, since certain aspects of the analysis performed in 2022 did not meet certain requirements in AQR Section 120, Saguaro is not able to use the currently approved AQR Section 121 RACT determination to satisfy AQR Section 120. As is the case for many of the other facilities included in AQR Section 121, the only requirement of AQR Section 120 that the 2022 RACT determination did not meet is the requirement that the baseline for cost-effectiveness analyses be based on each emission unit's PTE. This is because, under certain circumstances, DAQ allowed the use of actual emissions for the baseline for the moderate nonattainment classification RACT analyses that were performed. The cost-effectiveness calculations that were included in the RACT analysis performed by Saguaro at that time used the actual emissions as the baseline.

This report summarizes the AQR Section 120 required revised RACT analysis performed by Saguaro that includes the requirement for use of PTE as the baseline for emissions and contains its source specific recommendations for RACT.

## 2.0 RACT Applicability

Saguaro's Henderson facility is an electricity and steam generating operation located in HA 212. It currently operates as a Part 70 major stationary source according to the conditions contained in the Part 70 Operating Permit Source ID 393 issued by DAQ. The current permit includes two 35-MW natural gas combined cycle combustion turbine generators (CTGs); two diesel starter engines; two auxiliary natural gas-fired boilers; a three-celled cooling tower; and four 25 MMBtu/hr supplemental-firing duct burners. In addition, the permit includes a 29.1 MW extraction/condensing steam turbine generator system and an ammonia storage and injection system as insignificant activities. RACT is required only if the permitted PTE for either VOC or $NO_x$ exceeds the serious area major source thresholds (50 tons per year for both VOC and NOx). According to Table 1 contained in the facility's current Part 70 operating permit, the PTE for $NO_x$ emissions is 158.45 tons per year and the PTE for VOC emissions is 12.84 tons per year. Therefore, based on the current permit, only $NO_x$ emissions exceed the serious area major source thresholds and the analysis can be limited to $NO_x$ emissions. In May 2025, Saguaro submitted an AQR Section 12.4 Authority to Construct Application that included the permanent shutdown of the two auxiliary natural gas-fired boilers. Since the combined $NO_x$ PTE for these emissions units is only 23.27 tons per year, the total facility PTE for $NO_x$ still exceeds the serious area major source threshold when excluding these emissions.

## 3.0 Affected Emission Units Subject to RACT

DAQ delineated the emission unit applicability requirement to a so-called "affected unit" that includes only those individual emission units at the major stationary source with a PTE that exceeds 5 tons per year. Table 1 lists the emission units in the current permit that exceed this threshold for $NO_x$. Although the $NO_x$ PTE for each of the two auxiliary boilers exceeds 5 tons per year, these emission units are not included in Table 1 since, as explained above, Saguaro has requested the permanent shutdown of these emission units.

**Table 1 – Affected Emission Units Subject to RACT**

| Emission Unit ID[1] | Description | Maximum Rating | Manufacturer | Model | Fuel Type | $NO_x$ PTE[2] (tons per year) |
|---|---|---|---|---|---|---|
| A01 | Combustion Turbine Generator #1 with a fired HRSG[3] | 35 MW | General Electric | PG6541B | Natural gas | 66.58[4] |
| F05 | Supplemental Duct Burner, Skid #1 | 25 MMBtu/hr | John Zink | LDR-11-LE | Natural gas | |
| F05a | Supplemental Duct Burner, Skid #1 | 25 MMBtu/hr | John Zink | LDR-11-LE | Natural gas | |
| A02 | Combustion Turbine Generator #2 with a fired HRSG[3] | 35 MW | General Electric | PG6541B | Natural gas | 66.58[4] |
| F06 | Supplemental Duct Burner, Skid #2 | 25 MMBtu/hr | John Zink | LDR-11-LE | Natural gas | |
| F06a | Supplemental Duct Burner, Skid #2 | 25 MMBtu/hr | John Zink | LDR-11-LE | Natural gas | |

Notes: [1] Emission Unit ID from Part 70 Operating Permit Table II-A-1: List of Emission Units.
[2] PTE from Part 70 Operating Permit Table II-D-1: Emission Unit PTE, Including Startup and Shutdowns (tons per year).
[3] Emission units F05, F05a, F06 and F06a make up the fired HRSG.
[4] Emissions based on 8,760 hours per year operation.

In addition, each emission unit listed in Table 1 has emission limits in pounds per hour and exhaust gas $NO_x$ concentrations in ppm as well as limitations on the amount of fuel burned annually. These additional limitations are summarized in Tables 2 and 3.

**Table 2 – Emission Unit Emissions Limitations**

| Emission Unit ID | Fuel Type | $NO_x$ Emission Rate (lb/hr) | $NO_x$ Concentration (ppm) |
|---|---|---|---|
| A01, F05, F05a | Natural gas | 15.20 | 10 @ 15% $O_2$ |
| A02, F06, F06a | Natural gas | 15.20 | 10 @ 15% $O_2$ |

**Table 3 - Emission Unit Throughput Limitations**

| Emission Unit ID | Fuel Type | Fuel Use | |
|---|---|---|---|
| | | Hourly | Annual |
| A01 | Natural gas | 447 MMBtu | 3,915,720 MMBtu |
| A02 | Natural gas | 447 MMBtu | 3,915,720 MMBtu |
| F05, F05a | Natural gas | 25 MMBtu | 219,000 MMBtu |
| F06, F06a | Natural gas | 25 MMBtu | 219,000 MMBtu |

## 4.0 RACT Analysis

The RACT analysis consists of various steps:

- Identification of existing equipment and baseline emissions
- Identification of available control options
- Elimination of technically infeasible control options
- Determination of the cost effectiveness of control options
- Evaluation of the benefits and disadvantages (environmental, energy and economic) associated with the technically feasible control options
- Identification of RACT control technology including emission limitations, monitoring, testing, recordkeeping and reporting requirements

RACT emissions limitations can take various forms depending on the type of source and as long as the emissions limitations achieve the required emissions reductions and are legally and practically enforceable through appropriate monitoring, recordkeeping and reporting requirements. In addition, RACT is a continuous emissions reduction requirement and must apply over the range of operations [steady-state, startup, shutdown, and malfunctions (SSM)]; however RACT can include alternative emissions limitations or work practices for SSM.

For uniformity of comparison, AQR Section 120 requires major sources to use a 6% interest rate to compute annualized costs. This rate was used in all cost analyses contained in this report. In addition, AQR Section 120 requires sources to use each emissions units permitted PTE as the base case for determining potential emission reductions associated with any control measures being evaluated for RACT. A cost-effectiveness threshold of $5,500/ton was used for this review, which is consistent with the October 19, 2023 DAQ RACT review report prepared for the ozone moderate nonattainment implementation plan.

## 5.0 $NO_x$ RACT Assessment

This RACT analysis follows the same procedures and incorporates many of the same assumptions that were used in the 2022 analysis. Although the heat recovery steam generator portion of each turbine includes supplemental duct burners (EUs F05, F05a, F06 and F06a), these are not included in this analysis since, as explained in the 2022 analysis, current normal operation does not include their operation. This also results in a more conservative analysis for the gas turbines. Since both emission units A01 and A02 are identical with identical emission and operating limitations, an individual analysis for each emission unit is unnecessary.

### 5.1 Baseline Emissions

As noted above, the baseline emissions used for an AQR Section 120 RACT analysis are required to be equal to the permitted PTE for each emission unit evaluated. The permitted $NO_x$ PTE used is therefore that presented in Table 1 above (66.58 tons per year).

### 5.2 Identification of Available Controls

Each turbine is currently equipped with steam injection and Selective Catalytic Reduction (SCR) for $NO_x$ control. Potential control technologies that were evaluated included Dry Low $NO_x$ Burners (DLNB) with SCR and SCR catalyst replacement. Other potential control technologies were evaluated in the 2022 analysis but were eliminated as technically infeasible. These other technologies included Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (NSCR).

The calculation of the potential emissions reductions associated with the control technologies evaluated assumes that the catalyst replacement option would be capable of reducing current $NO_x$ emissions from 10 ppm to 3 ppm (70 % reduction) and the DLNB + SCR option would be capable of reducing current $NO_x$ emissions from 10 ppm to 2 ppm (80% reduction). The most stringent control level of 2 ppm used is consistent with the 2022 analysis conducted and a review of the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) summary of determinations provided in the October 19, 2023 *Case-By-Case RACT for Major VOC and NOx Sources in Hydrographic Area 212.* In addition, the RBLC was searched for any more recent determinations with a more stringent limitation, but none were found. It should be noted that the level of control assumed for the catalyst replacement option is consistent with the 2022 evaluation but is very conservative since it compares a complete new installation to one that involves a retrofit of SCR in an existing, space-limited HRSG.

### 5.3 Cost Effectiveness of Controls

In order to determine the cost-effectiveness of each control option, the total annualized capital and operating costs are compared to the potential emissions reduction to derive a value of cost per ton of pollutant removed ($/ton). The total annualized capital cost is calculated by applying a capital recovery factor to the total capital investment which includes both the initial capital investment and any direct and indirect costs. The capital recovery factor is based on the estimated equipment life in years and the applicable investment interest rate.

For the purposes of this analysis, the same initial capital investment amounts as used in the 2022 analysis were used. For both control options, these amounts include both the initial capital investment and any direct and indirect costs. In addition, the same cost of ammonia was added to both analyses to reflect the anticipated increase in ammonia use associated with each option. These costs are not expected to be significantly different in present day dollars since the Chemical Engineering Plant Cost Index has not changed significantly since the 2022 analysis was performed.

As noted in Section 4, an interest rate of 6% was used in the calculation of the capital recovery factor.

An estimated equipment life expectancy of 10 years was used for the catalyst replacement option reflecting the estimated useful life of a replacement for the SCR catalyst in the existing, space-limited HRSG. According to an Electric Power Research Institute (EPRI) report, catalyst lifetime guarantees are provided by catalyst suppliers and typically range from 5 to 10 years (EPRI, *Selective Catalytic Reduction Design Considerations for Gas Turbines Firing Hydrogen and Ammonia Fuels, September 2021).* The use of 10 years for this metric, along with the 3 ppm control level (see Section 5.2), therefore results in a very conservatively low estimate for cost effectiveness in $/ton of $NO_x$ removed. An estimated equipment life expectancy of 30 years was used for the DLNB + SCR option reflecting the AQR Section 120.5(a)(3) specified metric. The use of 30 years for this metric, along with the 2 ppm control level (see Section 5.2),

therefore results in a very conservatively low estimate for cost effectiveness in $/ton of NOx removed as well.

The detailed cost effectiveness calculations for each control option are provided in Attachment A. A summary of the results is provided in Table 4 below.

**Table 4 – Cost-effectiveness Calculation Summary**

| Control Option | Emission Reduction (tons per year) | Total Annualized Cost ($) | Cost-effectiveness ($/ton) |
|---|---|---|---|
| Catalyst replacement | 46.61 | 290,040 | 6,223 |
| DLNB + SCR | 53.26 | 483,057 | 9,069 |

As shown above, the calculated cost-effectiveness of each option analyzed exceeds the RACT threshold of $5,500.

### 5.4 Evaluation of the Benefits and Disadvantages

Evaluation of the benefits and disadvantages includes an evaluation of any additional environmental, energy and economic impacts associated with the control technologies evaluated for RACT. These additional impacts are discussed in this section.

Environmental Impacts

SCR as a control device presents a negative environmental impact due to the released ammonia during its operation. This process is known as Ammonia Slip. Higher NOX control associated with an SCR system corresponds to higher overall ammonia emissions associated with ammonia slip. An additional environmental impact associated with using SCR comes from ammonia transportation and storage. Ammonia is considered a toxic chemical substance and in the event of spill or fire, presents an enormous environmental liability in the form of air, soil and groundwater contamination, and employee injuries. Any SCR system will incorporate these additional impacts to some extent regardless of final NOX control efficiency.

Energy Impacts

There are additional power requirements associated with SCR operation due to running the pumps electrical motors associated with the system. However, since the existing baseline operation utilizes SCR, no significant energy impact is associated with implementation of this enhanced technology. No significant energy impacts have been identified for the implementation of DLN technology implementation other than that it would require the power station to be offline for several months in order to reconfigure/overhaul the turbines resulting in a loss of power production for the community during that time period.

Economic Impacts

Installation of either control option on the existing combustion turbine units at Saguaro would entail significant capital costs. As shown above in Section 5.3, the cost-effectiveness of the control options evaluated exceeds the RACT threshold of $5,500 per ton.

**5.5 $NO_x$ RACT Determination**

After reviewing similar facilities for emission control technologies, eliminating technically infeasible options and evaluating the remaining technologies for environmental, energy, and economic impacts it is determined that the existing SCR and steam injection controls satisfy RACT for compliance with AQR Section 120.

The specific RACT control, monitoring, testing, recordkeeping and reporting conditions necessary to ensure compliance are described below.

RACT Control Requirements

For the turbine generators (EUs: A01 and A02), including duct burners (EUs: F05, F05a, F06, and F06a):

(1) Limit $NO_x$ emissions to 10 ppmvd at 15% O2, excluding startup and shutdown;
(2) Limit $NO_x$ emissions to an emissions rate of 66 lb/hr during startup and shutdown; and
(3) Operate and maintain the units using Good Combustion Practices during startup, shut-down, and other non-normal operations, to include operating the units in accordance with the manufacturer's O&M manual.

RACT Monitoring Requirements

For the turbine generators (EUs: A01–A02):

(1) Install, calibrate, maintain, operate, and certify CEMS for $NO_x$;
(2) Require periodic audit procedures and QA/AC procedures for the CEMS;
(3) Conduct RATA of the $NO_x$ CEMS;
(4) Monitor CEMS $NO_x$ data;
(5) Monitor the occurrences and durations of startup/shutdown cycles; and
(6) Demonstrate compliance with NOx emissions limits.

RACT Testing Requirements

No additional testing requirements were identified.

RACT Recordkeeping and Reporting Requirements

For the turbine generators (EUs: A01–A02):

(1) Maintain records of required reporting, including records of all inspections, maintenance, and repairs;
(2) Maintain records of the date, time, and duration of each startup and shut-down cycle of each turbine;
(3) Maintain records of QA/QC procedures;

(4) Maintain records of CEMS audit and calibration results, along with any corrective actions taken;
(5) Maintain records of the time, duration, nature, and probable cause of any CEMS downtown, and of any corrective actions taken; and
(6) Maintain records of CEMS VOC and $NO_x$ data.
(7) Submit performance test reports;
(8) Submit an annual emissions inventory report; and
(9) Submit an annual compliance certification.

**Attachment A - Cost Effectiveness Calculations**

| COST EFFECTIVENESS CALCULATION | |
|---|---|
| SAGUARO POWER COMPANY | |
| CTG 1 AND CTG2 (COMBINED CYCLE UNITS) | |
| **Emissions Unit** | A01/A02 |
| Pollutant | $NO_x$ |
| Control Technology | Replace Catalyst on Existing SCRs |
| Baseline Emissions (ppm@15% O2) | 10 |
| Controlled Emissions (ppm@15% O2) | 3 |
| Baseline Emissions Rate (tpy) | 66.58 |
| Controlled Emissions (tpy) | 19.97 |
| Emissions Reduction (%) | 70% |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment | 607,500 |
| Direct & Indirect Costs | |
| Total Capital Investment | 607,500 |
| Estimated Equipment Life, years | 10 |
| Interest Rate, % | 6.00% |
| Capital Recovery Factor | 0.136 |
| Annualized Total Capital Investment | 82,540 |
| | |
| **Annual Operating Costs** | |
| Ammonia | 207,500 |
| | |
| | |
| | |
| **Total Annualized Cost** | **290,040** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 46.61 |
| Cost Effectiveness ($/ton) | **6,223** |

Capitol Recovery Factor = $r(1 + r)^n / ((1 + r)^n - 1)$, where r is the interest rate and n is the equipment life in years
Annualized Total Capital Investment = Total Capital Investment x Capital Recovery Factor

| COST EFFECTIVENESS CALCULATION | |
|---|---|
| SAGUARO POWER COMPANY | |
| CTG 1 AND CTG2 (COMBINED CYCLE UNITS) | |
| **Emissions Unit** | A01/A02 |
| Pollutant | $NO_x$ |
| Control Technology | DLNB+SCR |
| Baseline Emissions (ppm@15% O2) | 10 |
| Controlled Emissions (ppm@15% O2) | 2 |
| Baseline Emissions Rate (tpy) | 66.58 |
| Controlled Emissions (tpy) | 13.32 |
| Emissions Reduction (%) | 80% |
| | |
| **Annualized Capital Costs** | |
| Initial Capital Investment | 3,793,000 |
| Direct & Indirect Costs | |
| Total Capital Investment | 3,793,000 |
| Estimated Equipment Life, years | 30 |
| Interest Rate, % | 6.00% |
| Capital Recovery Factor | 0.073 |
| Annualized Total Capital Investment | 275,557 |
| | |
| **Annual Operating Costs** | |
| Ammonia | 207,500 |
| | |
| | |
| | |
| **Total Annualized Cost** | **483,057** |
| | |
| **Cost Effectiveness (CE)** | |
| Emissions Reduction (tpy) | 53.26 |
| Cost Effectiveness ($/ton) | **9,069** |

Capitol Recovery Factor = $r(1 + r)^n / ((1 + r)^n - 1)$, where r is the interest rate and n is the equipment life in years
Annualized Total Capital Investment = Total Capital Investment x Capital Recovery Factor

# ATTACHMENT 9: Cost Effectiveness Calculations

## Cost Effectiveness Calculation 1

| | | |
|---|---|---|
| Nellis Air Force Base (NAFB) | | |
| Emergency Diesel Engine | | |
| Emulsified Diesel | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | Unit G009 | *1635 hp, 1250 kW* |
| Emission Unit Description | Emergency Diesel Engine | |
| Pollutant | $NO_x$ | |
| Control Technology | ED | |
| Baseline Emissions Rate (tpy) | 9.81 | *PTE* |
| Emissions Reduction (%) | 50% | *Based only 10% water in emulsion. Can go higher in water and reduce NOx more, but stability of emulsion decreased rapidly with additional water* |
| Controlled Emissions (tpy) | 4.91 | |

| Annualized Capital Costs | | |
|---|---|---|
| Initial Capital Investment | $30,000 | *Based on $24/kW capital costs. Assumes conservative cost based from Issa et al., 2019, Table 5.* |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | **$30,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital investment** | **$2,179** | |

| Annual Operating Costs | | |
|---|---|---|
| Maintenance | $3,000 | *Assumes this is the additional cost of maintenance.* |
| Fuel cost difference ($0.22/gallon, 5,959 gal/year at 500 hr/yr) | $1,311 | |
| | | |
| **Total Annualized Cost** | **$6,490** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 4.91 | |
| **Cost Effectiveness ($/ton)** | **$1,323.23** | |

| Fuel Calculation | | | | | |
|---|---|---|---|---|---|
| 5959 | 5417 | 500 | 0.22 | 186.42 | 0.26 |
| gal/year | gal/year | hrs/yr | sfc (liters/hr) | kW | gal/liter |
| With 10% added consumption values due to emulsions have lower energy and require higher consumption (Tyrovola et al. 2015). | | (U.S. Environmental Protection Agency, 1995) | (101 Generator, 2026) | 250 hp | |

## Cost Effectiveness Calculation 2

| | | |
|---|---|---|
| Caesars | | |
| Boilers | | |
| OT | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | CP02 | |
| Emission Unit Description | Natural Gas Boiler | |
| Pollutant | $NO_x$ | |
| Control Technology | OT | |
| Baseline Emissions Rate (tpy) | 5.46 | *PTE* |
| Emissions Reduction (%) | 15% | *From Oland 2002, p. 5-6.* |
| Controlled Emissions (tpy) | 4.64 | |

| Annualized Capital Costs | | |
|---|---|---|
| Initial Capital Investment | $7,335 | *Based on 1994 ACT cost in 1992 $ of $100/MM Btu/hr (U.S. Environmental Protection Agency 1994). This is $3,300 for a 33 MMBtu/hr burner. Adjusted for inflation with Chem Engr index to 2024 (2024/1992 = $796.16/$358.2), so ($796.16/$358.2)*$3300 = $7335).* |
| Direct & Indirect Costs | $7,335 | *Assumes the monitoring instrumentation (CEM) is same as capital cost* |
| **Total Capital Investment** | **$14,670** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital Investment** | **$1,066** | |

| Annual Operating Costs | | |
|---|---|---|
| Maintenance | $2,000 | *General estimate.* |
| | | |
| | | |
| **Total Annualized Cost** | **$3,066** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 0.82 | |
| **Cost Effectiveness ($/ton)** | **$3,743.30** | |

## Cost Effectiveness Calculation 3

| | | |
|---|---|---|
| Caesars | | |
| Boilers | | |
| Fuel-Induced Recirculation (FIR2) | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | CP02 | |
| Emission Unit Description | Natural Gas Boiler | |
| Pollutant | $NO_x$ | |
| Control Technology | FIR2 | |
| Baseline Emissions Rate (tpy) | 5.46 | *PTE* |
| Emissions Reduction (%) | 43% | |
| Controlled Emissions (tpy) | 3.11 | |

| Annualized Capital Costs | | |
|---|---|---|
| Initial Capital Investment | $91,560 | *Based on 1975 cost for retrofit from 1978 EPA Control Techniques document of $21K (p. 4-55), adjusted with Chem Engr Cost Index (ratio = 796.16 (2024)/182.4 (1975) = 4.36). (U.S. Environmental Protection Agency 1978b)*<br>*4.36x21,000 = $91,560* |
| Direct & Indirect Costs | $3,000 | *General estimate* |
| **Total Capital Investment** | **$94,560** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital Investment** | **$6,870** | |

| Annual Operating Costs | | |
|---|---|---|
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **$6,870** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 2.35 | |
| **Cost Effectiveness ($/ton)** | **$2,926.01** | |

## Cost Effectiveness Calculation 4

| | | |
|---|---|---|
| Caesars | | |
| Boilers | | |
| ULTRA-LOW NOx BURNERS (ULNB) | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | CP02 | |
| Emission Unit Description | Natural Gas Boiler | |
| Pollutant | $NO_x$ | |
| Control Technology | ULNB | |
| Baseline Emissions Rate (tpy) | 5.46 | *PTE* |
| Emissions Reduction (%) | 70% | |
| Controlled Emissions (tpy) | 1.64 | |

| Annualized Capital Costs | | |
|---|---|---|
| Initial Capital Investment+A15 | $330,000 | *From Ceasars RACT analysis. Cost based on vendor estimate includes installation and startup.* |
| Direct & Indirect Costs | $3,000 | |
| **Total Capital Investment** | **$333,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital Investment** | **$24,192** | |

| Annual Operating Costs | | |
|---|---|---|
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **$24,192** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 3.82 | |
| **Cost Effectiveness ($/ton)** | **$6,329.69** | |

## Cost Effectiveness Calculation 5

| | | |
|---|---|---|
| Caesars | | |
| Boilers | | |
| Gas Fuel Flow Modifiers (GFFM) | | |

| **Emissions Unit/Control Technology** | | **Notes** |
|---|---|---|
| Emissions Unit | CP02 | |
| Emission Unit Description | Natural Gas Boiler | |
| Pollutant | $NO_x$ | |
| Control Technology | GFFM | |
| Baseline Emissions Rate (tpy) | 5.46 | *PTE* |
| Emissions Reduction (%) | 15% | **Assumes 15% reduction in $NO_x$* |
| Controlled Emissions (tpy) | 4.64 | |

| **Annualized Capital Costs** | | |
|---|---|---|
| Initial Capital Investment+A15 | $165,000 | **Assumes half the cost of installing ULNB* |
| Direct & Indirect Costs | $1,500 | **Assumes half the cost of installing ULNB* |
| **Total Capital Investment** | **$166,500** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital Investment** | **$12,096** | |

| **Annual Operating Costs** | | |
|---|---|---|
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **$12,096** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 0.82 | |
| **Cost Effectiveness ($/ton)** | **$14,769.28** | |

## Cost Effectiveness Calculation 6

| | | |
|---|---|---|
| Caesars 6 | | |
| Boilers | | |
| OFA | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | CP02 | |
| Emission Unit Description | Natural Gas Boiler | |
| Pollutant | $NO_x$ | |
| Control Technology | OFA | |
| Baseline Emissions Rate (tpy) | 5.46 | *PTE* |
| Emissions Reduction (%) | 50% | |
| Controlled Emissions (tpy) | 2.73 | |

| Annualized Capital Costs | | |
|---|---|---|
| Initial Capital Investment | $91,560 | *Assumes similar cost to FIR2. Based on 1975 cost for retrofit from 1978 EPA Control Techniques doc of $21K (p. 4-55), adjusted for inflation with Chem Engr index to 2024 (2024/1975 = $796.16/182.4 = 4.36) (U.S. Environmental Protection Agency 1978b)* |
| Direct & Indirect Costs | $3,000 | *General Estimate* |
| **Total Capital Investment** | **$94,560** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital Investment** | **$6,870** | |

| Annual Operating Costs | | |
|---|---|---|
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **$6,870** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 2.73 | |
| **Cost Effectiveness ($/ton)** | **$2,516.37** | |

## Cost Effectiveness Calculation 7

| | | |
|---|---|---|
| MGMRI | | |
| Emergency Engines | | |
| Manifold Air Temperature | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | MG17 | |
| Emission Unit Description | Emergency Engine | |
| Pollutant | NOx | |
| Control Technology | MAT | |
| Baseline Emissions Rate (tpy) | 15.12 | *PTE* |
| Emissions Reduction (%) | 70% | *70% reduction based on formula from 1978 EPA Control Techniques document, Table 4- 20, and Komatsu report on an air-cooled aftercooler that lowered inlet air from 356 to 122 F* |
| Controlled Emissions (tpy) | 4.54 | |

| Annualized Capital Costs | | |
|---|---|---|
| Initial Capital Investment | $400,000 | *1993 ACT, Fig. 6-10* |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | **$400,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital investment** | **$29,060** | |

| Annual Operating Costs | | |
|---|---|---|
| Maintenance | $60,000 | *1993 ACT, Figure 6-10* |
| | | |
| | | |
| **Total Annualized Cost** | **$89,060** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 10.58 | |
| **Cost Effectiveness ($/ton)** | **$8,414.55** | |

## Cost Effectiveness Calculation 8

| | | |
|---|---|---|
| MGMRI | | |
| Emergency Egines | | |
| Emulsified Diesel | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | TBA15 | *1,180 hp* |
| Emission Unit Description | Emergency Egines | |
| Pollutant | $NO_x$ | |
| Control Technology | DE | |
| Baseline Emissions Rate (tpy) | 7.08 | *PTE* |
| Emissions Reduction (%) | 50% | *Based only 10% water in emulsion. Can go higher in water and reduce NOx more, but stability of emulsion decreased rapidly with additional water.* |
| Controlled Emissions (tpy) | 3.54 | |

| Annualized Capital Costs | | |
|---|---|---|
| Initial Capital Investment | $21,000 | *Based on $24/kW capital costs. Assumes conservative cost based from Issa et al., 2019, Table 5.* |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | **$21,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital investment** | **$1,526** | |

| Annual Operating Costs | | |
|---|---|---|
| Maintenance | $3,000 | *Assumes this is the additional cost of maintenance.* |
| Fuel cost difference ($0.22/gallon, 5959 gal/year at 500 hr/yr) | $1,311 | |
| | | |
| **Total Annualized Cost** | **$5,837** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 3.54 | |
| **Cost Effectiveness ($/ton)** | **$1,648.76** | |

| Fuel Estimate | | | | | |
|---|---|---|---|---|---|
| 5959 | 5417 | 500 | 0.22 | 186.42 | 0.26 |
| gal/year | gal/year | hrs/yr | sfc (liters/hr) | kW | gal/liter |
| With 10% added consumption values due to emulsions have lower energy and require higher consumption (Tyrovola et al. 2015). | | (U.S. Environmental Protection Agency, 1995) | (101 Generator. 2026) | 250 hp | |

# Cost Effectiveness Calculation 9

| | | |
|---|---|---|
| CertainTeed Gypsum Manufacturing, Inc. | | |
| Diesel Engine | | |
| New Tier 4 Machine | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | N5 | |
| Emission Unit Description | Continuous Duty Diesel Engine | |
| Pollutant | $NO_x$ | |
| Control Technology | New Tier 4 Machine | |
| Baseline Emissions Rate (tpy) | 5.73 | *PTE* |
| Emissions Reduction (%) | 90% | |
| Controlled Emissions (tpy) | 0.57 | |

| Annualized Capital Costs | | |
|---|---|---|
| Initial Capital Investment | $916,850 | *Estimate from CertainTeed RACT analysis. Includes all direct and indirect costs.* |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | **$916,850** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital Investment** | **$66,608** | |

| Annual Operating Costs | | |
|---|---|---|
| Urea | $11,520 | |
| | | |
| | | |
| **Total Annualized Cost** | **$78,128** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 5.16 | |
| **Cost Effectiveness ($/ton)** | **$15,149.92** | |

## Cost Effectiveness Calculation 10

| | | |
|---|---|---|
| Certainteed Gypsum Manufacturing, Inc. | | |
| Diesel Engine | | |
| Emulsified Diesel | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | N5 | *575 HP, 430 kW* |
| Emission Unit Description | Continuous Duty Diesel Engine | |
| Pollutant | $NO_x$ | |
| Control Technology | Emulsified Diesel | |
| Baseline Emissions Rate (tpy) | 5.73 | *PTE* |
| Emissions Reduction (%) | 50% | *Based only 10% water in emulsion. Can go higher in water and reduce $NO_x$ more, but stability of emulsion decreased rapidly with additional water.* |
| Controlled Emissions (tpy) | 2.87 | |

| Annualized Capital Costs | | |
|---|---|---|
| Initial Capital Investment | $10,320 | *Based on $24/kW capital costs. Assumes conservative cost based from Issa et al. 2019, Table 5.* |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | **$10,320** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital investment** | **$750** | |

| Annual Operating Costs | | |
|---|---|---|
| Maintenance | $3,000 | *Assumes this is the additional cost of maintenance.* |
| Fuel cost difference ($0.22/gallon,28,603 gal/year at 2,400 hr/yr) | $6,293 | |
| | | |
| **Total Annualized Cost** | **$10,042** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 2.87 | |
| **Cost Effectiveness ($/ton)** | **$3,505.23** | |

| Fuel Estimate | | | | | |
|---|---|---|---|---|---|
| 28603 gal/year | 26003 gal/year | 2400 hrs/yr | 0.22 sfc (liters/hr) | 186.42 kW | 0.26 gal/liter |
| With 10% added consumption values due to emulsions have lower energy and require higher consumption (Tyrovola et al. 2015). | | From allowed hours from permit | (101 Generator. 2026) | 250 hp | |

# Cost Effectiveness Calculation 11

| | | |
|---|---|---|
| CertainTeed Gypsum Manufacturing, Inc. | | |
| CP Mill | | |
| Low $NO_x$ Staged | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | E11 | |
| Emission Unit Description | CP Mill | |
| Pollutant | $NO_x$ | |
| Control Technology | Low NOx Staged | |
| Baseline Emissions Rate (tpy) | 7.88 | *PTE* |
| Emissions Reduction (%) | 55% | |
| Controlled Emissions (tpy) | 3.55 | |

| Annualized Capital Costs | | |
|---|---|---|
| Initial Capital Investment | $360,480 | *Estimate from CertainTeed RACT analysis. Includes all direct and indirect costs.* |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | **$360,480** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital investment** | **$26,188** | |

| Annual Operating Costs | | |
|---|---|---|
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **$26,188** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 4.33 | |
| **Cost Effectiveness ($/ton)** | **$6,042.57** | |

## Cost Effectiveness Calculation 12

| | | |
|---|---|---|
| CertainTeed Gypsum Manufacturing, Inc. | | |
| AKI Board Dryer | | |
| Ultra Low $NO_x$ | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | J3 | |
| Emission Unit Description | AKI Board Dryer | |
| Pollutant | $NO_x$ | |
| Control Technology | Ultra Low NOx | |
| Baseline Emissions Rate (tpy) | 28.41 | *PTE* |
| Emissions Reduction (%) | 74% | |
| Controlled Emissions (tpy) | 7.39 | |

| Annualized Capital Costs | | |
|---|---|---|
| Initial Capital Investment | $1,944,182 | *Estimate from CertainTeed RACT analysis. Includes all direct and indirect costs. 2017 Cost from similar facility of $1,388,701 adjusted for CEPCI (796.5/567.5)* |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | **$1,944,182** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital investment** | **$141,243** | |

| Annual Operating Costs | | |
|---|---|---|
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **$141,243** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 21.02 | |
| **Cost Effectiveness ($/ton)** | **$6,718.36** | |

# Cost Effectiveness Calculation 13

| | | |
|---|---|---|
| Las Vegas Generating Station | | |
| Unit 1 | | |
| SCR System Upgrade | | |

| Emissions Unit/Control Technology | | Notes |
|---|---|---|
| Emissions Unit | Unit 1 | |
| Emission Unit Description | Combustion Turbine | |
| Pollutant | $NO_x$ | |
| Control Technology | SCR replacement | |
| Baseline Emissions (ppm@15% O2) | 10.00 | |
| Controlled Emissions (ppm@15% O2) | 2.00 | |
| Baseline Emissions Rate (tpy) | 43.00 | *PTE (NV Energy proposed capped emissions)* |
| Emissions Reduction (%) | 80% | *Achievable emissions for water injection are based on the lowest RBLC determination for similarly equipped unit for 2012-2025 (see RBLC Determinations). Further investigation may be required to confirm this level of performance.* |
| Controlled Emissions (tpy) | 8.60 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $880,000 | *Vendor (Environex) capital cost estimate* |
| Sales Tax | $40,480 | *4.6% Nevada sales tax* |
| Indirect Installation Costs | $322,168 | *35% of capital equipment cost (OAQPS Manual)* |
| | | |
| **Total Capital Investment** | **$1,242,648** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital investment** | **$101,553** | |

| Annual Operating Costs | | |
|---|---|---|
| Catalyst changeout | $69,400 | *5 year life, 7.14% RI, Vendor catalyst cost* |
| NH3 usage | $13,000 | *Estimated additional $NH_3$ consumption at 1.05 lbmol $NH_3$/lbmol $NO_x$ removed and $0.69/gal* |
| Annual maintenance | $6,213 | *0.5% of total capital investment (OAQPS Manual)* |
| **Total Annualized Cost** | **$190,166** | |

| Cost Effectiveness (CE) | | |
|---|---|---|
| Emissions Reduction (tpy) | 34.40 | |
| **Cost Effectiveness ($/ton)** | **$5,528.08** | |

# Cost Effectiveness Calculation 14

| | | |
|---|---|---|
| Las Vegas Generating Station | | |
| Unit 1 | | |
| SCR System Upgrade | | |

| **Emissions Unit/Control Technology** | | **Notes** |
|---|---|---|
| Emissions Unit | Unit 1 | |
| Emission Unit Description | Combustion Turbine | |
| Pollutant | $NO_x$ | |
| Control Technology | SCR replacement | |
| Baseline Emissions (ppm@15% O2) | 10.00 | |
| Controlled Emissions (ppm@15% O2) | 2.00 | |
| Baseline Emissions Rate (tpy) | 42.00 | *PTE (DAQ proposed capped emissions)* |
| Emissions Reduction (%) | 80% | *Achievable emissions for water injection are based on the lowest RBLC determination for similarly equipped unit for 2012-2025 (see RBLC Determinations). Further investigation may be required to confirm this level of performance.* |
| Controlled Emissions (tpy) | 8.40 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $880,000 | *Vendor (Environex) capital cost estimate* |
| Sales Tax | $40,480 | *4.6% Nevada sales tax* |
| Indirect Installation Costs | $322,168 | *35% of capital equipment cost (OAQPS Manual)* |
| | | |
| **Total Capital Investment** | **$1,242,648** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital investment** | **$101,553** | |

| **Annual Operating Costs** | | |
|---|---|---|
| Catalyst changeout | $69,400 | *5 year life, 7.14% RI, Vendor catalyst cost* |
| NH3 usage | $13,000 | *Estimated additional $NH_3$ consumption at 1.05 lbmol $NH_3$/lbmol $NO_x$ removed and $0.69/gal* |
| Annual maintenance | $6,213 | *0.5% of total capital investment (OAQPS Manual)* |
| **Total Annualized Cost** | **$190,166** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 33.60 | |
| **Cost Effectiveness ($/ton)** | **$5,659.70** | |

# Cost Effectiveness Calculation 15

| | | |
|---|---|---|
| Las Vegas Generating Station | | |
| Unit 1 | | |
| SCR + DLNC | | |

| **Emissions Unit/Control Technology** | | **Notes** |
|---|---|---|
| Emissions Unit | Unit 1 | |
| Emission Unit Description | Combustion Turbine | |
| Pollutant | $NO_x$ | |
| Control Technology | SCR + DLNC | |
| Baseline Emissions (ppm@15% O2) | 10.00 | |
| Controlled Emissions (ppm@15% O2) | 2.00 | |
| Baseline Emissions Rate (tpy) | 43.00 | *PTE (NV Energy proposed capped emissions)* |
| Emissions Reduction (%) | 80% | *Achievable emissions for SCR+LBN are based on the lowest RBLC determination for similarly equipped unit for 2015-2025 . Further investigation may be required to confirm this level of performance.* |
| Controlled Emissions (tpy) | 8.60 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $3,793,000 | *LNB total installed cost is based on Saguaro Power Company vendor estimate from the previous RACT submittal.* |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | **$3,793,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital investment** | **$309,974** | |

| **Annual Operating Costs** | | |
|---|---|---|
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **$309,974** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 34.40 | |
| **Cost Effectiveness ($/ton)** | **$9,010.88** | |

## Cost Effectiveness Calculation 16

| | | |
|---|---|---|
| Clark Generating Station | | |
| Unit 4 (Combustion Turbine) | | |
| Selective Catalytic Reduction (SCR) | | |

| **Emissions Unit/Control Technology** | | |
|---|---|---|
| Emissions Unit | Unit 4 | |
| Emission Unit Description | Combustion Turbine | |
| Pollutant | $NO_x$ | |
| Control Technology | SCR | |
| Baseline Emissions (ppm@15% O2) | 120.00 | |
| Controlled Emissions (ppm@15% O2) | 4.00 | *Achievable emissions for SCR and oxidation catalyst retrofit is based on vendor data provided by NV Energy in their 2022/2023 RACT analysis (see "PMC Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle CT" )* |
| Baseline Emissions Rate (tpy) | 292.00 | *PTE (NV Energy proposed capped emissions)* |
| Emissions Reduction (%) | 97% | |
| Controlled Emissions (tpy) | 9.73 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $10,100,000 | *SCR costs provided by NV Energy based on vendor estimate in their 2022/2023 RACT analysis* |
| Sales Tax | $464,600 | *4.6% Nevada sales tax* |
| **Direct Installation Cost** | **$7,000,000** | *SCR costs provided by NV Energy based on vendor estimate in their 2022/2023 RACT analysis. Vendor (PMC) direct installation cost* |
| Indirect Installation Cost | $3,697,610 | *35% of capital equipment cost (OAQPS Manual)* |
| **Total Capital Investment** | **$21,262,210** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$1,737,123** | |

| **Annual Operating Costs** | | |
|---|---|---|
| Catalyst Changeout | $156,100 | *5 year life, 7.14% ROI, Vendor catalyst cost* |
| | | |
| | | |
| **Total Annualized Cost** | **$1,893,223** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 282.27 | |
| **Cost Effectiveness ($/ton)** | **$6,707.21** | |

## Cost Effectiveness Calculation 17

| | | |
|---|---|---|
| Clark Generating Station | | |
| Unit 4 (Combustion Turbine) | | |
| Water Injection | | |

| **Emissions Unit/Control Technology** | | **Notes** |
|---|---|---|
| Emissions Unit | Unit 4 | |
| Emission Unit Description | Combustion Turbine | |
| Pollutant | $NO_x$ | |
| Control Technology | Water Injection | |
| Baseline Emissions (ppm@15% O2) | 120.00 | |
| Controlled Emissions (ppm@15% O2) | 25 | |
| Baseline Emissions Rate (tpy) | 292.00 | *PTE* |
| Emissions Reduction (%) | 79% | *Achievable emissions for water injection are based on the lowest RBLC determination for similarly equipped unit. Further investigation may be required to confirm this level of performance.* |
| Controlled Emissions (tpy) | 60.83 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | | *EPA CoST Model (version 4.1): Annual Cost (1999$) = annual cost multiplier x design capcity^annual cost exponent + annual base cost* |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$0** | |

| **Annual Operating Costs** | | |
|---|---|---|
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **$3,175,071** | *Value from 2022/2023 RACT submittal. EPA CoST Model (version 4.1): Annual Cost (1999$) = annual cost multiplier x design capcity^annual cost exponent + annual base cost; Annual Cost (1999$) = 3700.2*600^0.95+0; Design capacity = (60 MW)(1,000 kW/MW)(10,000 Btu/kWh)/1,000,000 = 600 MMBtu/hr* |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 231.17 | |
| **Cost Effectiveness ($/ton)** | **$13,734.99** | |

| **Cost Adjustment** | | |
|---|---|---|
| $ 1,612,386.00 | 1.97 | $ 3,175,071.21 |
| 1999 Cost | Adjusted to 2024 using CEPCI (=769.16/390.6) | |

## Cost Effectiveness Calculation 18

| | | |
|---|---|---|
| Clark Generating Station | | |
| Unit 4 (Combustion Turbine) | | |
| Oxidation Catalyst | | |

| **Emissions Unit/Control Technology** | | |
|---|---|---|
| Emissions Unit | Unit 4 | |
| Emission Unit Description | Combustion Turbine | |
| Pollutant | VOC | |
| Control Technology | Oxidation Catalyst | |
| Baseline Emissions (ppm@15% O2) | 85.00 | |
| Controlled Emissions (ppm@15% O2) | 17 | |
| Baseline Emissions Rate (tpy) | 94.50 | *Non-capped emissions* |
| Emissions Reduction (%) | 80% | *Achievable emissions for SCR and oxidation catalyst retrofit is based on vendor data provided by NV Energy in their 2022/2023 RACT analysis (see "PMC Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle CT")* |
| Controlled Emissions (tpy) | 18.90 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $2,030,000 | |
| Direct & Indirect Costs | $1,500,000 | |
| **Total Capital Investment** | **$3,530,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$288,401** | |

| **Annual Operating Costs** | | |
|---|---|---|
| Catalyst | $130,100 | *Estimated equipment life for all control options based on EPA CoST Model (version 4.1)* |
| Maintenance | | |
| **Total Annualized Cost** | **$418,501** | |
| | | |
| **Cost Effectiveness (CE)** | | |
| Emissions Reduction (tpy) | 75.60 | |
| **Cost Effectiveness ($/ton)** | **$5,535.73** | |

| **Capped tpy calculation:** | | | |
|---|---|---|---|
| tpy | Hour limitation (hrs/year) | Emission Rate (lb/hr) | |
| 16 | 1480 | 21.6 | VOC |
| 292 | 1480 | 395 | NOX |

## Cost Effectiveness Calculation 19

| | | |
|---|---|---|
| Clark Generating Station | | |
| Unit 4 (Combustion Turbine) | | |
| Oxidation Catalyst | | |

| **Emissions Unit/Control Technology** | | |
|---|---|---|
| Emissions Unit | Unit 4 | |
| Emission Unit Description | Combustion Turbine | |
| Pollutant | VOC | |
| Control Technology | Oxidation Catalyst | |
| Baseline Emissions (ppm@15% O2) | 85.00 | |
| Controlled Emissions (ppm@15% O2) | 17 | |
| Baseline Emissions Rate (tpy) | 16.00 | *DAQ proposed capped emissions based off a estimated 1,480 hours for the emission cap on Unit 4 for $NO_x$ emissions* |
| Emissions Reduction (%) | 80% | *Achievable emissions for SCR and oxidation catalyst retrofit is based on vendor data provided by NV Energy (see NE Energery 2022/2023 RACT analysis, "PMC Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle CT")* |
| Controlled Emissions (tpy) | 3.20 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $2,030,000 | |
| Direct & Indirect Costs | $1,500,000 | |
| **Total Capital Investment** | **$3,530,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$288,481** | |

| **Annual Operating Costs** | | |
|---|---|---|
| Catalyst | $130,100 | *Estimated equipment life for all control options based on EPA CoST Model (version 4.1)* |
| Maintenance | | |
| **Total Annualized Cost** | **$418,581** | |
| | | |
| **Cost Effectiveness (CE)** | | |
| Emissions Reduction (tpy) | 12.80 | |
| **Cost Effectiveness ($/ton)** | **$32,701.65** | |

| **Capped tpy calculation:** | | | |
|---|---|---|---|
| tpy | Hour limitation (hrs/year) | Emission Rate (lb/hr) | |
| 16 | 1480 | 21.6 | VOC |
| 292 | 1480 | 395 | NOX |

# Cost Effectiveness Calculation 20

| | | |
|---|---|---|
| Clark Generating Station | | |
| Unit 7 | | |
| Selective Catalytic Reduction (SCR) | | |

| **Emissions Unit/Control Technology** | | |
|---|---|---|
| Emissions Unit | Unit 7 | *Unit 5-8 have a combined $NO_x$ PTE. 85 MW each. This approach assumes control on Unit 7 and full PTE on Unit 7.* |
| Emission Unit Description | Combustion Cycle Units | |
| Pollutant | $NO_x$ | |
| Control Technology | SCR/LNB | |
| Baseline Emissions (ppm@15% O2) | 5.00 | |
| Controlled Emissions (ppm@15% O2) | 2.00 | |
| Baseline Emissions Rate (tpy) | 360.00 | *PTE* |
| Emissions Reduction (%) | 60% | *Achievable emissions for SCR/LNB is based the lowest RBLC determination for a similarly equipped unit (see RBLC Determinations, attachment 10)* |
| Controlled Emissions (tpy) | 144.00 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $12,447,496 | *SCR capital, installation, and catalyst cost is based on NV Energy Unit 4 vendor estimate scaled according to generating capacity using 'six-tenths factor' methodology* |
| Direct & Indirect Costs | $8,626,977 | |
| **Total Capital Investment** | **$21,074,473** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$1,721,784** | |

| **Annual Operating Costs** | | |
|---|---|---|
| Catalyst | $192,382 | |
| | | |
| | | |
| **Total Annualized Cost** | **$1,914,166** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 216.00 | |
| **Cost Effectiveness ($/ton)** | **$8,861.88** | |

## Cost Effectiveness Calculation 21

| | | |
|---|---|---|
| Clark Generating Station | | |
| Unit 5-8 (Combined Cycle Units) | | |
| Selective Catalytic Reduction (SCR) | | |

| **Emissions Unit/Control Technology** | | |
|---|---|---|
| Emissions Unit | Unit 5-8 | *Unit 5-8 have a combined $NO_x$ PTE. 85 MW each. This approach assumes controls all 4 units and a combined tpy limit.* |
| Emission Unit Description | Combustion Cycle Units | |
| Pollutant | $NO_x$ | |
| Control Technology | SCR/LNB | |
| Baseline Emissions (ppm@15% O2) | 5.00 | |
| Controlled Emissions (ppm@15% O2) | 2.00 | |
| Baseline Emissions Rate (tpy) | 360.00 | *PTE* |
| Emissions Reduction (%) | 60% | *Achievable emissions for SCR/LNB is based the lowest RBLC determination for a similarly equipped unit (see RBLC Determinations - Attachment 10)* |
| Controlled Emissions (tpy) | 144.00 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $49,789,984 | *SCR capital, installation, and catalyst cost is based on NV Energy Unit 4 vendor estimate scaled according to generating capacity using 'six-tenths factor' methodology multiple by 4 for control on each unit.* |
| Direct & Indirect Costs | $34,507,908 | |
| **Total Capital Investment** | **$84,297,892** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$6,887,138** | |

| **Annual Operating Costs** | | |
|---|---|---|
| Catalyst | $769,528 | |
| | | |
| | | |
| **Total Annualized Cost** | **$7,656,666** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 216.00 | |
| **Cost Effectiveness ($/ton)** | **$35,447.53** | |

# Cost Effectiveness Calculation 22

| | | |
|---|---|---|
| Clark Generating Station | | |
| Unit 5-8 (Combined Cycle Units) | | |
| Oxidation Catalyst | | |

| **Emissions Unit/Control Technology** | | |
|---|---|---|
| Emissions Unit | Unit 7 | *Units 5-8 have the same VOC per unit* |
| Emission Unit Description | Combustion Cycle Units | |
| Pollutant | VOC | |
| Control Technology | Oxidation Catalyst | |
| Baseline Emissions (ppm@15% O2) | 16.00 | |
| Controlled Emissions (ppm@15% O2) | 2.00 | |
| Baseline Emissions Rate (tpy) | 21.90 | *PTE* |
| Emissions Reduction (%) | 88% | *Achievable oxidation catalyst retrofit is based on vendor data provided by NV Energy in their 2022/2023 RACT analysis (see "PMC Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle CT")* |
| Controlled Emissions (tpy) | 2.74 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $2,500,000 | |
| Direct & Indirect Costs | $1,500,000 | |
| **Total Capital Investment** | **$4,000,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$326,891** | |

| **Annual Operating Costs** | | |
|---|---|---|
| Catalyst | $130,100 | *Oxidation catalyst costs provided by NV Energy based on vendor estimate* |
| | | |
| | | |
| **Total Annualized Cost** | **$456,991** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 19.16 | |
| **Cost Effectiveness ($/ton)** | **$23,848.18** | |

# Cost Effectiveness Calculation 23

| | | |
|---|---|---|
| Clark Generating Station | | |
| Unit 11-22 (Combustion Turbines) | | |
| Selective Catalytic Reduction (SCR) with LNB | | |

| **Emissions Unit/Control Technology** | | |
|---|---|---|
| Emissions Unit | Unit 12 | *All have the same emissions* |
| Emission Unit Description | Combustion Turbines | |
| Pollutant | $NO_x$ | |
| Control Technology | SCR/LNB | |
| Baseline Emissions (ppm@15% O2) | 5.00 | |
| Controlled Emissions (ppm@15% O2) | 2.00 | |
| Baseline Emissions Rate (tpy) | 30.96 | *PTE* |
| Emissions Reduction (%) | 60% | *Achievable emissions for SCR/LNB is based the lowest RBLC determination for a similarly equipped unit (see RBLC Determinations - Attachment 10)* |
| Controlled Emissions (tpy) | 12.38 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | | |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | **$19,000,000** | *LNB total installed cost is based on CCGS Unit 4 vendor estimate* |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$1,552,300** | |

| **Annual Operating Costs** | | |
|---|---|---|
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **$1,552,300** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 18.58 | |
| **Cost Effectiveness ($/ton)** | **$83,564.81** | |

## Cost Effectiveness Calculation 24

| | | |
|---|---|---|
| Sun Peak Generating Station | | |
| Units 3 (Combustion Turbines) | | |
| Selective Catalytic Reduction (SCR) | | |

| **Emissions Unit/Control Technology** | | **Notes** |
|---|---|---|
| Emissions Unit | Unit 3 | *This approach assumes control on Unit 3 and full PTE on Unit 3.* |
| Emission Unit Description | | |
| Pollutant | $NO_x$ | |
| Control Technology | SCR | |
| Baseline Emissions (ppm@15% O2) | 42.00 | *Natural gas - 42 ppmvd@15 O2; #2 Oil - 65 ppmvd @ 15% O2* |
| Controlled Emissions (ppm@15% O2) | 2.00 | |
| Baseline Emissions Rate (tpy) | 249.11 | *PTE. Total of 3 units is 249.11 for NG.* |
| Emissions Reduction (%) | 95% | *Achievable emissions for SCR is based on vendor data provided by NV Energy in their 2022/2023 RACT analysis.* |
| Controlled Emissions (tpy) | 11.86 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $12,500,000 | *SCR total installed cost is based on SPGS vendor estimate in their 2022/2023 RACT analysis.* |
| Sales tax | $575,000 | *4.6% Nevada Sales tax* |
| Direct Installation Cost | $8,500,000 | *Vendor (PMC) direct Installation cost* |
| Indirect Installation Cost | $4,375,000 | *35% of capital equipment cost (OAQPS manual)* |
| **Total Capital Investment** | **$25,950,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$2,120,704** | |

| **Annual Operating Costs** | | |
|---|---|---|
| | | |
| Catalyst | $192,382 | *SCR catalyst cost is based on vendor estimate for CCGS Unit 4 in their 2022/2023 RACT analysis.* |
| | | |
| **Total Annualized Cost** | **$2,313,086** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 237.25 | |
| **Cost Effectiveness ($/ton)** | **$9,749.67** | |

## Cost Effectiveness Calculation 25

| | | |
|---|---|---|
| Sun Peak Generating Station | | |
| Units 3-5 (Combustion Turbines) | | |
| Selective Catalytic Reduction (SCR) | | |

| **Emissions Unit/Control Technology** | | **Notes** |
|---|---|---|
| Emissions Unit | Unit 3 - 5 | *This approach assumes controls all 3 units and a combined tpy limit.* |
| Emission Unit Description | | |
| Pollutant | $NO_x$ | |
| Control Technology | SCR | |
| Baseline Emissions (ppm@15% O2) | 42.00 | *Natural gas - 42 ppmvd@15 O2; #2 Oil - 65 ppmvd @ 15% O2* |
| Controlled Emissions (ppm@15% O2) | 2.00 | |
| Baseline Emissions Rate (tpy) | 249.11 | *PTE. Total of 3 units is 249.11 for NG.* |
| Emissions Reduction (%) | 95% | *Achievable emissions for SCR is based on vendor data provided by NV Energy in their 2022/2023 RACT analysis.* |
| Controlled Emissions (tpy) | 11.86 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $37,500,000 | *SCR total installed cost is based on SPGS vendor estimate in their 2022/2023 RACT analysis.* |
| Sales tax | $1,725,000 | *4.6% Nevada Sales tax* |
| Direct Installation Cost | $25,500,000 | *Vendor (PMC) direct Installation cost* |
| Indirect Installation Cost | $13,125,000 | *35% of capital equipment cost (OAQPS manual)* |
| **Total Capital Investment** | **$77,850,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$6,362,112** | |

| **Annual Operating Costs** | | |
|---|---|---|
| | | |
| Catalyst | $577,146 | *SCR catalyst cost is based on vendor estimate for CCGS Unit 4 in their 2022/2023 RACT analysis.* |
| | | |
| **Total Annualized Cost** | **$6,939,258** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 237.25 | |
| **Cost Effectiveness ($/ton)** | **$29,249.01** | |

## Cost Effectiveness Calculation 26

| | | |
|---|---|---|
| Sun Peak Generating Station | | |
| Units 3 (Combustion Turbines) | | |
| LNB | | |

| **Emissions Unit/Control Technology** | | **Notes** |
|---|---|---|
| Emissions Unit | Unit 3 | *This approach assumes control on Unit 3 and full PTE on Unit 3.* |
| Emission Unit Description | | |
| Pollutant | $NO_x$ | |
| Control Technology | LNB | |
| Baseline Emissions (ppm@15% O2) | 42.00 | *Natural gas - 42 ppmvd@15 O2; #2 Oil - 65 ppmvd @ 15% O2* |
| Controlled Emissions (ppm@15% O2) | 9.00 | *Based off analysis provided by NVE* |
| Baseline Emissions Rate (tpy) | 249.11 | *PTE. Total of 3 units is 249.11 for NG. 249.11/3 = 83.04 per unit. Using NG instead of Diesel as NG (249.11) results in slightly greater PTE (249.02 for diesel)* |
| Emissions Reduction (%) | 79% | *Achievable emissions for SCR is based on vendor data provided by NV Energy in their 2022/2023 RACT analysis.* |
| Controlled Emissions (tpy) | 53.38 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $9,000,000 | *LNB total installed cost is based on CGS Unit 4 vendor estimate in their 2022/2023 RACT analysis.* |
| Sales Tax | $414,000 | *4.6% Nevada Sales tax* |
| Direct Installation Cost | $1,500,000 | *Vendor (PMC) direct Installation cost* |
| Indirect Installation Costs | $3,150,000 | *35% of capital equipment cost (OAQPS manual)* |
| **Total Capital Investment** | **$14,064,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$1,149,348** | |

| **Annual Operating Costs** | | |
|---|---|---|
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **$1,149,348** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 195.73 | |
| **Cost Effectiveness ($/ton)** | **$5,872.13** | |

## Cost Effectiveness Calculation 27

| | | |
|---|---|---|
| Sun Peak Generating Station | | |
| Units 3-5 (Combustion Turbines) | | |
| LNB | | |

| **Emissions Unit/Control Technology** | | **Notes** |
|---|---|---|
| Emissions Unit | Unit 3-5 | *This approach assumes controls all 3 units and a combined tpy limit.* |
| Emission Unit Description | | |
| Pollutant | $NO_x$ | |
| Control Technology | LNB | |
| Baseline Emissions (ppm@15% O2) | 42.00 | *Natural gas - 42 ppmvd@15 O2; #2 Oil - 65 ppmvd @ 15% O2* |
| Controlled Emissions (ppm@15% O2) | 9.00 | *Based off analysis provided by NVE* |
| Baseline Emissions Rate (tpy) | 249.11 | *PTE. Total of 3 units is 249.11 for NG. 249.11/3 = 83.04 per unit. Using NG instead of Diesel as NG (249.11) results in slightly greater PTE (249.02 for diesel)* |
| Emissions Reduction (%) | 79% | *Achievable emissions for SCR is based on vendor data provided by NV Energy in their 2022/2023 RACT analysis.* |
| Controlled Emissions (tpy) | 53.38 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $27,000,000 | *LNB total installed cost is based on 2022/2023 RACT submittal vendor estimate.* |
| Sales Tax | $1,242,000 | *4.6% Nevada Sales tax* |
| Direct Installation Cost | $4,500,000 | *Vendor (PMC) direct Installation cost* |
| Indirect Installation Costs | $9,450,000 | *35% of capital equipment cost (OAQPS manual)* |
| **Total Capital Investment** | **$42,192,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 7.1% | *Capital interest rate based on interest rate for other capital projects approved by the public utility commission* |
| Capital Recovery Factor | 0.0817 | |
| **Annualized Total Capital Investment** | **$3,448,044** | |

| **Annual Operating Costs** | | |
|---|---|---|
| | | |
| | | |
| | | |
| **Total Annualized Cost** | **$3,448,044** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 195.73 | |
| **Cost Effectiveness ($/ton)** | **$17,616.39** | |

# Cost Effectiveness Calculation 28

| | | |
|---|---|---|
| Saguaro Power Company | | |
| Unit 1 and 2 | | |
| Selective Catalytic Reduction (SCR) with upgraded LNB | | |

| **Emissions Unit/Control Technology** | | **Notes** |
|---|---|---|
| Emissions Unit | Unit 1&2 | *Combined both units for analysis as both have the same PTE* |
| Emission Unit Description | Combined Cycle Units | |
| Pollutant | $NO_x$ | |
| Control Technology | SCR/LNB | |
| Baseline Emissions (ppm@15% O2) | 10.00 | |
| Controlled Emissions (ppm@15% O2) | 2.00 | |
| Baseline Emissions Rate (tpy) | 66.58 | *PTE* |
| Emissions Reduction (%) | 80% | |
| Controlled Emissions (tpy) | 13.32 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $3,793,000 | *LNB total installed cost is based on SPC vendor estimate from the 2022/2023 RACT submittal* |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | **$3,793,000** | |
| Estimated Equipment Life, years | 30 | |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.0726 | |
| **Annualized Total Capital investment** | **$275,557** | |

| **Annual Operating Costs** | | |
|---|---|---|
| Ammonia | $207,500 | |
| | | |
| | | |
| **Total Annualized Cost** | **$483,057** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 53.26 | |
| **Cost Effectiveness ($/ton)** | **$9,069.11** | |

## Cost Effectiveness Calculation 29

| | | |
|---|---|---|
| Saguaro Power Company | | |
| Unit 1 and 2 | | |
| Catalyst Replacement | | |

| **Emissions Unit/Control Technology** | | **Notes** |
|---|---|---|
| Emissions Unit | Unit 1&2 | *Combined both units for analysis as both have the same PTE* |
| Emission Unit Description | Combustion Turbine | |
| Pollutant | $NO_x$ | |
| Control Technology | Replace Catalyst on existing SCR | |
| Baseline Emissions (ppm@15% O2) | 10.00 | |
| Controlled Emissions (ppm@15% O2) | 3.00 | |
| Baseline Emissions Rate (tpy) | 66.58 | *PTE* |
| Emissions Reduction (%) | 70% | *Achievable emissions with the catalyst replacement is based on the highest RBLC determination (range is 2-3 ppm @ 15% O2) for a similarly equipped unit (SCR/steam injection) (see RBLC Determinations - Attachment 10)* |
| Controlled Emissions (tpy) | 19.97 | |
| | | |
| **Annualized Capital Costs** | | |
| Initial Capital Investment | $607,500 | *SCR catalyst replacement costs are vased on Aguaro Power Company vendor estimate from previous submittal* |
| Direct & Indirect Costs | | |
| **Total Capital Investment** | **$607,500** | |
| Estimated Equipment Life, years | 10 | *DAQ accepts a 10 year replacement for the SCR catalyst.* |
| Interest Rate, % | 6.0% | |
| Capital Recovery Factor | 0.1359 | *Assuming 10 years and 6% interest* |
| **Annualized Total Capital investment** | **$82,540** | |

| **Annual Operating Costs** | | |
|---|---|---|
| Ammonia | $207,500 | |
| | | |
| | | |
| **Total Annualized Cost** | **$290,040** | |

| **Cost Effectiveness (CE)** | | |
|---|---|---|
| Emissions Reduction (tpy) | 46.61 | |
| **Cost Effectiveness ($/ton)** | **$6,223.23** | |

# ATTACHMENT 10: RBLC Results

# Gas Fired Simple Cycle Turbines (15.110)

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT ISSUANCE DATE | PROCESS NAME | PROCCESS TYPE | THROUGHPUT | THROUGHPUT UNIT | POLLUTANT | CONTROL METHOD DESCRIPTION | EMISSION LIMIT 1 | EMISSION LIMIT 1 UNIT | EMISSION LIMIT 1 AVG TIME CONDITION | EMISSION LIMIT 2 | EMISSION LIMIT 2 UNIT | EMISSION LIMIT 2 AVGERAGE TIME CONDITION | STANDARAD EMISSION LIMIT | STANDARD EMISSION LIMIT UNIT | STANDARD LIMIT AVERAGE TIME CONDITION |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AK-0085 | GAS TREATMENT PLANT | AK | 08/13/2020  ACT | Six (6) Simple Cycle Gas-Turbines (Power Generation) | 15.11 | 386 | MMBtu/hr | Nitrogen Oxides (NOx) | DLN combustors and Good Combustion Practices | 15 | PPMV @ 15% O2 | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AK-0085 | GAS TREATMENT PLANT | AK | 08/13/2020  ACT | Six (6) Simple Cycle Gas-Turbines (Power Generation) | 15.11 | 386 | MMBtu/hr | Volatile Organic Compounds (VOC) | Good Combustion Practices and burning clean fuels (NG) | 0.0022 | LB/MMBTU | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AK-0088 | LIQUEFACTION PLANT | AK | 07/07/2022  ACT | Six Simle Cycle Gas-Fired Turbines | 15.11 | 1113 | MMBtu/hr | Nitrogen Oxides (NOx) | SCR, DLN combustors, and good combustion practices | 2 | PPMV @ 15% O2 | 3-HOURS | 0 | | | 0 | | |
| AK-0088 | LIQUEFACTION PLANT | AK | 07/07/2022  ACT | Six Simle Cycle Gas-Fired Turbines | 15.11 | 1113 | MMBtu/hr | Volatile Organic Compounds (VOC) | Oxidation catalyst and good combustion practices | 2 | PPMV @ 15% O2 | 3-HOURS | 0 | | | 0 | | |
| AL-0329 | COLBERT COMBUSTION TURBINE PLANT | AL | 09/21/2021  ACT | Three 229 MW Simple Cycle Combustion Turbines | 15.11 | 229 | MW | Nitrogen Oxides (NOx) | | 9 | PPMVD | 3 HOUR AVG @ 15% O2 | 380 | TONS | 12 MONTH | 0 | | |
| CA-1238 | PUENTE POWER | CA | 10/13/2016  ACT | Gas turbine | 15.11 | 262 | MW | Nitrogen Oxides (NOx) | | 2.5 | PPMVD | 1 HOUR@15%O2 | 0 | | | 0 | | |
| CA-1238 | PUENTE POWER | CA | 10/13/2016  ACT | Gas turbine | 15.11 | 262 | MW | Volatile Organic Compounds (VOC) | | 2 | PPMVD AS METHANE | 1 HOUR@15%O2 | 0 | | | 0 | | |
| FL-0354 | LAUDERDALE PLANT | FL | 08/25/2015  ACT | Five 200-MW combustion turbines | 15.11 | 2100 | MMBtu/hr (approx) | Nitrogen Oxides (NOx) | Dry-low-NOx combustion system. Wet injection when firing ULSD. | 9 | PPMVD@15%O2 | 24-HR BLOCK AVERAGE | 42 | PPMVD@ 15%O2 | 4-HR ROLLING | 0 | | |
| FL-0355 | FORT MYERS PLANT | FL | 09/10/2015  ACT | Combustion Turbines | 15.11 | 2262.4 | MMBtu/hr gas | Nitrogen Oxides (NOx) | DLN and wet injection (for ULSD operation) | 9 | PPMVD@15% O2 | GAS FIRING, 24-HR BLOCK AVG | 42 | PPMVD@ 15% O2 | ULSD FIRING, 4-HR ROLLING AVG | 0 | | |
| IL-0121 | INVENERGY NELSON EXPANSION LLC | IL | 09/27/2016  ACT | Two Simple Cycle Combustion Turbines | 15.11 | 190 | MW | Nitrogen Oxides (NOx) | Dry low-NOx combustion technology for natural gas and low-NOx combustion technology and water injection for ULSD. | 0.033 | LB/MMBTU | | 0.164 | LB/MMBTU | | 0 | | |
| IN-0261 | VERMILLION GENERATING STATION | IN | 02/28/2017  ACT | SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES | 15.11 | 80 | MW | Nitrogen Oxides (NOx) | GOOD COMBUSTION PRACTICES | 250 | LB/H | EACH TURBINE | 25 | TON/12 CONSEC. MONTH | COMPLIANCE DETERMINED END OF EACH MONTH | 0 | | |
| IN-0261 | VERMILLION GENERATING STATION | IN | 02/28/2017  ACT | SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES | 15.11 | 80 | MW | Volatile Organic Compounds (VOC) | GOOD COMBUSTION PRACTICES | 17.6 | LB/H | EACH TURBINE | 1.76 | TON/12 CONSEC. MONTH | COMPLIANCE DETERMINED END OF EACH MONTH | 0 | | |
| IN-0264 | MONTPELIER GENERATING STATION | IN | 01/06/2017  ACT | PRATT & TWIN-PAC SIMPLE CYCLE TURBINES | 15.11 | 270.9 | MMBTU/H | Nitrogen Oxides (NOx) | WATER INJECTION | 25 | PPMV | AT 15% O2 FOR NATURAL GAS | 42 | PPMV | AT 15% O2 FOR FUEL OIL | 0 | | |
| IN-0384 | SYCAMORE RIVERSIDE ENERGY LLC | IN | 03/31/2025  ACT | Four GE 7FA.05 simple cycle combustion turbines | 15.11 | 240 | MW Each | Nitrogen Oxides (NOx) | dry low-NOx combustors, water injection when using ULSD, good combustion practices, clean fuels | 9 | PPMVD | @ 15% O2 (NG) STEADY STATE OPERATIONS | 76.2 | LB | HR (NG) STEADY STATE OPERATIONS | 0 | | |
| IN-0384 | SYCAMORE RIVERSIDE ENERGY LLC | IN | 03/31/2025  ACT | Four GE 7FA.05 simple cycle combustion turbines | 15.11 | 240 | MW Each | Volatile Organic Compounds (VOC) | CLEAN FUELS AND GOOD COMBUSTION PRACTICES | 1.4 | PPMVD | @ 15% O2 (NG) STEADY STATE OPERATIONS | 3.5 | LB | HR NG STEADY STATE | 0 | | |
| KY-0104 | CASH CREEK GENERATING STATION | KY | 06/10/2015  ACT | Combined cycle combustion turnbine with HRSG and duct firing | 15.11 | 849 | MW | Nitrogen Oxides (NOx) | SCR, low NOx burners | 2 | PPMVD | @15% O2 THREE HOUR ROLLING AVERAGE | 0 | | | 0 | | |
| KY-0104 | CASH CREEK GENERATING STATION | KY | 06/10/2015  ACT | Combined cycle combustion turnbine with HRSG and duct firing | 15.11 | 849 | MW | Volatile Organic Compounds (VOC) | burn Pipeline quality Natural Gas | 0 | | | 0 | | | 0 | | |
| LA-0307 | MAGNOLIA LNG FACILITY | LA | 03/21/2016  ACT | Gas Turbines (8 units) | 15.11 | 333 | mm btu/hr | Volatile Organic Compounds (VOC) | good combustion practices and fueled by natural gas | 0 | | | 0 | | | 0 | | |
| LA-0307 | MAGNOLIA LNG FACILITY | LA | 03/21/2016  ACT | Gas Turbines (8 units) | 15.11 | 333 | mm btu/hr | Nitrogen Oxides (NOx) | Dry Low NOX burners and good combustion practices | 25 | PPMVD | @15 %O2 | 0 | | | 0 | | |
| LA-0316 | CAMERON LNG FACILITY | LA | 02/17/2017  ACT | Gas turbines (9 units) | 15.11 | 1069 | mm btu/hr | Nitrogen Oxides (NOx) | good combustion practices and dry low nox burners | 15 | PPMVD | @15%O2 | 0 | | | 0 | | |
| LA-0316 | CAMERON LNG FACILITY | LA | 02/17/2017  ACT | Gas turbines (9 units) | 15.11 | 1069 | mm btu/hr | Volatile Organic Compounds (VOC) | good combustion practices and fueled by natural gas | 1.6 | PPMVD | @15%O2 | 0 | | | 0 | | |
| LA-0324 | COMMONWEALTH LNG FACILITY | LA | 03/28/2023  ACT | Refrgeration Turbines and Generator Turbines (EQT0001 - EQT0006 and EQT0013 - EQT0015) | 15.11 | 575 | mm btu/hr | Nitrogen Oxides (NOx) | Good combustion practices and use clean fuel. Dry low-NOx and selective catalytic reduction. | 2.5 | PPMVD | @15% O2 | 0 | | | 0 | | |
| LA-0324 | COMMONWEALTH LNG FACILITY | LA | 03/28/2023  ACT | Refrgeration Turbines and Generator Turbines (EQT0001 - EQT0006 and EQT0013 - EQT0015) | 15.11 | 575 | mm btu/hr | Volatile Organic Compounds (VOC) | Good combustion practices and use of clean fuel. | 3 | PPMVD | @15% O2 | 0 | | | 0 | | |

# Gas Fired Simple Cycle Turbines (15.110)

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005] | 15.11 | 2201 | MM BTU/hr | Nitrogen Oxides (NOx) | Pipeline quality natural gas & dry-low-NOX burners | 240 | LB/HR | HOURLY MAXIMUM | 42 | TONS/YR | ANNUAL AVERAGE | 0 | | |
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005] | 15.11 | 2201 | MM BTU/hr | Volatile Organic Compounds (VOC) | Good combustion practices & use of pipeline quality natural gas | 0 | | | 0 | | | 0 | | |
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006] | 15.11 | 2201 | MM BTU/hr | Nitrogen Oxides (NOx) | Pipeline quality natural gas & dry-low-NOX burners | 240 | LB/HR | HOURLY MAXIMUM | 42 | TONS/YR | ANNUAL AVERAGE | 0 | | |
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006] | 15.11 | 2201 | MM BTU/hr | Volatile Organic Compounds (VOC) | Good combustion practices & use of pipeline quality natural gas | 0 | | | 0 | | | 0 | | |
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019] | 15.11 | 2201 | MM BTU/hR | Volatile Organic Compounds (VOC) | Good combustion practices & use of pipeline quality natural gas | 0 | | | 0 | | | 0 | | |
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019] | 15.11 | 2201 | MM BTU/hR | Nitrogen Oxides (NOx) | Pipeline quality natural gas & dry-low-NOX burners | 86.38 | LB/HR | HOURLY MAXIMUM | 0 | | | 0 | | |
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020] | 15.11 | 2201 | MM BTU/hr | Volatile Organic Compounds (VOC) | Good combustion practices & use of pipeline quality natural gas | 0 | | | 0 | | | 0 | | |
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020] | 15.11 | 2201 | MM BTU/hr | Nitrogen Oxides (NOx) | Pipeline quality natural gas & dry-low-NOX burners | 86.38 | LB/HR | HOURLY MAXIMUM | 0 | | | 0 | | |
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017] | 15.11 | 2201 | MM BTU/hr | Nitrogen Oxides (NOx) | Pipeline quality natural gas & dry-low-NOX burners | 9 | PPMVD @15%O2 | 30-DAY ROLLING AVERAGE | 73.08 | LB/HR | HOURLY MAXIMUM | 0 | | |
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017] | 15.11 | 2201 | MM BTU/hr | Volatile Organic Compounds (VOC) | Good combustion practices & use of pipeline quality natural gas | 0 | | | 0 | | | 0 | | |
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018] | 15.11 | 2201 | MM BTU/hr | Nitrogen Oxides (NOx) | Pipeline quality natural gas & dry-low-NOX burners | 9 | PPMVD @15%O2 | 30-DAY ROLLING AVERAGE | 73.08 | LB/HR | HOURLY MAXIMUM | 0 | | |
| *LA-0327 | WASHINGTON PARISH ENERGY CENTER | LA | 05/23/2018  ACT | CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018] | 15.11 | 2201 | MM BTU/hr | Volatile Organic Compounds (VOC) | Good combustion practices & use of pipeline quality natural gas | 0 | | | 0 | | | 0 | | |
| LA-0331 | CALCASIEU PASS LNG PROJECT | LA | 09/21/2018  ACT | Simple Cycle Combustion Turbines (SCCT1 to SCCT3) | 15.11 | 927 | MM BTU/h | Nitrogen Oxides (NOx) | Dry Low NOx Combustor Design, Good Combustion Practices, and Natural Gas Combustion. | 9 | PPMV | 30 DAY ROLLING AVERAGE | 0 | | | 0 | | |
| LA-0331 | CALCASIEU PASS LNG PROJECT | LA | 09/21/2018  ACT | Simple Cycle Combustion Turbines (SCCT1 to SCCT3) | 15.11 | 927 | MM BTU/h | Volatile Organic Compounds (VOC) | Proper Equipment Design, Proper Operation, and Good Combustion Practices. | 1.4 | PPMV | 3 HOUR AVERAGE | 0 | | | 0 | | |
| LA-0343 | SABINE PASS LNG TERMINAL | LA | 09/06/2019  ACT | gas turbines during startups, shutdowns, and maintenance | 15.11 | 0 | | Nitrogen Oxides (NOx) | good combustion practices | 96 | PPMV | @ 15% O2 | 0 | | | 0 | | |
| LA-0349 | DRIFTWOOD LNG FACILITY | LA | 07/10/2018  ACT | Compressor Turbines (20) | 15.11 | 540 | mm btu/hr | Volatile Organic Compounds (VOC) | Good Combustion Practices and Use of low sulfur facility fuel gas | 0.002 | LB/MM BTU | HHV | 0 | | | 0 | | |
| LA-0349 | DRIFTWOOD LNG FACILITY | LA | 07/10/2018  ACT | Compressor Turbines (20) | 15.11 | 540 | mm btu/hr | Nitrogen Oxides (NOx) | DLN and SCR | 5 | PPMVD | @ 15% O2 | 0 | | | 0 | | |
| LA-0383 | LAKE CHARLES LNG EXPORT TERMINAL | LA | 09/03/2020  ACT | Turbines (EQT0020 - EQT0031) | 15.11 | 0 | | Volatile Organic Compounds (VOC) | Good combustion practices | 0 | | | 0 | | | 0 | | |
| LA-0383 | LAKE CHARLES LNG EXPORT TERMINAL | LA | 09/03/2020  ACT | Turbines (EQT0020 - EQT0031) | 15.11 | 0 | | Nitrogen Oxides (NOx) | LNB + SCR | 3.1 | PPMVD @15%O2 | 3-HOUR AVERAGE | 0 | | | 0 | | |
| MI-0441 | LBWL--ERICKSON STATION | MI | 12/21/2018  ACT | EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG | 15.11 | 667 | MMBTU/H | Nitrogen Oxides (NOx) | Dry low NOx burners (DLNB) and good combustion practices. | 25 | PPM | AT 15%O2;4-HR ROLL AVG; SEE NOTES BELOW | 60 | LB/H | 24-HR ROLL AVG; SEE NOTES BELOW | 0 | | |
| MI-0441 | LBWL--ERICKSON STATION | MI | 12/21/2018  ACT | EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG | 15.11 | 667 | MMBTU/H | Volatile Organic Compounds (VOC) | Good combustion practices. | 5 | LB/H | HOURLY EXCEPT DURING STARTUP/SHUTDOWN | 0 | | | 0 | | |

# Gas Fired Simple Cycle Turbines (15.110)

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| MI-0447 | LBWL--ERICKSON STATION | MI | 01/07/2021  ACT | EUCTGSC1-natural gas fired simple cycle CTG | 15.11 | 667 | MMBTU/H | Volatile Organic Compounds (VOC) | Good combustion practices | 5 | LB/H | HOURLY; EXCEPT DURING STARTUP/SHUTDOWN | 0 | | | 0 | | |
| MI-0447 | LBWL--ERICKSON STATION | MI | 01/07/2021  ACT | EUCTGSC1-natural gas fired simple cycle CTG | 15.11 | 667 | MMBTU/H | Nitrogen Oxides (NOx) | DLNB and good combustion practices. | 25 | PPM | 4-HR ROLL AVG EXCEPT LESS THAN 75% PEAK | 60 | LB/H | 24-HR ROLL AVG EXCEPT SS | 0 | | |
| MI-0454 | LBWL-ERICKSON STATION | MI | 12/20/2022  ACT | EUCTGSC1--A nominally rated 667 MMBTU/H natural gas-fired simple cycle CTG | 15.11 | 667 | MMBTU/H | Nitrogen Oxides (NOx) | DLNB and good combustion practices. | 25 | PPM | 4-HR ROLLING AVG EXCEPT <75% PEAK LOAD | 60 | LB/H | 24-HR ROLLING AVG EXCEPT SU/SD | 0 | | |
| MI-0454 | LBWL-ERICKSON STATION | MI | 12/20/2022  ACT | EUCTGSC1--A nominally rated 667 MMBTU/H natural gas-fired simple cycle CTG | 15.11 | 667 | MMBTU/H | Volatile Organic Compounds (VOC) | Good combustion practices. | 5 | LB/H | HOURLY EXCEPT DURING SU/SD | 0 | | | 0 | | |
| *MI-0462 | CONSUMERS ENERGY CO. - ZEELAND GENERATING STATION | MI | 01/08/2025  ACT | EUGT1A | 15.11 | 2046 | MMBTU/H | Nitrogen Oxides (NOx) | Dry-Low NOx, addition of advanced gas path (AGP) and axial fuel staging (AFS) | 0.04 | LB/MMBTU | AVG ALL OPERATING HR/DAY; NO SUSD | 67.1 | LB/H | AVG ALL OPERATING HR/DAY; NO SUSD | 0 | | |
| *MI-0462 | CONSUMERS ENERGY CO. - ZEELAND GENERATING STATION | MI | 01/08/2025  ACT | EUGT1A | 15.11 | 2046 | MMBTU/H | Volatile Organic Compounds (VOC) | Addition of advanced gas path (AGP) and axial fuel staging (AFS) | 5.8 | LB/HR | AVG OF ALL OPERATING HRS/DAY; NO SUSD | 25.4 | T/YR | 12-MONTH ROLLING TIME PERIOD | 0 | | |
| *MI-0462 | CONSUMERS ENERGY CO. - ZEELAND GENERATING STATION | MI | 01/08/2025  ACT | EUGT1B | 15.11 | 2046 | MMBTU/H | Nitrogen Oxides (NOx) | Dry-Low NOx, addition of advanced gas path (AGP) and axial fuel staging (AFS) | 0.04 | LB/MMBTU | AVG ALL OPERATING HR/DAY; NO SUSD | 67.1 | LB/H | AVG ALL OPERATING HR/DAY; NO SUSD | 0 | | |
| *MI-0462 | CONSUMERS ENERGY CO. - ZEELAND GENERATING STATION | MI | 01/08/2025  ACT | EUGT1B | 15.11 | 2046 | MMBTU/H | Volatile Organic Compounds (VOC) | Addition of advanced gas path (AGP) and axial fuel staging (AFS) | 5.8 | LB/HR | AVG OF ALL OPERATING HRS/DAY; NO SUSD | 25.4 | T/YR | 12-MONTH ROLLING TIME PERIOD | 0 | | |
| NJ-0084 | PSEG FOSSIL LLC SEWAREN GENERATING STATION | NJ | 03/10/2016  ACT | Combined Cycle Combustion Turbine with Duct Burner firing natural gas | 15.11 | 0 | | Nitrogen Oxides (NOx) | SCR and use of natural gas a clean burning fuel | 2 | PPMVD@15%O2 | 3 H ROLLING AV BASED ON ONE H BLOCK | 30.7 | LB/H | AV OF THREE ONE H STACK TESTS | 0 | | |
| NJ-0084 | PSEG FOSSIL LLC SEWAREN GENERATING STATION | NJ | 03/10/2016  ACT | Combined Cycle Combustion Turbine with Duct Burner firing natural gas | 15.11 | 0 | | Volatile Organic Compounds (VOC) | Oxidation Catalyst and good combustion practices | 2 | PPMVD | 3 H ROLLING AV BASED ON ONE H BLOCK | 10.7 | LB/H | AV OF THREE ONE H STACK TESTS | 0 | | |
| NJ-0084 | PSEG FOSSIL LLC SEWAREN GENERATING STATION | NJ | 03/10/2016  ACT | Combined Cycle Combustion Turbine without Duct Burner Firing Natural Gas | 15.11 | 28169501 | MMBTU/YR | Nitrogen Oxides (NOx) | SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM | 2 | PPMVD@15%O2 | 3 H ROLLING AV BASED ON ONE H BLOCK | 25.4 | LB/H | AV OF THREE ONE H STACK TESTS | 0 | | |
| NJ-0084 | PSEG FOSSIL LLC SEWAREN GENERATING STATION | NJ | 03/10/2016  ACT | Combined Cycle Combustion Turbine without Duct Burner Firing Natural Gas | 15.11 | 28169501 | MMBTU/YR | Volatile Organic Compounds (VOC) | OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES | 1 | PPMVD@15%O2 | 3 H ROLLING AV BASED ON ONE H BLOCK | 4.41 | LB/H | AV OF THREE ONE H TESTS | 0 | | |
| NJ-0086 | BAYONNNE ENERGY CENTER | NJ | 08/26/2016  ACT | Simple Cycle Stationary Turbines firing Natural gas | 15.11 | 2143980 | MMBTU/YR | Nitrogen Oxides (NOx) | Selective Catalytic Reduction, water injection, use of natural gas a low NOx emitting fuel | 2.5 | PPMVD@15%O2 | 3 H ROLLING AV BASED ON ONE H BLOCK AV | 5.92 | LB/H | AV OF THREE ONE H STACK TESTS EVERY 5 YR | 0 | | |
| NJ-0086 | BAYONNNE ENERGY CENTER | NJ | 08/26/2016  ACT | Simple Cycle Stationary Turbines firing Natural gas | 15.11 | 2143980 | MMBTU/YR | Volatile Organic Compounds (VOC) | Add-on VOC control is Oxidation Catalyst, and use of natural gas as fuel for pollution prevention | 2 | PPMVD@15%O2 | 3 H ROLLING AV BASED ON ONE H BLOCK AV | 1.65 | LB/H | AV OF THREE ONE H STACK TESTS EVERY 5 YR | 0 | | |
| NY-0103 | CRICKET VALLEY ENERGY CENTER | NY | 02/03/2016  ACT | Turbines and duct burners | 15.11 | 228 | mw | Nitrogen Oxides (NOx) | dry low NOx burners in combination with selective catalytic reduction | 2 | PPMVD @ 15% O2 | 1 H | 0 | | | 0 | | |
| NY-0103 | CRICKET VALLEY ENERGY CENTER | NY | 02/03/2016  ACT | Turbines and duct burners | 15.11 | 228 | mw | Volatile Organic Compounds (VOC) | good combustion practices and oxidation catalyst | 0.7 | PPMVD @ 15% O2 | 1 H | 0 | | | 0 | | |
| NY-0106 | GREENIDGE STATION | NY | 09/07/2016  ACT | Turbine - natural gas | 15.11 | 107 | MW | Nitrogen Oxides (NOx) | Advanced low NOx burners, closed-coupled and staged over-fire air, Selective Non-Catalytic Reduction, and Selective Catalytic Reduction. | 0.03 | LB/MMBTU | 12 MO | 0.0365 | LB/MMBTU | 1 H | 0 | | |
| PA-0305 | SHELL CHEM APPALACHIA/PETROCHEMICALS COMPLEX | PA | 06/18/2015  ACT | Combustion turbine wih duct burner and heat recovery steam generator | 15.11 | 0 | Three 40.6 MW turbines | Nitrogen Oxides (NOx) | | 2 | PPMDV @ 15% O2 | 1 HOUR AVG EX DURING STARTUP AND SHUTDOW | 65.4 | TONS | ANY CONSECUTIVE 12 MONTH PERIOD | 0 | | |
| PA-0305 | SHELL CHEM APPALACHIA/PETROCHEMICALS COMPLEX | PA | 06/18/2015  ACT | Combustion turbine wih duct burner and heat recovery steam generator | 15.11 | 0 | Three 40.6 MW turbines | Volatile Organic Compounds (VOC) | | 1 | PPMDV @ 15% O2 | 1 HR AVERAGE | 0 | | | 0 | | |
| PA-0306 | TENASKA PA PARTNERS/WESTMORELAND GEN FAC | PA | 02/12/2016  ACT | Large Combustion turbine | 15.11 | 0 | | Volatile Organic Compounds (VOC) | Ox Cat and good combustion practices | 1.4 | PPMVD @ 15% O2 | | 9.4 | LB/HR | | 0 | | |
| *TN-0187 | TENNESSEE VALLEY AUTHORITY - JOHNSONVILLE COMBUSTION TURBINE | TN | 08/31/2022  ACT | Ten Simple Cycle NG Turbines | 15.11 | 465.8 | MMBtu/hr | Nitrogen Oxides (NOx) | dry low-NOx burners selective catalytic reduction | 5 | PPMVD @ 15% O2 | 4-HOUR ROLLING AVERAGE EXCLUDING STA/SHU | 21.8 | LB/EVENT | STARTUP AND SHUTDOWN | 0 | | |

# Gas Fired Simple Cycle Turbines (15.110)

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TX-0694 | INDECK WHARTON ENERGY CENTER | TX | 02/02/2015  ACT | (3) combustion turbines | 15.11 | 220 | MW | Nitrogen Oxides (NOx) | DLN combustors | 9 | PPMVD | @15% O2, 3-HR ROLLING AVERAGE | 0 | | | 0 | | |
| TX-0733 | ANTELOPE ELK ENERGY CENTER | TX | 05/12/2015  ACT | Simple Cycle Turbine & Generator | 15.11 | 202 | MW | Nitrogen Oxides (NOx) | Dry Low NOx burners | 9 | PPMVD AT 15% O2 | | 0 | | | 0 | | |
| TX-0733 | ANTELOPE ELK ENERGY CENTER | TX | 05/12/2015  ACT | Simple Cycle Turbine & Generator | 15.11 | 202 | MW | Volatile Organic Compounds (VOC) | Good combustion practices | 2 | PPMVD @ 15% O2 | | 0 | | | 0 | | |
| TX-0734 | CLEAR SPRINGS ENERGY CENTER (CSEC) | TX | 05/08/2015  ACT | Simple Cycle Turbine | 15.11 | 183 | MW | Nitrogen Oxides (NOx) | dry low-NOx (DLN) burners | 9 | PPMVD @ 15% O2 | 3-HR AVERAGE | 0 | | | 0 | | |
| TX-0764 | NACOGDOCHES POWER ELECTRIC GENERATING PLANT | TX | 10/14/2015  ACT | Natural Gas Simple Cycle Turbine (>25 MW) | 15.11 | 232 | MW | Nitrogen Oxides (NOx) | Dry Low NOx burners, good combustion practices, limited operations | 9 | PPMVD @ 15% O2 | | 0 | | | 0 | | |
| TX-0764 | NACOGDOCHES POWER ELECTRIC GENERATING PLANT | TX | 10/14/2015  ACT | Natural Gas Simple Cycle Turbine (>25 MW) | 15.11 | 232 | MW | Volatile Organic Compounds (VOC) | Pipeline quality natural gas; limited hours; good combustion practices. | 2 | PPMVD @ 15% O2 | | 0 | | | 0 | | |
| TX-0768 | SHAWNEE ENERGY CENTER | TX | 10/09/2015  ACT | Simple cycle turbines greater than 25 megawatts (MW) | 15.11 | 230 | MW | Nitrogen Oxides (NOx) | Dry Low NOx burners | 9 | PPMVD @ 15% O2 | | 0 | | | 0 | | |
| TX-0768 | SHAWNEE ENERGY CENTER | TX | 10/09/2015  ACT | Simple cycle turbines greater than 25 megawatts (MW) | 15.11 | 230 | MW | Volatile Organic Compounds (VOC) | Pipeline quality natural gas; limited hours; good combustion practices. | 1.4 | PPMV | | 0 | | | 0 | | |
| TX-0769 | VAN ALSTYNE ENERGY CENTER (VAEC) | TX | 10/27/2015  ACT | Simple Cycle Turbine | 15.11 | 183 | MW | Nitrogen Oxides (NOx) | DLN burners | 9 | PPMVD @ 15% O2 | 3-HR AVERAGE | 0 | | | 0 | | |
| TX-0777 | UNION VALLEY ENERGY CENTER | TX | 12/09/2015  ACT | Simple Cycle Turbine | 15.11 | 183 | MW | Nitrogen Oxides (NOx) | dry low NOX burners | 9 | PPMVD @ 15% O2 | 3-HR ROLLING AVERAGE PEAK | 0 | | | 0 | | |
| TX-0788 | NECHES STATION | TX | 03/24/2016  ACT | Large Combustion Turbines > 25 MW | 15.11 | 232 | MW | Nitrogen Oxides (NOx) | Dry low-NOx burners (DLN), good combustion practices | 9 | PPM | | 0 | | | 0 | | |
| TX-0788 | NECHES STATION | TX | 03/24/2016  ACT | Large Combustion Turbines > 25 MW | 15.11 | 232 | MW | Volatile Organic Compounds (VOC) | good combustion practices | 2 | PPM | | 0 | | | 0 | | |
| TX-0794 | HILL COUNTY GENERATING FACILITY | TX | 04/07/2016  ACT | Simple cycle turbine | 15.11 | 171 | MW | Nitrogen Oxides (NOx) | Emission controls consist of dry low-NOx combustors (DLN). DLN combustors use two stages of combustion, transitioning from initial startup with fuel and flame in the primary nozzles only, through a lean lean stage with fuel and flame in the primary and secondary nozzles, to fuel in the secondary stage only, extinguishing the primary flame, and in full operation, premix mode, with fuel to both nozzles, but flame only in the second stage. When natural gas and air are well-mixed before combustion, the flame temperature and resulting NOx emissions are greatly reduced compared to conventional diffusion flame combustion. | 9 | PPMVD @ 15% O2 | 3-HR ROLLING AVERAGE | 0 | | | 0 | | |
| TX-0794 | HILL COUNTY GENERATING FACILITY | TX | 04/07/2016  ACT | Simple cycle turbine | 15.11 | 171 | MW | Volatile Organic Compounds (VOC) | Premixing of fuel and air enhances combustion efficiency and minimizes emissions. | 5.4 | LB/H | | 0 | | | 0 | | |
| TX-0816 | CORPUS CHRISTI LIQUEFACTION | TX | 02/14/2017  ACT | Refrigeration compressor turbines | 15.11 | 40000 | HP | Nitrogen Oxides (NOx) | Dry low emission burners | 25 | PPMDV | @ 15% O2 | 0 | | | 0 | | |
| TX-0816 | CORPUS CHRISTI LIQUEFACTION | TX | 02/14/2017  ACT | Refrigeration compressor turbines | 15.11 | 40000 | HP | Volatile Organic Compounds (VOC) | Good combustion practices | 0.68 | LB/H | | 0 | | | 0 | | |
| TX-0819 | GAINES COUNTY POWER PLANT | TX | 04/28/2017  ACT | Simple Cycle Turbine | 15.11 | 227.5 | MW | Nitrogen Oxides (NOx) | Dry Low NOx burners (control), natural gas, good combustion practices, limited operating hours (prevention) | 9 | PPMV | 15% O2 3-H AVG | 0 | | | 0 | | |
| TX-0819 | GAINES COUNTY POWER PLANT | TX | 04/28/2017  ACT | Simple Cycle Turbine | 15.11 | 227.5 | MW | Volatile Organic Compounds (VOC) | Pipeline quality natural gas; limited hours; good combustion practices | 2 | PPMVD | 145% O2 | 0 | | | 0 | | |
| TX-0826 | MUSTANG STATION | TX | 08/16/2017  ACT | Simple Cycle Turbine | 15.11 | 162.8 | MW | Nitrogen Oxides (NOx) | Dry low-NOx burners | 9 | PPMVD | | 0 | | | 0 | | |
| TX-0833 | JACKSON COUNTY GENERATORS | TX | 01/26/2018  ACT | Combustion Turbines | 15.11 | 920 | MW | Nitrogen Oxides (NOx) | Dry low NOx burners | 9 | PPMVD | | 0 | | | 0 | | |
| TX-0833 | JACKSON COUNTY GENERATORS | TX | 01/26/2018  ACT | Combustion Turbines | 15.11 | 920 | MW | Volatile Organic Compounds (VOC) | Good combustion practices | 2 | PPMVD | | 0 | | | 0 | | |

# Gas Fired Simple Cycle Turbines (15.110)

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| TX-0833 | JACKSON COUNTY GENERATORS | TX | 01/26/2018  ACT | Combustion Turbines MSS | 15.11 | 0 | | Nitrogen Oxides (NOx) | Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices. | 0.01 | TON/YR | | 0 | | | 0 | | |
| TX-0833 | JACKSON COUNTY GENERATORS | TX | 01/26/2018  ACT | Combustion Turbines MSS | 15.11 | 0 | | Volatile Organic Compounds (VOC) | Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices. | 0.06 | TON/YR | | 0 | | | 0 | | |
| TX-0851 | RIO BRAVO PIPELINE FACILITY | TX | 12/17/2018  ACT | Refrigeration Compression Turbines | 15.11 | 967 | MMBTU/HR | Nitrogen Oxides (NOx) | Dry Low NOx burners. Good combustion practices | 9 | PPMVD | 15% O2 | 0 | | | 0 | | |
| TX-0851 | RIO BRAVO PIPELINE FACILITY | TX | 12/17/2018  ACT | Refrigeration Compression Turbines | 15.11 | 967 | MMBTU/HR | Volatile Organic Compounds (VOC) | Good combustion practices | 2 | PPMVD | 15% O2 | 0 | | | 0 | | |
| TX-0900 | ECTOR COUNTY ENERGY CENTER | TX | 08/17/2020  ACT | Simple Cycle Turbines | 15.11 | 0 | | Nitrogen Oxides (NOx) | Equipped with dry-low NOx burners with best management practices and good combustion practices. Minimize the duration of startup and shutdown events to less than 60 minutes per event. Limit MSS by 140 lb/hr maximum allowable emission rate for each turbine. | 9 | PPMVD | 3% O2 3 HR AVG | 15 | PPMVD | PEAK 3% O2 1 HR AVG | 0 | | |
| TX-0933 | NACERO PENWELL FACILITY | TX | 11/17/2021  ACT | TURBINE | 15.11 | 0 | | Nitrogen Oxides (NOx) | LOW NOX BURNERS AND SCR | 9 | PPMVD | 15% O2 | 0 | | | 0 | | |
| TX-0933 | NACERO PENWELL FACILITY | TX | 11/17/2021  ACT | TURBINE | 15.11 | 0 | | Volatile Organic Compounds (VOC) | Oxidization catalyst, good combustion practices and the use of gaseous fuel | 1.7 | PPMVD | | 0 | | | 0 | | |
| TX-0975 | FREESTONE PEAKERS PLANT | TX | 06/13/2024  ACT | Simple Cycle Gas Turbines | 15.11 | 221 | MW | Nitrogen Oxides (NOx) | Dry low-NOx burners (DLNB) and good combustion practices. | 9 | PPMVD | 15% O2 | 0 | | | 0 | | |
| TX-0975 | FREESTONE PEAKERS PLANT | TX | 06/13/2024  ACT | Simple Cycle Gas Turbines | 15.11 | 221 | MW | Volatile Organic Compounds (VOC) | Good combustion practices | 2 | PPMVD | 15% O2 | 0 | | | 0 | | |
| TX-0986 | JACK COUNTY GENERATION FACILITY | TX | 12/27/2024  ACT | COMBUSTION TURBINES | 15.11 | 180.2 | MW | Nitrogen Oxides (NOx) | Each turbine is limited to 15 ppmvd concentration at 15% O2 on a 3-hour average through an upgrade to â€¯HR3â€™ Dry Low-NOx (DLN) burners. 14 ppmvd at 15% O2 is achieved on an annual average and also includes during periods when wet compression (evaporative air cooling) is applied. MSS - Limited to 50 startups and 50 shutdowns per year for each turbine. Startup and shutdown events are each expected to last less than an hour in duration. | 15 | PPMVD | 15% O2 | 0 | | | 0 | | |
| TX-0986 | JACK COUNTY GENERATION FACILITY | TX | 12/27/2024  ACT | COMBUSTION TURBINES | 15.11 | 180.2 | MW | Volatile Organic Compounds (VOC) | Each turbine is limited to 2 ppmvd at 15% O2, which meets Tier I BACT. Good combustion practices are used. MSS - Limited to 50 startups and 50 shutdowns per year for each turbine. Startup and shutdown events are each expected to last less than an hour in duration. | 2 | PPMVD | 15% O2 | 0 | | | 0 | | |

# Gas Fired Simple Cycle Turbines (15.110)

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| TX-0986 | JACK COUNTY GENERATION FACILITY | TX | 12/27/2024  ACT | LUBE OIL VENTS | 15.11 | 0 | | Volatile Organic Compounds (VOC) | Lube oil vents are equipped with mist eliminators to minimize emissions. Good design and operating practices are used. Lube oil is assumed to emit as VOC, PM, PM10, and PM2.5. It is assumed that PM is equal to PM10, which is equal to PM2.5. The unloading, storage, and heated recirculation of lube oil in the gas and steam turbine reservoirs will emit less than 0.01 gallon per day of oil per turbine mist eliminator vent, based on oil consumption limits permitted for similar turbines. | 0 | | | 0 | | | 0 | | |
| *TX-0989 | LONE STAR POWER STATION | TX | 03/17/2025  ACT | Simple Cycle Gas Turbines | 15.11 | 0 | | Nitrogen Oxides (NOx) | Dry-low NOx (DLN) combustors and an aqueous ammonia-based SCR system | 2.5 | PPMVD | 15% O2 1-HR | 0 | | | 0 | | |
| *TX-0989 | LONE STAR POWER STATION | TX | 03/17/2025  ACT | Simple Cycle Gas Turbines | 15.11 | 0 | | Volatile Organic Compounds (VOC) | Oxidation catalyst and good combustion practices | 1 | PPMVD | 15% O2 3-HR | 0 | | | 0 | | |
| VA-0326 | DOSWELL ENERGY CENTER | VA | 10/04/2016  ACT | Two (2) GE 7FA simple cycle combustion turbines | 15.11 | 1961 | MMBTU/HR | Nitrogen Oxides (NOx) | Low NOx Burners/Combustion Technology | 9 | PPM | VD/12 MO ROLLING TOTAL | 74.2 | LB | H/12 MO ROLLING TOTAL | 0 | | |
| WV-0026 | WAVERLY FACILITY | WV | 01/23/2017  ACT | GE Model 7FA Turbine | 15.11 | 1571 | mmbtu/hr | Nitrogen Oxides (NOx) | Dry Low-NOx Combustion System (DLNB), Water Injection | 9 | PPM | NATURAL GAS | 49 | PPM | FUEL OIL | 9 | PPM | NATURAL GAS |
| WV-0028 | WAVERLY POWER PLANT | WV | 03/13/2018  ACT | GE 7FA.004 Turbine | 15.11 | 167.8 | MW | Nitrogen Oxides (NOx) | Dry LNB | 69 | LB/HR | | 232.3 | TONS/YEAR | | 9 | PPM | |

# Gas Fired Combined Cycle Turbines (15.210)

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT ISSUANCE DATE | PROCESS NAME | PROCCESS TYPE | THROUGHPUT | THROUGHPUT UNIT | POLLUTANT | CONTROL METHOD DESCRIPTION | EMISSION LIMIT 1 | EMISSION LIMIT 1 UNIT | EMISSION LIMIT 1 AVG TIME CONDITION | EMISSION LIMIT 2 | EMISSION LIMIT 2 UNIT | EMISSION LIMIT 2 AVGERAGE TIME CONDITION | STANDARAD EMISSION LIMIT | STANDARD EMISSION LIMIT UNIT | STANDARD LIMIT AVERAGE TIME CONDITION |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AK-0085 | GAS TREATMENT PLANT | AK | 08/13/2020  ACT | Six (6) Cogeneration Gas-Fired Turbines (Treated Gas Compressor Turbines) | 15.21 | 576 | MMBtu/hr | Nitrogen Oxides (NOx) | DLN combustors and Good Combustion Practices | 17 | PPMV @ 15% O2 | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AK-0085 | GAS TREATMENT PLANT | AK | 08/13/2020  ACT | Six (6) Cogeneration Gas-Fired Turbines (Treated Gas Compressor Turbines) | 15.21 | 576 | MMBtu/hr | Volatile Organic Compounds (VOC) | Oxidation catalyst and good combustion practices | 0.0022 | LB/MMBTU | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AK-0085 | GAS TREATMENT PLANT | AK | 08/13/2020  ACT | Six (6) Cogeneration Gas-Fired Turbines (CO2 Compressor Turbines)) | 15.21 | 431 | MMBtu/hr | Nitrogen Oxides (NOx) | DLN combustors and good combustion practices | 17 | PPMV @ 15% O2 | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AK-0085 | GAS TREATMENT PLANT | AK | 08/13/2020  ACT | Six (6) Cogeneration Gas-Fired Turbines (CO2 Compressor Turbines)) | 15.21 | 431 | MMBtu/hr | Volatile Organic Compounds (VOC) | Oxidation catalyst and good combustion control practices | 0.0022 | LB/MMBTU | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AK-0088 | LIQUEFACTION PLANT | AK | 07/07/2022  ACT | Four Combined Cycle Gas-Fired Turbines | 15.21 | 384 | MMBtu/hr | Nitrogen Oxides (NOx) | SCR, DLN combustors, and good combustion practices | 2 | PPMV @ 15% O2 | 3-HOURS | 0 | | | 0 | | |
| AK-0088 | LIQUEFACTION PLANT | AK | 07/07/2022  ACT | Four Combined Cycle Gas-Fired Turbines | 15.21 | 384 | MMBtu/hr | Volatile Organic Compounds (VOC) | Oxidation catalyst and good combustion practices | 2 | PPMV @ 15% O2 | 3-HOURS | 0 | | | 0 | | |
| LA-0331 | CALCASIEU PASS LNG PROJECT | LA | 09/21/2018  ACT | Combined Cycle Combustion Turbines (CCCT1 to CCCT5) | 15.21 | 921 | MM BTU/h | Nitrogen Oxides (NOx) | Low NOx Burners, SCR, and Good Combustion Practices | 2.5 | PPMV | 30 DAY ROLLING AVERAGE | 0 | | | 0 | | |
| LA-0331 | CALCASIEU PASS LNG PROJECT | LA | 09/21/2018  ACT | Combined Cycle Combustion Turbines (CCCT1 to CCCT5) | 15.21 | 921 | MM BTU/h | Volatile Organic Compounds (VOC) | Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices. | 1.1 | PPMV | 3 HOUR AVERAGE | 0 | | | 0 | | |
| MI-0441 | LBWL--ERICKSON STATION | MI | 12/21/2018  ACT | EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG. | 15.21 | 667 | MMBTU/H | Nitrogen Oxides (NOx) | Dry low NOx burners and selective catalytic reduction for NOx control. | 3 | PPM | PPMVD@15%O2; 24-H AVG; SEE NOTES | 25 | PPM | PPMVD@15%O2; 4-H AVG; SEE NOTES | 0 | | |
| MI-0441 | LBWL--ERICKSON STATION | MI | 12/21/2018  ACT | EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG. | 15.21 | 667 | MMBTU/H | Volatile Organic Compounds (VOC) | An oxidation catalyst for VOC control and good combustion practices. | 3 | PPM | PPMVD@15%O2; HOURLY; SEE NOTES | 5 | LB/H | HOURLY EXCEPT STARTUP/SHUTDOWN; SEE NOTE | 0 | | |
| MI-0441 | LBWL--ERICKSON STATION | MI | 12/21/2018  ACT | EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG) | 15.21 | 667 | MMBTU/H | Nitrogen Oxides (NOx) | Dry low NOx burners and selective catalytic reduction for NOx control. | 3 | PPM | PPMVD@15%O2; 24-H ROLL AVG; SEE NOTES | 25 | PPM | PPMVD@15%O2; 4-HR ROLL AVG; SEE NOTES | 0 | | |
| MI-0441 | LBWL--ERICKSON STATION | MI | 12/21/2018  ACT | EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG) | 15.21 | 667 | MMBTU/H | Volatile Organic Compounds (VOC) | An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices. | 3 | PPM | PPMVD@15%O2; HOURLY EXC. START/SHUT; NOTE | 5 | LB/H | HOURLY EXCEPT STARTUP/SHUTDOWN; SEE NOTE | 0 | | |
| MI-0447 | LBWL--ERICKSON STATION | MI | 01/07/2021  ACT | EUCTGHRSG1 | 15.21 | 667 | MMBTU/H | Volatile Organic Compounds (VOC) | An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices. | 3 | PPM | HOURLY EXCEPT STARTUP SHUTDOWN | 5 | LB/H | HOURLY EXCEPT STARTUP SHUTDOWN | 0 | | |
| MI-0447 | LBWL--ERICKSON STATION | MI | 01/07/2021  ACT | EUCTGHRSG1 | 15.21 | 667 | MMBTU/H | Nitrogen Oxides (NOx) | Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit. | 60 | LB/H | HOURLY; INCL STRT/SHUT IN COMBINED CYCLE | 60 | LB/H | 24-H ROLL AVG EACH OP HR; IN HRSG BYPASS | 0 | | |
| MI-0447 | LBWL--ERICKSON STATION | MI | 01/07/2021  ACT | EUCTGHRSG2 | 15.21 | 667 | MMBTU/H | Nitrogen Oxides (NOx) | Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit. | 60 | LB/H | HOURLY; INCL STRT/SHUT IN COMBINED CYCLE | 60 | LB/H | 24-HR ROLL AVG IN HRSG BYPASS MODE | 0 | | |
| MI-0447 | LBWL--ERICKSON STATION | MI | 01/07/2021  ACT | EUCTGHRSG2 | 15.21 | 667 | MMBTU/H | Volatile Organic Compounds (VOC) | An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices. | 3 | PPM | HOURLY; EXCEPT DURING STARTUP/SHUTDOWN | 5 | LB/H | HOURLY EXCEPT DURING STARTUP/SHUTDOWN | 0 | | |
| MI-0454 | LBWL-ERICKSON STATION | MI | 12/20/2022  ACT | EUCTGHRSG1 | 15.21 | 667 | MMBTU/H | Nitrogen Oxides (NOx) | Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit. | 3 | PPM | PPMVD AT 15%O2; 24-HR ROLL AVG EXC SU/SD | 60 | LB/H | HOURLY INCL SU/SD IN COMB CYC MODE | 0 | | |
| MI-0454 | LBWL-ERICKSON STATION | MI | 12/20/2022  ACT | EUCTGHRSG1 | 15.21 | 667 | MMBTU/H | Volatile Organic Compounds (VOC) | An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices. | 3 | PPM | PPMVD AT 15%O2; HOURLY EXC SU/SD | 5 | LB/H | HOURLY EXCEPT SU/SD | 0 | | |
| MI-0454 | LBWL-ERICKSON STATION | MI | 12/20/2022  ACT | EUCTGHRSG2 | 15.21 | 667 | MMBTU/H | Nitrogen Oxides (NOx) | Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit. | 3 | PPM | @15%OX; 24-HR ROLL AVG EXCEPT START/SHUT | 60 | LB/H | HOURLY INCLU START/SHUT IN COMBINE CYCLE | 0 | | |
| MI-0454 | LBWL-ERICKSON STATION | MI | 12/20/2022  ACT | EUCTGHRSG2 | 15.21 | 667 | MMBTU/H | Volatile Organic Compounds (VOC) | An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices. | 3 | PPM | PPMVD AT 15%O2; HOURLY EXC SU/SD. CC MOD | 5 | LB/H | HOURLY, EXC. SU/SD; APPLY IN HRSG BYPASS | 0 | | |
| PA-0306 | TENASKA PA PARTNERS/WESTMORELAND GEN FAC | PA | 02/12/2016  ACT | Large combustion turbine | 15.21 | 0 | | Nitrogen Oxides (NOx) | SCR, DLN, and good combustion practice | 2 | PPMVD@15% O2 | | 26.5 | LB/HR | | 0 | | |
| PA-0306 | TENASKA PA PARTNERS/WESTMORELAND GEN FAC | PA | 02/12/2016  ACT | Large combustion turbine | 15.21 | 0 | | Volatile Organic Compounds (VOC) | Ox Cat and good combustion practices | 2.4 | PPMDV@15% O2 | | 9.4 | LB/HR | | 0 | | |
| TX-0788 | NECHES STATION | TX | 03/24/2016  ACT | Combined Cycle & Cogeneration | 15.21 | 231 | MW | Nitrogen Oxides (NOx) | Selective Catalytic Reduction | 2 | PPM | | 0 | | | 0 | | |
| TX-0788 | NECHES STATION | TX | 03/24/2016  ACT | Combined Cycle & Cogeneration | 15.21 | 231 | MW | Volatile Organic Compounds (VOC) | OXIDATION CATALYST | 2 | PPM | | 0 | | | 0 | | |
| TX-0819 | GAINES COUNTY POWER PLANT | TX | 04/28/2017  ACT | Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator | 15.21 | 426 | MW | Nitrogen Oxides (NOx) | Selective Catalytic Reduction (SCR) and Dry Low NOx burners | 2 | PPMVD | 15% O2 3-H AVG | 0 | | | 0 | | |
| TX-0819 | GAINES COUNTY POWER PLANT | TX | 04/28/2017  ACT | Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator | 15.21 | 426 | MW | Volatile Organic Compounds (VOC) | Oxidation catalyst and good combustion practices | 3.5 | PPMVD | 15% O2 | 0 | | | 0 | | |

# Institutional Gas Fired Boilers (13.310)

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT ISSUANCE DATE | PROCESS NAME | PROCCESS TYPE | THROUGHPUT | THROUGHPUT UNIT | POLLUTANT | CONTROL METHOD DESCRIPTION | EMISSION LIMIT 1 | EMISSION LIMIT 1 UNIT | EMISSION LIMIT 1 AVG TIME CONDITION | EMISSION LIMIT 2 | EMISSION LIMIT 2 UNIT | EMISSION LIMIT 2 AVGERAGE TIME CONDITION | STANDARAD EMISSION LIMIT | STANDARD EMISSION LIMIT UNIT | STANDARD LIMIT AVERAGE TIME CONDITION |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AK-0085 | GAS TREATMENT PLANT | AK | 08/13/2020  ACT | Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters | 13.31 | 32 | MMBtu/hr | Nitrogen Oxides (NOx) | Low NOx Burners, Good Combustion Practices, Limited Operation of 500 hours per year per heater. | 0.036 | LB/MMBTU | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AL-0307 | ALLOYS PLANT | AL | 10/09/2015  ACT | PACKAGE BOILER | 13.31 | 17.5 | MMBTU/H | Nitrogen Oxides (NOx) | LOW NOX BURNER FLUE GAS RECIRCULATION GCP | 30 | PPMVD | 3% O2 | 0.64 | LB/H | | 0 | | |
| AL-0307 | ALLOYS PLANT | AL | 10/09/2015  ACT | 2 CALP LINE BOILERS | 13.31 | 24.59 | MMBTU/H | Nitrogen Oxides (NOx) | LOW NOX BURNER FLUE GAS RECIRCULATION (FGR) GOOD COMBUSTION PRACTICES (GCP) | 30 | PPMVD | 3% O2 | 0.9 | LB/H | | 0 | | |
| AL-0328 | PLANT BARRY | AL | 11/09/2020  ACT | 90.5 MMBtu/hr Aux Boiler | 13.31 | 90.5 | MMBtu/hr | Nitrogen Oxides (NOx) | | 0.011 | LB/MMBTU | 3 HOUR AVG | 0 | | | 0 | | |
| AL-0329 | COLBERT COMBUSTION TURBINE PLANT | AL | 09/21/2021  ACT | Three Gas Heaters | 13.31 | 10 | MMBtu/hr | Nitrogen Oxides (NOx) | | 0.011 | LB/MMBTU | 3 HOUR AVG | 0 | | | 0 | | |
| *AL-0342 | ARCELORMITTAL CALVERT, LLC - NOES FACILITY | AL | 06/04/2025  ACT | Boiler #1 & Boiler #2 | 13.31 | 45.5 | MMBtu/hr | Nitrogen Oxides (NOx) | | 0.036 | LB/MMBTU | 3-HOUR AVERAGE | 1.64 | LB/HR | 3-HOUR AVERAGE | 0 | | |
| AR-0155 | BIG RIVER STEEL LLC | AR | 11/07/2018  ACT | BOILER, PICKLE LINE | 13.31 | 53.7 | MMBTU/HR | Nitrogen Oxides (NOx) | LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0155 | BIG RIVER STEEL LLC | AR | 11/07/2018  ACT | BOILER SN-26, GALVANIZING LINE | 13.31 | 53.7 | MMBTU/HR | Nitrogen Oxides (NOx) | LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0155 | BIG RIVER STEEL LLC | AR | 11/07/2018  ACT | PREHEATER, GALVANIZING LINE SN-28 | 13.31 | 78.2 | MMBTU/HR | Nitrogen Oxides (NOx) | SCR, LOW NOX BURNERS, AND COMBUSTION OF CLEAN FUEL AND GOOD COMBUSTION PRACTICES | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0159 | BIG RIVER STEEL LLC | AR | 04/05/2019  ACT | BOILER, PICKLE LINE | 13.31 | 0 | | Nitrogen Oxides (NOx) | LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0159 | BIG RIVER STEEL LLC | AR | 04/05/2019  ACT | PREHEATERS, GALVANIZING LINE SN-28 and SN-29 | 13.31 | 0 | | Nitrogen Oxides (NOx) | SCR, LOW NOX BURNERS, AND COMBUSTION OF CLEAN FUEL AND GOOD COMBUSTION PRACTICES | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0159 | BIG RIVER STEEL LLC | AR | 04/05/2019  ACT | BOILER, ANNEALING PICKLE LINE | 13.31 | 0 | | Nitrogen Oxides (NOx) | Low NOx burners, Combustion of clean fuel, and Good Combustion Practices | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0159 | BIG RIVER STEEL LLC | AR | 04/05/2019  ACT | BOILERS SN-26 AND SN-27, GALVANIZING LINE | 13.31 | 0 | | Nitrogen Oxides (NOx) | LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0167 | LION OIL COMPANY | AR | 12/01/2020  ACT | SN-803 - #4 Pre-Flash Column Reboiler | 13.31 | 40 | MMBtu/hr | Nitrogen Oxides (NOx) | Ultra-low NOx burners and good combustion practice | 1.9 | LB/HR | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AR-0167 | LION OIL COMPANY | AR | 12/01/2020  ACT | SN-805 - #4 Pre-Flash Reboiler | 13.31 | 75 | MMBtu/hr | Nitrogen Oxides (NOx) | Ultra-low NOx burners and good combustion practice | 3.5 | LB/HR | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AR-0167 | LION OIL COMPANY | AR | 12/01/2020  ACT | SN-808 - #7 FCCU Furnace | 13.31 | 56 | MMBtu/hr | Nitrogen Oxides (NOx) | Good combustion practice | 2.8 | LB/HR | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AR-0167 | LION OIL COMPANY | AR | 12/01/2020  ACT | SN-810 - #9 Hydrotreater Furnace/Reboiler | 13.31 | 70 | MMBtu/hr | Nitrogen Oxides (NOx) | | 12.7 | LB/HR | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AR-0167 | LION OIL COMPANY | AR | 12/01/2020  ACT | SN-842 - #12 Unit Distillate Hydrotreater | 13.31 | 50 | MMBtu/hr | Nitrogen Oxides (NOx) | Good combustion practice | 5.3 | LB/HR | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AR-0168 | BIG RIVER STEEL LLC | AR | 03/17/2021  ACT | Galvanizing Line #2 Furnace | 13.31 | 150.5 | MMBtu/hr | Nitrogen Oxides (NOx) | SCR, Low NOx burners Combustion of clean fuel Good Combustion Practices | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0168 | BIG RIVER STEEL LLC | AR | 03/17/2021  ACT | Decarburizing Line Furnace Section | 13.31 | 58 | MMBtu/hr | Nitrogen Oxides (NOx) | Low NOx burners SCR Combustion of clean fuel Good Combustion Practices | 0.1 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0171 | NUCOR STEEL ARKANSAS | AR | 02/14/2019  ACT | SN-142 Vacuum Degasser Boiler | 13.31 | 50.4 | MMBTU/hr | Nitrogen Oxides (NOx) | Low Nox Burners | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0171 | NUCOR STEEL ARKANSAS | AR | 02/14/2019  ACT | SN-233 Galvanizing Line Boilers | 13.31 | 15 | MMBTU/hr each | Nitrogen Oxides (NOx) | Low Nox Burners | 0.1 | LB/MMBTU | 3-HR | 0 | | | 0 | | |
| AR-0172 | NUCOR STEEL ARKANSAS | AR | 09/01/2021  ACT | SN-202, 203, 204 Pickle Line Boilers | 13.31 | 0 | | Nitrogen Oxides (NOx) | Low NOx burners | 0.035 | LB/MMBTU | | 0 | | | 0 | | |

# Institutional Gas Fired Boilers (13.310)

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| AR-0173 | BIG RIVER STEEL LLC | AR | 01/31/2022  ACT | Hydrogen Plant #2 Reformer Furnace | 13.31 | 75 | MMBtu/hr | Nitrogen Oxides (NOx) | Low NOx burners Combustion of clean fuel Good Combustion Practices | 0.1 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0173 | BIG RIVER STEEL LLC | AR | 01/31/2022  ACT | Furnace Dedusting | 13.31 | 0 | | Nitrogen Oxides (NOx) | Combustion of Natural Gas and Good Combustion Practices | 0.0032 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0173 | BIG RIVER STEEL LLC | AR | 01/31/2022  ACT | Pickle Line Boiler | 13.31 | 53.7 | MMBtu/hr | Nitrogen Oxides (NOx) | Low NOx burners Combustion of clean fuel Good Combustion Practices | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0173 | BIG RIVER STEEL LLC | AR | 01/31/2022  ACT | Galvanizing Line Boilers #1 and #2 | 13.31 | 53.7 | MMBtu/hr | Nitrogen Oxides (NOx) | Low NOx burners Combustion of clean fuel Good Combustion Practices | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| AR-0173 | BIG RIVER STEEL LLC | AR | 01/31/2022  ACT | Pickle Galvanizing Line Boiler | 13.31 | 53.7 | MMBtu/hr | Nitrogen Oxides (NOx) | Low NOx burners Combustion of clean fuel Good Combustion Practices | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| CT-0159 | CPV TOWANTIC, LLC | CT | 11/30/2015  ACT | Aux Boiler | 13.31 | 359.6 | MMCF | Nitrogen Oxides (NOx) | Boiler permit does not specify any add-on control other than ultr-low NOx burner. Unit may be required to use additional control options to meet emissions limit. | 7 | PPMVD @3% O2 | | 0 | | | 0 | | |
| FL-0356 | OKEECHOBEE CLEAN ENERGY CENTER | FL | 03/09/2016  ACT | Auxiliary Boiler, 99.8 MMBtu/hr | 13.31 | 99.8 | MMBtu/hr | Nitrogen Oxides (NOx) | Low-NOx burners | 0.05 | LB/MMBTU | | 0 | | | 0 | | |
| FL-0356 | OKEECHOBEE CLEAN ENERGY CENTER | FL | 03/09/2016  ACT | Two natural gas heaters | 13.31 | 10 | MMBtu/hr | Nitrogen Oxides (NOx) | Must have NOx emission design value less than 0.1 lb/MMBtu | 0.1 | LB/MMBTU | | 0 | | | 0 | | |
| FL-0363 | DANIA BEACH ENERGY CENTER | FL | 12/04/2017  ACT | Two natural gas heaters | 13.31 | 9.9 | MMBtu/hr | Nitrogen Oxides (NOx) | Manufacturer certification | 0.1 | LB/MMBTU | DESIGN VALUE | 0 | | | 0 | | |
| FL-0367 | SHADY HILLS COMBINED CYCLE FACILITY | FL | 07/27/2018  ACT | 60 MMBtu/hour Auxiliary Boiler | 13.31 | 60 | MMBtu/hour | Nitrogen Oxides (NOx) | low-NOx burners | 0.05 | LB/MMBTU | | 0 | | | 0 | | |
| FL-0371 | SHADY HILLS COMBINED CYCLE FACILITY | FL | 06/07/2021  ACT | 60 MMBtu/hour Auxiliary Boiler | 13.31 | 60 | MMBtu/hour | Nitrogen Oxides (NOx) | Low-NOx burners | 0.05 | LB/MMBTU | | 0 | | | 0 | | |
| IL-0129 | CPV THREE RIVERS ENERGY CENTER | IL | 07/30/2018  ACT | Auxiliary Boiler | 13.31 | 96 | mmBtu/hr | Nitrogen Oxides (NOx) | Ultra-low NOx burners and flue gas recirculation, air preheater, automated combustion management system with O2 trim system and automated water blowdown, and good combustion practices. | 0.011 | LB/MMBTU | 3-HOUR AVERAGE | 0 | | | 0 | | |
| IL-0130 | JACKSON ENERGY CENTER | IL | 12/31/2018  ACT | Auxiliary Boiler | 13.31 | 96 | mmBtu/hr | Nitrogen Oxides (NOx) | Ultra low-NOx burners and flue gas recirculation air preheater, automated combustion management systems, automated water blowdown, good combustion practices | 0.01 | LB/MMBTU | 3-HOUR AVERAGE | 0 | | | 0 | | |
| IL-0133 | LINCOLN LAND ENERGY CENTER | IL | 07/29/2022  ACT | Auxiliary Boiler | 13.31 | 80 | mmBtu/hour | Nitrogen Oxides (NOx) | Ultra low-NOx burners and flue gas recirculation, air preheater, automated combustion management system, with an oxygen trim system and an automated water blowdown system. | 0.01 | POUNDS/MMBTU | ROLLING 3-OPERATING HOUR | 0 | | | 0 | | |
| IL-0134 | CRONUS CHEMICALS | IL | 12/21/2023  ACT | Startup Heater | 13.31 | 47.7 | mmBtu/hr | Nitrogen Oxides (NOx) | LNB, good burner design, and GCP | 0.07 | LB/MMBTU | 3-HR AVG | 0 | | | 0 | | |
| IN-0263 | MIDWEST FERTILIZER COMPANY LLC | IN | 03/23/2017  ACT | STARTUP HEATER EU-002 | 13.31 | 70 | MMBTU/HR | Nitrogen Oxides (NOx) | GOOD COMBUSTION PRACTICES | 12.611 | LB/H | 3 HOUR AVERAGE | 200 | H/YR | | 0 | | |
| IN-0285 | WHITING CLEAN ENERGY, INC. | IN | 08/02/2017  ACT | Space Heaters | 13.31 | 0 | | Nitrogen Oxides (NOx) | | 0.05 | LB/MMBTU | UNITS 1-6, COMBUSTING NATURAL GAS | 0.092 | LB/MMBTU | UNITS 7-9, COMBUSTING NATURAL GAS | 0 | | |
| IN-0324 | MIDWEST FERTILIZER COMPANY LLC | IN | 05/06/2022  ACT | startup heater EU-002 | 13.31 | 33.34 | MMBtu/hr | Nitrogen Oxides (NOx) | shall combust natural gas, shall be controlled by good combustion practices | 200 | HR/YR | TWELVE CONSECUTIVE MONTH PERIOD | 6.007 | LB/HR | | 0 | | |
| IN-0359 | NUCOR STEEL | IN | 03/30/2023  ACT | Boiler (CC-BOIL) | 13.31 | 50 | MMBtu/hr | Nitrogen Oxides (NOx) | low NOx burners | 0.035 | LB/MMBTU | | 0 | | | 0 | | |
| IN-0359 | NUCOR STEEL | IN | 03/30/2023  ACT | Hot Water Circuit Burner for Galvanizing Line | 13.31 | 9 | MMBtu/hr | Nitrogen Oxides (NOx) | low NOx burners, good combustion practices, use of pipeline quality natural gas | 50 | LB/MMSCF | | 0 | | | 0 | | |

# Institutional Gas Fired Boilers (13.310)

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| IN-0359 | NUCOR STEEL | IN | 03/30/2023  ACT | Hot Water Circuit Burner for Sheet Metal Coating Line | 13.31 | 5.12 | MMBtu/hr | Nitrogen Oxides (NOx) | low NOx burners, good combustion practices and only pipeline quality natural gas shall be combusted | 50 | LB/MMSCF | | 0 | | | 0 | | | |
| *IN-0365 | MAPLE CREEK ENERGY LLC | IN | 06/19/2023  ACT | Auxiliary Boiler | 13.31 | 96 | MMBtu per hour | Nitrogen Oxides (NOx) | | 0.037 | LB PER MMBTU | BASED ON A 3-HR AVERAGE | 0 | | | 0 | | | |
| IN-0371 | WABASH VALLEY RESOURCES, LLC | IN | 01/11/2024  ACT | Auxiliary Boiler (AB-3) | 13.31 | 20 | MMBtu/hr | Nitrogen Oxides (NOx) | Low NOx burners and Good Combustion Practices | 35 | LB/MMSCF | | 0 | | | 0 | | | |
| IN-0371 | WABASH VALLEY RESOURCES, LLC | IN | 01/11/2024  ACT | Dewpoint Heater | 13.31 | 1.44 | MMBtu/hr | Nitrogen Oxides (NOx) | Low NOx burners and good combustion practices | 50 | LB/MMSCF | | 0 | | | 0 | | | |
| KS-0030 | MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION | KS | 03/31/2016  ACT | Indirect fuel-gas heater | 13.31 | 2 | mmBTU/hr | Nitrogen Oxides (NOx) | | 0.2 | LB/H | EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION | 0 | | | 0 | | | |
| KS-0041 | HOLLYFRONTIER EL DORADO REFINERY | KS | 10/30/2019  ACT | B2502 | 13.31 | 48.2 | MMBTU/H | Nitrogen Oxides (NOx) | Ultra Low NOx Burners | 0.04 | LB/MMBTU | 30 DAY ROLLING AVERAGE | 0 | | | 0 | | | |
| KS-0041 | HOLLYFRONTIER EL DORADO REFINERY | KS | 10/30/2019  ACT | B3401 | 13.31 | 69 | MMBTU/H | Nitrogen Oxides (NOx) | Ultra Low NOx Burners | 0.04 | LB/MMBTU | 30 DAY ROLLING AVERAGE | 0 | | | 0 | | | |
| KS-0041 | HOLLYFRONTIER EL DORADO REFINERY | KS | 10/30/2019  ACT | B2701 | 13.31 | 17.7 | MMBTU/H | Nitrogen Oxides (NOx) | Ultra Low NOx Burners | 0.04 | LB/MMBTU | 30 DAY ROLLING AVERAGE | 0 | | | 0 | | | |
| KS-0041 | HOLLYFRONTIER EL DORADO REFINERY | KS | 10/30/2019  ACT | B2031 | 13.31 | 45.2 | MMBTU/H | Nitrogen Oxides (NOx) | Ultra Low NOx Burners | 0.04 | LB/MMBTU | 30 DAY ROLLING AVERAGE | 0 | | | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters | 13.31 | 40 | MMBtu/hr, combined | Nitrogen Oxides (NOx) | Low-Nox Burner (Designed to maintain 0.07 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan. | 70 | LB/MMSCF | | 12.02 | TON/YR | 12-MONTH ROLLING, COMBINED | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3 | 13.31 | 28 | MMBtu/hr, each | Nitrogen Oxides (NOx) | Low-Nox Burner (Designed to maintain 0.08 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan. | 81.6 | LB/MMSCF | | 29.43 | TON/YR | 12-MONTH ROLLING, COMBINED | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 04-02 - Austenitizing Furnace | 13.31 | 54 | MMBtu/hr | Nitrogen Oxides (NOx) | Low-Nox Burner (Designed to maintain 0.15 lb/MMBtu in flameless mode and 0.25 lb/MMBtu in flame mode); and a Good Combustion and Operating Practices (GCOP) Plan. | 158 | LB/MMSCF | FLAMELESS MODE | 257 | LB/MMSCF | FLAME MODE | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 05-02 - Group 2 Car Bottom Furnaces A & B | 13.31 | 60 | MMBtu/hr, combined | Nitrogen Oxides (NOx) | Low-Nox Burner (Designed to maintain 0.08 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan. | 81.6 | LB/MMSCF | | 21.02 | TON/YR | 12-MONTH ROLLING, COMBINED | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 03-02 - Ingot Car Bottom Furnaces #1-#4 | 13.31 | 37 | MMBtu/hr, each | Nitrogen Oxides (NOx) | Low-Nox Burner (Designed to maintain 0.18 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan. | 181.6 | LB/MMSCF | | 115.4 | TON/YR | 12-MONTH ROLLING | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2 | 13.31 | 17.5 | MMBtu/hr, each | Nitrogen Oxides (NOx) | Low-Nox Burner (Designed to maintain 0.08 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan. | 81.6 | LB/MMSCF | | 12.26 | TON/YR | 12-MONTH ROLLING | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 04-03 - Tempering Furnace | 13.31 | 48 | MMBtu/hr | Nitrogen Oxides (NOx) | Low-Nox Burner (Designed to maintain 0.07 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan. | 70 | LB/MMSCF | | 14.43 | TON/YR | 12-MONTH ROLLING | 0 | | | |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Cold Mill Complex Makeup Air Units (EP 21-19) | 13.31 | 40 | MMBtu/hr, total | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan | 100 | LB/MMSCF | | 17.18 | TONS/YR | 12-MONTH ROLLING | 0 | | | |

# Institutional Gas Fired Boilers (13.310)

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| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Vacuum Degasser Boiler (EP 20-13) | 13.31 | 50.4 | MMBtu/hr | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. Also equipped with low-NOx burners. | 35 | LB/MMSCF | | 7.57 | TON/YR | 12-MONTH ROLLING | 0 | | |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Pickle Line #2 â€" Boiler #1 & #2 (EP 21-04 & EP 21-05) | 13.31 | 18 | MMBtu/hr, each | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. Equipped with low-NOx burners. | 50 | LB/MMSCF | EACH | 5.25 | TON/YR | 12-MONTH ROLLING, EACH | 0 | | |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B) | 13.31 | 23 | MMBtu/hr | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is also required to be equipped with low-NOx burners (0.07 lb/MMBtu). | 50 | LB/MMSCF | | 4.94 | TON/YR | 12-MONTH ROLLING | 0 | | |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B) | 13.31 | 36 | MMBtu/hr | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is also equipped with a SCR/SNCR system to control emissions. During a cold start, SCR does not reach operating temperature for approximately 30 minutes. During this time, only low-NOx burners are controlling emissions of NOx. NSG estimates the unit may undergo 1 cold start every two (2) weeks. | 7.5 | LB/MMSCF | 3-HR AVERAGE | 1.16 | TON/YR | 12-MONTH ROLLING | 0 | | |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Galvanizing Line #2 Anneating Furnaces (15) (EP 21-15) | 13.31 | 4.8 | MMBtu/hr, each | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is equipped with low-NOx burners. | 50 | LB/MMSCF | | 15.57 | TON/YR | 12-MONTH ROLLING, COMBINED | 0 | | |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Galvanizing Line #2 Preheat Furnace (EP 21-08A) | 13.31 | 94 | MMBtu/hr | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is also equipped with a SCR/SNCR system to control emissions. During a cold start, SCR does not reach operating temperature for approximately 30 minutes. During this time, only low-NOx burners are controlling emissions of NOx. NSG estimates the unit may undergo 1 cold start every two (2) weeks. | 7.5 | LB/MMSCF | 3-HR AVERAGE | 3.03 | TON/YR | 12-MONTH ROLLING | 0 | | |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Galvanizing Line #2 Zinc Pot Preheater (EP 21-09) | 13.31 | 3 | MMBtu/hr | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is equipped with a low-NOx burner. | 70 | LB/MMSCF | | 0.017 | TON/YR | 12-MONTH ROLLING | 0 | | |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Heated Transfer Table Furnace (EP 02-03) | 13.31 | 65.5 | MMBtu/hr | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. Equipped with low NOx burners (0.07 lb/MMBtu). | 70 | LB/MMSCF | 3-HR AVERAGE | 19.69 | TONS/YR | 12-MONTH ROLLING | 0 | | |

# Institutional Gas Fired Boilers (13.310)

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| KY-0116 | NOVELIS CORPORATION - GUTHRIE | KY | 07/25/2022  ACT | EU 037 - Sow Dryer | 13.31 | 20 | MMBtu/hr | Nitrogen Oxides (NOx) | Good Combustion & Operation Practices (GCOP) Plan, Low-Nox Burners (LNBs) capable of meeting 0.054 lb/MMBtu. | 1.08 | LB/HR | MONTHLY AVERAGE | 4.73 | TONS/YR | 12-MONTH ROLLING TOTAL | 0 | | |
| KY-0116 | NOVELIS CORPORATION - GUTHRIE | KY | 07/25/2022  ACT | EU 041a - Direct-Fired Building Heating Systems | 13.31 | 53 | MMBtu/hr (total) | Nitrogen Oxides (NOx) | Good Combustion & Operation Practices (GCOP) Plan | 5.3 | LB/HR | MONTHLY AVERAGE | 23.21 | TONS/YR | 12-MONTH ROLLING TOTAL | 0 | | |
| KY-0116 | NOVELIS CORPORATION - GUTHRIE | KY | 07/25/2022  ACT | EU 041b - Indirect-Fired Building Heating Systems â‰¤ 1 MMBtu | 13.31 | 3 | MMBtu/hr (total) | Nitrogen Oxides (NOx) | Good Combustion & Operation Practices (GCOP) Plan | 0.3 | LB/HR | MONTHLY AVERAGE | 1.31 | TONS/YR | 12-MONTH ROLLING TOTAL | 0 | | |
| KY-0116 | NOVELIS CORPORATION - GUTHRIE | KY | 07/25/2022  ACT | EU 041c - Indirect-Fired Building Heating Systems > 1 MMBtu | 13.31 | 19.2 | MMBtu/hr (total) | Nitrogen Oxides (NOx) | Good Combustion & Operation Practices (GCOP) Plan | 1.92 | LB/HR | MONTHLY AVERAGE | 8.41 | TONS/YR | 12-MONTH ROLLING TOTAL | 0 | | |
| LA-0305 | LAKE CHARLES METHANOL FACILITY | LA | 06/30/2016  ACT | Gasifier Start-up Preheat Burners | 13.31 | 23 | MM BTU/hr (each) | Nitrogen Oxides (NOx) | good engineering practices, good combustion technology, and use of clean fuels | 0 | | | 0 | | | 0 | | |
| LA-0305 | LAKE CHARLES METHANOL FACILITY | LA | 06/30/2016  ACT | WSA Preheat Burners | 13.31 | 0 | | Nitrogen Oxides (NOx) | good engineering design and practices and use of clean fuels | 0 | | | 0 | | | 0 | | |
| LA-0307 | MAGNOLIA LNG FACILITY | LA | 03/21/2016  ACT | Regenerative Heaters | 13.31 | 7.37 | mm btu/hr | Nitrogen Oxides (NOx) | good combustion practices | 0 | | | 0 | | | 0 | | |
| LA-0349 | DRIFTWOOD LNG FACILITY | LA | 07/10/2018  ACT | Hot Oil Heaters (5) | 13.31 | 16.13 | mm btu/hr | Nitrogen Oxides (NOx) | ULNB and Good Combustion Practices | 0 | | | 0 | | | 0 | | |
| LA-0364 | FG LA COMPLEX | LA | 01/06/2020  ACT | Hot Oil Heaters 1 and 2 | 13.31 | 0 | | Nitrogen Oxides (NOx) | LNB | 0.06 | LB/MMBTU | | 0 | | | 0 | | |
| LA-0364 | FG LA COMPLEX | LA | 01/06/2020  ACT | PR Waste Heat Boiler | 13.31 | 94 | mm btu/h | Nitrogen Oxides (NOx) | SCR and LNB | 14.41 | LB/H | 12-MONTH ROLLING AVERAGE | 0 | | | 0 | | |
| LA-0377 | TOKAI ADDIS FACILITY | LA | 05/27/2020  ACT | 1-19 Burner 1 | 13.31 | 12 | MW | Nitrogen Oxides (NOx) | Low NOx Burners and good combustion practices. | 0.08 | LB/MMBTU | | 9.6 | LB/H | | 0 | | |
| LA-0391 | MAGNOLIA POWER GENERATING STATION UNIT 1 | LA | 06/03/2022  ACT | Auxiliary Boiler | 13.31 | 80 | mm BTU/h | Nitrogen Oxides (NOx) | Ultra-low NOx burners and good combustion practices. | 0.01 | LB/MM BTU | | 0 | | | 0 | | |
| *LA-0394 | GEISMAR PLANT | LA | 12/12/2023  ACT | 55-22 - PAO Thermal Oxidizer | 13.31 | 2 | MM BTU/hr | Nitrogen Oxides (NOx) | Use of good thermal oxidizer design and implementation of good combustion practices | 0.23 | LB/HR | HOURLY MAXIMUM | 0.86 | TONS/YR | ANNUAL MAXIMUM | 0 | | |
| LA-0398 | CAMERON LNG FACILITY | LA | 09/19/2023  ACT | Hot Oil Heaters (EQT0111, EQT0112, EQT0113) | 13.31 | 90 | mm btu/hr | Nitrogen Oxides (NOx) | Ultra-low NOx burners | 0.01 | LB/MM BTU | ANNUAL | 0 | | | 0 | | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 5H-1 - Hydrochloric Acid Production Furnace - 5 | 13.31 | 51 | MM BTU/hr | Nitrogen Oxides (NOx) | Low NOX burners, Selective Catalytic Reduction system, and good combustion practices | 0.89 | LB/HR | | 3.26 | TONS/YEAR | | 0.0146 | LB/MMBTU | |
| *LA-0406 | MCA GEIMAR SITE | LA | 07/24/2024  ACT | POx Unit Start-up Burner (EQT0006) | 13.31 | 8 | mm btu/hr | Nitrogen Oxides (NOx) | Use of gaseous fuels (fuel gas and/or natural gas). Good combustion practices. Proper equipment (burner) design/operation. | 0.098 | LB/MM BTU | | 0 | | | 0 | | |
| MD-0045 | MATTAWOMAN ENERGY CENTER | MD | 11/13/2015  ACT | AUXILIARY BOILER | 13.31 | 42 | MMBTU/H | Nitrogen Oxides (NOx) | EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, ULTRA LOW-NOX BURNERS, AND GOOD COMBUSTION PRACTICES | 0.01 | LB/MMBTU | 3-HOUR BLOCK AVERAGE | 0 | | | 0 | | |
| MI-0420 | DTE GAS COMPANY--MILFORD COMPRESSOR STATION | MI | 06/03/2016  ACT | FGAUXBOILERS | 13.31 | 6 | MMBTU/H | Nitrogen Oxides (NOx) | Ultra low NOx burners and good combustion practices. | 14 | PPMVOL | AT 15%O2; TEST PROTOCOL | 0 | | | 0 | | |
| MI-0421 | GRAYLING PARTICLEBOARD | MI | 08/26/2016  ACT | EUFLTOS1 in FGTOH (Thermal Oil System for Thermally Fused Lamination Lines) | 13.31 | 34 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners and good design and combustion practices. | 0.05 | LB/MMBTU | TEST PROTOCOL WILL SPECIFY AVG TIME | 2.2 | T/YR | BASED UPON A 12-MO ROLLING TIME PERIOD | 0 | | |
| MI-0421 | GRAYLING PARTICLEBOARD | MI | 08/26/2016  ACT | EUTOH (In FGTOH)--Thermal Oil Heater | 13.31 | 34 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners and good design and combustion practices. | 0.05 | LB/MMBTU | TEST PROTOCOL WILL SPECIFY AVG TIME | 7.3 | T/YR | 12-MO ROLLING TIME PERIOD | 0 | | |
| MI-0423 | INDECK NILES, LLC | MI | 01/04/2017  ACT | FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2) | 13.31 | 27 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices. | 2.65 | LB/H | HOURLY; EACH UNIT | 0 | | | 0 | | |
| MI-0424 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | MI | 12/05/2016  ACT | EUFUELHTR (Fuel pre-heater) | 13.31 | 3.7 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices. | 0.55 | LB/H | TEST PROTOCOL WILL SPECIFY AVG TIME. | 0 | | | 0 | | |

# Institutional Gas Fired Boilers (13.310)

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| MI-0424 | HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET | MI | 12/05/2016  ACT | EUAUXBOILER (Auxiliary boiler) | 13.31 | 83.5 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners/Internal flue gas recirculation and good combustion practices. | 0.05 | LB/MMBTU | TEST PROTOCOL WILL SPECIFY AVG TIME | 0 | | | 0 | | |
| MI-0425 | GRAYLING PARTICLEBOARD | MI | 05/09/2017  ACT | EUTOH in FGTOH | 13.31 | 38 | MMBTU/H | Nitrogen Oxides (NOx) | Good design and combustion practices, Low NOx burners. | 0.05 | LB/MMBTU | TEST PROTOCOL SHALL SPECIFY | 8.16 | T/YR | 12-MO ROLLING TIME PERIOD | 0 | | |
| MI-0425 | GRAYLING PARTICLEBOARD | MI | 05/09/2017  ACT | EUFLTOS1 in FGTOH | 13.31 | 10.2 | MMBTU/H | Nitrogen Oxides (NOx) | Good design and combustion practices, low NOx burners. | 0.05 | LB/MMBTU | TEST PROTOCOL SHALL SPECIFY | 2.2 | T/YR | 12-MO ROLLING TIME PERIOD | 0 | | |
| MI-0426 | DTE GAS COMPANY - MILFORD COMPRESSOR STATION | MI | 03/24/2017  ACT | FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C) | 13.31 | 3 | MMBTU/H | Nitrogen Oxides (NOx) | Ultra-low NOx burners and good combustion practices. | 20 | PPM AT 3% O2 | EACH 3 MMBTU/H BOILER | 9 | PPM AT 3% O2 | EACH 1 MMBTU/H BOILER | 0 | | |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | MI | 06/29/2018  ACT | EUAUXBOILER (North Plant): Auxiliary Boilder | 13.31 | 61.5 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners/flue gas recirculation and good combustion practices. | 0.04 | LB/MMBTU | 30-DAY ROLLING AVG TIME PERIOD | 0 | | | 0 | | |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | MI | 06/29/2018  ACT | EUAUXBOILER (South Plant): Auxiliary Boiler | 13.31 | 61.5 | MMBTU/h | Nitrogen Oxides (NOx) | Low NOx burners/flue gas recirculation and good combustion practices. | 0.04 | LB/MMBTU | 30 DAY ROLLING AVG TIME PERIOD | 0 | | | 0 | | |
| MI-0435 | BELLE RIVER COMBINED CYCLE POWER PLANT | MI | 07/16/2018  ACT | EUAUXBOILER: Auxiliary Boiler | 13.31 | 99.9 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners/Flue gas recirculation. | 0.036 | LB/MMBTU | HOURLY | 3.6 | LB/H | HOURLY | 0 | | |
| MI-0435 | BELLE RIVER COMBINED CYCLE POWER PLANT | MI | 07/16/2018  ACT | EUFUELHTR1: Natural gas fired fuel heater | 13.31 | 20.8 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burner | 0.75 | LB/H | HOURLY | 0 | | | 0 | | |
| MI-0435 | BELLE RIVER COMBINED CYCLE POWER PLANT | MI | 07/16/2018  ACT | EUFUELHTR2: Natural gas fired fuel heater | 13.31 | 3.8 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burner | 0.14 | LB/H | HOURLY | 0 | | | 0 | | |
| MI-0440 | MICHIGAN STATE UNIVERSITY | MI | 05/22/2019  ACT | FGFUELHEATERS | 13.31 | 25 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners and good combustion practices. | 0.05 | LB/MMBTU | HOURLY; EACH HEATER | 0 | | | 0 | | |
| MI-0441 | LBWL--ERICKSON STATION | MI | 12/21/2018  ACT | EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H | 13.31 | 99 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners (LNB) or flue gas recirculation along with good combustion practices. | 30 | PPM | @3%O2; HOURLY | 0 | | | 0 | | |
| MI-0442 | THOMAS TOWNSHIP ENERGY, LLC | MI | 08/21/2019  ACT | FGAUXBOILER | 13.31 | 80 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices and low NOx burners. | 0.036 | LB/MMBTU | HOURLY; EACH BOILER | 0 | | | 0 | | |
| MI-0442 | THOMAS TOWNSHIP ENERGY, LLC | MI | 08/21/2019  ACT | FGPREHEAT | 13.31 | 7 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices and low NOx burners | 0.036 | LB/MMBTU | HOURLY; EACH UNIT | 0 | | | 0 | | |
| *MI-0445 | INDECK NILES, LLC | MI | 11/26/2019  ACT | FGFUELHTR (2 fuel pre-heaters) | 13.31 | 27 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices | 1.32 | LB/H | HOURLY; EACH FUEL HEATER | 0 | | | 0 | | |
| MI-0447 | LBWL--ERICKSON STATION | MI | 01/07/2021  ACT | EUAUXBOILER--nat gas fired auxiliary boiler | 13.31 | 50 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners (LNB) or flue gas recirculation (FGR) along with good combustion practices. | 30 | PPM | AT 3% O2; HOURLY | 0 | | | 0 | | |
| MI-0448 | GRAYLING PARTICLEBOARD | MI | 12/18/2020  ACT | Thermal oil heater (EUTOH in FGTOH) | 13.31 | 38 | MMBTU/H | Nitrogen Oxides (NOx) | Good design and combustion practices, low NOx burners | 0.05 | LB/MMBTU | HOURLY | 8.16 | T/YR | 12-MO ROLLING TIME PERIOD | 0 | | |
| MI-0448 | GRAYLING PARTICLEBOARD | MI | 12/18/2020  ACT | Thermal oil system for thermally fused lamination lines (EUFLTOS1 in FGTOH) | 13.31 | 10.2 | MMBTU/H | Nitrogen Oxides (NOx) | Good design and combustion practices, low NOx burners | 0.05 | LB/MMBTU | HOURLY | 2.2 | T/YR | 12-MO ROLLING TIME PERIOD | 0 | | |
| MI-0451 | MEC NORTH, LLC | MI | 06/23/2022  ACT | EUAUXBOILER (North Plant): Auxiliary Boiler | 13.31 | 61.5 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners/Flue gas recirculation and good combustion practices. | 0.04 | LB/MMBTU | 30-DAY ROLLING AVERAGE | 0 | | | 0 | | |
| MI-0452 | MEC SOUTH, LLC | MI | 06/23/2022  ACT | EUAUXBOILER (South Plant): Auxiliary Boiler | 13.31 | 61.5 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx Burners/Flue Gas Recirculation and Good Combustion Practices | 0.04 | LB/MMBTU | 30-DAY ROLLING AVERAGE | 0 | | | 0 | | |
| MI-0454 | LBWL-ERICKSON STATION | MI | 12/20/2022  ACT | EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H | 13.31 | 50 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx Burners (LNB) or Flue Gas Recirculation (FGR) along with good combustion practices. | 30 | PPM | HOURLY | 0 | | | 0 | | |
| NJ-0084 | PSEG FOSSIL LLC SEWAREN GENERATING STATION | NJ | 03/10/2016  ACT | Auxiliary Boiler firing natural gas | 13.31 | 687 | MMCFT/YR | Nitrogen Oxides (NOx) | low NOx burners and flue gas recirculation (FGR) | 0.8 | LB/H | AV OF THREE ONE H STACK TESTS | 0.01 | LB/MMBTU | AV OF THREE ONE H STACK TESTS | 0 | | |
| NJ-0085 | MIDDLESEX ENERGY CENTER, LLC | NJ | 07/19/2016  ACT | AUXILIARY BOILER | 13.31 | 4000 | H/YR | Nitrogen Oxides (NOx) | Low NOx burners and Flue Gas Recirculation (FGR) and use of natural gas a clean burning fuel | 0.975 | LB/H | AV OF THREE ONE H INITIAL STACK TEST | 0.01 | LB/MMBTU | AV OF THREE ONE H INITIAL STACK TEST | 0 | | |
| NY-0103 | CRICKET VALLEY ENERGY CENTER | NY | 02/03/2016  ACT | Auxiliary boiler | 13.31 | 60 | MMBTU/H | Nitrogen Oxides (NOx) | flue gas recirculation with low NOx burners | 0.0085 | LB/MMBTU | 1 H | 0 | | | 0 | | |
| OH-0366 | CLEAN ENERGY FUTURE - LORDSTOWN, LLC | OH | 08/25/2015  ACT | Auxiliary Boiler (B001) | 13.31 | 34 | MMBTU/H | Nitrogen Oxides (NOx) | Flue gas recirculation (FGR) and low NOx burner | 0.68 | LB/H | | 0.68 | T/YR | PER ROLLING 12 MONTH PERIOD | 0.02 | LB/MMBTU | |

# Institutional Gas Fired Boilers (13.310)

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| OH-0367 | SOUTH FIELD ENERGY LLC | OH | 09/23/2016  ACT | Auxiliary Boiler (B001) | 13.31 | 99 | MMBTU/H | Nitrogen Oxides (NOx) | Flue gas recirculation (FGR), low NOx burner, and natural gas/ultra low sulfur diesel | 9.9 | LB/H | | 10.65 | T/YR | PER ROLLING 12 MONTH PERIOD | 0.02 | LB/MMBTU | FOR NATURAL GAS. SEE NOTES. |
| OH-0368 | PALLAS NITROGEN LLC | OH | 04/19/2017  ACT | Startup Heater (B001) | 13.31 | 100 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing). | 10 | LB/H | | 2.4 | T/YR | PER ROLLING 12 MONTH PERIOD | 0.1 | LB/MMBTU | |
| OH-0370 | TRUMBULL ENERGY CENTER | OH | 09/07/2017  ACT | Auxiliary Boiler (B001) | 13.31 | 37.8 | MMBTU/H | Nitrogen Oxides (NOx) | Flue gas recirculation (FGR), low NOx burner | 0.76 | LB/H | | 0.76 | T/YR | PER ROLLING 12 MONTH PERIOD | 0.02 | LB/MMBTU | |
| OH-0372 | OREGON ENERGY CENTER | OH | 09/27/2017  ACT | Auxiliary Boiler (B001) | 13.31 | 37.8 | MMBTU/H | Nitrogen Oxides (NOx) | low NOX burners and flue gas recirculation | 0.76 | LB/H | | 0.76 | T/YR | PER ROLLING 12 MONTH PERIOD | 0.02 | LB/MMBTU | |
| OH-0374 | GUERNSEY POWER STATION LLC | OH | 10/23/2017  ACT | Fuel Gas Heaters (2 identical, P007 and P008) | 13.31 | 15 | MMBTU/H | Nitrogen Oxides (NOx) | Low-NOx gas burner | 0.3 | LB/H | | 1.31 | T/YR | PER ROLLING 12 MONTH PERIOD | 0.02 | LB/MMBTU | |
| OH-0375 | LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER | OH | 11/07/2017  ACT | Auxiliary Boiler (B001) | 13.31 | 26.8 | MMBTU/H | Nitrogen Oxides (NOx) | Flue gas recirculation and low NOX burner | 0.29 | LB/H | | 0.74 | T/YR | PER ROLLING 12 MONTH PERIOD | 0.011 | LB/MMBTU | |
| OH-0377 | HARRISON POWER | OH | 04/19/2018  ACT | Auxiliary Boiler (B001) | 13.31 | 44.55 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices and low NOx burner | 1.56 | LB/H | | 0.84 | T/YR | PER ROLLING 12 MONTH PERIOD | 0.035 | LB/MMBTU | |
| OH-0377 | HARRISON POWER | OH | 04/19/2018  ACT | Auxiliary Boiler (B002) | 13.31 | 80 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices and low NOx burner | 2.19 | LB/H | | 1.18 | T/YR | PER ROLLING 12 MONTH PERIOD | 0.027 | LB/MMBTU | |
| OH-0379 | PETMIN USA INCORPORATED | OH | 02/06/2019  ACT | Startup boiler (B001) | 13.31 | 15.17 | MMBTU/H | Nitrogen Oxides (NOx) | Low-NOX burners, good combustion practices and the use of natural gas | 0.634 | LB/H | | 2.78 | T/YR | PER ROLLING 12 MONTH PERIOD | 0.0418 | LB/MMBTU | |
| OH-0379 | PETMIN USA INCORPORATED | OH | 02/06/2019  ACT | Ladle Preheaters (P002, P003 and P004) | 13.31 | 15 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices and the use of natural gas | 2.12 | LB/H | | 9.29 | T/YR | PER ROLLING 12 MONTH PERIOD | 0.141 | LB/MMBTU | |
| OH-0381 | NORTHSTAR BLUESCOPE STEEL, LLC | OH | 09/27/2019  ACT | Tunnel Furnace #2 (P018) | 13.31 | 88 | MMBTU/H | Nitrogen Oxides (NOx) | Use of natural gas, use of low NOx burners, good combustion practices and design | 6.16 | LB/H | | 26.98 | T/YR | PER ROLLING, 12-MONTH PERIOD | 0.07 | LB/MMBTU | |
| OH-0387 | INTEL OHIO SITE | OH | 09/20/2022  ACT | 45.6 MMBtu/hr Natural Gas-Fired Nitrogen Vaporizers: B029 through B032 | 13.31 | 45.6 | MMBTU/H | Nitrogen Oxides (NOx) | Ultra-low NOX burners, good combustion practices, and the use of natural gas | 2.59 | T/YR | PER ROLLING 12 MONTH PERIOD COMBINED | 0 | | | 0.011 | LB/MMBTU | |
| OH-0387 | INTEL OHIO SITE | OH | 09/20/2022  ACT | 29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028 | 13.31 | 29.4 | MMBTU/H | Nitrogen Oxides (NOx) | Ultra-low NOX burners, good combustion practices, and the use of natural gas | 9.74 | T/YR | PER ROLLING 12 MONTH PERIOD B001 TO B014 | 9.74 | T/YR | PER ROLLING 12 MONTH PERIOD B015 TO B028 | 0.011 | LB/MMBTU | |
| OK-0173 | CMC STEEL OKLAHOMA | OK | 01/19/2016  ACT | Heaters (Gas-Fired) | 13.31 | 0 | | Nitrogen Oxides (NOx) | Natural Gas Fuel | 0.1 | LB/MMBTU | | 0 | | | 0 | | |
| PA-0309 | LACKAWANNA ENERGY CTR/JESSUP | PA | 12/23/2015  ACT | Auxillary Boiler | 13.31 | 13.31 | MMBtu/hr | Nitrogen Oxides (NOx) | SCR and ultra low NOx burners, Fired only on natural gas supplied by a public utility. | 0.006 | LB/MMBTU | 30-DAY ROLLING AVERAGE BASIS | 2.22 | TPY | 12-MOTH ROLLING BASIS | 0 | | |
| PA-0310 | CPV FAIRVIEW ENERGY CENTER | PA | 09/02/2016  ACT | Auxilary boiler | 13.31 | 92.4 | MMBtu/hr | Nitrogen Oxides (NOx) | Ultra low NOx burners, FGR, good combustion practices | 0.011 | LB/MMBTU | AVG OF 3 1-HR TEST RUNS | 2.03 | TPY | 12-MONTH ROLLING BASIS | 0 | | |
| PA-0311 | MOXIE FREEDOM GENERATION PLANT | PA | 09/01/2015  ACT | Auxilary Boiler | 13.31 | 55.4 | MMBtu/hr | Nitrogen Oxides (NOx) | | 0.006 | LB/MMBTU | | 0.66 | TPY | 12-MONTH ROLLING BASIS | 0 | | |
| *PA-0316 | RENOVO ENERGY CENTER, LLC | PA | 01/26/2018  ACT | Auxiliary Boiler | 13.31 | 118800 | MMBtu/12 month period | Nitrogen Oxides (NOx) | ‘‘ultra-low NOx burners and flue gas re-circulation‘‘ operated in accordance with the manufacturerâ€™s specifications and good operating practices | 0.011 | LB | MMBTU | 0.65 | TPY | | 0 | | |
| *PA-0319 | RENAISSANCE ENERGY CENTER | PA | 08/27/2018  ACT | NATURAL GAS FIRED AUXILIARY BOILER | 13.31 | 88 | MMBtu/hr | Nitrogen Oxides (NOx) | Lo-NOx burners, Flue Gas Recirculation, good combustion practices, proper operation and maintainance. | 0.02 | LB/MMBTU | HR | 0 | | | 0 | | |
| TX-0772 | PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT) | TX | 11/06/2015  ACT | Commercial/Institutional-Size Boilers/Furnaces | 13.31 | 40 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners | 0.036 | LB/MMBTU | | 0 | | | 0 | | |
| TX-0772 | PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT) | TX | 11/06/2015  ACT | Commercial/Institutional-Size Boilers/Furnaces | 13.31 | 95.7 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners and flue gas recirculation | 0.011 | LB/MMBTU | | 0 | | | 0 | | |
| TX-0772 | PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT) | TX | 11/06/2015  ACT | Commercial/Institutional-Size Boilers/Furnaces | 13.31 | 13.2 | MMBTU/H | Nitrogen Oxides (NOx) | | 0.1 | LB/MMBTU | | 0 | | | 0 | | |

# Institutional Gas Fired Boilers (13.310)

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TX-0845 | ARKEMA BEAUMONT PLANT | TX | 08/24/2018  ACT | HEATERS | 13.31 | 31 | BTU/HR | Nitrogen Oxides (NOx) | LOW NOX BURNERS, CLEAN FUEL | 0.04 | LB/MMBTU | | 0 | | | 0 | | |
| TX-0851 | RIO BRAVO PIPELINE FACILITY | TX | 12/17/2018  ACT | Thermal Oxidizer | 13.31 | 71.3 | MMBTU/HR | Nitrogen Oxides (NOx) | Low NOx burners and good combustion practices. | 0.162 | LB/MMBTU | | 0 | | | 0 | | |
| TX-0888 | ORANGE POLYETHYLENE PLANT | TX | 04/23/2020  ACT | Heaters | 13.31 | 100 | MMBtu | Nitrogen Oxides (NOx) | Low NOx burners and good combustion practice. | 0.04 | LB/MMBTU | | 0 | | | 0 | | |
| TX-0955 | INEOS OLIGOMERS CHOCOLATE BAYOU | TX | 03/14/2023  ACT | HOT OIL HEATER | 13.31 | 0 | | Nitrogen Oxides (NOx) | Burner design for good combustion efficiency and to minimize NOx formation with a SCR system to further reduce NOx. | 0.014 | LB/MMBTU | 1-HR | 0.006 | LB/MMBTU | ANNUAL AVG | 0 | | |
| TX-0955 | INEOS OLIGOMERS CHOCOLATE BAYOU | TX | 03/14/2023  ACT | HEATER NO 2 | 13.31 | 0 | | Nitrogen Oxides (NOx) | Burner design for good combustion efficiency and to minimize NOx formation. | 0.01 | LB/MMBTU | 1-HR | 0 | | | 0 | | |
| TX-0964 | NEDERLAND FACILITY | TX | 10/05/2023  ACT | HEATERS | 13.31 | 0 | | Nitrogen Oxides (NOx) | LOW NOX BURNERS | 9 | PPMVD | | 0.012 | LB/MMBTU | | 0 | | |
| *TX-0999 | SEMICONDUCTOR MANUFACTURING FACILITY | TX | 07/07/2025  ACT | BOILERS | 13.31 | 0 | | Nitrogen Oxides (NOx) | ultra-low NOx burners | 0.03 | LB/MMBTU | HHV 1-HR AVG | 0 | | | 0 | | |
| WI-0283 | AFE, INC. â€"LCM PLANT | WI | 04/24/2018  ACT | B01-B12, Boilers | 13.31 | 28 | mmBTU/hr | Nitrogen Oxides (NOx) | Ultra-low NOx Burners, Flue Gas Recirculation and Good Combustion Practices | 0.0105 | LB/MMBTU | | 0 | | | 0 | | |
| WI-0284 | SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT | WI | 04/24/2018  ACT | B13-B24 & B25-B36 Natural Gas-Fired Boilers | 13.31 | 28 | mmBTU | Nitrogen Oxides (NOx) | Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices. | 0.0105 | LB/MMBTU | 1-HOUR AVERAGE | 0 | | | 0 | | |
| WI-0291 | GRAYMONT WESTERN LIME-EDEN | WI | 01/28/2019  ACT | P05 Natural Gas Fired Line Heater | 13.31 | 1.5 | mmBTU/hr | Nitrogen Oxides (NOx) | Good Combustion Practices | 0.1 | LB/MMBTU | | 0 | | | 0 | | |
| WI-0300 | NEMADJI TRAIL ENERGY CENTER | WI | 09/01/2020  ACT | Natural Gas-Fired Auxiliary Boiler (B02) | 13.31 | 100 | MMBTU/H | Nitrogen Oxides (NOx) | Ultra-low NOx burners, flue gas recirculation, and operate and maintain B02 according to the manufacturerâ€™s recommendations. | 0.011 | LB/MMBTU | | 0 | | | 0 | | |
| WI-0306 | WPL- RIVERSIDE ENERGY CENTER | WI | 02/28/2020  ACT | Temporary Boiler (B98A) | 13.31 | 14.67 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOx burners, flue gas recirculation, shall be operated for no more than 500 hours, and shall combust only pipeline quality natural gas. | 0.04 | LB/MMBTU | AVG. OVER ANY CONSECUTIVE 3-HR PERIOD | 0 | | | 0 | | |
| *WI-0326 | NEMADJI TRAIL ENERGY CENTER | WI | 09/19/2023  ACT | Boiler; S02/B02 | 13.31 | 100 | MMBtu/hr | Nitrogen Oxides (NOx) | (a) B02 shall be equipped with ultra-low NOx burners and flue gas recirculation.<br>(b) The permittee shall operate and maintain B02 according to the manufacturerâ€™s recommendations. | 0.011 | LB/MMBTU | | 0 | | | 0 | | |
| *WI-0326 | NEMADJI TRAIL ENERGY CENTER | WI | 09/19/2023  ACT | Heaters: S04/P04 and S05/P05 | 13.31 | 10 | MMBtu/hr | Nitrogen Oxides (NOx) | (a) P04 and P05 shall be equipped with low-NOx burners.<br>(b) Only pipeline quality natural gas may be combusted in P04 and P05.<br>(c) The permittee shall operate and maintain P04 and P05 according to the manufacturerâ€™s recommendations.<br>(d) The permittee shall tune within 120 days of the initial operation, and within 24-months of each preceding tune-up.<br>(e) NOx emissions from P04 and P05 may not exceed 0.049 lb/MMBtu each. | 0.049 | LB/MMBTU | | 0 | | | 0 | | |
| *WI-0331 | WPL SHEBOYGAN FALLS ENERGY FACILITY | WI | 01/22/2025  ACT | P07 5 Natural Gas Boiler Heaters | 13.31 | 3 | mmBtu/hr | Nitrogen Oxides (NOx) | Good combustion practices, use of low NOx burners | 0.05 | LB/MMBTU | | 0 | | | 0 | | |

# Institutional Gas Fired Boilers (13.310)

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *WV-0029 | HARRISON COUNTY POWER PLANT | WV | 03/27/2018  ACT | Auxiliary Boiler | 13.31 | 77.8 | mmBtu/hr | Nitrogen Oxides (NOx) | LNB, FGR, Good Combustion Practices | 0.86 | LB/HR | | 1.96 | TONS/YEAR | | 0.0011 | LB/MMBTU | |
| *WV-0032 | BROOKE COUNTY POWER PLANT | WV | 09/18/2018  ACT | Auxiliary Boiler | 13.31 | 111.9 | mmBtu/hr | Nitrogen Oxides (NOx) | LNB, Good Combustion Practices | 1.23 | LB/HR | | 2.82 | TONS/YEAR | | 0.011 | LB/MMBTU | |

# Internal Combustion Engines Fuel Oil (17.110)

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT ISSUANCE DATE | PROCESS NAME | PROCCESS TYPE | THROUGHPUT | THROUGHPUT UNIT | POLLUTANT | CONTROL METHOD DESCRIPTION | EMISSION LIMIT 1 | EMISSION LIMIT 1 UNIT | EMISSION LIMIT 1 AVG TIME CONDITION | EMISSION LIMIT 2 | EMISSION LIMIT 2 UNIT | EMISSION LIMIT 2 AVGERAGE TIME CONDITION | STANDARAD EMISSION LIMIT | D EMISSION LIMIT UNIT | LIMIT AVERAGE TIME CONDITION |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AK | 01/23/2015  ACT | Emergency Camp Generators | 17.11 | 2695 | hp | Nitrogen Oxides (NOx) | | 4.8 | GRAMS/HP-H | | 0 | | | 0 | | |
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AK | 01/23/2015  ACT | Fine Water Pumps | 17.11 | 610 | hp | Nitrogen Oxides (NOx) | | 3 | GRAMS/HP-H | | 0 | | | 0 | | |
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AK | 01/23/2015  ACT | Bulk Tank Generator Engines | 17.11 | 891 | hp | Nitrogen Oxides (NOx) | | 4.8 | GRAMS/HP-H | | 0 | | | 0 | | |
| AK-0084 | DONLIN GOLD PROJECT | AK | 06/30/2017  ACT | Black Start and Emergency Internal Cumbustion Engines | 17.11 | 1500 | kWe | Nitrogen Oxides (NOx) | Good Combustion Practices | 8 | G/KW-HR | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AK-0084 | DONLIN GOLD PROJECT | AK | 06/30/2017  ACT | Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines | 17.11 | 143.5 | MMBtu/hr | Nitrogen Oxides (NOx) | Selective Catalytic Reduction (SCR) and Good Combustion Practices | 0.53 | G/KW-HR (ULSD) | 3-HOUR AVERAGE | 0.08 | G/KW-HR (NATURAL GAS | 3-HOUR AVERAGE | 0 | | |
| AK-0085 | GAS TREATMENT PLANT | AK | 08/13/2020  ACT | One (1) Black Start Generator Engine | 17.11 | 186.6 | gph | Nitrogen Oxides (NOx) | Good combustion practices, limit operation to 500 hours per year. | 3.3 | G/HP-HR | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AK-0088 | LIQUEFACTION PLANT | AK | 07/07/2022  ACT | Diesel Fire Pump Engine | 17.11 | 27.9 | Gal/hr | Nitrogen Oxides (NOx) | Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII | 3.6 | G/HP-HR | | 500 | HRS/YR | | 0 | | |
| AL-0318 | TALLADEGA SAWMILL | AL | 12/18/2017  ACT | 250 Hp Emergency CI, Diesel-fired RICE | 17.11 | 0 | | Nitrogen Oxides (NOx) | | 0 | | | 0 | | | 0 | | |
| AL-0328 | PLANT BARRY | AL | 11/09/2020  ACT | Diesel Emergency Engines | 17.11 | 0 | | Nitrogen Oxides (NOx) | | 3 | GR/BHP-HR | NMHC + NOX | 0 | | | 0 | | |
| *AL-0337 | KRONOSPAN, LLC | AL | 09/21/2022  ACT | Fire Pump #1 (X074) | 17.11 | 0 | | Nitrogen Oxides (NOx) | Catalyst | 3 | G/HP-HR | | 3.04 | LB/HR | | 0 | | |
| *AL-0337 | KRONOSPAN, LLC | AL | 09/21/2022  ACT | Emergency Engine No.4 | 17.11 | 0 | | Nitrogen Oxides (NOx) | Catalyst | 4.8 | G/HP-HR | | 11.97 | LB/HR | | 0 | | |
| *AL-0337 | KRONOSPAN, LLC | AL | 09/21/2022  ACT | Emergency Engine No.5 | 17.11 | 0 | | Nitrogen Oxides (NOx) | Catalyst | 4.8 | G/HP-HR | | 11.97 | LB/HR | | 0 | | |
| *AL-0357 | THE WESTERVELT COMPANY-THOMASVILLE MILL | AL | 11/22/2019  ACT | Emergency Generator (ENG3) | 17.11 | 0 | | Nitrogen Oxides (NOx) | | 4.7 | G/KWM-HR | | 3.5 | G/HP-HR | | 0 | | |
| *AL-0357 | THE WESTERVELT COMPANY-THOMASVILLE MILL | AL | 11/22/2019  ACT | Emergency Generator (ENG4) | 17.11 | 0 | | Nitrogen Oxides (NOx) | | 4.7 | G/KWM-HR | | 3.5 | G/HP-HR | | 0 | | |

# Internal Combustion Engines Fuel Oil (17.110)

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AR-0161 | SUN BIO MATERIAL COMPANY | AR | 09/23/2019  ACT | Emergency Engines | 17.11 | 0 | | Nitrogen Oxides (NOx) | Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII | 0.4 | G/KW-H | | 0 | | | 0 | | |
| AR-0163 | BIG RIVER STEEL LLC | AR | 06/09/2019  ACT | Emergency Engines | 17.11 | 0 | | Nitrogen Oxides (NOx) | Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII | 4.86 | G/KW-HR | | 0 | | | 0 | | |
| AR-0177 | NUCOR STEEL ARKANSAS | AR | 11/21/2022  ACT | SN-230 Galvanizing Line No, 2 Emergency Generator | 17.11 | 3634 | Horsepower | Nitrogen Oxides (NOx) | | 5.6 | G/KW-HR | | 0 | | | 0 | | |
| AR-0180 | HYBAR LLC | AR | 04/28/2023  ACT | Emergency Generators | 17.11 | 0 | | Nitrogen Oxides (NOx) | Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII | 3.9 | G/BHP-HR | | 0 | | | 0 | | |
| *AR-0192 | GREEN BAY PACKAGING | AR | 10/26/2023  ACT | Black Start Generator No.1 and 2 | 17.11 | 0 | | Nitrogen Oxides (NOx) | ULSD, Good Design and Operating Practices | 6.39 | G/BHP-HR | | 0 | | | 0 | | |
| FL-0367 | SHADY HILLS COMBINED CYCLE FACILITY | FL | 07/27/2018  ACT | 1,500 kW Emergency Diesel Generator | 17.11 | 14.82 | MMBtu/hour | Nitrogen Oxides (NOx) | Operate and maintain the engine according to the manufacturer's written instructions | 6.4 | G/KW-HOUR | | 0 | | | 0 | | |
| FL-0371 | SHADY HILLS COMBINED CYCLE FACILITY | FL | 06/07/2021  ACT | 1,500 kW Emergency Diesel Generator | 17.11 | 14.82 | MMBtu/hour | Nitrogen Oxides (NOx) | | 6.4 | G/KW-HOUR | FOR NMHC+NOX | 0 | | | 0 | | |
| IL-0129 | CPV THREE RIVERS ENERGY CENTER | IL | 07/30/2018  ACT | Emergency Engines | 17.11 | 0 | | Nitrogen Oxides (NOx) | | 0 | | | 0 | | | 0 | | |
| IL-0130 | JACKSON ENERGY CENTER | IL | 12/31/2018  ACT | Emergency Engine | 17.11 | 1500 | kW | Nitrogen Oxides (NOx) | | 6.4 | G/KW-HR | | 0 | | | 0 | | |
| IL-0133 | LINCOLN LAND ENERGY CENTER | IL | 07/29/2022  ACT | Emergency Engines | 17.11 | 1250 | kW | Nitrogen Oxides (NOx) | | 6.4 | GRAMS | KILOWATT-HOUR | 0 | | | 0 | | |
| IL-0134 | CRONUS CHEMICALS | IL | 12/21/2023  ACT | Emergency Generator Engine | 17.11 | 3985 | hp | Nitrogen Oxides (NOx) | | 6.4 | G/KW-HR | 3-HR AVG | 75 | HR/YR | OPERATIONAL LIMIT | 0 | | |
| IN-0263 | MIDWEST FERTILIZER COMPANY LLC | IN | 03/23/2017  ACT | EMERGENCY GENERATORS (EU014A AND EU-014B) | 17.11 | 3600 | HP EACH | Nitrogen Oxides (NOx) | GOOD COMBUSTION PRACTICES | 4.42 | G/HP-H EACH | 3 HOUR AVERAGE | 500 | H/YR EACH | | 0 | | |
| IN-0317 | RIVERVIEW ENERGY CORPORATION | IN | 06/11/2019  ACT | Emergency generator EU-6006 | 17.11 | 2800 | HP | Nitrogen Oxides (NOx) | Tier II diesel engine | 6.4 | G/KWH | TIER II NOX + NMHC LIMIT | 0 | | | 0 | | |
| IN-0317 | RIVERVIEW ENERGY CORPORATION | IN | 06/11/2019  ACT | Emergency fire pump EU-6008 | 17.11 | 750 | HP | Nitrogen Oxides (NOx) | Engine that complies with Table 4 to Subpart IIII of Part 60 | 4 | G/KWH | COMBINED NOX + NMHC LIMIT | 0 | | | 0 | | |
| IN-0324 | MIDWEST FERTILIZER COMPANY LLC | IN | 05/06/2022  ACT | emergency generator EU 014a | 17.11 | 3600 | HP | Nitrogen Oxides (NOx) | | 4.42 | G/HP-HR | | 500 | HR/YR | TWELVE (12) CONSECUTIVE MONTH PERIOD | 0 | | |
| IN-0324 | MIDWEST FERTILIZER COMPANY LLC | IN | 05/06/2022  ACT | fire water pump EU-015 | 17.11 | 500 | HP | Nitrogen Oxides (NOx) | | 2.83 | G/HP-HR | | 500 | HR/YR | TWELVE (12) CONSECUTIVE MONTH PERIOD | 0 | | |

# Internal Combustion Engines Fuel Oil (17.110)

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IN-0359 | NUCOR STEEL | IN | 03/30/2023  ACT | Emergency Generator (CC-GEN1) | 17.11 | 3000 | Horsepower | Nitrogen Oxides (NOx) | certified engine | 4.8 | G/HP-HR | | 0 | | | 0 | | |
| *IN-0365 | MAPLE CREEK ENERGY LLC | IN | 06/19/2023  ACT | Emergency generator | 17.11 | 2012 | hp | Nitrogen Oxides (NOx) | | 4.8 | G/HP-HR | | 0 | | | 0 | | |
| *IN-0365 | MAPLE CREEK ENERGY LLC | IN | 06/19/2023  ACT | Emergency fire pump | 17.11 | 420 | brake hp | Nitrogen Oxides (NOx) | | 4 | G/KW-HR | | 0 | | | 0 | | |
| IN-0371 | WABASH VALLEY RESOURCES, LLC | IN | 01/11/2024  ACT | Emergency Generator (400 kW) | 17.11 | 619 | HP | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements. | 2.29 | G/HP-HR | | 0 | | | 0 | | |
| IN-0371 | WABASH VALLEY RESOURCES, LLC | IN | 01/11/2024  ACT | Emergency Generator (1000 kW) | 17.11 | 1000 | kW | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements. | 3.81 | G/HP-HR | | 0 | | | 0 | | |
| IN-0371 | WABASH VALLEY RESOURCES, LLC | IN | 01/11/2024  ACT | Emergency Generator (2000 kW) | 17.11 | 2000 | kW | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements. | 3.81 | G/HP-HR | | 0 | | | 0 | | |
| IN-0371 | WABASH VALLEY RESOURCES, LLC | IN | 01/11/2024  ACT | Ammonia Plant Emergency Generator | 17.11 | 500 | kW | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements. | 4.8 | G/HP-HR | | 0 | | | 0 | | |
| IN-0384 | SYCAMORE RIVERSIDE ENERGY LLC | IN | 03/31/2025  ACT | Black Start Emergency Generators | 17.11 | 3000 | kWe, each | Nitrogen Oxides (NOx) | GOOD COMBUSTION PRACTICES AND LOW SULFUR FUELS | 4.56 | G | HP-HR | 43.55 | LB | HR | 0 | | |
| IN-0384 | SYCAMORE RIVERSIDE ENERGY LLC | IN | 03/31/2025  ACT | plant emergency generator | 17.11 | 1500 | kWe | Nitrogen Oxides (NOx) | good combustion practices and low sulfur fuel | 4.56 | G | HP-HR | 20.22 | LB | HR | 0 | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 10-02 - North Water System Emergency Generator | 17.11 | 2922 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 4.77 | G/HP-HR | NMHC + NOX | 0 | | | 0 | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 10-03 - South Water System Emergency Generator | 17.11 | 2922 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 4.77 | G/HP-HR | NMHC + NOX | 0 | | | 0 | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 10-04 - Emergency Fire Water Pump | 17.11 | 920 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 4.77 | G/HP-HR | NMHC + NOX | 0 | | | 0 | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 10-07 - Air Separation Plant Emergency Generator | 17.11 | 700 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 4.77 | G/HP-HR | NMHC + NOX | 0 | | | 0 | | |

# Internal Combustion Engines Fuel Oil (17.110)

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| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 10-01 - Caster Emergency Generator | 17.11 | 2922 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 4.77 | G/HP-HR | NMHC + NOX | 0 | | | 0 | | |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | New Pumphouse (XB13) Emergency Generator #1 (EP 08-05) | 17.11 | 2922 | HP | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan | 0 | | | 0 | | | 4.8 | G/B-HP-H | NMHC+NOX |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Tunnel Furnace Emergency Generator (EP 08-06) | 17.11 | 2937 | HP | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan | 0 | | | 0 | | | 4.8 | G/B-HP-H | NMHC+NOX |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Caster B Emergency Generator (EP 08-07) | 17.11 | 2937 | HP | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan | 0 | | | 0 | | | 4.8 | G/B-HP-H | NMHC+NOX |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Air Separation Unit Emergency Generator (EP 08-08) | 17.11 | 700 | HP | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan | 0 | | | 0 | | | 4.8 | G/B-HP-H | NMHC+NOX |
| LA-0292 | HOLBROOK COMPRESSOR STATION | LA | 01/22/2016  ACT | Emergency Generators No. 1 & No. 2 | 17.11 | 1341 | HP | Nitrogen Oxides (NOx) | Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart IIII | 14.16 | LB/HR | HOURLY MAXIMUM | 0.71 | TPY | ANNUAL MAXIMUM | 4.8 | G/BHP-HR | |
| LA-0305 | LAKE CHARLES METHANOL FACILITY | LA | 06/30/2016  ACT | Diesel Engines (Emergency) | 17.11 | 4023 | hp | Nitrogen Oxides (NOx) | Complying with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 0 | | |
| LA-0307 | MAGNOLIA LNG FACILITY | LA | 03/21/2016  ACT | Diesel Engines | 17.11 | 0 | | Nitrogen Oxides (NOx) | good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 0 | | |
| LA-0309 | BENTELER STEEL TUBE FACILITY | LA | 06/04/2015  ACT | Emergency Generator Engines | 17.11 | 2922 | hp (each) | Nitrogen Oxides (NOx) | Complying with 40 CFR 60 Subpart IIII | 6.4 | G/KW-HR | | 0 | | | 0 | | |
| *LA-0312 | ST. JAMES METHANOL PLANT | LA | 06/30/2017  ACT | DFP1-13 - Diesel Fire Pump Engine (EQT0013) | 17.11 | 650 | horsepower | Nitrogen Oxides (NOx) | Compliance with NSPS Subpart IIII | 6.6 | LB/HR | | 0 | | | 0 | | |
| *LA-0312 | ST. JAMES METHANOL PLANT | LA | 06/30/2017  ACT | DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012) | 17.11 | 1474 | horsepower | Nitrogen Oxides (NOx) | Compliance with NSPS Subpart IIII | 19.23 | LB/HR | | 0 | | | 0 | | |

# Internal Combustion Engines Fuel Oil (17.110)

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LA-0313 | ST. CHARLES POWER STATION | LA | 08/31/2016  ACT | SCPS Emergency Diesel Generator 1 | 17.11 | 2584 | HP | Nitrogen Oxides (NOx) | Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel). | 27.34 | LB/H | HOURLY MAXIMUM | 6.84 | T/YR | ANNUAL MAXIMUM | 4.8 | G/BHP-HR | |
| LA-0316 | CAMERON LNG FACILITY | LA | 02/17/2017  ACT | emergency generator engines (6 units) | 17.11 | 3353 | hp | Nitrogen Oxides (NOx) | Complying with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 0 | | |
| LA-0317 | METHANEX - GEISMAR METHANOL PLANT | LA | 12/22/2016  ACT | Emergency Generator Engines (4 units) | 17.11 | 0 | | Nitrogen Oxides (NOx) | complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ | 0 | | | 0 | | | 0 | | |
| LA-0317 | METHANEX - GEISMAR METHANOL PLANT | LA | 12/22/2016  ACT | Firewater pump Engines (4 units) | 17.11 | 896 | hp (each) | Nitrogen Oxides (NOx) | complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ | 0 | | | 0 | | | 0 | | |
| LA-0318 | FLOPAM FACILITY | LA | 01/07/2016  ACT | Diesel Engines | 17.11 | 0 | | Nitrogen Oxides (NOx) | Complying with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 0 | | |
| LA-0323 | MONSANTO LULING PLANT | LA | 01/09/2017  ACT | Fire Water Diesel Pump No. 3 Engine | 17.11 | 600 | hp | Nitrogen Oxides (NOx) | Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 0 | | |
| LA-0323 | MONSANTO LULING PLANT | LA | 01/09/2017  ACT | Fire Water Diesel Pump No. 4 Engine | 17.11 | 600 | hp | Nitrogen Oxides (NOx) | Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 0 | | |
| LA-0324 | COMMONWEALTH LNG FACILITY | LA | 03/28/2023  ACT | Firewater Pump Engine (EQT0017 - EQT0020) | 17.11 | 0 | | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage. | 5.53 | G/KW-HR | | 0 | | | 0 | | |
| LA-0324 | COMMONWEALTH LNG FACILITY | LA | 03/28/2023  ACT | Generator Engines (EQT0016) | 17.11 | 4290 | kw | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage. | 8.46 | G/KW-HR | | 0 | | | 0 | | |
| LA-0331 | CALCASIEU PASS LNG PROJECT | LA | 09/21/2018  ACT | Firewater Pumps | 17.11 | 634 | kW | Nitrogen Oxides (NOx) | Good Combustion and Operating Practices. | 3.1 | G/HP-H | | 0 | | | 0 | | |
| LA-0331 | CALCASIEU PASS LNG PROJECT | LA | 09/21/2018  ACT | Large Emergency Engines (>50kW) | 17.11 | 5364 | HP | Nitrogen Oxides (NOx) | Good Combustion and Operating Practices | 5.6 | G/KW-H | | 0 | | | 0 | | |

# Internal Combustion Engines Fuel Oil (17.110)

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| LA-0346 | GULF COAST METHANOL COMPLEX | LA | 01/04/2018  ACT | emergency generators (4 units) | 17.11 | 13410 | hp (each) | Nitrogen Oxides (NOx) | Comply with standards of 40 CFR 60 Subpart JJJJ | 2 | G/BHP-HR | | 0 | | | 0 | | |
| LA-0350 | BENTELER STEEL TUBE FACILITY | LA | 03/28/2018  ACT | emergency generators (3 units) EQT0039, EQT0040, EQT0041 | 17.11 | 0 | | Nitrogen Oxides (NOx) | Comply with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 0 | | |
| LA-0364 | FG LA COMPLEX | LA | 01/06/2020  ACT | Emergency Generator Diesel Engines | 17.11 | 550 | hp | Nitrogen Oxides (NOx) | Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage. | 0 | | | 0 | | | 0 | | |
| LA-0364 | FG LA COMPLEX | LA | 01/06/2020  ACT | Emergency Fire Water Pumps | 17.11 | 550 | hp | Nitrogen Oxides (NOx) | Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage. | 0 | | | 0 | | | 0 | | |
| LA-0379 | SHINTECH PLAQUEMINES PLANT 1 | LA | 05/04/2021  ACT | VCM Unit Emergency Generator A | 17.11 | 1389 | hp | Nitrogen Oxides (NOx) | Good combustion practices/gaseous fuel burning. | 6.9 | G/HP-HR | | 0 | | | 0 | | |
| LA-0379 | SHINTECH PLAQUEMINES PLANT 1 | LA | 05/04/2021  ACT | C/A Emergency Generator B | 17.11 | 1800 | hp | Nitrogen Oxides (NOx) | Good combustion practices/gaseous fuel burning. | 6.9 | G/HP-HR | | 0 | | | 0 | | |
| LA-0382 | BIG LAKE FUELS METHANOL PLANT | LA | 04/25/2019  ACT | Emergency Engines (EQT0014 - EQT0017) | 17.11 | 0 | | Nitrogen Oxides (NOx) | Comply with standards of 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 0 | | |
| LA-0383 | LAKE CHARLES LNG EXPORT TERMINAL | LA | 09/03/2020  ACT | Emergency Engines (EQT0011 - EQT0016) | 17.11 | 0 | | Nitrogen Oxides (NOx) | Comply with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 0 | | |
| LA-0391 | MAGNOLIA POWER GENERATING STATION UNIT 1 | LA | 06/03/2022  ACT | Emergency Diesel Generator Engine | 17.11 | 2937 | hp | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra-low sulfur diesel fuel. | 4.8 | G/HP-HR | | 0 | | | 0 | | |

# Internal Combustion Engines Fuel Oil (17.110)

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| *LA-0394 | GEISMAR PLANT | LA | 12/12/2023  ACT | 06-22 - AO-5 Emergency Generator | 17.11 | 670.5 | horsepower | Nitrogen Oxides (NOx) | Use of good combustion practices and compliance with NSPS Subpart IIII | 4.24 | LB/HR | HOURLY MAXIMUM | 0 | | | 3.88 | G/KW-HR | |
| *LA-0394 | GEISMAR PLANT | LA | 12/12/2023  ACT | 53-22 - PAO Emergency Generator | 17.11 | 670.5 | horsepower | Nitrogen Oxides (NOx) | Use of good combustion practices, compliance with NSPS Subpart IIII | 4.24 | LB/HR | HOURLY MAXIMUM | 0 | | | 3.88 | G/KW-HR | |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | LA | 12/20/2023  ACT | EGEN - Plant Emergency Generator | 17.11 | 3634 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 38.24 | LB/HR | | 0 | | | 0 | | |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | LA | 12/20/2023  ACT | E. GEN 01 - Generac SD 2000 | 17.11 | 2923 | horsepower | Nitrogen Oxides (NOx) | Compliance with the requirements of 40 CFR 60 Subpart IIII | 28.48 | LB/HR | | 0 | | | 0 | | |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | LA | 12/20/2023  ACT | E. GEN 02 - Generac SD 2000 | 17.11 | 2923 | horsepower | Nitrogen Oxides (NOx) | Compliance with the requirements of 40 CFR 60 Subpart IIII | 28.48 | LB/HR | | 0 | | | 0 | | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4C-6A - C/A Emergency Generator A | 17.11 | 2346 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 18.41 | LB/HR | | 0 | | | 6.4 | G/KW-HR | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4C-6B - C/A Emergency Generator B | 17.11 | 2346 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 18.41 | LB/HR | | 0 | | | 6.4 | G/KW-HR | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4C-6C - C/A Emergency Generator C | 17.11 | 2346 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 18.41 | LB/HR | | 0 | | | 6.4 | G/KW-HR | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4U-7A - Fire Water Pump A | 17.11 | 552 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 2.71 | LB/HR | | 0 | | | 4 | G/KW-HR | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4U-7B - Fire Water Pump B | 17.11 | 552 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 2.71 | LB/HR | | 0 | | | 4 | G/KW-HR | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4U-7C - Fire Water Pump C | 17.11 | 552 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 2.71 | LB/HR | | 0 | | | 4 | G/KW-HR | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4U-10 - Utility Emergency Generator | 17.11 | 2012 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 15.79 | LB/HR | | 0.51 | TONS/YEAR | | 6.4 | G/KW-HR | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4U-12 - VCM/CA/UT CCR Emergency Generator | 17.11 | 760 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 5.97 | LB/HR | | 0.19 | TONS/YEAR | | 6.4 | G/KW-HR | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4M-11A - VCM Emergency Generator A | 17.11 | 2346 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 18.41 | LB/HR | | 0 | | | 6.4 | G/KW-HR | |

# Internal Combustion Engines Fuel Oil (17.110)

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| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4M-11B - VCM Emergency Generator B | 17.11 | 2346 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 18.41 | LB/HR | | 0 | | | 6.4 | G/KW-HR | |
| *LA-0405 | SHINTECH LOUISIANA, LLC - PLAQUEMINE ETHYLENE PLANT 2 | LA | 12/16/2024  ACT | Emergency Generator and Fire Water Pump Engines | 17.11 | 535 | hp | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII. | 6.4 | G/KW-H | | 4 | G/KW-H | | 0 | | |
| *LA-0406 | MCA GEIMAR SITE | LA | 07/24/2024  ACT | Diesel Emergency Generator (EQT0012) | 17.11 | 1140 | hp | Nitrogen Oxides (NOx) | Proper equipment design and good combustion practices. Use ultra-low sulfur diesel as fuel. Low emission combustion. Compliance with 40 CFR 60 Subpart IIII. | 4.8 | G/HP-HR | NMEHC + NOX | 0 | | | 0 | | |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 1 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 2 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |

# Internal Combustion Engines Fuel Oil (17.110)

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| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 3 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 4 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 5 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 6 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |

# Internal Combustion Engines Fuel Oil (17.110)

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| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 7 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 8 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 9 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 10 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |

# Internal Combustion Engines Fuel Oil (17.110)

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| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 11 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 12 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 13 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 14 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |

# Internal Combustion Engines Fuel Oil (17.110)

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| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 15 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 16 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 17 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 18 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |

# Internal Combustion Engines Fuel Oil (17.110)

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| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 19 | 17.11 | 1000 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 20 | 17.11 | 1000 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 21 | 17.11 | 2500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 6.4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Emergency Generator 22 (ADMIN) | 17.11 | 500 | Kilowatts | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII. | 0 | | | 0 | | | 4 | G/KW-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |

# Internal Combustion Engines Fuel Oil (17.110)

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| MA-0043 | MIT CENTRAL UTILITY PLANT | MA | 06/21/2017  ACT | Cold Start Engine | 17.11 | 19.04 | MMBTU/HR | Nitrogen Oxides (NOx) | | 35.09 | LB/HR | 1 HR BLOCK AVG | 5.3 | TONS/C12 MP | CONSECUTIVE TWELVE MONTH PERIOD | 0 | | |
| MI-0418 | WARREN TECHNICAL CENTER | MI | 01/14/2015  ACT | FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines) | 17.11 | 3490 | KW | Nitrogen Oxides (NOx) | No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation. | 8 | G/KW-H | TEST PROTOCOL (LIMIT IS PER ENGINE) | 0 | | | 0 | | |
| MI-0418 | WARREN TECHNICAL CENTER | MI | 01/14/2015  ACT | Four (4) emergency engines in FG-BACKUPGENS | 17.11 | 2710 | KW | Nitrogen Oxides (NOx) | No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation. | 7.13 | G/KW-H | TEST PROTOCOL (LIMIT IS PER ENGINE) | 0 | | | 0 | | |
| MI-0421 | GRAYLING PARTICLEBOARD | MI | 08/26/2016  ACT | Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE) | 17.11 | 500 | H/YR | Nitrogen Oxides (NOx) | Certified engines, limited operating hours. | 22.6 | LB/H | TEST PROTOCOL WILL SPECIFY AVG TIME | 0 | | | 0 | | |
| MI-0421 | GRAYLING PARTICLEBOARD | MI | 08/26/2016  ACT | Dieself fire pump engine (EUFIREPUMP in FGRICE) | 17.11 | 500 | H/YR | Nitrogen Oxides (NOx) | Certified engines, limited operating hours. | 3.53 | LB/H | TEST PROTOCOL WILL SPECIFY AVG TIME | 0 | | | 0 | | |
| MI-0423 | INDECK NILES, LLC | MI | 01/04/2017  ACT | EUEMENGINE (Diesel fuel emergency engine) | 17.11 | 22.68 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS IIII requirements. | 6.4 | G/KW-H | TEST PROTOCOL WILL SPECIFY AVG TIME | 0 | | | 0 | | |
| MI-0425 | GRAYLING PARTICLEBOARD | MI | 05/09/2017  ACT | EUEMRGRICE1 in FGRICE (Emergency diesel generator engine) | 17.11 | 500 | H/YR | Nitrogen Oxides (NOx) | Certified engines, limited operating hours. | 21.2 | LB/H | TEST PROTOCOL SHALL SPECIFY | 0 | | | 0 | | |
| MI-0425 | GRAYLING PARTICLEBOARD | MI | 05/09/2017  ACT | EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine) | 17.11 | 500 | H/YR | Nitrogen Oxides (NOx) | Certified engines, limited operating hours | 4.4 | LB/H | TEST PROTOCOL SHALL SPECIFY | 0 | | | 0 | | |
| MI-0425 | GRAYLING PARTICLEBOARD | MI | 05/09/2017  ACT | EUFIREPUMP in FGRICE (Diesel fire pump engine) | 17.11 | 500 | H/YR | Nitrogen Oxides (NOx) | Certified engines. Limited operating hours. | 3.53 | LB/H | TEST PROTOCOL SHALL SPECIFY | 0 | | | 0 | | |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | MI | 06/29/2018  ACT | EUEMENGINE (North Plant): Emergency Engine | 17.11 | 1341 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 6.4 | G/KW-H | HOURLY | 0 | | | 0 | | |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | MI | 06/29/2018  ACT | EUEMENGINE (South Plant): Emergency Engine | 17.11 | 1341 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS IIII requirements. | 6.4 | G/KW-H | HOURLY | 0 | | | 0 | | |

# Internal Combustion Engines Fuel Oil (17.110)

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| MI-0434 | FLAT ROCK ASSEMBLY PLANT | MI | 03/22/2018  ACT | EUENGINE01 through EUENGINE08 | 17.11 | 3633 | BHP | Nitrogen Oxides (NOx) | Good combustion practices. | 6.4 | G/KW-H | HOURLY; EACH ENGINE; NMHC+NOX | 42.6 | LB/H | HOURLY; EACH ENGINE; NOX | 0 | | |
| MI-0435 | BELLE RIVER COMBINED CYCLE POWER PLANT | MI | 07/16/2018  ACT | EUEMENGINE: Emergency engine | 17.11 | 2 | MW | Nitrogen Oxides (NOx) | State of the art combustion design. | 6.4 | G/KW-H | HOURLY | 0 | | | 0 | | |
| MI-0441 | LBWL--ERICKSON STATION | MI | 12/21/2018  ACT | EUEMGD1--A 1500 HP diesel fueled emergency engine | 17.11 | 1500 | HP | Nitrogen Oxides (NOx) | Good combustion practices and will be NSPS compliant. | 6.4 | G/KW-H | HOURLY | 0 | | | 0 | | |
| MI-0441 | LBWL--ERICKSON STATION | MI | 12/21/2018  ACT | EUEMGD2--A 6000 HP diesel fuel fired emergency engine | 17.11 | 6000 | HP | Nitrogen Oxides (NOx) | Good combustion practices and will be NSPS compliant. | 6.4 | G/KW-H | HOURLY | 0 | | | 0 | | |
| MI-0442 | THOMAS TOWNSHIP ENERGY, LLC | MI | 08/21/2019  ACT | FGEMENGINE | 17.11 | 1100 | KW | Nitrogen Oxides (NOx) | | 5.3 | G/HP-H | HOURLY; EACH ENGINE | 0 | | | 0 | | |
| *MI-0445 | INDECK NILES, LLC | MI | 11/26/2019  ACT | EUEMENGINE (diesel fuel emergency engine) | 17.11 | 22.68 | MMBTU/H | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements | 6.4 | G/KW-H | HOURLY | 0 | | | 0 | | |
| MI-0448 | GRAYLING PARTICLEBOARD | MI | 12/18/2020  ACT | Emergency diesel generator engine (EUEMRGRICE1 in FGRICE) | 17.11 | 500 | h/yr | Nitrogen Oxides (NOx) | Certified engines, limited operating hours | 21.2 | LB/H | HOURLY | 0 | | | 0 | | |
| MI-0448 | GRAYLING PARTICLEBOARD | MI | 12/18/2020  ACT | Emergency diesel generator engine (EUEMRGRICE2 in FGRICE) | 17.11 | 500 | h/yr | Nitrogen Oxides (NOx) | Certified Engines, Limited Operating Hours | 4.4 | LB/H | HOURLY | 0 | | | 0 | | |
| MI-0448 | GRAYLING PARTICLEBOARD | MI | 12/18/2020  ACT | Diesel fire pump engine (EUFIREPUMP in FGRICE) | 17.11 | 500 | h/yr | Nitrogen Oxides (NOx) | Certified Engines, Limited Operating Hours | 3.53 | LB/H | HOURLY | 0 | | | 0 | | |
| MI-0451 | MEC NORTH, LLC | MI | 06/23/2022  ACT | EUEMENGINE (North Plant): Emergency engine | 17.11 | 1341 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 6.4 | G/KW-H | HOURLY | 0 | | | 0 | | |
| MI-0452 | MEC SOUTH, LLC | MI | 06/23/2022  ACT | EUEMENGINE (South Plant): Emergency engine | 17.11 | 1341 | HP | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements | 6.4 | G/KW-H | HOURLY | 0 | | | 0 | | |
| MI-0454 | LBWL-ERICKSON STATION | MI | 12/20/2022  ACT | EUEMGD | 17.11 | 4474.2 | KW | Nitrogen Oxides (NOx) | Good combustion practices and will be NSPS compliant. | 6.4 | G/KW-H | HOURLY | 0 | | | 0 | | |
| MI-0459 | LANSING BOARD OF WATER AND LIGHT--DELTA ENERGY PARK | MI | 06/27/2024  ACT | EUEMGEN | 17.11 | 762 | bhp | Nitrogen Oxides (NOx) | | 6.4 | G/KW-H | HOURLY | 0 | | | 0 | | |

# Internal Combustion Engines Fuel Oil (17.110)

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| MN-0095 | BLUE LAKE | MN | 08/07/2024  ACT | Emergency Generator 2 (EQUI 26) | 17.11 | 1049 | horsepower | Nitrogen Oxides (NOx) | Emergency classification, hourly restriction, and NSPS compliance | 4.8 | G/HP-HR | 24 HOUR ROLLING AVERAGE | 11.03 | LB/HR | 3 HOUR AVERAGE | 0 | | |
| MN-0095 | BLUE LAKE | MN | 08/07/2024  ACT | Emergency Generator 3 (EQUI 27) | 17.11 | 1049 | horsepower | Nitrogen Oxides (NOx) | Emergency classification, hourly restriction, and NSPS compliance | 4.8 | G/HP-HR | 24 HOUR ROLLING AVERAGE | 11.03 | LB/HR | 3 HOUR AVERAGE | 0 | | |
| MN-0095 | BLUE LAKE | MN | 08/07/2024  ACT | Emergency Generator 4 (EQUI 28) | 17.11 | 1049 | horsepower | Nitrogen Oxides (NOx) | Emergency classification, hourly restriction, and NSPS compliance | 4.8 | G/HP-HR | 24 HOUR ROLLING AVERAGE | 11.03 | LB/HR | 3 HOUR AVERAGE | 0 | | |
| MN-0095 | BLUE LAKE | MN | 08/07/2024  ACT | Emergency Generator 5 (EQUI 43) | 17.11 | 772 | horsepower | Nitrogen Oxides (NOx) | Emergency classification, hourly restriction, and NSPS compliance | 4.8 | G/HP-HR | 24 HOUR ROLLING AVERAGE | 8.12 | LB/HR | 3 HOUR AVERAGE | 0 | | |
| MN-0095 | BLUE LAKE | MN | 08/07/2024  ACT | Emergency Generator 6 (EQUI 43) | 17.11 | 772 | horsepower | Nitrogen Oxides (NOx) | Emergency classification, hourly restriction, and NSPS compliance | 4.8 | G/HP-HR | 24 HOUR ROLLING AVERAGE | 8.12 | LB/HR | 3 HOUR AVERAGE | 0 | | |
| NE-0064 | NORFOLK CRUSH, LLC | NE | 11/21/2022  ACT | Emergency Fire Water Pump Engine 1 | 17.11 | 510 | hp | Nitrogen Oxides (NOx) | | 2.38 | G/HP-HR | 3-HOUR OR TEST METHOD AVERAGE | 0 | | | 0 | | |
| NJ-0084 | PSEG FOSSIL LLC SEWAREN GENERATING STATION | NJ | 03/10/2016  ACT | Diesel Fired Emergency Generator | 17.11 | 44 | H/YR | Nitrogen Oxides (NOx) | use of ultra low sulfur diesel a clean burning fuel. | 42.3 | LB/H | | 0 | | | 0 | | |
| NY-0103 | CRICKET VALLEY ENERGY CENTER | NY | 02/03/2016  ACT | Black start generator | 17.11 | 3000 | KW | Nitrogen Oxides (NOx) | Generator equipped with selective catalytic reduction. Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations. | 2.11 | G/BHP-H | 1 H | 0 | | | 0 | | |
| OH-0366 | CLEAN ENERGY FUTURE - LORDSTOWN, LLC | OH | 08/25/2015  ACT | Emergency generator (P003) | 17.11 | 2346 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 21.6 | LB/H | | 5.41 | T/YR | PER ROLLING 12 MONTH PERIOD | 0 | | SEE NOTES |
| OH-0367 | SOUTH FIELD ENERGY LLC | OH | 09/23/2016  ACT | Emergency generator (P003) | 17.11 | 2947 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 27.18 | LB/H | | 6.8 | T/YR | PER ROLLING 12 MONTH PERIOD | 0 | | SEE NOTES |
| OH-0368 | PALLAS NITROGEN LLC | OH | 04/19/2017  ACT | Emergency Generator (P009) | 17.11 | 5000 | HP | Nitrogen Oxides (NOx) | good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII | 5.5 | LB/H | | 0.3 | T/YR | PER ROLLING 12 MONTH PERIOD | 0 | | SEE NOTES |
| OH-0370 | TRUMBULL ENERGY CENTER | OH | 09/07/2017  ACT | Emergency generator (P003) | 17.11 | 1529 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 16.07 | LB/H | | 4.02 | T/YR | PER ROLLING 12 MONTH PERIOD | 0 | | SEE NOTES |
| OH-0372 | OREGON ENERGY CENTER | OH | 09/27/2017  ACT | Emergency generator (P003) | 17.11 | 1529 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 16.1 | LB/H | | 4.02 | T/YR | PER ROLLING 12 MONTH PERIOD | 4.8 | G/B-HP-H | SEE NOTES |

# Internal Combustion Engines Fuel Oil (17.110)

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| OH-0374 | GUERNSEY POWER STATION LLC | OH | 10/23/2017  ACT | Emergency Generators (2 identical, P004 and P005) | 17.11 | 2206 | HP | Nitrogen Oxides (NOx) | Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the manufacturerâ€™s operating manual. | 23.21 | LB/H | NMHC+NOX. SEE NOTES. | 1.16 | T/YR | NMHC+NOX. SEE NOTES. | 4.77 | G/BHP-H | NMHC+NOX. SEE NOTES. |
| OH-0375 | LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER | OH | 11/07/2017  ACT | Emergency Diesel Generator Engine (P001) | 17.11 | 2206 | HP | Nitrogen Oxides (NOx) | Good combustion design | 24.71 | LB/H | NMHC+NOX. SEE NOTES. | 1.24 | T/YR | NMHC+NOX. SEE NOTES. | 4.8 | G/BHP-H | NMHC+NOX. SEE NOTES. |
| OH-0375 | LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER | OH | 11/07/2017  ACT | Emergency Diesel Fire Pump Engine (P002) | 17.11 | 700 | HP | Nitrogen Oxides (NOx) | Good combustion design | 4.97 | LB/H | NMHC+NOX. SEE NOTES. | 0.25 | T/YR | NMHC+NOX. SEE NOTES. | 3 | G/BHP-H | NMHC+NOX. SEE NOTES. |
| OH-0376 | IRONUNITS LLC - TOLEDO HBI | OH | 02/09/2018  ACT | Emergency diesel-fired generator (P007) | 17.11 | 2682 | HP | Nitrogen Oxides (NOx) | Comply with NSPS 40 CFR 60 Subpart IIII | 28.2 | LB/H | | 7.05 | T/YR | PER ROLLING 12 MONTH PERIOD | 4.8 | G/BHP-H | SEE NOTES |
| OH-0377 | HARRISON POWER | OH | 04/19/2018  ACT | Emergency Diesel Generator (P003) | 17.11 | 1860 | HP | Nitrogen Oxides (NOx) | Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII | 19.68 | LB/H | NMHC+NOX. SEE NOTES. | 0.98 | T/YR | NMHC+NOX. SEE NOTES. | 4.8 | G/BHP-H | NMHC+NOX. SEE NOTES. |
| OH-0378 | PTTGCA PETROCHEMICAL COMPLEX | OH | 12/21/2018  ACT | Emergency Diesel-fired Generator Engine (P007) | 17.11 | 3353 | HP | Nitrogen Oxides (NOx) | certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual | 37.41 | LB/H | SEE NOTES. | 1.87 | T/YR | PER ROLLING 12 MONTH PERIOD. SEE NOTES. | 4.8 | G/BHP-H | SEE NOTES |
| OH-0378 | PTTGCA PETROCHEMICAL COMPLEX | OH | 12/21/2018  ACT | 1,000 kW Emergency Generators (P008 - P010) | 17.11 | 1341 | HP | Nitrogen Oxides (NOx) | certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual | 14.96 | LB/H | SEE NOTES. | 0.75 | T/YR | PER ROLLING 12 MONTH PERIOD. SEE NOTES. | 4.8 | G/BHP-H | SEE NOTES |
| OH-0379 | PETMIN USA INCORPORATED | OH | 02/06/2019  ACT | Emergency Generators (P005 and P006) | 17.11 | 3131 | HP | Nitrogen Oxides (NOx) | Tier IV engine Tier IV NSPS standards certified by engine manufacturer. | 3.45 | LB/H | | 0.17 | T/YR | | 0.5 | G/BHP-H | |
| OH-0383 | PETMIN USA INCORPORATED | OH | 07/17/2020  ACT | Diesel-fired emergency fire pumps (2) (P009 and P010) | 17.11 | 3131 | HP | Nitrogen Oxides (NOx) | Tier IV NSPS standards certified by engine manufacturer. | 0 | | | 0 | | | 3 | G/BHP-H | |

# Internal Combustion Engines Fuel Oil (17.110)

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| OH-0387 | INTEL OHIO SITE | OH | 09/20/2022  ACT | 5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046 | 17.11 | 5051 | HP | Nitrogen Oxides (NOx) | Certified to meet Tier 2 standards and good combustion practices | 6.4 | G/KW-H | 6.4 GRAMS NOX + NMHC/KW-HR | 65.7 | LB/H | EACH GENERATOR, SEE NOTES | 0 | | |
| PA-0309 | LACKAWANNA ENERGY CTR/JESSUP | PA | 12/23/2015  ACT | 2000 kW Emergency Generator | 17.11 | 0 | | Nitrogen Oxides (NOx) | | 5.45 | GM/HP-HR | | 0.81 | TONS | 12-MONTH ROLLING BASIS | 0 | | |
| PA-0310 | CPV FAIRVIEW ENERGY CENTER | PA | 09/02/2016  ACT | Emergency Generator Engines | 17.11 | 0 | | Nitrogen Oxides (NOx) | | 4.8 | G/BHP-HR | | 0 | | | 0 | | |
| PA-0311 | MOXIE FREEDOM GENERATION PLANT | PA | 09/01/2015  ACT | Emergency Generator | 17.11 | 0 | | Nitrogen Oxides (NOx) | | 4.93 | G/HP-HR | | 0.4 | TPY | 12-MONTH ROLLING BASIS | 0 | | |
| PA-0311 | MOXIE FREEDOM GENERATION PLANT | PA | 09/01/2015  ACT | Fire Pump Engine | 17.11 | 0 | | Nitrogen Oxides (NOx) | | 3 | G/HP-HR | | 0.08 | TPY | 12-MONTH ROLLING BASIS | 0 | | |
| TX-0728 | PEONY CHEMICAL MANUFACTURING FACILITY | TX | 04/01/2015  ACT | Emergency Diesel Generator | 17.11 | 1500 | hp | Nitrogen Oxides (NOx) | Minimized hours of operations Tier II engine | 0.0218 | G/HP HR | | 0.35 | TPY | | 0 | | |
| TX-0876 | PORT ARTHUR ETHANE CRACKER UNIT | TX | 02/06/2020  ACT | Emergency generator | 17.11 | 0 | | Nitrogen Oxides (NOx) | Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation | 0 | | | 0 | | | 0 | | |
| TX-0876 | PORT ARTHUR ETHANE CRACKER UNIT | TX | 02/06/2020  ACT | Emergency firewater pumps | 17.11 | 0 | | Nitrogen Oxides (NOx) | Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation | 0 | | | 0 | | | 0 | | |
| TX-0879 | MOTIVA PORT ARTHUR TERMINAL | TX | 02/19/2020  ACT | Emergency Firewater Engine | 17.11 | 0 | | Nitrogen Oxides (NOx) | Meeting the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight). Limited to 100 hrs/yr of non-emergency operation. Have a non-resettable runtime meter. | 0 | | | 0 | | | 0 | | |
| TX-0888 | ORANGE POLYETHYLENE PLANT | TX | 04/23/2020  ACT | EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES | 17.11 | 0 | | Nitrogen Oxides (NOx) | well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use. | 0 | | | 0 | | | 0 | | |

# Internal Combustion Engines Fuel Oil (17.110)

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| TX-0904 | MOTIVA POLYETHYLENE MANUFACTURING COMPLEX | TX | 09/09/2020  ACT | EMERGENCY GENERATOR | 17.11 | 0 | | Nitrogen Oxides (NOx) | 100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101 | 0 | | | 0 | | | 0 | | |
| TX-0905 | DIAMOND GREEN DIESEL PORT ARTHUR FACILITY | TX | 09/16/2020  ACT | EMERGENCY GENERATOR | 17.11 | 0 | | Nitrogen Oxides (NOx) | limited to 100 hours per year of non-emergency operation | 0 | | | 0 | | | 0 | | |
| TX-0933 | NACERO PENWELL FACILITY | TX | 11/17/2021  ACT | Emergency Generators | 17.11 | 0 | | Nitrogen Oxides (NOx) | limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards | 0 | | | 0 | | | 0 | | |
| TX-0955 | INEOS OLIGOMERS CHOCOLATE BAYOU | TX | 03/14/2023  ACT | Engine Emergency Generator | 17.11 | 0 | | Nitrogen Oxides (NOx) | TIER III ENGINE, OPERATIONS LIMITED TO 100 HRS/YR | 3.9 | G/HP HR | | 0 | | | 0 | | |
| *TX-0976 | CORPUS CHRISTI LIQUEFACTION STAGE 3 | TX | 05/30/2025  ACT | EMERGENCY GENERATOR | 17.11 | 0 | | Nitrogen Oxides (NOx) | EPA Tier 2, limited to 100 hours per year of non-emergency operation. GHGs from the emergency engines will be limited through engine design and certification in accordance with standards, limited operational hours, and proper operation and maintenance | 0 | | | 0 | | | 0 | | |
| VA-0325 | GREENSVILLE POWER STATION | VA | 06/17/2016  ACT | DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1) | 17.11 | 0 | | Nitrogen Oxides (NOx) | Good Combustion Practices/Maintenance | 6.4 | G/KW | PER HR | 10.6 | T/YR | 12 MO ROLLING TOTAL | 0 | | |
| VA-0328 | C4GT, LLC | VA | 04/26/2018  ACT | Emergency Diesel GEN | 17.11 | 500 | H/YR | Nitrogen Oxides (NOx) | good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. | 4.8 | G/HP H | | 9.6 | T/YR | 12 MO ROLLING AV | 0 | | |
| VA-0332 | CHICKAHOMINY POWER LLC | VA | 06/24/2019  ACT | Emergency Diesel Generator - 300 kW | 17.11 | 500 | H/YR | Nitrogen Oxides (NOx) | good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. | 4.8 | G/HP-H | | 11.7 | T/YR | 12 MO ROLLING AVG | 0 | | |
| WI-0284 | SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT | WI | 04/24/2018  ACT | Diesel-Fired Emergency Generators | 17.11 | 0 | | Nitrogen Oxides (NOx) | The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices | 5.36 | G/KWH | | 0 | | | 0 | | |

# Internal Combustion Engines Fuel Oil (17.110)

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| WI-0286 | SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT | WI | 04/24/2018  ACT | P42 -Diesel Fired Emergency Generator | 17.11 | 0 | | Nitrogen Oxides (NOx) | Good Combustion Practices, The Use of an Engine Turbocharger and Aftercooler. | 5.36 | G/KWH | | 0 | | | 0 | | |
| WI-0300 | NEMADJI TRAIL ENERGY CENTER | WI | 09/01/2020  ACT | Emergency Diesel Generator (P07) | 17.11 | 1490 | HP | Nitrogen Oxides (NOx) | Operation limited to 500 hours/year and operate and maintain according to the manufacturerâ€™s recommendations. | 4.8 | G/HP-H | | 0 | | | 0 | | |
| *WI-0326 | NEMADJI TRAIL ENERGY CENTER | WI | 09/19/2023  ACT | Emergency Generator | 17.11 | 1490 | HP | Nitrogen Oxides (NOx) | Good combustion practices and combusting clean fuels | 4.8 | G/HP-HR | | 500 | HOURS | PER EACH 12 ROLLING CALENDAR MONTHS | 0 | | |
| WV-0027 | INWOOD | WV | 09/15/2017  ACT | Emergency Generator - ESDG14 | 17.11 | 900 | bhp | Nitrogen Oxides (NOx) | Engine Design | 4.77 | G/HP-HR | | 0 | | | 0 | | |
| *WV-0033 | MAIDSVILLE | WV | 01/05/2022  ACT | Emergency Generator | 17.11 | 2100 | hp | Nitrogen Oxides (NOx) | Combustion Control (retarded timing and/or lean burn) | 24.6 | LB/HR | | 6.4 | G/BKW | NMHC+NOX | 6.4 | G/BKW | NMHC+NOX |
| *WV-0033 | MAIDSVILLE | WV | 01/05/2022  ACT | Fire Water Pump | 17.11 | 240 | bhp | Nitrogen Oxides (NOx) | Combustion control (retarded timing and/or lean burn) | 1.59 | LB/HR | | 4 | G/BKW | | 4 | G/BKW | NMHC+NOX |

# Small Internal Combustion Engines Fuel Oil (17.210)

| RBLCID | FACILITY NAME | FACILITY STATE | PERMIT ISSUANCE DATE | PROCESS NAME | PROCCESS TYPE | THROUGHPUT | THROUGHPUT UNIT | POLLUTANT | CONTROL METHOD DESCRIPTION | EMISSION LIMIT 1 | EMISSION LIMIT 1 UNIT | EMISSION LIMIT 1 AVG TIME CONDITION | EMISSION LIMIT 2 | EMISSION LIMIT 2 UNIT | EMISSION LIMIT 2 AVGERAGE TIME CONDITION | STANDARAD EMISSION LIMIT | STANDARD EMISSION LIMIT UNIT | STANDARD LIMIT AVERAGE TIME CONDITION |
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| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AK | 01/23/2015  ACT | Airstrip Generator Engine | 17.21 | 490 | hp | Nitrogen Oxides (NOx) | | 4.8 | GRAMS/HP-H | | 0 | | | 0 | | |
| AK-0082 | POINT THOMSON PRODUCTION FACILITY | AK | 01/23/2015  ACT | Agitator Generator Engine | 17.21 | 98 | hp | Nitrogen Oxides (NOx) | | 5.6 | GRAMS/HP-H | | 0 | | | 0 | | |
| AK-0084 | DONLIN GOLD PROJECT | AK | 06/30/2017  ACT | Fire Pump Diesel Internal Combustion Engines | 17.21 | 252 | hp | Nitrogen Oxides (NOx) | Good Combustion Practices | 3.7 | G/KW-HR | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AK-0085 | GAS TREATMENT PLANT | AK | 08/13/2020  ACT | Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators | 17.21 | 19.4 | gph | Nitrogen Oxides (NOx) | Good combustion practices, limit operation to 500 hours per year per engine | 3.6 | G/HP-HR | 3-HOUR AVERAGE | 0 | | | 0 | | |
| AK-0088 | LIQUEFACTION PLANT | AK | 07/07/2022  ACT | Auxiliary Air Compressor Engine | 17.21 | 14.6 | Gal/hr | Nitrogen Oxides (NOx) | Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII | 0.45 | G/HP-HR | | 500 | HRS/YR | | 0 | | |
| *AL-0337 | KRONOSPAN, LLC | AL | 09/21/2022  ACT | Fire Pump #2 (X074) | 17.21 | 0 | | Nitrogen Oxides (NOx) | Catalyst | 7.8 | G/HP-HR | | 7.12 | LB/HR | | 0 | | |
| *AL-0357 | THE WESTERVELT COMPANY-THOMASVILLE MILL | AL | 11/22/2019  ACT | Emergency Generator (ENG1) | 17.21 | 0 | | Nitrogen Oxides (NOx) | | 4 | G/KWM-HR | | 3 | G/HP-HR | | 0 | | |
| *AL-0357 | THE WESTERVELT COMPANY-THOMASVILLE MILL | AL | 11/22/2019  ACT | Emergency Generator (ENG2) | 17.21 | 0 | | Nitrogen Oxides (NOx) | | 4 | G/KWM-HR | | 3 | G/HP-HR | | 0 | | |
| *AL-0357 | THE WESTERVELT COMPANY-THOMASVILLE MILL | AL | 11/22/2019  ACT | Emergency Generator (ENG5) | 17.21 | 0 | | Nitrogen Oxides (NOx) | | 7.5 | G/KWM-HR | | 5.6 | G/HP-HR | | 0 | | |
| AR-0180 | HYBAR LLC | AR | 04/28/2023  ACT | Emergency Water Pumps | 17.21 | 0 | | Nitrogen Oxides (NOx) | Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII | 14.06 | G/BHP-HR | | 0 | | | 0 | | |
| FL-0367 | SHADY HILLS COMBINED CYCLE FACILITY | FL | 07/27/2018  ACT | Emergency Fire Pump Engine (347 HP) | 17.21 | 8700 | gal/year | Nitrogen Oxides (NOx) | Operate and maintain the engine according to the manufacturer's written instructions | 4 | G/KW-HR | | 0 | | | 0 | | |
| FL-0371 | SHADY HILLS COMBINED CYCLE FACILITY | FL | 06/07/2021  ACT | Emergency Fire Pump Engine (347 HP) | 17.21 | 2.46 | MMBtu/hour | Nitrogen Oxides (NOx) | | 4 | G/KW-HOUR | NMHC + NOX STANDARD | 0 | | | 0 | | |

# Small Internal Combustion Engines Fuel Oil (17.210)

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IL-0129 | CPV THREE RIVERS ENERGY CENTER | IL | 07/30/2018  ACT | Firewater Pump Engine | 17.21 | 0 | | Nitrogen Oxides (NOx) | | 0 | | | 0 | | | 0 | | | |
| IL-0130 | JACKSON ENERGY CENTER | IL | 12/31/2018  ACT | Firewater Pump Engine | 17.21 | 420 | horsepower | Nitrogen Oxides (NOx) | | 4 | G/KW-HR | | 0 | | | 0 | | | |
| IL-0133 | LINCOLN LAND ENERGY CENTER | IL | 07/29/2022  ACT | Fire Water Pump Engine | 17.21 | 320 | horsepower | Nitrogen Oxides (NOx) | | 4 | GRAMS | KILOWATT-HOUR | 0 | | | 0 | | | |
| IL-0134 | CRONUS CHEMICALS | IL | 12/21/2023  ACT | Firewater Pump Engine | 17.21 | 369 | hp | Nitrogen Oxides (NOx) | | 4 | G/KW-HR | 3-HR AVG | 100 | HR/YR | OPERATIONAL LIMIT | 0 | | | |
| IN-0359 | NUCOR STEEL | IN | 03/30/2023  ACT | Emergency Generator (CC-GEN2) | 17.21 | 500 | Horsepower | Nitrogen Oxides (NOx) | certified engine | 3 | G/HP-HR | | 0 | | | 0 | | | |
| IN-0384 | SYCAMORE RIVERSIDE ENERGY LLC | IN | 03/31/2025  ACT | emergency fire water pump | 17.21 | 282 | bhp | Nitrogen Oxides (NOx) | Good combustion practices, low sulfur fuel | 2.85 | G | HP-HR | 1.77 | LB | HR | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 11-01 - Melt Shop Emergency Generator | 17.21 | 260 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 2.98 | G/HP-HR | NMHC + NOX | 0 | | | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 11-02 - Reheat Furnace Emergency Generator | 17.21 | 190 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 2.98 | G/HP-HR | NMHC + NOX | 0 | | | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 11-03 - Rolling Mill Emergency Generator | 17.21 | 440 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 2.98 | G/HP-HR | NMHC + NOX | 0 | | | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 11-04 - IT Emergency Generator | 17.21 | 190 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 2.98 | G/HP-HR | NMHC + NOX | 0 | | | 0 | | | |
| KY-0110 | NUCOR STEEL BRANDENBURG | KY | 07/23/2020  ACT | EP 11-05 - Radio Tower Emergency Generator | 17.21 | 61 | HP | Nitrogen Oxides (NOx) | This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan. | 3.5 | G/HP-HR | NMHC + NOX | 0 | | | 0 | | | |
| KY-0115 | NUCOR STEEL GALLATIN, LLC | KY | 04/19/2021  ACT | Cold Mill Complex Emergency Generator (EP 09-05) | 17.21 | 350 | HP | Nitrogen Oxides (NOx) | The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan | 0 | | | 0 | | | 3 | G/B-HP-H | NMHC+NOX | |
| LA-0309 | BENTELER STEEL TUBE FACILITY | LA | 06/04/2015  ACT | Firewater Pump Engines | 17.21 | 288 | hp (each) | Nitrogen Oxides (NOx) | Complying with 40 CFR 60 Subpart IIII | 3 | G/BHP-HR | | 0 | | | 0 | | | |
| LA-0313 | ST. CHARLES POWER STATION | LA | 08/31/2016  ACT | SCPS Emergency Diesel Firewater Pump 1 | 17.21 | 282 | HP | Nitrogen Oxides (NOx) | Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel). | 1.87 | LB/H | HOURLY MAXIMUM | 0.47 | T/YR | ANNUAL MAXIMUM | 3 | G/BHP-H | | |

# Small Internal Combustion Engines Fuel Oil (17.210)

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LA-0323 | MONSANTO LULING PLANT | LA | 01/09/2017  ACT | Standby Generator No. 9 Engine | 17.21 | 400 | hp | Nitrogen Oxides (NOx) | Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 0 | | |
| LA-0379 | SHINTECH PLAQUEMINES PLANT 1 | LA | 05/04/2021  ACT | PVC Emergency Combustion Equipment A | 17.21 | 450 | hp | Nitrogen Oxides (NOx) | Good combustion practices/gaseous fuel burning. | 6.9 | G/HP-HR | | 0 | | | 0 | | |
| LA-0379 | SHINTECH PLAQUEMINES PLANT 1 | LA | 05/04/2021  ACT | VCM Unit Emergency Generator B | 17.21 | 439 | hp | Nitrogen Oxides (NOx) | Good combustion practices/gaseous fuel burning. | 6.9 | G/HP-HR | | 0 | | | 0 | | |
| LA-0379 | SHINTECH PLAQUEMINES PLANT 1 | LA | 05/04/2021  ACT | VCM Unit Emergency Cooling Water Pumps | 17.21 | 180 | hp | Nitrogen Oxides (NOx) | Good combustion practices/gaseous fuel burning. | 2.98 | G/KW-HR | | 0 | | | 0 | | |
| LA-0379 | SHINTECH PLAQUEMINES PLANT 1 | LA | 05/04/2021  ACT | PVC Emergency Combustion Equipment B | 17.21 | 375 | hp | Nitrogen Oxides (NOx) | Good combustion practices/gaseous fuel burning. | 4.41 | LB/MM BTU | | 0 | | | 0 | | |
| LA-0379 | SHINTECH PLAQUEMINES PLANT 1 | LA | 05/04/2021  ACT | PVC Emergency Combustion Equipment 2A and 2B | 17.21 | 300 | hp | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII. | 0.4 | G/KW-HR | | 0 | | | 0 | | |
| LA-0391 | MAGNOLIA POWER GENERATING STATION UNIT 1 | LA | 06/03/2022  ACT | Emergency Diesel Fired Water Pump Engine | 17.21 | 355 | hp | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra-low sulfur diesel fuel. | 3 | G/HP-HR | | 0 | | | 0 | | |
| *LA-0394 | GEISMAR PLANT | LA | 12/12/2023  ACT | 05-22 - AO-5 BDL Area PAD Sump Pump Driver | 17.21 | 200 | horsepower | Nitrogen Oxides (NOx) | Use of good combustion practices and compliance with NSPS Subpart IIII | 1.26 | LB/HR | HOURLY MAXIMUM | 0 | | | 3.88 | G/KW-HR | |
| *LA-0394 | GEISMAR PLANT | LA | 12/12/2023  ACT | 52-22 - PAO Area PAD Sump Pump Driver | 17.21 | 200 | horsepower | Nitrogen Oxides (NOx) | Use of good combustion practices, compliance with NSPS Subpart IIII | 1.26 | LB/HR | HOURLY MAXIMUM | 0 | | | 3.88 | G/KW-HR | |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | LA | 12/20/2023  ACT | FWP-01 - Firewater Pump Engine No. 1 | 17.21 | 422 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 3.96 | LB/HR | | 0 | | | 0 | | |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | LA | 12/20/2023  ACT | FWP-02 - Firewater Pump Engine No. 2 | 17.21 | 422 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 3.96 | LB/HR | | 0 | | | 0 | | |
| *LA-0401 | KOCH METHANOL (KME) FACILITY | LA | 12/20/2023  ACT | FWP-03 - Firewater Pump Engine No. 3 | 17.21 | 237 | horsepower | Nitrogen Oxides (NOx) | Compliance with the requirements of 40 CFR 60 Subpart IIII | 1.49 | LB/HR | | 0 | | | 0 | | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4U-11 - Substation Emergency Generator | 17.21 | 70 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 0.4 | LB/HR | | 0.02 | TONS/YEAR | | 4.7 | G/KW-HR | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4M-11C - VCM Emergency Pump A | 17.21 | 200 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 0.98 | LB/HR | | 0 | | | 4 | G/KW-HR | |
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4M-11D - VCM Emergency Pump B | 17.21 | 200 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 0.98 | LB/HR | | 0 | | | 4 | G/KW-HR | |

# Small Internal Combustion Engines Fuel Oil (17.210)

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *LA-0403 | SHINTECH PLAQUEMINE PLANT 4 | LA | 12/16/2024  ACT | 4M-11E - VCM Emergency Pump C | 17.21 | 200 | horsepower | Nitrogen Oxides (NOx) | Compliance with 40 CFR 60 Subpart IIII | 0.98 | LB/HR | | 0 | | | 4 | G/KW-HR | |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Fire Water Pump 1 (LNG Terminal) | 17.21 | 488 | Brake Horsepower | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 2.57 | G/HP-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Fire Water Pump 2 (Power Plant) | 17.21 | 488 | Brake Horsepower | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 2.57 | G/HP-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Fire Water Pump 3 (Jetty) | 17.21 | 488 | Brake Horsepower | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 2.57 | G/HP-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |

# Small Internal Combustion Engines Fuel Oil (17.210)

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *LA-0414 | CP2 LNG TERMINAL | LA | 07/22/2025  ACT | Fire Water Pump 4 (Jetty) | 17.21 | 488 | Brake Horsepower | Nitrogen Oxides (NOx) | Proper engine design and good combustion practices, combust only clean, low sulfur diesel fuel, installation time retard for NOx emissions, limit hours of non-emergency operation for each emergency generator and for each fire water pump to 100 hrs/yr, and compliance with 40 CFR 60 Subpart IIII | 0 | | | 0 | | | 2.57 | G/HP-HR | AVERAGE OF THREE 1-HOUR STACK TEST RUNS |
| MI-0423 | INDECK NILES, LLC | MI | 01/04/2017  ACT | EUFPENGINE (Emergency engine--diesel fire pump) | 17.21 | 1.66 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 3 | G/BHP-H | TEST PROTOCOL WILL SPECIFY AVG TIME | 0 | | | 0 | | |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | MI | 06/29/2018  ACT | EUFPENGINE (South Plant): Fire pump engine | 17.21 | 300 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 3 | G/BHP-H | HOURLY | 0 | | | 0 | | |
| MI-0433 | MEC NORTH, LLC AND MEC SOUTH LLC | MI | 06/29/2018  ACT | EUFPENGINE (North Plant): Fire pump engine | 17.21 | 300 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 3 | G/BHP-H | HOURLY | 0 | | | 0 | | |
| MI-0434 | FLAT ROCK ASSEMBLY PLANT | MI | 03/22/2018  ACT | EUFIREPUMPENGS (2 emergency fire pump engines) | 17.21 | 250 | BHP | Nitrogen Oxides (NOx) | Good combustion practices. | 3 | G/B-HP-H | HOURLY; EACH ENGINE (NMHC+NOX) | 2.8 | LB/H | HOURLY; EACH ENGINE (NOX) | 0 | | |
| MI-0434 | FLAT ROCK ASSEMBLY PLANT | MI | 03/22/2018  ACT | EULIFESAFETYENG - One diesel-fueled emergency engine/generator | 17.21 | 500 | KW | Nitrogen Oxides (NOx) | Good combustion practices. | 4 | G/KW-H | HOURLY; NMHC+NOX | 8.47 | LB/H | HOURLY; NOX | 0 | | |
| MI-0435 | BELLE RIVER COMBINED CYCLE POWER PLANT | MI | 07/16/2018  ACT | EUFPENGINE: Fire pump engine | 17.21 | 399 | BHP | Nitrogen Oxides (NOx) | State of the art combustion design. | 4 | G/KW-H | HOURLY | 0 | | | 0 | | |
| *MI-0445 | INDECK NILES, LLC | MI | 11/26/2019  ACT | EUFPENGINE (Emergency engine-diesel fire pump | 17.21 | 1.66 | MMBTU/H | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements | 3 | G/BHP-H | HOURLY | 0 | | | 0 | | |
| MI-0451 | MEC NORTH, LLC | MI | 06/23/2022  ACT | EUFPENGINE (North Plant): Fire Pump Engine | 17.21 | 300 | HP | Nitrogen Oxides (NOx) | Good combustion practices and meeting NSPS Subpart IIII requirements. | 3 | G/B-HP-H | HOURLY | 0 | | | 0 | | |
| MI-0452 | MEC SOUTH, LLC | MI | 06/23/2022  ACT | EUFPENGINE (South Plant): Fire pump engine | 17.21 | 300 | HP | Nitrogen Oxides (NOx) | Good Combustion Practices and meeting NSPS Subpart IIII requirements | 3 | G/B-HP-H | HOURLY | 0 | | | 0 | | |

# Small Internal Combustion Engines Fuel Oil (17.210)

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| MI-0454 | LBWL-ERICKSON STATION | MI | 12/20/2022  ACT | EUFPRICE--A 315 HP diesel-fueled emergency engine | 17.21 | 2.5 | MMBTU/H | Nitrogen Oxides (NOx) | Good combustion practices. | 3 | G/HP-H | HOURLY | 0 | | | 0 | | |
| MI-0459 | LANSING BOARD OF WATER AND LIGHT--DELTA ENERGY PARK | MI | 06/27/2024  ACT | EUFIREPUMP | 17.21 | 500 | bhp | Nitrogen Oxides (NOx) | | 4 | G/KW-H | HOURLY | 0 | | | 0 | | |
| NE-0064 | NORFOLK CRUSH, LLC | NE | 11/21/2022  ACT | Emergency Fire Water Pump Engine 2 | 17.21 | 510 | hp | Nitrogen Oxides (NOx) | | 2.38 | G/HP-HR | 3-HOUR OR TEST METHOD AVERAGE | 0 | | | 0 | | |
| NJ-0084 | PSEG FOSSIL LLC SEWAREN GENERATING STATION | NJ | 03/10/2016  ACT | Emergency Diesel Fire Pump | 17.21 | 100 | H/YR | Nitrogen Oxides (NOx) | use of ULSD a clean burning fuel, and limited hours of operation | 1.7 | LB/H | | 0 | | | 0 | | |
| NY-0103 | CRICKET VALLEY ENERGY CENTER | NY | 02/03/2016  ACT | Emergency fire pump | 17.21 | 460 | hp | Nitrogen Oxides (NOx) | Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations. | 2.6 | G/BHP-H | 1 H | 0 | | | 0 | | |
| OH-0366 | CLEAN ENERGY FUTURE - LORDSTOWN, LLC | OH | 08/25/2015  ACT | Emergency fire pump engine (P004) | 17.21 | 140 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 0.81 | LB/H | | 0.2 | T/YR | PER ROLLING 12 MONTH PERIOD | 0 | | SEE NOTES |
| OH-0367 | SOUTH FIELD ENERGY LLC | OH | 09/23/2016  ACT | Emergency fire pump engine (P004) | 17.21 | 311 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 1.79 | LB/H | | 0.45 | T/YR | PER ROLLING 12 MONTH PERIOD | 0 | | SEE NOTES |
| OH-0368 | PALLAS NITROGEN LLC | OH | 04/19/2017  ACT | Emergency Fire Pump Diesel Engine (P008) | 17.21 | 460 | HP | Nitrogen Oxides (NOx) | good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII | 0.3 | LB/H | | 0.02 | T/YR | PER ROLLING 12 MONTH PERIOD | 0 | | SEE NOTES |
| OH-0370 | TRUMBULL ENERGY CENTER | OH | 09/07/2017  ACT | Emergency fire pump engine (P004) | 17.21 | 300 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 1.97 | LB/H | | 0.49 | T/YR | PER ROLLING 12 MONTH PERIOD | 0 | | SEE NOTES |
| OH-0372 | OREGON ENERGY CENTER | OH | 09/27/2017  ACT | Emergency fire pump engine (P004) | 17.21 | 300 | HP | Nitrogen Oxides (NOx) | State-of-the-art combustion design | 1.97 | LB/H | | 0.49 | T/YR | PER ROLLING 12 MONTH PERIOD | 3 | G/B-HP-H | SEE NOTES |
| OH-0374 | GUERNSEY POWER STATION LLC | OH | 10/23/2017  ACT | Emergency Fire Pump (P006) | 17.21 | 410 | HP | Nitrogen Oxides (NOx) | Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturerâ€™s operating manual | 2.7 | LB/H | NMHC+NOX. SEE NOTES. | 0.14 | T/YR | NMHC+NOX. SEE NOTES. | 3 | G/BHP-H | NMHC+NOX. SEE NOTES. |
| OH-0376 | IRONUNITS LLC - TOLEDO HBI | OH | 02/09/2018  ACT | Emergency diesel-fueled fire pump (P006) | 17.21 | 250 | HP | Nitrogen Oxides (NOx) | Comply with NSPS 40 CFR 60 Subpart IIII | 1.6 | LB/H | | 0.41 | T/YR | PER ROLLING 12 MONTH PERIOD | 3 | G/BHP-H | SEE NOTES |
| OH-0377 | HARRISON POWER | OH | 04/19/2018  ACT | Emergency Fire Pump (P004) | 17.21 | 320 | HP | Nitrogen Oxides (NOx) | Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII | 2.12 | LB/H | NMHC+NOX. SEE NOTES. | 0.11 | T/YR | NMHC+NOX. SEE NOTES. | 3 | G/BHP-H | NMHC+NOX. SEE NOTES. |

# Small Internal Combustion Engines Fuel Oil (17.210)

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| OH-0378 | PTTGCA PETROCHEMICAL COMPLEX | OH | 12/21/2018  ACT | Firewater Pumps (P005 and P006) | 17.21 | 402 | HP | Nitrogen Oxides (NOx) | Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturerâ€™s operating manual | 2.64 | LB/H | SEE NOTES. | 0.13 | T/YR | PER ROLLING 12 MONTH PERIOD. SEE NOTES. | 3 | G/BHP-H | SEE NOTES |
| OH-0379 | PETMIN USA INCORPORATED | OH | 02/06/2019  ACT | Black Start Generator (P007) | 17.21 | 158 | HP | Nitrogen Oxides (NOx) | Tier IV engine<br>Tier IV NSPS standards certified by engine manufacturer. | 0.104 | LB/H | | 5.2 | X10-3 T/YR | | 0.3 | G/BHP-H | |
| OH-0387 | INTEL OHIO SITE | OH | 09/20/2022  ACT | 275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine | 17.21 | 275 | HP | Nitrogen Oxides (NOx) | Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices | 4 | G/KW-H | 4.0 GRAMS NOX + NMHC/KW-HR | 8.5 | LB/H | SEE NOTES | 0 | | |
| PA-0309 | LACKAWANNA ENERGY CTR/JESSUP | PA | 12/23/2015  ACT | Fire pump engine | 17.21 | 15 | gal/hr | Nitrogen Oxides (NOx) | | 3 | GM/HP-HR | | 0.05 | TONS | 12-MONTH ROLLING BASIS | 0 | | |
| PA-0310 | CPV FAIRVIEW ENERGY CENTER | PA | 09/02/2016  ACT | Emergency Fire Pump Engine | 17.21 | 0 | | Nitrogen Oxides (NOx) | | 3 | G/BHP-HR | | 0 | | | 0 | | |
| VA-0325 | GREENSVILLE POWER STATION | VA | 06/17/2016  ACT | DIESEL-FIRED WATER PUMP 376 bph (1) | 17.21 | 0 | | Nitrogen Oxides (NOx) | Good Combustion Practices/Maintenance | 0 | | | 0 | | | 0 | | |
| VA-0328 | C4GT, LLC | VA | 04/26/2018  ACT | Emergency Fire Water Pump | 17.21 | 500 | HR/YR | Nitrogen Oxides (NOx) | Good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. | 3 | G/HP-HR | | 0 | | | 0 | | |
| VA-0332 | CHICKAHOMINY POWER LLC | VA | 06/24/2019  ACT | Emegency Fire Water Pump | 17.21 | 500 | HR/YR | Nitrogen Oxides (NOx) | good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. | 3 | G/HP-HR | | 0.7 | T/YR | | 0 | | |
| WI-0300 | NEMADJI TRAIL ENERGY CENTER | WI | 09/01/2020  ACT | Emergency Diesel Fire Pump (P06) | 17.21 | 282 | HP | Nitrogen Oxides (NOx) | Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturerâ€™s recommendations. | 3 | G/HP-H | | 0 | | | 0 | | |

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| *WI-0326 | NEMADJI TRAIL ENERGY CENTER | WI | 09/19/2023  ACT | Fire Pump; S06/P06 â€“ Emergency Diesel Fire Pump | 17.21 | 282 | HP | Nitrogen Oxides (NOx) | Good combustion practices and combusting clean fuels: (a) P06 may not operate more than 500 hours per each 12 rolling calendar months. (b) P06 shall be operated and maintained according to the manufacturerâ€™s recommendations. (c) NOx emissions from P06 may not exceed 3.0 g/hp-hr. | 3 | G/HP-HR | | 500 | HOURS | 12 ROLLING CALENDAR MONTHS | 0 | | |

# Non-Metallic Mineral Processing (90.024)

| RBLCID | FACILITY NAME | SIC CODE | NAICS CODE | PROCESS NAME | PROCCESS TYPE | PRIMARY FUEL | PROCESS NOTES | POLLUTANT | CONTROL METHOD DESCRIPTION | EMISSION LIMIT 1 | EMISSION LIMIT 1 UNIT | EMISSION LIMIT 1 AVG TIME CONDITION | OTHER APPLICABLE REQUIREMENTS | OTHER FACTORS | EMISSION LIMIT 2 | EMISSION LIMIT 2 UNIT | EMISSION LIMIT 2 AVGERAGE TIME CONDITION | COST EFFECTIVENESS | POLLUTANT COMPLIANCE NOTES |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AL-0234 | LIVITE DIVISION | 3295 | 327992 | KILN NO.3 - COAL FIRED ROTARY KILN | 90.024 | COAL | | Nitrogen Oxides (NOx) | GOOD COMBUSTION | 220 | LB/H | | NSPS | N | 0 | | | 0 | ANNUAL NOX EMISSIONS TEST REQUIRED |
| LA-0209 | GRAVELITE DIVISION | 3295 | 327992 | ROTARY KILNS, NOS. 1-4 | 90.024 | COAL | THROUGHPUT FOR EACH KILN. COAL: 41 MMBTU/H PETROLEUM COKE: 34 MMBTU/H NATURAL GAS: 5 MMBTU/H | Nitrogen Oxides (NOx) | GOOD COMBUSTION AND MAINTENANCE PRACTICES | 57.22 | LB/H | HOURLY MAXIMUM | OPERATING PERMIT | U | 250.64 | T/YR | ANNUAL MAXIMUM | 0 | |
| NC-0077 | CAROLINA STALITE COMPANY - GOLD HILL | 3281 | 327991 | ROTARY EXPANDING KILN | 90.024 | COAL | HEAT INPUT OF KILN: 52 MMBTU/HR. | Nitrogen Oxides (NOx) | GOOD COMBUSTION TECHNIQUES | 43.7 | LB/H | | | | 0 | | | 0 | |
| OR-0042 | EAGLE- PICHER VALE, OREGON PLANT | 1481 | 213115 | DRYER 2/CALCINER 2 | 90.024 | NATURAL GAS | throughput is DRY LBS/WEEK ORE | Nitrogen Oxides (NOx) | GOOD COMBUSTION PRACTICES | 7.1 | LB/H | 3-hour average | | | 0 | | | 0 | |
| OR-0042 | EAGLE- PICHER VALE, OREGON PLANT | 1481 | 213115 | DRYER 1/CALCINER 1 | 90.024 | NATURAL GAS | Throughput is DRY LBS/WEEK OF ORE | Nitrogen Oxides (NOx) | GOOD COMBUSTION CONTROL | 6.6 | LB/H | 3-hr average | | | 0 | | | 0 | |
| WY-0055 | WOLD TRONA COMPANY, INC. | 1474 | | ROM ORE STORAGE DUST COLLECTOR (E3) | 90.024 | | THROUGHPUT: 49500 SCFM, 49500 DSCFM. HOUSEKEEPING DUST FROM INFLATABLE FABRIC COVERED ORE STORAGE VENTS AND MATERIAL HANDLING CONVEYORS TRANSFER POINTS. | Nitrogen Oxides (NOx) | LOW NOX BURNER | 8.1 | LB/H (PHASE 1) | | | | 16.3 | LB/H (PHASE 2) | | 0 | |
| WY-0055 | WOLD TRONA COMPANY, INC. | 1474 | | MINE VENT (E1) | 90.024 | DIESEL | THROUGHPUT: 325,040 SCFM; 325,040 DSCFM. TAILPIPE EXHAUST OF UNDERGROUND DIESEL FIRED MINING SYSTEM, BURNING APPROXIMATELY 160 GALLONS DIESEL FUEL / DAY (58,400 GAL/YR) PLUS ADDITIONAL VOC PICKED UP IN VENTILATION OF MINE BEDS. | Nitrogen Oxides (NOx) | | 1.7 | LB/H | | | | 7.5 | T/YR | | 0 | |

# Calciners Dryers and Mineral Processing Facilities (90.017)

| RBLCID | FACILITY NAME | FACILITY_STATE | PERMIT ISSUANCE DATE | PROCESS NAME | PROCCESS TYPE | PRIMARY FUEL | PROCESS NOTES | POLLUTANT | CONTROL METHOD DESCRIPTION | EMISSION LIMIT 1 | EMISSION LIMIT 1 UNIT | EMISSION LIMIT 1 AVG TIME CONDITION | OTHER APPLICABLE REQUIREMENTS | EMISSION LIMIT 2 | EMISSION LIMIT 2 UNIT | EMISSION LIMIT 2 AVGERAGE TIME CONDITION | COST EFFECTIVENESS | POLLUTANT COMPLIANCE NOTES |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GA-0145 | CARBO CERAMICS INC. - MILLEN FACILITY | GA | 04/06/2012  ACT | CALCINER | 90.017 | NATURAL GAS | FACILITY HAS FOUR CALCINERS | Nitrogen Oxides (NOx) | LOW NOX PROCESS TECHNOLOGY | 121 | LB/H | 3-H | NSPS | 0 | | | 0 | TEST METHOD: METHOD 7 OR 7E<br>40 CFR 60, SUBPART UUU |
| GA-0145 | CARBO CERAMICS INC. - MILLEN FACILITY | GA | 04/06/2012  ACT | SPRAY DRYER | 90.017 | NATURAL GAS | 8 UNITS | Nitrogen Oxides (NOx) | GOOD COMBUSTION TECHNIQUES. TEST METHOD 7 OR 7E | 8.3 | LB/H | 3 H | NSPS | 0 | | | 0 | 40 CFR 60, SUBPART UUU |
| GA-0147 | PYRAMAX CERAMICS, LLC - KING'S M:U FACILITY | GA | 01/27/2012  ACT | CALCINERS/KILNS | 90.017 | NATURAL GAS | THE FACILITY HAS TWO CALCINERS/KILNS | Nitrogen Oxides (NOx) | ‘‘CATALYTIC BAGHOUSE‘‘/CERAMIC FILTER TUBE SYSTEM AND LOW NOX COMBUSTION TECHNOLOGY. THE CERAMIC TUBES ARE EMBEDED WITH NOX CATALYSES. | 36.3 | LB/H | 3 HR | | 80 | % CONTROL | 3 HR | 0 | TEST METHOD: METHOD 7 OR 7E |
| TX-0253 | AKZO NOBEL CHEMICALS, INC. | TX | 06/20/2000  ACT | CALCINER | 90.017 | | THE SCC CODE WAS CHOSEN BASED ON THE ASSUMPTION THAT THE CALCINER IS USED AS PART OF A PETROLEUM REFINING PROCESS. | Nitrogen Oxides (NOx) | PROCESS EXHAUST GASES ARE ROUTED TO SCR | 0.066 | LB/MMBTU | | | 0 | | | 0 | |
| TX-0536 | SEADRIFT COKE | TX | 04/20/2009  ACT | CALCINERS PETROLEUM | 90.017 | NATURAL GAS | SEADRIFT COKE IS REQUESTING AN AMENDMENT TO BUILD A NEW DECANT HYDROGEN DESULFURIZATION UNIT (HDS) TO REDUCE FEEDSTOCK SULFUR LEVELS. THEY WILL ALSO BUILD A NEW HYDROGEN PLANT TO PROVIDE HYDROGEN TO THE HDS UNIT, SOUR WATER STORAGE, SOUR WATER STRIPPING, AMINE SYSTEM AND SUFLUR RECOVERY UNIT. A 2ND KILN WILL BE ADDED. | Nitrogen Dioxide (NO2) | COMPANY COSTED OUT OF CONTROLS FOR NO2 CONTROL | 415 | T/YR | | NSPS , NESHAP , MACT | 95 | LB/H | | 0 | |
| WY-0055 | WOLD TRONA COMPANY, INC. | WY | 04/27/2000  ACT | TRONA ORE CALCINER STACK (E5) (E15) | 90.017 | NATURAL GAS | THROUGHPUT: 111,204 SCFM. EXHAUST FROM WET SCRUBBER (E11) CONTROLLING EMISSIONS FROM #1 FLUID BED CALCINER AND PORTION OF EMISSIONS FROM 460,000 LB/H STEAM RATE BOILER (E12). PHASE 2 WILL ADD STREAM E15 FROM SECOND SET OF ORE PROCESSING EQUIPMENT. NO PERMIT EMISSION LIMITS ON CO AND VOC. | Nitrogen Oxides (NOx) | LOW NOX BURNER. ALT. EMISSION LIMIT: PHASE 2 - 16.1 LB/H. | 0.038 | LB/MMBTU | | | 8.1 | LB/H (PHASE 1) | | 0 | |
| WY-0055 | WOLD TRONA COMPANY, INC. | WY | 04/27/2000  ACT | BENETRON ORE UPGRADE FACILITY STACK (E4) | 90.017 | | THROUGHPUT: 117, 340 SCFM. PROCESS EMISSIONS FROM ORE CRUSHER AND 3-STAGE BENETRON TRONA/ROCK SEPARATION. STREAM E14 EMISSIONS ADDED IN PHASE 2 ALSO INCLUDES PORTION OF BOILER EMISSIONS. NO PERMIT EMISSION LIMITS FOR CO AND VOC. CONTROLLING CO WOULD INCREASE NOX. | Nitrogen Oxides (NOx) | LOW NOX BURNER | 8.1 | LB/H (PHASE 1) | | | 16.3 | LB/H (PHASE 2) | | 0 | |
| *WY-0078 | BIG ISLAND MINE & REFINERY | WY | 03/27/2017  ACT | Unit 6 Calciner | 90.017 | natural gas | heat input is 235 MMBtu/hr | Nitrogen Oxides (NOx) | Low NOx burners with FGR | 9.5 | LB/H | 3-HOUR AVERAGE | | 0 | | | 0 | |
| *WY-0078 | BIG ISLAND MINE & REFINERY | WY | 03/27/2017  ACT | Unit 7 Calciner | 90.017 | natural gas | 365 MMBtu/hr | Nitrogen Oxides (NOx) | Low NOx burners and FGR | 14 | LB/H | 3-HOUR AVERAGE | | 0 | | | 0 | |
| *WY-0078 | BIG ISLAND MINE & REFINERY | WY | 03/27/2017  ACT | Unit 4 Dryer | 90.017 | natural gas | 143 MMBtu/hr | Nitrogen Oxides (NOx) | low nox burners | 13.4 | LB/H | 3-HOUR AVERAGE | | 0 | | | 0 | |