ATTACHMENT D:

Major Source
Reasonably Available Control Technology Analysis

Case-By-Case RACT for Major VOC and NO_x Sources in Hydrographic Area 212

togetherforbetter

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

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ACRONYMS AND ABBREVIATIONS

<u>Acronyms</u>

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).

1.2.2 Caesars

Caesars Entertainment, Inc. ("Caesars") owns a number of properties with boilers and emergency generators. DAQ identified and evaluated 23 boiler control technologies. For the five boilers reviewed for RACT, only one control technology (in addition to what is already required) appeared cost-effective: switching to ceramic fiber burners, which would have reduced emissions from 30 parts per million (ppm) at 3% O_2 down to 15 ppm and reportedly save fuel and reduce maintenance. However, Caesars' boilers are all around 30 MMBtu/hr in size and ceramic fiber burner applications, according to several manufacturers, are available only up to about 16 MMBtu/hr.[1]

Further research indicates that 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 are suitable for larger boilers up to over 100 MM Btu/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 the metal mesh burner technology is not considered cost effective for these boilers.

Therefore, DAQ finds that ceramic fiber burners are not available for these emissions units and that metal mesh burners are not cost effective, so concludes that the existing controls constitute RACT for these boilers.

Caesars properties also host 27 emergency generators subject to RACT review. The diesel generators are rated from 600 to 2,100 kW, and are limited to 100 hours of operation per year for testing and maintenance and up to 50 hours per year for nonemergency situations (which count toward the 100 hours). All the engines are turbocharged and aftercooled. Of the 18 control technologies evaluated, only the existing controls (turbocharging, GCP/GMP, and aftercooler) were determined to be cost-effective. DAQ concludes that these existing controls constitute RACT for these emergency diesel generators. The Caesars Title V operating permit (OP) includes compliance and monitoring requirements to ensure these conditions are met; DAQ concludes these constitute adequate monitoring, reporting, and recordkeeping to ensure RACT compliance.

1.2.3 Switch

No individual Switch, Ltd ("Switch") emission unit has a PTE above 5 tpy NO_x, but the 117 large (3,353 horsepower (hp) / 2,503 kilowatt (kW)) emergency diesel generators nevertheless were reviewed in the RACT analysis. The Switch Title V OP requires that the source have turbochargers and aftercoolers on all emergency generators, follow the manufacturer's operations and

[1] The highest annual emissions from the five boilers from 2019 to 2021 is 10.89 tpy NO_x; ceramic burners, had they been applicable to these boilers, would have reduced that to 5.445 tpy, reducing NO_x by the same amount (5.445 tpy). The burners have the benefit of increasing efficiency and saving fuel, which makes them more cost effective. For example, the cost-effectiveness (CE) for CP02 with 2.74 tpy actual emissions (without considering fuel savings) is $3,895/ton, which is cost-effective, while the CE for CP04 with 1.08 tpy is $9,881/ton, which is not. However, a 5% fuel savings, assuming the lowest hours of operation (446.6—CP01 in 2021), would be $6,815/year, which would result in a CE of -$1,080 to -$2,739/year (depending on the unit), which is cost-effective. The reduction in actual emissions from equipping the boilers with ceramic burners (had ceramic burners been available for that size boiler) would have been 5.445 tpy NO_x.

maintenance (O&M) guidance, and ensure all 117 units comply with the emissions limitations in 40 CFR Part 60, Subpart IIII. DAQ concludes that these requirements are RACT. Switch's Title V OP includes compliance and monitoring requirements to ensure these conditions are met; DAQ concludes these constitute adequate monitoring, reporting, and recordkeeping to ensure RACT compliance.

1.2.4 MGM Resorts International

MGM Resorts International (MGMRI) is currently a major source of NO_x, with a source-wide PTE of 757.05 tpy, but it reported only 65.07 tpy of actual NO_x emissions in 2017. The emission units include two natural gas-fired boilers, each with a capacity of 32.66 million British thermal units per hour (MMBtu/hr), and 46 diesel-fired emergency generators ranging from 1,100 to 3,700 hp.

DAQ evaluated 23 boiler control technologies; only ceramic fiber burners appeared to be potentially feasible as additional RACT. However, the MGMRI boilers are all around 30 MMBtu/hr in size and ceramic fiber burner applications, according to several manufacturers, are available only up to about 16 MMBtu/hr.

Further research indicates that 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 are suitable for larger boilers up to over 100 MM Btu/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 the metal mesh burner technology is not considered cost effective for these boilers.

Therefore, DAQ determined that ceramic fiber burners are not available for these emissions units and that metal mesh burners are not cost effective, so concludes that the existing controls constitute RACT for these boilers.

All 46 of the emergency generators are required to follow the manufacturer's O&M guidance, which is generally accepted as constituting GCP. In addition, the OP requires all units have turbochargers and aftercoolers except:

- Turbochargers only: EX007-EX010 and NY27-NY29.
- Neither: TM01.

TM01 is the only unit for which the OP does not explicitly require turbocharging or aftercoolers, but it is also the only unit specifically mentioned as subject to EPA's Tier Certification. The unit's manufactured control technology must comply with the applicable New Source Performance Standard, thereby meeting the requirements of this certification and satisfying the definition of RACT.

The emergency generators currently:

- Are all required to practice GCP and GMP;

- 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.

use of oxidation catalyst controls and GCP for Units 4–8; Units 11–22 are already equipped with oxidation catalyst controls. All other control technologies were considered technically infeasible.

The evaluation showed that there were no cost-effective control options for NO_x or VOC for any of the units except Unit 4. For Unit 4, the proposed NO_x RACT for Unit 4 was an emission limit of 120 ppmvd @ 15% O_2 based on the use of GCP for all periods of operation; for all other units, DAQ determined the current NO_x limits represented RACT based on the use of existing control equipment and compliance determination procedures.

For VOC RACT, DAQ determined that RACT for Unit 4 was an emission limit of 21.6 lb/hr based on GCP. For Units 5-8, DAQ determined that the existing VOC limits represent RACT based on the existing control configuration and compliance determination procedures.

DAQ determined that GCP would also apply to startup and shutdown operations as part of the NO_x and VOC determinations for all applicable units. DAQ included a requirement to develop a best operating practices guideline with adequate reporting and recordkeeping procedures to ensure that each unit maintains compliance with the good operating practices work practice standard.

1.2.7 Sun Peak Generating Station

The emission units at SPGS that were analyzed consisted of three natural gas-fired, simple cycle CTs (Units 3–5). All units were subject only to a RACT evaluation for NOx. VOC RACT did not apply because emissions for each unit were below the RACT applicability threshold. There were no other sources at the facility with NO_x or VOC emissions above the applicability threshold.

All turbines are currently equipped with water injection for NO_x control. Potential upgrade options that were evaluated include SCR, DLNC, and the combination of SCR with DLNC for all units. All other options were considered technically infeasible. The cost evaluation was conducted based on actual emissions data due to limited operation of each unit. The evaluation showed that there were no cost-effective control options for any of the units. Therefore, DAQ determined the current NO_x limits represented RACT based on existing controls and compliance determination procedures.

DAQ also determined that GCP would apply to startup and shutdown operations, with an additional requirement to develop a best operating practices guideline with adequate reporting and recordkeeping procedures to ensure that each unit maintains compliance with the good operating practices work practice standard.

1.2.8 Saguaro Power Company

The emission units at Saguaro Power Company (“Saguaro”) that were analyzed consisted of two natural gas/oil-fired combined cycle units (Units 1 and 2) and two natural gas-fired auxiliary boilers (Units 5 and 6). All turbines and boilers were subject only to a RACT evaluation for NO_x, since VOC emissions for these units were below the RACT applicability threshold. There were no other sources at the facility with NO_x or VOC emissions above the applicability threshold.

All turbines are currently equipped with steam injection and SCR for NO_x control. Potential control technologies that were evaluated included DLNC and SCR catalyst replacement. All other options were considered technically infeasible. The cost evaluation was conducted based on actual emissions data. The evaluation showed that there were no cost-effective control options for either unit. Thus, DAQ determined that the current NO_x limits represented RACT based on existing controls and compliance determination procedures.

Both boilers are equipped with LNB although the Unit 5 boiler is also equipped with flue gas recirculation (FGR). For Unit 5, DAQ evaluated an extensive list of potential NO_x control technologies although, with the exception of a few technologies, all were considered technically infeasible. DAQ lacked sufficient information to determine feasibility for certain combustion-related technologies, including LNB, staged combustion, excess air reduction, and gas flow modifiers. However, none of these options would be considered cost-effective regardless of whether they were deemed technically feasible. Therefore, DAQ concluded the current NO_x limit represented RACT using existing controls and compliance determination procedures.

For Unit 6, DAQ also evaluated an extensive list of potential control technologies although only the following technologies were considered technically feasible: LNB upgrade with FGR, the installation of a ceramic fiber burner, the installation of a forced internal recirculation burner, and fuel-induced recirculation, although further evaluation would be required to confirm the feasibility of the burner replacements and use of fuel-induced recirculation. Based on the cost evaluation, DAQ concluded there were no cost-effective upgrades for this unit. Therefore, the current NO_x limit represented RACT using existing controls and compliance determination methods.

Finally, DAQ proposed the use of GCP as RACT for all units during startup and shutdown operations, with an additional requirement to develop a best operating practices guideline.

1.3 REQUIREMENTS FOR RACT ANALYSIS BASED ON ACTUAL EMISSIONS

One of the more significant findings of this evaluation was that essentially all of the RACT analyses were conducted using either average annual actual emissions (usually a 3-year average, in tpy) or the highest annual actual emissions rate (in tpy) over some period of time (1 to 5 years), based on the DAQ RACT Methodology guidance document. The presumption behind this methodology is that the annual actual emissions used for the cost effectiveness calculation is representative of normal operation for the source as a whole and/or for the individual emissions unit being evaluated. Because actual emissions from many of the individual emissions units were low, the CE calculation is sensitive to the actual emissions levels.[6]

Although most sources indicated that the baseline period was reasonably representative of future operation, it is possible that unanticipated increases in operation may cause future emissions that,

[6] For example, a boiler with actual emissions of 2.74 tpy and a reduction of 1.15 tpy from a control technology has a CE of $7533/ton, above the $5500/ton threshold. If the actual emissions rose only 2.26 tpy, to 5 tpy, the reduction would be 2.1 tpy and the CE would drop to $4128/ton, below the threshold, so would be cost effective for RACT.

if used to re-evaluate RACT, would result in a CE below the RACT applicability threshold, particularly for those sources in the electric utility sector. Therefore, where actual emissions were used (instead of PTE) for the CE calculation, DAQ expects to require those sources to provide calendar year annual actual emissions information on at least the individual units analyzed. If such actual emissions from an emissions unit increases over the baseline actual emissions used in the RACT analysis by 5 tpy or more (particularly if such increase occurs 2 or more years within a 3-year period), DAQ will evaluate whether the increase represents an increase in normal operation. If so, DAQ may conduct a revised RACT analysis and, if the new analysis results in a CE below the threshold, impose that level of control as RACT.[7] The purpose of this tracking and reassessment is to ensure that unanticipated increases in actual emissions from these sources do not interfere with attainment and maintenance of the ozone NAAQS. Therefore, in addition to a reported actual emissions increase above the 5 tpy threshold, DAQ will weigh such factors as the likelihood that the increased actual emissions are more representative of normal operation in the future (e.g., a single year in which emissions increase above the 5 tpy threshold does not necessarily indicate that this new, higher level is representative or will be repeated in the future), whether such increase could interfere with progress toward attainment, and any changes to other factors that affect CE, such as increased costs for equipment, maintenance and operation of the control device or a reduced remaining life of the unit.

[7] DAQ would specify that the source is to make the comparison with baseline and to notify DAQ by within 30 or 60 days of the end of each calendar year whether actual emissions have increased by the triggering amount.

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

Facility ID	Facility Name	Total Facility NO_X PTE (tpy)	2017 NEI Emissions (tpy)	2017 NEI Emissions (tpd)
NO_X Major Sources				
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.

4.0 ENGINE AND SMALL BOILER RACT

4.1 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 is major mainly due to diesel engines (mostly emergency generators) and /or commercial boilers[10]. DAQ relied on information provided in the major sources' proposed RACT analyses (Appendices 2–9), supplementing these analyses where 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 major source for multiple RACT determinations. In some cases, DAQ adjusted life expectancy in cost calculations when a source did not provide any basis for a shorter life expectancy.

This section does not repeat all the information relied on in each major source's proposed RACT analysis, but highlights key information critical to DAQ's decision-making process. Appendices 2–9 provide the full scope of information DAQ considered in making a RACT determination for each major source.

4.2 POTENTIALLY AVAILABLE NO_X CONTROL TECHNOLOGIES

Emissions units at several of the major sources are emergency generators, engines that serve as secondary sources of power whenever a primary source of power is interrupted or insufficient to meet short-term energy demands. These engines are generally powered with natural gas or diesel fuel, and run for fewer than 500 hours per year. When evaluating whether to regulate emergency generators, EPA generally has found that add-on emissions controls are not economically reasonable because of the few hours the engines operate in a year (Appendix 4, p. 2-2), and instead imposes operational restrictions and/or work practices to minimize emissions. Sections 4.2.1–4.2.16 provide an overview of the control technology options DAQ considered in determining RACT for emergency engines at major sources. Some descriptions are taken verbatim from a source's proposed RACT, with information added to explain the applicability of the control technology to emergency generators. A number of add-on control technologies are also applicable to boilers, as discussed below.

4.2.1 Selective Catalytic Reduction

SCR is a post-combustion treatment of the engine exhaust that involves the injection of ammonia into the system in the presence of a catalyst that converts NO_x emissions to nitrogen and water in the presence of a catalyst. SCR on boilers works in essentially the same manner: "The catalyst allows the ammonia to reduce NO_x levels at lower exhaust temperatures than an alternative control technology called selective noncatalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400–1600°F, SCR can be utilized where exhaust gases are between 500°F and 1200°F, depending on the catalyst used. SCR can result in NO_x reductions up to 75%" (Appendix 3, p. 2).

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

New engines that must meet EPA's Tier 4 manufacturer certification standards are built with SCR systems. Existing engines can be retrofitted with SCR, but exhaust temperature will impact its effectiveness as an emission control device; at too low a temperature, SCR efficiency decreases. Figure 1 presents an efficiency curve for SCR operation at various temperatures. Extrapolating beyond the curve for a boiler or emergency generator with a 400°F flue gas temperature yields a NO_x removal efficiency of less than 5%.

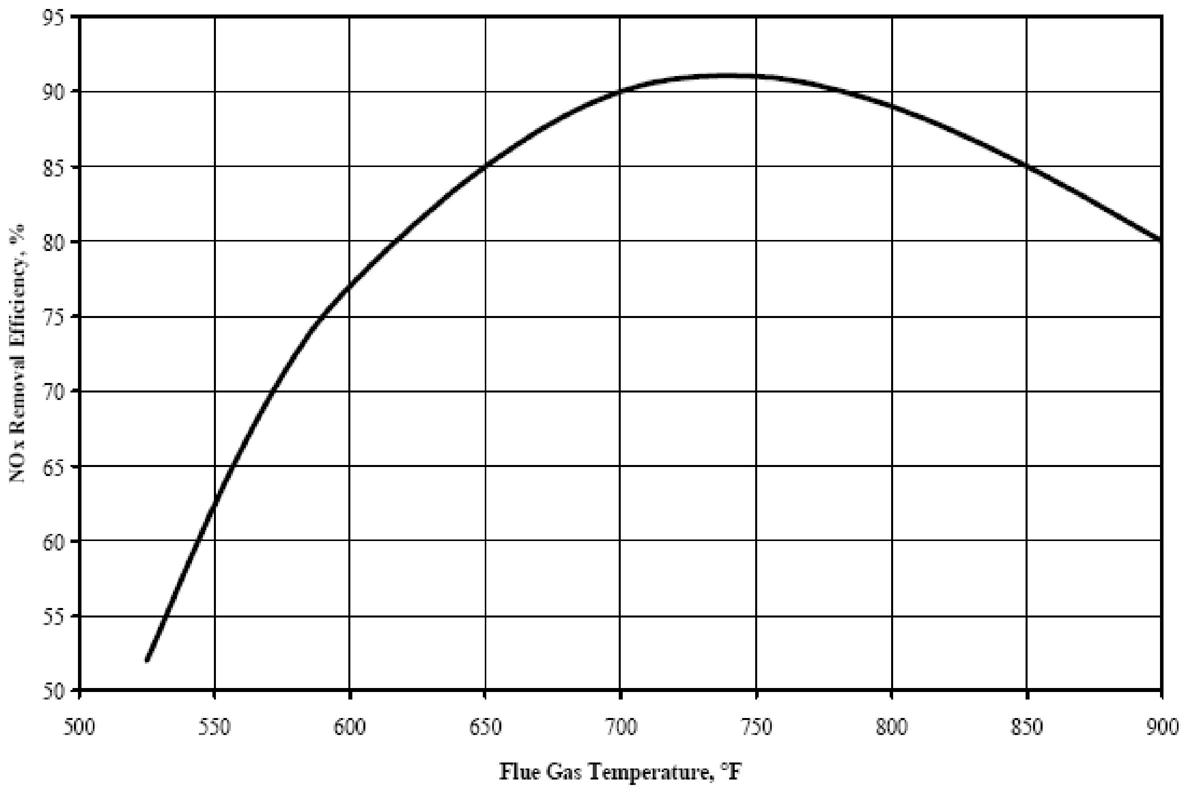

Figure 4-1. SCR–NO_x Removal versus Temperature.[11]

For emergency engines in particular, intermittent operation causes the average exhaust gas temperature to fall below the temperature required for the catalytic reaction (Appendix 2, p. 12). This makes application of SCR to most emergency engines economically unreasonable because the costs far exceed the emissions reduction benefit. Boilers are usually operated more than emergency generators, but SCR on small boilers, especially if the boilers are used intermittently (e.g., for hot water), are also generally not cost effective. For example, a search of the RACT/BACT/LAER Clearinghouse[12] for NO_x control determinations for small boilers shows a 2021 determination for the Lansing, MI 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 LNB and FGR as BACT, which is generally more stringent than RACT. The cost-effectiveness of SCR for the boiler was calculated at $18,527, which was determined to be unreasonable for that facility.

[11] *Graph from* Air Pollution Control Cost Manual 7th Edition, Section 4, Section 4.2, Chapter 2 Selective Catalytic Reduction, p. 2-17. Document EPA-HQ-OAR-2015-0341-0061, available at: https://www.regulations.gov/document/EPA-HQ-OAR-2015-0341-0061.

[12] Database of control technology determinations maintained by EPA.

4.2.2 Selective Non-Catalytic Reduction

"SNCR involves the injection of a NO_x reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1400–1600°F. The ammonia or urea breaks down the NO_x in the exhaust gases into water and atmospheric nitrogen. SNCR reduces NO_x up to 50%" (Appendix 3, Appendix B at p. 3).

SNCR is less costly than SCR, so the control technology can be more cost-effective, but like SCR, the efficiency of SNCR as a NO_x emission control decreases at higher and lower exhaust gas temperatures. The optimal range of SNCR is between 920–1,095°C (1,688–1,940°F). At a 400–700°F exhaust temperature, SNCR has a control efficiency of near 0%.

Figure 2 presents an efficiency curve for SNCR operations at various temperatures. The Y axis is % NO_x control; the X axis is temperature in °C.

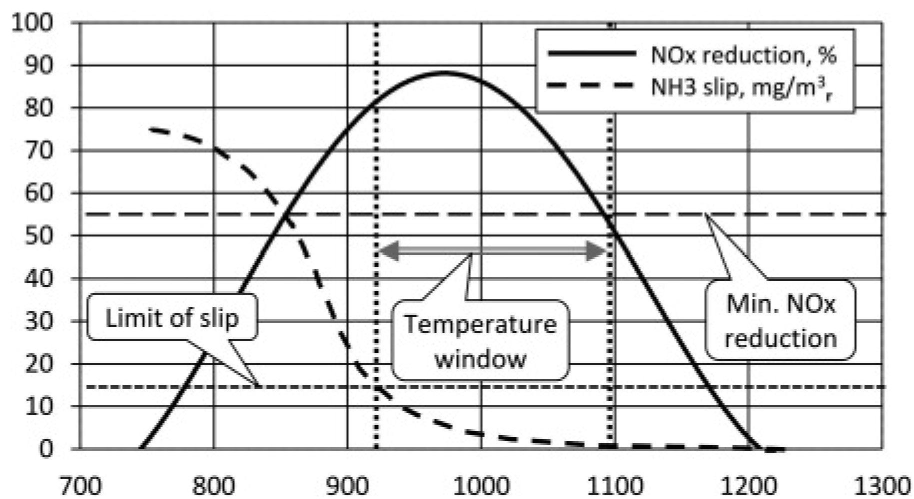

Figure 4-2. Exhaust Gas Temperature and NO_x Control Using SNCR.[13]

4.2.3 Low NO_x Burners

LNB control technology is principally found on boilers. An LNB controls air-to-fuel mixing to reduce the peak flame temperature in stages. By lowering the peak flame temperature, less NO_x is produced during combustion. Many boiler burners sold today are designed with at least LNB technology. "The two most common types of low NO_x burners being applied to natural gas boilers are staged air burners and staged fuel burners, or a combination thereof" (Appendix 3, p. 3).

4.2.4 Good Combustion and Maintenance Practices

Good combustion and maintenance practices involve operating the engine or boiler to maximize energy output or thermal efficiency while maintaining optimized oxygen levels to assure complete combustion. GCP can also involve running equipment in accordance with the

[13] *Environmentally Oriented Modernization of Power Boilers*, Chapter 4.4. Pronobis, M. 2020.

manufacturer's recommended settings and preventative maintenance schedules (Appendix 4, p. 2-2; Appendix 5, p. 2-3).

4.2.5 Operating Restrictions

Emergency engines can be subject to a variety of restrictions on the number of hours of operation; for example, the San Joaquin Valley Air Pollution Control District's Rule 4702 limits NO_x emissions from internal combustion engines with greater than 25 brake horsepower by limiting annual operating hours and allowing operations only for specific purposes (i.e., testing, maintenance, and emergency purposes) (Appendix 4, p. 2-3). DAQ did not consider operating restrictions a viable control technology for identifying RACT because they generally do not control NO_x or VOC emissions during emission unit operation. Such restrictions can, however, be used to avoid applicability, including RACT requirements.

4.2.6 Ultra-Low NO_x Burners for Boilers or Low Emission Control for Engines

Recent advancements in combustion technology have advanced LNB to higher levels of emission control, ultra-low NO_x burners (ULNB). This technology can reduce NO_x concentrations in a boiler exhaust to 9 ppm @ 3% O_2; however, the reduced NO_x emission level comes at the expense of increased carbon monoxide (CO) emissions (Appendix 3, Appendix B at p. 3). Many existing LNB cannot be fine-tuned to reach ULNB levels, so a replacement of the burners in a boiler is necessary to achieve ULNB.

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 consider replacement of engines a viable option for RACT because RACT is determined based on the design of the existing emission unit.

4.2.7 Flue Gas Recirculation

FGR is a control technology primarily applied to boilers. An FGR system reduces NO_x emissions in two ways by recirculating gas. "The gas suppresses formation of NO_x during combustion by reducing combustion temperatures by diluting the gas stream. It also lowers the oxygen concentration in the primary flame zone. An FGR system is normally used in combination with low NO_x burners to achieve a 60–90% reduce in NO_x emissions" (Appendix 5, p. 2-2). It may not be possible to retrofit this technology into all boiler types, and retrofitting may be limited by existing space constraints (Appendix 3, Appendix B at p. 3).

4.2.8 Exhaust Gas Recirculation

Exhaust gas recirculation (EGR) can reduce NO_x by 40% on low-load mobile diesels, but EPA notes that EGR requires external hardware retrofits, some additional controls, and possibly cooling/cleaning of 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 being offered for production compression ignition (CI) engines.[14] In

[14] "Alternative Control Techniques Document—NOx Emissions from Stationary Reciprocating Internal Combustion Engines," p. 5–85. EPA-453/R-93-032, July 1993.

addition, a National Resources Defense Council (NRDC) study reported that EGR results in fuel penalties of 0–5%, that it is among the most costly of available control options, and that it results in increased particulate emissions.[15]

4.2.9 Injection Timing Retardation

ITR is a good combustion practice that is applied principally on engines. The technology reduces the maximum combustion temperature and pressure, which decreases NO_x formation. Its use for NO_x emissions reduction comes with tradeoffs because ITR degrades performance and longevity and increases CO, PM, CO_2, and hydrocarbons (HC). EPA literature identifies these concerns, including a 3% fuel penalty.[16]

4.2.10 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, it comes with substantial fuel penalties (up to 5%) and increases in HC and CO emissions, and is not very effective for diesel engines.[17]

4.2.11 Derating/Increasing Speed

EPA is unenthusiastic about this option, noting that derating 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 unit would increase; increasing engine speed is equivalent to derating in loss of power and is not a feasible option for existing units.[18] EPA also points out that the reduction in NO_x emissions may be no more than the equivalent reduction in output, echoing the NAFB/manufacturer comment, and that NO_x emissions are less responsive to derating for turbocharged engines.[19]

4.2.12 Inlet Manifold Air Temperature (MAT) 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. Cooling requires 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).[20] At least one study indicated that cooling intake air is an effective technique to reduce NO_x emissions, showing a reduction of

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[15] "Cleaning Up Today's Dirty Diesels." NRDC 2005.

[16] "Control Techniques for Nitrogen Oxides Emissions from Stationary Sources – Second Edition," p. 4-67. EPA-450/1-78-001, January 1978.

[17] "Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition," p. 4-66. EPA-450/1-78-001, January 1978.

[18] "Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition," p. 4-63. EPA-450/1-78-001, January 1978.

[19] Emission Factor Documentation for AP-42, Vol. I, Section 3.4, "Large Stationary Diesel & All Stationary Dual Fuel Engines," p. 2-15. EPA, April 1993.

[20] Part 70 Operating Permit, Source No. 114, Section V.B.3.a, p. 34. Issued by DAQ on July 15, 2021. The OP requires using a turbocharger, but does not mention an aftercooler.

more than 50% NO_x in some operating conditions.[21] With a built-in air-cooling aftercooler, the temperature dropped from 356°F to 122°F, a delta of 234°F.[22]

Temperatures in Clark County can reach 115°F in the summer, but can drop to 30°F in the winter; air cooling requires less hardware than water cooling, but either can be used. The 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 $0.3 \bullet (\Delta T°F)\%$.[23] Using this equation and a delta of 234°F yields a control efficiency of $0.3 \bullet 234 = 70\%$.

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 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 operating costs associated with it. 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.

4.2.13 Water Injection (Direct Water Injection/Steam Injection)

According to EPA, water injection works by reducing 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.[24] 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. However, the work required to create an injection system for different engine types makes this approach more suited for the original equipment manufacturer (OEM) rather than a retrofit. A water/fuel emulsion is a better route, according to studies, and outlined in more detail below.[25]

In general, water can be introduced into the diesel combustion process using one of the following methods:

- Emulsified fuel,

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[21] "Experimental and Computational Investigation of Effects of Cooling Intake Air in NO_x Reduction and Performance of Diesel Engines." Lashkarpour, Bahlouli, Razavi and Milani. *Asian Journal of Applied Sciences, 4:30-41*, 2011.
[22] "Introduction of High Output Engine SAA12V140 for Generator," Komatsu Technical Report, Vol. 49, No. 152, 2003.
[23] "Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition," Table 4-20. EPA-450/1-78-001, January 1978. 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.
[24] Emission Factor Documentation for AP-42, Vol. I, Section 3.4, "Large Stationary Diesel & All Stationary Dual Fuel Engines," Table 3.4-6. EPA, April 1993.
[25] "Water in Diesel Combustion." W.A. Majewski. DieselNet Technology Guide, 2002. Water in Diesel Combustion.

- 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 “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 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 [Holtbecker 1998].[26] 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 in that 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 emission control strategies that can simultaneously reduce NO_x and particulate matter (PM) emissions with no, or only a small, fuel economy penalty. Reduction of PM emissions by emulsions has not been as thoroughly researched as NO_x reduction; nevertheless, 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 may be needed, without affecting engine reliability. Direct water injection needs to be carefully optimized with respect to injection timing, water consumption, emissions, and other parameters. This 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 emission 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 than for retrofit applications.

[26] Cited in: W. Addy Majewski, Water in Diesel Combustion, DieselNet Technology Guide, dieselnet.com/tech/engine_water.php, 2002.

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].[27]

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.[28]

In-cylinder injection is more suitable for OEM and requires development to retrofit on existing engines. It is unlikely to be 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."[29]

A literature search produced no information on the technical feasibility of adding water or steam injection to boilers with LNB—and whether the amount of NO_x reduction would be less, since LNB already have reduced emissions—and very little cost information. One study is cited 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.[30] The study includes both Oxygen Trim and Water/Steam inject systems and 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), $CE_{2022} = \$3{,}903_{1992} \bullet (\$824.5_{2022}/\$358.2_{1992}) = \$8984/\text{ton}$.

4.2.14 Water/Fuel Emulsions

The literature indicates this is a viable option, even more so than water injection; one source indicates that NO_x control is limited to 20% without engine modifications, but reductions of 50%

[27] Cited in: W. Addy Majewski, Water in Diesel Combustion, DieselNet Technology Guide, dieselnet.com/tech/engine_water.php, 2002.
[28] W. Addy Majewski, Water in Diesel Combustion, DieselNet Technology Guide, 2002. Online at: Dieselnet.com/tech/engine_water.php.
[29] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-43.
[30] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. D-3.

are possible with modifications.[31] Another study indicates that emissions reductions up to 80% are possible.[32]

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 cost about 4.4% more than regular diesel in Europe in 2015, so that cost differential is assumed: for example, if diesel costs $5/gallon, then emulsified diesel costs $5.22/gal. The gallons of fuel used per year can be estimated using the size of the engine and hours of operation;[33] taking the gallons per year times a delta of $0.22/gal yields the cost of using emulsified diesel.[34]

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

4.2.14.1 Engine Performance Management System

The US. 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 generators.[36] In this way, an engine performance management system (EPMS) is different from GMP/GCP. The NRC recommends (or, in some cases, mandates) more extensive monitoring and different maintenance procedures than would constitute a comprehensive EPMS for emergency diesel generators; their guidance includes monitoring temperatures, quality of fuel (diesel degrades after a year), CO emissions that indicate the degree of combustion, and so forth.

EPMS alone does not appear to reduce NO_x emissions, and DAQ located 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.

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[31] W. Addy Majewski, Water in Diesel Combustion, DieselNet Technology Guide, dieselnet.com/tech/engine_water.php, 2002.

[32] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. See Table 5, p. 162. https://doi.org/10.4236/ojms.2019.93012

[33] Diesel Service & Supply | 625 Baseline Road, Brighton, Colorado 80603, sales@dieselserviceandsupply.com | www.dieselserviceandsupply.com Toll-Free: 800-853-2073 | Main Office: 303-659-2073 | Fax: 720-685-7920

[34] "Penetration Prospects of Emulsified Fuel in the Greek Oil Market," in *Proceedings of the 14th International Conference on Environmental Science and Technology,* Rhodes, Greece, September 2015. Tyrovola, Feligiannis, Dodos, and Zannikos.

[35] "Diesel-Water Emulsion, an Alternative Fuel to Reduce Diesel Engine Emissions. A Review." D. Scarpete, University of Galati, Romania.

[36] NRC 2011. ML11229A426-0420-E111. Contains 14 chapters addressing use of emergency diesel generators 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. https://www.nrc.gov/docs/ML1122/ML11229A061.html

4.2.14.2 High-Pressure Fuel Injection

A literature review found some articles indicating NO_x reductions may occur when increasing injection pressure is used 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.[37] DAQ thus does not consider it a viable control technology for RACT.

4.3 NELLIS AIR FORCE BASE (NAFB)

NAFB (Source ID: 114) is permitted as a major (Part 70) source for NO_x, a synthetic minor source for VOC, PM_{10}, $PM_{2.5}$, CO, and HAP, and a minor source for SO_2. It is also a source of GHG. The facility includes a stationary source category which, 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 the 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. According to NAFB, the most recent ATC (issued 10/13/22) lists the NO_x PTE as 200.47 tpy.

DAQ's RACT methodology (Appendix 1) notes that although NAFB has a NO_x PTE of around 200 tpy, it had only 19.81 tpy of actual NO_x emissions in 2017 (about 10% of PTE). In its RACT analysis, NAFB included all units with a PTE equal to or greater than 5 tpy as listed in the RACT methodology and the NAFB OP, plus a planned emergency generator for Building 1771 that has not yet been installed but has received a unit number (G188). NAFB noted that Unit G141 was permitted, but was never installed and will not be (it is the wrong size), and that Unit G176 has not yet been installed, so has no actual emissions, but was still included in the RACT analysis.

Altogether, NAFB conducted NO_x RACT analyses for a single non-emergency stationary engine (A032); seven emergency-use stationary engines (generators) (G009, G010, G032, G033, G041, G176, and G188); and two aircraft engine test cells (N001 and N002). All of the generators are diesel-fired and considered standby generators, so are allowed only limited use, and all are

[37] Fayad, M.A. Effect of Fuel Injection Strategy on Combustion Performance and NO_x/Smoke Trade-Off Under a Range of Operating Conditions for a Heavy-Duty DI Diesel Engine. *SN Appl. Sci.* 1, 1088 (2019). https://doi.org/10.1007/s42452-019-1083-2

operated at levels far below their potential use.[38] The DAQ RACT analyses in Section 4.3 are based on NAFB's analyses, supplemented as needed.

Most of the NAFB RACT analyses were for generators. NAFB used a more complete list of potential NO_x control retrofit technologies than most facilities, including the replacement of existing generators. 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.[39]

4.3.1 NO_x RACT for Unit A032

4.3.1.1 Control Technology Analysis

This diesel-fired generator (Appendix 2, p. 11; analysis indicates it is a low-load mobile diesel) supports the aggregate plant at the base; it has an annual operating limit of 2,080 hours, but was not used in 2021 and there were no plans to use it in 2022. Emissions from 2017–2021 ranged from 0.0 to 0.39 tpy NO_x, and the highest annual use of the engine in the past five years was in 2018 (102 hours). The unit is turbocharged. Its existing NO_x controls are GCP and GMP, typical for emergency generators.

Appendix 2 contains the NAFB RACT analysis. Table 4.3-1 lists the potentially available control technologies identified by NAFB. The table includes DAQ's analysis of NAFB's information, along with supplemental information on the availability and costs of the emissions controls and a conclusion on whether each control qualifies as RACT. NAFB proposed accepting an operating limit of 1,200 hours, which would reduce the current PTE of A032 from 8.06 tpy to 3.41 tpy to meet RACT requirements. DAQ found that the existing control technology requirements—turbocharging and ignition timing retardation—qualify as RACT, and proposes to establish a design and operating standard as RACT in lieu of restricting hours of operation. NAFB may, at its option, elect instead to accept an enforceable reduction in operating hours of A032 to avoid the RACT requirements.

The CE analyses in Table 4.3-1 are mostly first-order approximations based on information available in the literature; in a few cases, vendor information on cost or applicability was available. DAQ did not correct costs for inflation unless the initial CE calculation was below the CE threshold. Detailed cost calculations are in Appendix 9.

Table 4.3-1. NO_x RACT Analyses for Unit A032[40]

CT #	Control Technology	RACT	Discussion
1	SCR	No	This is a small unit (250 hp) that operates well below PTE.

[38] A032, for example, is authorized to operate 2,080 hours per year, but the highest operating level in the last five years was 102 hours in 2018.

[39] Even if replacement was a required option, the cost effectiveness (CE) analyses conducted by NAFB for replacing the generators with lower-emitting generators demonstrated that the cost (in $/ton NO_X decrease) was far higher than the threshold of $5500/ton.

[40] NAFB noted on 1/31/22 that this unit is not operational and there are no current plans to operate this unit in the future, but since it is still permitted, DAQ conducted a RACT analysis for the unit.

CT #	Control Technology	RACT	Discussion
			Intermittent operations of A032 would decrease control efficiency of SCR compared to steady-state operations. DAQ calculates a CE of $37,001/ton NO_x removed, more than 6 times higher than the $5,500/ton threshold. DAQ concurs this control technology does not qualify as RACT because it is not cost-effective.
2	SNCR	No	NAFB could not find examples of SNCR being used and concluded the control technology is not technically feasible for A032. Literature indicates that SNCR, though having a lower capital and operating cost, is not available for diesel engines because the technology operates best at temperatures of 1600–2000°F, and diesel engine exhaust gas ranges from 800–1200°F.[41] The exhaust gas temperature is too low for SNCR to be effective (Figure 4-2).[42] SNCR also needs a fuel-rich engine operation or use of reducing agents, so its use is limited to rich-burn engines. DAQ finds this control technology is not technically feasible for A032.
3	Dry Low NO_X (DLN) and SoLoNO$_X$ (SLN)	No	NAFB indicates these technologies are primarily for turbines and it found no examples for use on engines similar to A032. DAQ also could not locate articles, documents, or websites showing DLN or SLN use on diesel engines. DAQ concurs that this control technology is not technically feasible for A032.
4	Turbocharging	Yes	A turbocharger increases the power output of an engine by allowing more air to enter the combustion chamber. The increased air reduces the maximum combustion temperature and pressure, which decreases NO_x formation. A032 is currently equipped with a turbocharger and no additional cost is estimated to use this technology. DAQ concludes that use of a turbocharger qualifies as RACT. Turbocharging combined with EGR could further reduce NO_x emissions, but EGR has drawbacks (see #7).[43]
5	GCP, GMP	Yes	These are the most common RACT determinations in the RBLC and already implemented on A032 via its Title V OP.[44] DAQ finds this control technology available and cost-effective because NAFB would incur no additional costs to continue with these practices.
6	Pre-stratified charge	No	According to NAFB, the manufacturer says this control technology is not available. EPA documents support NAFB's analysis, indicating this technique is for spark ignition engines, not compression engines.[45] DAQ agrees this control technology does not qualify as RACT because it is not available.
7	EGR	No	DAQ makes no determination on availability, but agrees this control technology does not qualify as RACT because the potential energy and collateral pollutant disbenefits outweigh the benefit of NO_x emission reductions. See general discussion in Section 2.1.6.
8	ITR	Yes	The NAFB OP requires operating A032 with ITR,[46] which DAQ concludes qualifies as RACT. If the unit had not already been equipped for ITR, retrofit installation would have resulted in a CE of

[41] Marek Pronobis, Environmentally Oriented Modernization of Power Boilers, 2020, Chapter 4.4.2.

[42] Emission Factor Documentation, p. 2-18.

[43] Dond, DK, Gulhane, NP. Effect of a turbocharger and EGR on the performance and emission characteristics of a CRDI small diesel engine. *Heat Transfer*. 2022; 51: 1237- 1252. doi:10.1002/htj.22350

[44] Condition V.B,3.g. states: "The permittee shall operate and maintain all generators in accordance with the manufacturer's O&M manual for emissions-related components." DAQ assumes that this represents GCP and GMP.

[45] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 5-14.

[46] Source No. 114, Title V Operating Permit, issued 6/15/21. Condition V.B.3.c, p. 34.

CT #	Control Technology	RACT	Discussion
			$6,674/ton,[47] making this control technology not cost-effective.
9	AFR adjustments	No	DAQ makes no finding on availability, but concludes this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the benefits of the potential emissions reductions.
10	Derating / increasing speed	No	DAQ finds this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the potential for RACT emissions reductions.
11	MAT adjustment / after-cooler	No	DAQ estimates the CE for retrofitting a cooler on A032 at $15,000/ton. DAQ concludes this control technology is available but not cost-effective, so does not qualify as RACT.
12	DWI	No	The CE estimated for this 250-hp engine was based on much larger engines (6,000+ hp), giving a NO_x reduction of 90% at $10,279/ton, twice the threshold.[48] DAQ finds this control technology is not cost-effective, so does not qualify as RACT.
13	Water/fuel emulsions	No	Extrapolating from a 6,000-hp engine to a 250-hp one (equivalent to 186 kW) gives a rough $25/kW capital cost for the smaller engine. At 186 kW, A032 would have a $4,650 capital cost. There are also annual operating costs for using emulsified diesel: it cost about 4.4% more than regular diesel in Europe in 2015 (if regular diesel cost $5/gallon, emulsified diesel cost $5.22/gal). Further assuming 500 hrs/yr of operation for the 250-hp diesel engine yields about 6,274 gal/yr[49] which, with a delta of $0.22/gal, equals $1,479/year.[50] DAQ calculated a CE of $61,754/ton, so concludes this control technology is not RACT because it is not cost-effective.
14	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.
15	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.
16	Conversion to natural gas from diesel	No	NAFB's security directive prohibits reliance on natural gas for standby generation.[51] DAQ thus finds this control technology is not available.
17	Conversion to dual fuel (diesel/natural gas)	No	NAFB's security directive prohibits reliance on natural gas for standby generation; however, dual fuels might be acceptable by allowing use of diesel when natural gas is not available. Costs would include converting the generator to dual fuel and the piping needed to supply the unit with natural gas. Conversion cost for small diesels ranges from $7,000 to $12,000.[52] NO_x reductions of 20–30% are

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

[48] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

[49] Diesel Service & Supply | 625 Baseline Road, Brighton, Colorado 80603, sales@dieselserviceandsupply.com | www.dieselserviceandsupply.com Toll-Free: 800-853-2073 | Main Office: 303-659-2073 | Fax: 720-685-7920

[50] *Proceedings of the 14th International Conference on Environmental Science and Technology Rhodes, Greece, 3-5 September 2015;* PENETRATION PROSPECTS OF EMULSIFIED FUEL IN THE GREEK OIL MARKET, TYROVOLA TH., DELIGIANNIS A., DODOS G.S. AND ZANNIKOS F.

[51] NAFB included a copy of the directive in its RACT analysis.

[52] https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/

CT #	Control Technology	RACT	Discussion
			expected.[53] DAQ calculated a CE of $6,207/ton—slightly above the threshold—assuming no increase in maintenance costs and only a $2,000 cost to connect to natural gas.[54] DAQ finds this control technology does not qualify as RACT because it is not cost-effective.
18	Alternative fuels (other than natural gas)	NA	Literature indicates that other fuels are not available for these engines. Methanol and liquified natural gas (LNG) are the main alternatives besides emulsions. Methanol has serious corrosive and toxic problems, is costly, and can be readily contaminated with water, although NO_x reductions can reach 60%. LNG requires huge investments for storage and installation and has high CO emissions.[55] DAQ finds that alternative fuels are not RACT for these emergency generators because the costs and potential collateral pollutant disbenefits outweigh the benefits of potential emissions reductions.

4.3.1.1.1 RACT Emissions Limitation

DAQ determined that turbocharging, in combination with ITR, CGP, and GMP, qualifies as RACT for Unit A032 because the technology is feasible and cost-effective, since it is already required. It is not feasible, however, to establish an emissions limitation for any of these control technologies. Turbocharging represents a design standard, while ITR is an operational standard. DAQ proposes to adopt the following requirements for RACT:

1. NAFB shall operate A032 with turbochargers.

2. NAFB shall operate A032 with ITR.

3. NAFB shall operate the generator in accordance with manufacturer's recommended O&M specifications.

No additional NO_x emissions reductions are expected from compliance with RACT requirements.

NAFB concluded its RACT analysis by proposing a reduction in Unit A032's hours of operation, from the currently authorized 2,080 hours to 1,200 hours per year. This action would reduce A032's PTE to below 5 tpy. DAQ does not consider reduced hours of operation a potential control technology because it does not reduce emissions during times of operation. Because A032 already satisfies RACT requirements, NAFB need not accept the proposed operational restrictions; however, if NAFB wishes to avoid establishing RACT requirements on A032 (even though they impose no additional control), it may apply to reduce the PTE of the emissions unit to below 5 tpy.

[53] Talus Park, Dual fuel conversion of a direct-injection diesel engine, West Virginia University Master's Thesis, 1999.

[54] This cost may be underestimated.

[55] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

4.3.2 Emergency Generators

4.3.2.1 <u>Control Technology Analysis</u>

NAFB operates eight emergency generators with a PTE above 5 tpy, and included specifications for each of these engines in its RACT analysis (Appendix 2). Three engines are not included in this analysis. One unit (#141) was incorrectly sized when purchased, so rather than operate it, NAFB uses it for spare parts. EU G176 is a new engine that was installed with BACT. DAQ determined the existing BACT analysis remains current and satisfies RACT requirements for this unit. An additional emission unit is awaiting an ATC Permit that will address any RACT requirements for the unit when it is issued.

Since the eight emergency generators are similar in size and planned operation, both NAFB and DAQ performed a single analysis representing all eight. Appendix 2 contains the NAFB RACT analysis; DAQ included the potentially available control technologies identified by NAFB for the eight emergency engines in Table 4.3-2. The table also includes DAQ's analysis of information provided by NAFB, along with supplemental information on the availability and costs of the emissions controls and DAQ's conclusion on whether the control qualifies as RACT. Appendix 9 provides detailed cost calculations.

DAQ grouped the control technologies by type: CTs 1–3 are add-on controls; CTs 4–15 are modifications to the emission unit or its operation; and CTs 16–18 are fuel switch options, including conversion of the units to allow use of alternative fuels. NAFB included emission unit replacement as potentially available control technology options; however, DAQ does not consider 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 replacement options as RACT from further review.[56]

Table 4.3-2. NO_x RACT Analyses for Emergency Generators (G009, G010, G032, G033, G041)

CT #	Control Technology	RACT	Discussion
1	SCR	No	DAQ performed a cost-effectiveness analysis for G041, a small unit (1,220 hp) with the highest annual emissions of all emergency engines, so most likely to have a CE below the threshold. This conservative analysis resulted in a CE of $7,754/ton of NO_x removed, more than the $5,500/ton threshold. DAQ determined SCR is not RACT because it is not cost-effective.

[56] Notably, although DAQ finds replacing an existing emission unit and reducing hours of operation are not control technology options for RACT, a major source, at its election, 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
2	SNCR	No	NAFB could not find examples of SNCR being used, so considered it not technically feasible. Literature indicates SNCR is not available for diesel engines because it operates best at temperatures of 1600–2000°F and diesel engine exhaust gas ranges from 800-1200°F.[57] SNCR also needs a fuel-rich engine operation or the use of reducing agents; CI diesel engines are generally lean-burning. In addition, exhaust gas temperature makes SNCR unsuitable (Figure 4-1).[58] DAQ finds that SNCR does not qualify as RACT because it is not an available control technology.
3	DLN and SLN	No	NAFB indicates these technologies are primarily for turbines, and no examples for emergency engines were found. DAQ also could not find articles, documents, or websites showing use of either on diesel engines. DAQ thus finds that DLN and SLN are not commercially available for application to these emergency engines.
4	Turbocharging	Yes	NAFB's RACT analysis indicates that these emergency generators are currently equipped with turbochargers.[59] DAQ finds this control technology qualifies as RACT because it is both available and cost-effective.
5	GCP and GMP	Yes	These are the most common RACT determinations in the RBLC and already implemented on these units through the OP.[60]
6	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.[61] DAQ agrees this control technology does not qualify as RACT because it is not available.
7	EGR	No	DAQ makes no determination on the availability of this control technology, but agrees it does not quality as RACT because the potential energy and collateral pollutant disbenefits outweigh the benefit of NO_x emission reductions (Section 2.1.6).
8	ITR	Yes for G032 and G033; No for other units	The NAFB RACT analysis concludes ITR is not a desirable control technology because it degrades performance and longevity. The literature backs this up, indicating increases in CO, PM, and HC emissions and a fuel penalty of 3%. DEQ CE calculations result in a CE of $30,740/ton, much higher than the $5,500/ton threshold.[62] However, the OP already requires it for G032 and G033, so it is considered RACT for those units. DAQ concludes that ITR does not qualify as RACT for the other units because the energy and collateral pollutant disbenefits outweigh potential emission reductions, and the control technology is not cost-effective for the other engines.

[57] Marek Pronobis, Environmentally Oriented Modernization of Power Boilers, 2020, Chapter 4.4.2.

[58] Emission Factor Documentation, p. 2-18.

[59] The NAFB RACT analysis states that all these emergency generators are equipped with turbochargers (p. 16). The Part 70 Operating Permit requires all 100+HP generators be equipped with a turbocharger and aftercoolers. *See* Condition V.B.3.a, p. 34, Part 70 Operating Permit, Source No. 114, issued June 15, 2021.

[60] From the Title V permit (Condition V.B.3.g, p. 35):

> The permittee shall operate and maintain all generators in accordance with the manufacturer's O&M manual for emissions-related components.

[61] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 5-14.

[62] 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
9	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.
10	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
11	MAT adjustment / after-cooler	Yes	NAFB is required to use air cooling on these emergency generators.[63] DAQ concludes that air cooling qualifies as RACT because it is available and cost-effective.
12	DWI	No	The CE estimated for these emissions, based on much larger engines (6000+ hp), gives a NO_x reduction of 90% at $10,279/ton, twice the threshold.[64] DAQ concludes this technology is not RACT because the environmental impacts associated with increased water use and potential collateral pollutant disbenefits outweigh the potential for emissions reductions, and because it is not cost-effective.
13	Water/fuel emulsions	No	DAQ estimated this CE at $13,323/ton, so concludes this is not RACT because it is not cost-effective.
14	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.
15	High-pressure fuel injection	No	DAQ finds 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.
16	Conversion to natural gas from diesel	No	NAFB's security directive prohibits reliance on natural gas for standby generation (footnote #48; Appendix 2). DAQ finds this control technology does not qualify as RACT because it is not technically feasible.
17	Conversion to dual fuel (diesel/natural gas)	No	NAFB's security directive prohibits reliance on natural gas for standby generation; however, dual fuels might be acceptable by allowing use of diesel when natural gas is not available. Costs would include converting the generator to dual fuel and the piping needed to supply the unit with natural gas. Conversion cost for small diesels with turbochargers ranges from $8,000–$12,000.[65] Reductions of 20–30% NO_x are expected.[66] DAQ calculated a CE of $8,476/ton, assuming $2,000 to connect to natural gas.[67] DAQ finds this control technology does not qualify as RACT because it is not cost-effective.

[63] Condition V.B.3.a.: Generators greater than 100 hp (EUs: G004, G009, G010, G029 through G033, G035a, G041, G046 through G051, G064, G067 through G069, G073, G077, G080, G090 through G094, G097, G103, G121, G130 through G132, G136, G137, G139, G141, G142, G149, G154, A053, A076, G161 through G163, G165, G166, and G172 through G182) shall be equipped with turbochargers and aftercoolers.

[64] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

[65] https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/

[66] Talus Park, Dual fuel conversion of a direct-injection diesel engine, West Virginia University Master's Thesis, 1999.

[67] On 1/31/23, NAFB commented that natural gas is only available in the area for 6 of the 8 engines and that there are no lines to engines, so the cost to bring NG lines to the engines would be considerably higher than the assumed $2000/engine..

CT #	Control Technology	RACT	Discussion
18	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 greenhouse gas emissions. LNG requires huge investments for storage and installation, and increases CO emissions.[68] DAQ concludes that these alternative fuels are not RACT because LNG is not cost-effective and the collateral pollutant emissions disbenefits outweigh potential emissions reduction benefits.

4.3.2.2 RACT Emissions Limitation

NAFB concluded that RACT is no additional add-on NO_x emissions control and proposes to follow GCP and GMP to satisfy BACT requirements. For the reasons discussed in Table 4.3-2, DAQ finds the existing emissions controls, consisting of turbocharging and MAT adjustment / aftercooler, qualify as RACT. Similar to Unit A032, 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 with turbochargers and aftercoolers. No additional NO_x emissions reductions are expected from compliance with RACT requirements.

4.3.3 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. Allowable NO_x emissions are 46.42 tpy, compared to the five-year high of 12.90 tpy in 2019 and a five-year average of 9.622 tpy.

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

An on-line search on hush house controls showed at least one company in the business of providing noise control for hush houses offers an SCR to control NO_x emissions.[69] DAQ found no information on the internet 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),[70] requiring

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[68] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

[69] https://www.cecoenviro.com/wp-content/uploads/2022/06/Burgess-Aarding-Silencer-and-acoustical-technology.pdf

[70] 07-342, A National Historic Context for the Hush Houses and Test Cells on Department of Defense Installations, Jayne Aaron, LEED AP, November 2009

mixing with cool air to avoid damaging the noise reduction equipment, and has a higher volume, especially in the afterburner phase of operation. Exhaust mass ranges in one article were 18.8, 22.32, and 167.688 kg/sec at the three main test modes (idle, military, and afterburner).[71] DAQ therefore concludes that RACT is the current OP requirement of applying best management practices.[72]

4.4 CAESARS ENTERTAINMENT, LAS VEGAS

Caesars (Source ID: 257) owns and operates several adjacent and contiguous hotels and casinos, along with 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 440.10 tons per year of NO_x emissions and 26.76 tons per year of VOC. Only NO_x emissions exceed both the 40 CFR Part 70 major-source and moderate area major-source thresholds; therefore, DAQ limited the RACT analysis to emissions of NO_x. Appendix 3 contains the proposed RACT analysis from Caesars, which includes a complete list of emission units potentially subject to RACT requirements. These consist only of diesel-fired emergency generators and natural gas-fired boilers. DAQ followed Caesars's RACT analysis in grouping emission units with similar ratings or emissions concentrations in its own analysis.

Caesars reported 19.9 tpy actual NO_x emissions in 2017 for the National Emissions Inventory. Its RACT analysis generally aligns with this value, reporting actual emissions from 18.55 to 40.17

[71] Emission tests of the F100-PW-229 turbine jet engine during pre-flight verification of the F-16 aircraft, J. Merkisz, J. Markowski & J. Pielecha, Poznan University of Technology, Poland. WIT Transactions on Ecology and The Environment, Vol 174, 2013, p. 228. https://www.witpress.com/Secure/elibrary/papers/AIR13/AIR13019FU1.pdf

[72] Condition VI.B.3.a. "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 Title V permit also contains emissions limits, fuel limits, testing requirements, and monitoring and reporting requirements.

tpy from 2019 to 2021.[73] Source-wide actual emissions are thus less than 70% of the stationary source's PTE. The Caesars RACT analysis also reports that actual emissions from emergency generators are between 1–6% of PTE, while each boiler's actual emissions are less than 50% of its PTE.

4.4.1 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.[74] According to the Caesars RACT analysis, the Hurst and Burnham boilers are 3-pass fire-tube, 800-bhp boilers; the existing Riello burners associated with all five boilers include LNB designs and cannot be modified to increase NO_x reduction to the level of ULNB capability. Caesars uses these boilers more than emergency generators or boilers at other Caesars properties, although they still are small emitters, with actual emissions of less than 3 tpy. All the boilers fire natural gas and have NO_x emissions limits of 29–30 ppm at 3% O_2. There are no limits on fuel use or operating hours.

4.4.1.1 Control Technology Analysis

Table 4.4-1 shows DAQ's RACT analyses for the Caesars boilers, based on information from the Caesars (and MGMRI) RACT analyses and other documents, as indicated.

Table 4.4-1. NO_x RACT Determinations for Caesars Boilers

CT #	Control Technology	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 300–500°F, and Caesar reports exhaust temperatures of less than 400°F.[75] Figure 4-1 confirms the flue gas temperatures are too low for effective SCR operation. DAQ estimates a control effectiveness exceeding $18,000. DAQ concludes that this control technology is not RACT because it is neither cost-effective nor technically feasible for this type of boiler.
2	SNCR	No	Although having a lower capital and operating cost, SNCR is not available for this size industrial boiler because it operates best at temperatures of 1600–2000°F, but the boiler flue gas temperatures are less than 400°F (204°C)[76] (Figure 4-2). DAQ determines SNCR is not technically feasible for these boilers.
3	LNB	Yes	The boilers are equipped with LNB and required to operate at or below 30 ppm NO_x. DAQ finds that LNB qualifies as RACT.

73 The first row of data in Caesars RACT Analysis Table 3 lists emissions for the "entire source", which appears to include all the emissions from all the different properties, no matter how small. The remaining rows of data list each emission unit with a NO_x PTE of 5 tpy or more and actual emissions for the 3 years 2019-2021. For 2019, for example, the total for all the 5+tpy units is 15.99 tpy versus 21.51 tpy for all the units (entire source).

74 EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 1-1.

75 Technical advice on boiler combustion control, U.S. Department of Energy's Industrial Technologies Program, https://www.reliableplant.com/Read/22138/technical-advice-on-boiler-combustion-control

76 Marek Pronobis, Environmentally Oriented Modernization of Power Boilers, 2020, Chapter 4.4.2.

CT #	Control Technology	RACT	Discussion
4	ULNB	No	This category includes metal mesh burners (as well as ceramic burners—see CT#15). For metal mesh burners or equivalent ULNB, DAQ calculated a CE of $9,015/ton to upgrade the burners to ULNB. This cost estimate is based on Caesars's cost figures using a 70% control efficiency for ULNB and adjusting Caesars's estimate for a 30-year life expectancy. DAQ finds that ULNB is not RACT because it is not cost-effective.[77]
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.[78] Caesars indicates that the boilers already have LNB installed and some LNB include FGR to some extent as part of the design (even more so with ULNB).[79] 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. Although adding FGR to these boilers is likely not possible, DAQ calculated the CE to determine whether FGR was cost-effective. Several literature sources indicate a range of control efficiencies, in part due to different starting NO_x concentrations (e.g., from 260 to 110 ppm).[80] The Caesars boilers are already meeting NO_x limits of 30 ppm, so are already at a low concentration, but reductions of 40–50% using 20–30% FGR are possible.[81] Assuming a 50% emissions reduction and using a 1975 retrofit capital cost of $21,000,[82] adjusted for inflation using the CEPCI, DAQ estimated a CE of $6,182/ton NO_x removed. DAQ rejects FGR as RACT because the technology is technically infeasible to retrofit with the existing burners, and the control technology is not cost-effective.
7	LNB or ULNB + FGR	No	For Caesars, the cost of ULNB alone (see above) was not CE;

77 ULNB can reduce NOx 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 $235K; Caesars used a 10-year life without explanation, resulting in an annualized cost of about $32K. Because the amount of NOx reduction can be no more than 2.74 tpy (the actual emissions for the highest emitting boiler (CP02)), the cost effectiveness (CE) is high: $18,552. Using a 30-year life instead of 10, the capital recovery factor is reduced to 0.073 from 0.136, which reduces the annualized cost to $17,291, which still results in a high CE (e.g., for CP02, a removal of 1.918 tpy NOx results in a CE of $9015/ton and the CE for the other boilers would be higher). Caesars cited a number of CE determinations and thresholds for NOx, with the highest CE threshold being $5500/ton.

78 From the Caesars 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 NOX burner alone, this control option is not considered to be an alternative control strategy to an ultralow NOX burner."

79 APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 7-4.

80 EPA-450/1-78-001, Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition, January 1978, p. 3-25.

81 APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 6-18.

82 EPA-450/1-78-001, Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition, January 1978, p. 4-55.

CT #	Control Technology	RACT	Discussion
			nonetheless, DAQ evaluated the CE of this technology using cost information provided by MGMRI. DAQ estimated a CE for ULNB/FR for Caesars's boilers at $21,960/ton. DAQ concludes that this control technology combination is not RACT because it is not cost-effective.
8	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[83] that can reduce NO_x emissions by 5-10%[84] or 16-20% (by going to 2-7% EA).[85] Often this is done by changing burners, so the cost and CE would be similar to that of installing a ULNB. Accordingly, DAQ concludes that this control technology is not RACT because it is not cost-effective.
9	Burner Out of Service (BOOS)	No	This 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 available.
10	Overfire Air (OFA)	No	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.[86] The emissions reductions available are estimated at 30–58%.[87] 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.
11	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 overfire air, when the angle of the air flow can be adjusted. Since overfire air is not available or cost-effective, DAQ eliminated this control technology for further consideration in the RACT analysis.
12	Reduced Air Preheat (RAP)	No	Combustion air preheat is never used for fire-tube boiler configurations,[88] so there is no air preheat to reduce. When available, it can reduce NO_x emissions by 15–25%,[89] but is seldom used due to

83 APTI 418 Student Manual, p. 6-8.

84 http://cleanboiler.org/learn-about/boiler-efficiency-improvement/boiler-combustion/ However, this source also states that it is better to select a control technology that has little effect on excess air.

85 APTI 418 Student Manual, p. 6-9.

86 APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 6-10. "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."

87 APTI 418 Student Manual, p. 7-5. 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%)

88 EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 2-4.

89 APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 6-18 and 6-19.

CT #	Control Technology	RACT	Discussion
			efficiency penalties.[90] DAQ determined this control technology is not RACT because it is not available for these types of boilers.
13	Fuel conversion	No	This option is often addressed for several different pollutants, such as particulate matter and SO_x, when a fuel such as coal or oil is used. A fuel lower in nitrogen will produce less NO_x from nitrogen in the fuel.[91] 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.
14	Water / Steam Injection (WSI)	No	One study is cited 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.[92] 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 2022 costs using the CEPCI, CE_{2022} = $\$3,903_{1992}$ x ($\$824.5_{2022}$/$\$358.2_{1992}$) = \$8,984/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.
15	CFB / Radiant Ceramic Burners (RCB)	No	This is 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 l,800°F and typical emissions are 20 ppm CO, 15 ppm NO_x, and 2 ppm HC."[93] NO_x emissions as low as 10 ppm have been reported; 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, so the capital costs are relatively low. CFB have an additional advantage: thermal efficiency is increased by 1–2%, resulting in a savings of as much as 5% in natural gas. However, ceramic burners to date have been applied only in boilers of 16 MM Btu/hr or less, so are not feasible for the Caesars boilers, which are 30+ MM Btu/hr. Although ceramic burners are not technically feasible for the Caesars boilers, a CE analysis was conducted to provide information on how cost-effective the technology is. In a 2011 paper,[94] burner capital cost was estimated at \$0.78/1000 Btu, so CFB for a 33 MMBtu/hr boiler would be \$25,740 in 2011 dollars. Using the CEPCI, $Cost_{2022}$ = \$25,740 x ($\$824.5_{2022}$/$\$585.7_{2011}$) = \$36,235. Assuming the same direct/indirect costs of \$3,000 that Caesars used for other cost analyses, a 10-year life for the burners (the ceramic is reportedly easily damaged), and a reduction of 50% (from 30 ppm to 15 ppm), the CE for CP02 with 2.74 tpy is \$3,895/ton, which is cost-effective, but the CE for CP04 with 1.08 tpy is \$9,881/ton,

[90] Oland, C. B., ORNL/TM-2002/19, GUIDE TO LOW-EMISSION BOILER AND COMBUSTION EQUIPMENT SELECTION, April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-5.

[91] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-4.

[92] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. D-3.

[93] RADIANT FIBER BURNERS FOR GAS-FIRED APPLIANCES AND EQUIPMENT, John P. Kesselring, Robert M. Kendall, and Richard J. Schreiber, Alzeta Corporation'

[94] Xu, T., CHARACTERIZING COSTS, SAVINGS AND BENEFITS OF A SELECTION OF ENERGY EFFICIENT EMERGING TECHNOLOGIES IN THE UNITED STATES, Lawrence Berkeley National Laboratory, 3/31/2011, https://escholarship.org/uc/item/3nb0863v.

CT #	Control Technology	RACT	Discussion
			which is not. However, a 5% fuel savings,[95] assuming the lowest hours of operation of 446.6 (CP01 in 2021) would be $6,815/year, which would result in a CE of -$1080 – -$2,739)/year, depending on the unit. This CE, like most, is based on a number of assumptions, and the capital cost of other ULNB burners (based on vendor quotes) is considerably higher, so a more tailored analysis would be warranted to see if it would affect the RACT decision, including getting a quote from one of the manufacturers of these burners, such as the Alzeta Corporation.
16	Combined Combustion Modification (CCM)	No	This is a catch-all for different combinations of control techniques. The most demonstrated combination 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. Data have been collected for 101 natural gas-fired units, 44 distillate oil-fired boilers, and 13 residual oil-fired boilers. All were watertube boilers, the majority located in California, so this information may not apply to Caesars fire-tube boilers. Many of the California boilers were existing units retrofitted with LNB/FGR controls. NO_x reduction efficiencies of 55 to 84% were reported for five units firing natural gas.[96] The most widely used combination is LNB with FGR, which DAQ already determined is not RACT because of a CE of $21,960/ton (see CT #7 above).
17	Gas Fuel Flow Modifiers (GFFM)	No	A device known as a 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.[97] 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 reducing emissions. However, DAQ calculated CE using 15% reduction in NO_x and half the cost of installing ULNB. The CE was $21,300, so DAQ concludes that GFFM is not cost-effective for RACT.
18	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

[95] See https://www.eia.gov/dnav/ng/NG_PRI_SUM_DCU_SNV_M.htm for natural gas prices for Nevada.

[96] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-60.

[97] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-69.

CT #	Control Technology	RACT	Discussion
			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.[98] 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 $21,960/ton. DAQ finds that FIR is not RACT because it is not cost-effective.
19	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."[99] Reductions of 48–68% have been demonstrated on a utility boiler;[100] 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.
20	Burner Tuning (BT)	No	See Oxygen Trim (#21). BT appears to be similar to OT in terms of operation and costs.
21	Oxygen Trim (OT)	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.[101] An EPA publication mentions specific installations and 15–25% control.[102] 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[103] 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 ($824.5$_{2022}$/358.2_{1992}$) = $7,596.

98 Oland, C. B., ORNL/TM-2002/19, Guide to Low-Emission Boiler and Combustion Equipment Selection, p. 5-9. April 2002. Prepared for the U.S. Department of Energy, Office of Industrial Technologies.

99 EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-56.

100 Reese, James L., et al., Demonstration of Fuel Injection Recirculation (FIR) for NO_X Emissions Control, 1994. https://collections.lib.utah.edu/ark:/87278/s6zg6vvv

101 Oland, C. B., ORNL/TM-2002/19, Guide To Low-Emission Boiler And Combustion Equipment Selection, April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-5.

102 EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-64.

103 EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 2-17.

CT #	Control Technology	RACT	Discussion
			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.
21	Biased Firing (BF)	No	This 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, this is not an applicable control technique.
22	Natural Gas Reburning (NGR)	No	This 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%.[104] However, a literature search did not result in any articles or reports on use of NGR in natural gas-fired boilers (just coal-fired). DAQ concludes this technology is not technically feasible for gas-fired boilers.
23	Cyclonic Combustion Burner (CCB)	No	This 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.[105] To achieve ultra-low NO_x 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 did result 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 five years of RACT determinations in the RBLC and found none, so considered the following potential control options for NO_x RACT for industrial boilers: FGR, ULNB, SCR, and SNCR. DAQ did not conduct a separate RBLC search, but expanded the Caesars search by using a full 10-year review of the RBLC conducted by another Clark County major source, MGMRI. In addition to SCR, MGMRI's search identified natural gas-fired boiler NO_x control technologies that included two combinations of controls: LNB with FGR and ULNB

[104] Oland, C. B., ORNL/TM-2002/19, GUIDE TO LOW-EMISSION BOILER AND COMBUSTION EQUIPMENT SELECTION, April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-7.
[105] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-54.

with FGR. DAQ identified additional control options in EPA's *Alternative Control Techniques (ACT) Document for NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers*.[106]

Natural gas-fired boiler NO_x control techniques are divided into combustion and post-combustion controls. The LNB already installed on the Caesars boilers, which are in the first category, 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 4.4-1 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 BOOS, Biased Firing (BF), adjusting burners lean and rich, OFA, and LNB and ULNB when the burner design incorporates staged combustion; up to a 50% reduction in NO_x emissions has been reported, depending on the technique used and the type and size of boiler.[107] 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.[108]

The NO_x boiler control techniques identified and discussed in Table 4.4-1 have been identified in the literature. Some techniques, such as load reduction, reduced air preheat, and low excess air firing are not considered independent or viable control technologies. Fuel switching has traditionally not been viewed as a control technology. However, the switching from coal to oil or gas and from high-nitrogen residual oil to lighter oil fractions or gas have come under increased consideration in regional and seasonal NO_x compliance options."[109] 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.

Of the 23 boiler control technologies evaluated by DAQ, none appear to be both technically and economically feasible. CFB are not technically feasible (the boilers are too large for such burners), but if applicable, would appear to be economically feasible. CFB have the benefit of increasing efficiency and saving fuel. The CE for CP02 with 2.74 tpy actual emissions is $3,895/ton, which is cost-effective, while the CE for CP04 with 1.08 tpy is $9,881/ton, is not. However, a 5% fuel savings,[110] assuming the lowest hours of operation of 446.6 (CP01 in 2021) would be $6,815/year, which would result in a CE of -$1,080 to -$2,739/year, depending on the unit. The reduction in actual emissions for equipping the two boilers with ceramic burners would have been 5.445 tpy.

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[106] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers, March 1994, p. 5-39.
[107] Oland, C. B., ORNL/TM-2002/19, Guide To Low-Emission Boiler And Combustion Equipment Selection, April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-7.
[108] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers, March 1994, p. 5-57.
[109] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers, March 1994, p. 5-40.
[110] See https://www.eia.gov/dnav/ng/NG_PRI_SUM_DCU_SNV_M.htm for natural gas prices for Nevada.

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 MM Btu/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 the metal mesh burner technology is not considered cost effective for these boilers.

Therefore, DAQ finds that ceramic fiber burners are not available for these emissions units and that metal mesh burners are not cost effective, so concludes that the existing controls constitute RACT for these boilers.

4.4.1.2 RACT Emissions Limitation

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

Table 4.4-2. Proposed RACT-Based NO_X Emission Limitations

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

4.4.2 Emergency Generators

Caesars properties host 27 emergency generators subject to RACT review. The diesel generators are rated from 600 to 2,100 kW, and are limited to 100 hours of operation per year for testing and maintenance and up to 50 hours per year for nonemergency situations (which count toward the 100 hours). All the engines are turbocharged and aftercooled. In conducting its proposed RACT analysis, Caesars grouped the generators by power rating (hp) since those ratings largely determine the type and size of control device possible.

Caesars researched the most recent five years of RACT determinations in the RBLC and found none for similar generators. It also identified only SCR as an available control technology after consultation with its service contractor. DAQ considered this information and evaluated additional potentially available control technology options identified by other major sources and in the literature.

Table 4.4-3 contains DAQ's RACT conclusions for the Caesars emergency generators, based on information from the Caesars RACT analyses and other information in Section 2.1 or discussed in DAQ's conclusions. Unless otherwise noted, DAQ used a 30-year life, rather than the 10-year equipment life Caesars used, and 6% interest.

Table 4.4-3. NO_X RACT Analyses for Caesars Emergency Generators

CT #	Control Technology	RACT	Discussion
1	SCR	No	Even with a 30-year life, the CE is far above any threshold cited by the analysis (e.g., the $34,427/ton CE that Caesars calculated would only drop to $22,090/ton using a 30-year capital recovery factor). DAQ concludes that SCR is not RACT because it is not cost-effective.
2	SNCR	No	SNCR is not available for diesel engines because SCR operates best at temperatures of 1,600-2,000°F, while diesel engine exhaust gas ranges from 800-1,200°F.[111] SNCR also needs a 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 4-2).[112] DAQ finds SNCR is not RACT for the emergency generators because the control technology is not technically feasible.
3	DLN and SLN	No	DAQ located no articles, documents, or websites indicating use of DLN or SLN on diesel engines. DAQ finds that DLN and SLN are not commercially available for application to these engines.
4	Turbocharging	*Yes*	The emission units are currently equipped with a turbocharger and aftercooler.[113] Since they are already equipped with a turbocharger and no additional cost is estimated to use this control technology, DAQ concludes that use of a turbocharger qualifies as RACT.
5	GCP and GMP	*Yes*	These practices are the most common RACT determinations in the RBLC and are already being implemented through the Title V OP.[114] DAQ finds GCP and GMP qualify as RACT because they are cost-effective.
6	Pre-stratified charge	No	EPA documents indicate this technique is for spark ignition engines, not CI engines.[115] DAQ finds this control technology is technically infeasible for these CI-engine emergency generators.
7	EGR	No	DAQ makes no finding on the availability of this control technology, but agrees it does not quality as RACT because the potential energy and collateral pollutant disbenefits outweigh the benefit of NO_x emission reductions (Section 2.1.6).
8	ITR	No	If a unit is not already equipped for ITR, retrofit installation

[111] Marek Pronobis, *Environmentally Oriented Modernization of Power Boilers*, 2020, Chapter 4.4.2.

[112] Emission Factor Documentation, p. 2-18.

[113] The Title V permit requires:

> Condition III.E.4.p. The permittee shall operate each of the diesel engines with turbochargers and aftercoolers (EUs: CP13 through CP17, CP28, CP29, CP34, and CP35) (p. 44).

[114] From the Title V permit (Condition III.E.4. o. and q., p. 44):

> o. 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.
>
> q. The permittee shall ensure that the diesel engines are in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EUs: CP28, CP29, CP34, and CP35): *[40 CFR Part 60.4206]*
>
> i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and
>
> ii. installation and configuration of the engine according to the manufacturer's specifications.

[115] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 5-14.

CT #	Control Technology	RACT	Discussion
			results in a CE of $6,674/ton, higher than the $5,500/ton threshold.[116]
9	AFR Adjustments	No	DAQ makes no finding on the availability of this control technology, but finds it does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the benefits of the potential emissions reductions.
10	Derating / increasing speed	No	DAQ finds this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the potential for RACT emissions reductions.
11	Inlet MAT adjustment / aftercooler	Yes	Aftercooler already required, so DAQ considers it RACT.
12	DWI	No	The CE estimated for this 1,220-hp engine was based on larger engines (6000+ hp), giving a NO_x reduction of up to 60% at $11,006/ton.[117] This is nearly double the $5,500/ton threshold, even though it assumes a higher control level than the EPA literature value of 25–35%. DAQ concludes that DWI is not RACT because it is not cost-effective.
13	Water/fuel emulsions	No	DAQ estimates cost-effectiveness is $12,459/ton, over twice the threshold. DAQ finds this control technology is not RACT because it is not cost-effective.
14	EPMS	No	DAQ finds this control technology does not qualify as RACT because the amount of additional NO_x emissions reductions from its use is likely negligible.
15	High-pressure fuel injection	No	DAQ concludes this control technology does not qualify as RACT because its effect on reducing NO_x emissions and the ability to retrofit the technology for existing emission units is highly uncertain.
16	Conversion to natural gas (from diesel)	No	See #17—the numbers would be about the same.
17	Conversion to dual fuel (diesel/natural gas)	No	Some companies specialize in converting to dual fuels (e.g., https://engeniousengineering.com/ and https://dwppon.com /wp-ontent/uploads/2020/06/bifuel_compressed.pdf). Costs would include converting the generator to dual fuel (or to natural gas only, see #16) and the piping needed to supply the unit with natural gas; if natural gas is already available at the properties, the piping cost would be relatively low. Conversion cost for small diesels with turbochargers ranges from $8,000 to $12,000,[118] but because this is for small engines (truck/car), DAQ doubled the assumed cost to $24,000. Reductions of 20–-30% NO_x are expected.[119] EPA documents indicate the same range of control, with an estimated 26.5% reduction in NO_x between diesel and dual fuel engines.[120] CE = $17,739/ton, so DAQ found this technology is not cost-effective and rejected it as RACT.

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

[117] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

[118] https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/

[119] Talus Park, Dual fuel conversion of a direct-injection diesel engine, West Virginia University Master's Thesis, 1999.

[120] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 2-3.

CT #	Control Technology	RACT	Discussion
18	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 besides emulsions. Methanol has serious corrosive and toxic problems, is costly, and can be readily contaminated with water, even if NO_x reductions can reach 60%. LNG requires huge investments for storage and installation and has high CO emissions.[121] DAQ finds that alternative fuels are not RACT for these emergency generators because the costs and potential collateral pollutant disbenefits outweigh the benefits of potential emissions reductions.

Overall, DAQ's RACT determination is that the existing controls (turbocharging, GCP/GMP, and aftercooler) constitute RACT for these emergency diesel generators.

4.5 SWITCH, WEST CAMPUS

Switch (Source ID:16304) owns and operates six separate and adjacent advanced technology ecosystem communications facilities at the following addresses: 7135 S Decatur, Las Vegas, NV 89118; 5225 Capovilla Las Vegas, NV 89118; 7365 Lindell Rd, Las Vegas, NV 89139; 7370 Jones Blvd, Las Vegas, NV 89139; 7380 S Lindell Rd, Las Vegas, NV 89139; and 5325 Capovilla, Las Vegas, NV 89118. The source is categorized under SIC code 7375, "Information Retrieval Services," and NAICS code 517919, "All Other Telecommunications."[122] Information on the emission units is available in the latest Switch OP and Technical Support Document (TSD), available on the Clark County website.

Switch has a facility-wide PTE NO_x of 246.18 tpy and reported only 33.23 tpy of actual NO_x emissions in 2017. The emission units include various size diesel generators for emergencies (mainly NO_x emissions), fire pumps, and cooling towers. The four fire pumps emit less than 0.2 tpy each, and the cooling towers have no NO_x or VOC emissions; therefore, the only emissions units this RACT analysis addressed were the 117 diesel-fired emergency generators (each approximately 3,353 hp/2,500 kW). The generators are limited to operating no more than 104 hours per year, so their individual unit PTE is only 2.06 tpy.[123] The fire pumps are limited to 500 hours of annual use. The cooling towers have no restrictions on use, but have no VOC and NO_x emissions.

Though all emission units were below the 5 tpy applicability threshold, DAQ requested that Switch conduct a RACT analysis that covered at least a majority of potential emissions. After a search of the RBLC, and considering information found in other state regulations, Switch identified EPA Tier 2 Certification,[124] GCP, and operating restrictions as available control technology options. Appendix 4 contains Switch's proposed NO_x RACT analysis.

[121] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

[122] Switch Part 70 Permit and Switch Technical Support Document (TSD)

[123] Switch Part 70 Permit, issued 7/1/21, p. 21.

[124] PART 70 TECHNICAL SUPPORT DOCUMENT (STATEMENT of BASIS) APPLICATION FOR: Renewal of Part 70 Operating Permit, July 1, 2021, p. 23.

4.5.1 Control Technology Analysis

The EPA Tier 2 certification refers to 40 CFR Part 60, Subpart IIII (New Source Performance Standards (NSPS)) standards for reciprocating internal combustion engines (RICE). For Units A02-A12, NO_x emissions are limited to no more than 9.0 g/kW-hr;[125] for the remainder of the units, the limit is 6.4 g/kW-hr of non-methane hydrocarbon (NMHC) + NO_x.

In addition to the available control technologies Switch identified in its proposed RACT analysis, DAQ considered whether other control technologies identified by other major sources for emergency engines might be cost-effective for Switch. Because a control device has to be sized for the emission unit operating at full capacity, a cost that is reasonable for a unit operated 6,000–8,000 hours per year will often be unreasonable for a unit operating only 100–500 hours per year. Given the smaller size and actual emissions of Switch's emergency engines compared to others considered in this analysis, DAQ would not expect a control cost to be reasonable for Switch if we found it not to be cost-effective for another major source. For example, using capital costs from W.W. Williams (in the Caesars cost estimates) and annual costs from Caesars for similar-size engines, the cost-effectiveness for SCR at a Switch engine—using the highest engine actual emissions, 1.16 tons of NO_x in 2017—is $21,125/ton NO_x, more than three times the RACT cost-effective threshold of $5,500/ton. This is equivalent to the cost-effectiveness estimated for emergency generators at NAFB and other major sources, so DAQ expects the control costs for the Switch diesel generators would be similar to (or more costly than) the cost estimated for the other major sources. Accordingly, DAQ concludes that additional add-on controls are not RACT for Switch's emergency engines.

The Switch Title V OP requires turbochargers and aftercoolers on all emergency generators,[126] that the source follow the manufacturer's O&M guidance,[127] and that the 117 units comply with the emissions limitations in 40 CFR Part 60, Subpart IIII. DAQ concludes these requirements are RACT. Switch's OP includes compliance and monitoring requirements to ensure these conditions are met; DAQ concludes these conditions constitute adequate monitoring, reporting, and recordkeeping to ensure compliance with RACT requirements.

4.6 MGM RESORTS INTERNATIONAL, LAS VEGAS

4.6.1 Background

MGMRI (Source ID: 825) owns a group of hotels within HA 212. DAQ issued MGMRI a renewed OP on May 19, 2022, that includes requirements for the following hotels, hereby 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, and T-Mobile Arena.

[125] Part 70 Technical Support Document for Renewal of Part 70 Operating Permit, July 1, 2021, Appendix 4A, p. 31.
[126] Switch OP, issued 7/1/21, Condition III.C.3.a.
[127] Switch OP, issued 7/1/21, Condition III.C.3.b.

MGMRI is currently a major source of NO_x with a stationary source-wide PTE of 757.05 tpy, but reported only 65.07 tpy of actual NO_x emissions in 2017. Its RACT analysis computed actual emissions from average annual fuel use over the most recent three years (2019–2021) to show that its average annual actual emissions are approximately 24% of its PTE.

MGMRI listed all its emission units potentially subject to RACT (those with a PTE of 5 tpy or more) in a table in Appendix B of its proposed RACT analysis (Appendix 5).[128] These include two natural gas-fired boilers and 46 diesel-fired engines driving emergency generators.

The process equipment consists of two natural gas-fired boilers, each with a capacity of 32.66 MMBtu/hr, and 46 diesel-fired emergency generators that range from 1,100–3,700 hp. The boilers are classified as Commercial/Institutional (< 100 MMBtu/hr) and the engines as Large Internal Combustion Engines (> 500 hp). The two Cleaver Brooks boilers (MG13 and 14), which are Model CBLE series, are permitted to use only natural gas. According to the manufacturer's website, the CBLE are high-efficiency fire-tube boilers that can be ordered to achieve less than 60, 30, 9, or 5 ppm NO_x.[129] The permitted limit of 40 ppm at 3% O_2 is higher than the more common 30 ppm limit for LNB boilers.

Appendix 5 contains MGMRI's proposed RACT analysis. MGMRI indicated that it identified available control technologies via the RBLC, surveying agencies, engineering experience, vendor surveys, and surveys of available literature. The RBLC search was conducted for the most recent 10 years.

4.6.1.1 Boiler RACT

MGMRI identified the following as potentially available control technologies for natural gas-fired boilers:

- GCP use;
- LNB and FGR;
- ULNB and FGR; and
- SCR.

[128] While reviewing MGMRI's list of emission units, DAQ notes that although Table B lists the proper number of emission units, it is both difficult to read and appears to contain errors in labeling. Specifically, on page B-1, the right column skips from BE83 to BE85; BE85 should have been listed as BE84 (because that's the BE84 serial number in the description), BE86 should be labeled BE85, BE87 should be BE86, BE88 should be BE87, and (on page B-2, right column), CC009 should be BE88. Continuing on page B-2, CC010 should be CC009, CC011 should be CC010, etc., ending with CC015, which should be CC014. Finally, TM01 should be labeled CC015 and the first TBB15 (serial number DD501118) should be labeled TM01. Note, however, that the table does contain all the emission units that meet the criteria for a RACT analysis.

[129] MGMRI's OP limits the two boilers to 40 ppm NOx at 3% O2: "The permittee shall operate and maintain each of the boilers with burners that have a manufacturer's maximum emission concentration of 40 ppmv NOx, corrected to 3% oxygen (EUs: MG01, MG02, MG05, MG06, MG13, MG14, and MG16)." Condition III.A.5.c.

EPA has indicated[130] in a NO_x ACT document that the following are also potential combustion modification control technologies:

- Water /Steam Injection; [131]
- SCA (the most common LNB);
- CFB;
- CCM; and
- GFFM.

DAQ used MGMRI analyses for these control technologies and considered additional technologies not on either list (Table 4.6-1).

Table 4.6-1. NO_x RACT Determinations for MGMRI Boilers

CT #	Control Technology	RACT	Discussion
1	SCR	No	MGMRI rejected SCR because the boiler exhaust gas temperatures are too low; MGMRI did not document an actual flue temperature, but the flue-gas temperature of a typical boiler ranges between 300–500°F.[132] Figure 4-1 confirms that such flue gas temperatures are too low for effective SCR, so it is not technically feasible. Even if SCR could be applied, the Lansing SCR analysis for a larger boiler had a high cost-effectiveness value and DAQ expects costs for MGMRI would be similar. DAQ finds SCR is not RACT for these boilers because the control technology is not technically feasible or cost-effective.
2	SNCR	No	SNCR is not available for this size industrial boiler because it operates best at temperatures of 1,600-2,000°F, but the boiler flue gas temperature is only around 400°F (204°C)[133] (Figure 4-2). Therefore, SNCR is unsuitable RACT for these boilers.
3	LNB / ULNB	Yes	The boilers are already equipped with burners, presumably LNB, that allow them to meet a limit of 40 ppm NO_x at 3% O_2.[134] The literature appears to classify LNB as burners able to reduce NO_x concentrations from over 100 ppm to around 30 ppm (the most common).
	ULNB	No	The boilers are already equipped with LNB.[135] MGMRI's RACT

[130] EPA-453/R-94-022, Alternative Control Techniques Document—NOx Emissions from Industrial/ Commercial/Institutional (ICI) Boilers, March 1994.

[131] For example, the ACT document states that WI "has seen very limited application in Southern California, where NOx emission regulations are the most stringent. Because of low initial cost, the technique is considered particularly effective for small single-burner packaged boilers operated infrequently."

[132] Technical advice on boiler combustion control, U.S. Department of Energy's Industrial Technologies Program, https://www.reliableplant.com/Read/22138/technical-advice-on-boiler-combustion-control

[133] Marek Pronobis, *Environmentally Oriented Modernization of Power Boilers*, Chapter 4.4.2. 2020.

[134] Condition III.A.5.c.: "The permittee shall operate and maintain each of the boilers with burners that have a manufacturer's maximum emission concentration of 40 ppmv NOx, corrected to 3% oxygen (EUs: MG01, MG02, MG05, MG06, MG13, MG14, and MG16). [Title V OP (10/21/13)]"

[135] Condition III.A.5.c.: "The permittee shall operate and maintain each of the boilers with burners that have a manufacturer's maximum emission concentration of 40 ppmv NOx, corrected to 3% oxygen (EUs: MG01, MG02, MG05, MG06, MG13, MG14, and MG16). [Title V OP (10/21/13)]"

CT #	Control Technology	RACT	Discussion
			analysis did not consider upgrading the burners to ULNB control technology. However, DAQ analyzed the use of metal mesh ULNB, which can be used on boilers up to 100 MM Btu/hr or more. DAQ used a relatively low capital cost estimate (dated 9/13/22) of $235K from Pyro Combustion (Appendix 3, Caesars), a 77% control efficiency for ULNB alone, and a conservative 30-year (instead of 10) life; the CE was $13,357/ton of NO_x removed. DAQ finds that ULNB is not RACT because it is not cost-effective.
4	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 Title V OP (Condition III.A.5.b).[136] DAQ finds this control technology is RACT.
5	FGR	No	The MGMRI RACT analysis (Appendix 5, Table 2-1) states that adding FGR to the existing LNB would reduce emissions by 35.69%, with a capital investment of $77,200, an annual equipment cost of $13,587.20, and total annual operating cost of $39,520.61; the computed CE was $89,868. However, the operating cost was based on 8,760 hours per year, while the emissions reduction was based on actual emissions, which were equivalent to only 1.66/6.95 tpy = 0.239 (~24%), so the actual operating expenses would be $39,520 x 0.239 = $9,439/year. Using this value and a 30-year life, CE = $25,399/ton; even when the operating cost is left out completely, CE = $9,467, still higher than the $5,500 RACT threshold. There are some uncertainties about MGMRI capital costs, which are based on 1/3 of the cost for an installation that included an SCR, so DAQ conducted a separate cost estimate. A 1975 retrofit capital cost of $21,000[137] was adjusted for inflation using the CEPCI to obtain a CE of $6,182/ton NO_x removed, which is lower than the MGMRI and adjusted MGMRI values but still above the CE threshold of $5,500/ton. DAQ determines FGR is not RACT because it is not cost-effective.
6	LNB + FGR or ULNB + FGR	No	The first option, LNB+FGR, is addressed in the FGR determination (#5). The ULNB+FGR option was included in the MGMRI RACT analysis for its boilers, with a 75% reduction from current actual emissions of 1.66 tpy, $126,200 capital cost, $22,211 direct and indirect (equipment) costs, $39,520 annual operating costs (at 8,760 hr/yr), and 10-year life, so CE = $49,707. This is above the $5,500 threshold, but has too high an operating cost (see #5), which should be reduced to 23.9% based on actual hours of operation. In addition, the 10-year life assumed by MGMRI was not documented. Using the adjusted operating cost of $39,520 x 0.239 = $9,445 and a 30-year life, CE = $13,382, above the RACT CE threshold of $5,500. Based on the EPA cost manual, MGMRI calculated the annual equipment costs at $22,211 (Att. 5, Table 2-2, footnote 3). DAQ finds this control technology is not cost-effective.
7	EAR / LEA	No	Boilers are generally run with 10–20% EA to ensure full combustion (to minimize smoke, PM, and VOC, and for safety). Reducing EA is an "easy" approach[138] that can reduce NO_x emissions by 5–

136 "The permittee shall operate and maintain each boiler and heater in accordance with the manufacturer's operations and maintenance (O&M) manual for emissions-related components and good combustion practices."

137 EPA-450/1-78-001, Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition, January 1978, p. 4-55.

138 APTI 418 Student Manual, p. 6-8.

CT #	Control Technology	RACT	Discussion
			10%[139] or 16–20% (by going to 2–7% EA).[140] Often this is done by changing burners, so the cost would be similar to that of installing a ULNB. DAQ finds this control technology is not RACT because it is not cost-effective.
8	BOOS	No	This approach is available only for multi-burner boilers; from the manufacturer's website, the MGMRI boilers appear to be single-burner models. With BOOS, one or more burners are taken out of service, meaning they don't burn fuel but instead are used to inject air or flue gas. They have a similar effect and cost as FGR or OFA. DAQ finds this control technology is not RACT because it is not available for this type of boiler and, even if it were, it would not be cost-effective.
9	OFA	No	This is often used in conjunction with LNB, so may already be a part of the MGMRI boilers. If not, OFA requires modifications to the boiler and is not available for some boiler configurations.[141] The reduction available is estimated at 30–50%; using 50% and costs similar to FGR, CE = $6,327/ton NO_x. DAQ finds this control technology is not RACT because it is not cost-effective.
10	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 either 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. This technique is mainly done where there is overfire air and the angle of the air flow can be adjusted. Overfire air generally is not used in fire-tube boilers, so is not considered available.[142] DAQ finds this is not RACT because the control is not available.
11	RAP	No	Combustion air preheat is not used for fire-tube boiler configurations,[143] so there is no air preheat to reduce. When available, it can reduce NO_x emissions by 15–25%,[144] but it is seldom used due to efficiency penalties.[145] DAQ finds this control technology is not RACT because the energy disbenefits outweigh the potential emissions reduction benefits.
12	Fuel conversion	No	This option is often addressed for several different pollutants, such as PM and SO_x, when a fuel such as coal or oil is used. A fuel

139 http://cleanboiler.org/learn-about/boiler-efficiency-improvement/boiler-combustion/ However, this source also states that it is better to select a control technology that has little effect on excess air.
140 APTI 418 Student Manual, p. 6-9.
141 APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 6-10. "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."
142 EPA-450/1-78-001, Control Techniques for Nitrogen Oxides Emissions from Stationary Source – Second Edition, January 1978, p. 4-50.
143 EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 2-4.
144 APTI 418, Control of Nitrogen Oxides Emissions, Student Manual, 2000, p. 6-18 and 6-19.
145 Oland, C. B., ORNL/TM-2002/19, Guide To Low-Emission Boiler And Combustion Equipment Selection**,** April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-5.

CT #	Control Technology	RACT	Discussion
			lower in nitrogen will produce less NO_x from nitrogen in the fuel.[146] The best fossil fuel in terms of nitrogen content is natural gas, which the boilers already use, so switching is not an option. DAQ finds this control technology is not RACT because another fuel would not generate NO_x emissions reductions.
13	WSI	No	A literature search produced no information on the technical feasibility of adding water or steam injection to boilers with LNB and on whether the amount of NO_x reduction would be less (since LNB already have reduced emissions), and very little cost information. In one study cited 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.[147] This includes both OT and WSI and 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 CEPCI, CE_{2022} = $\$3903_{1992}$ x ($\$824.5_{2022}$ / $\$358.2_{1992}$) = \$8,984/ton. DAQ finds that WSI is not RACT because it is not cost-effective.
14	CFB / RCB	No	This is 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 l800°F and typical emissions are 20 ppm CO*,* 15 ppm NO_x, and 2 ppm HC.”[148] NO_x emissions as low as 10 ppm have been reported; 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, so the capital costs are relatively low. CFB have an additional advantage: thermal efficiency is increased by 1–2%, resulting in savings of up to 5% in natural gas. However, ceramic burners to date have been applied only in boilers of 16 MM Btu/hr or less, so are not feasible for the MGMRI boilers, which are 30+ MM Btu/hr. Although ceramic burners are not technically feasible for the MGMRI boilers, an analysis was conducted to provide information on how cost-effective the technology is. A 2011 paper[149] estimated burner capital cost at \$0.78/1000 Btu, so CFB for a 33 MMBtu/hour boiler would be \$25,740 in 2011 dollars. Using the CEPCI, $Cost_{2022}$ = \$25,740 x ($\$824.5_{2022}$/$\$585.7_{2011}$) = \$36,235. Assuming general direct/indirect costs of \$3,000 (used for other cost analyses), a 10-year life for the burners (the ceramic is reportedly easily damaged), and a reduction of 62.5% (from 40 ppm to 15 ppm), the CE for each boiler = \$5,143/ton, which is cost-effective. However, a 5% fuel savings,[150] assuming 2,094 hours of operation, would be a savings of \$31,959/year, which would yield a net annual cost of -\$26,623/year and a CE = -\$25,661/year. This CE, like most, is based on a number of assumptions, and the

[146] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-4.
[147] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. D-3.
[148] Radiant Fiber Burners For Gas-Fired Appliances And Equipment, John P. Kesselring, Robert M. Kendall, and Richard J. Schreiber, Alzeta Corporation'
[149] Xu, T., Characterizing Costs, Savings And Benefits Of A Selection Of Energy Efficient Emerging Technologies In The United States, Lawrence Berkeley National Laboratory, 3/31/2011, https://escholarship.org/uc/item/3nb0863v.
[150] See https://www.eia.gov/dnav/ng/NG_PRI_SUM_DCU_SNV_M.htm for natural gas prices for Nevada.

CT #	Control Technology	RACT	Discussion
			capital cost of other ULNB burners based on vendor quotes is considerably higher, so a more tailored analysis would be warranted to see if it would affect the RACT decision, including getting a quote from one of the burner manufacturers, such as the Alzeta Corporation.
15	CCM	No	This is a catch-all for different combinations of control techniques. The most demonstrated combination is the use of 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. Data have been collected for 101 natural gas-fired units, 44 distillate oil-fired boilers, and 13 residual oil-fired boilers. All were watertube boilers, not the fire-tube boilers MGMRI has; most were in California. Many of the California boilers were existing units retrofitted with LNB/FGR controls. NO_x reduction efficiencies of 55–84% were reported for five units firing natural gas.[151] The most widely used combination, LNB with FGR, has a CE = $21,960/ton (see #6). DAQ finds this control technology is not RACT because it is not cost-effective.
16	GFFM	No	A device known as a 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 between 2–10%, but have been as high as 35%. From a NO_x standpoint, 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, turbulator use 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.[152] The MGMRI boilers are already equipped with LNB, which incorporate air-fuel mixing strategies, and are already emitting at only 40 ppm or less, so this technique likely will have little or no effect in reducing emissions. However, CE was calculated using a 15% reduction in NO_x and half the cost of installing ULNB. The CE was $21,300/ton. DAQ finds GFFM is not RACT because it is not cost-effective.
17	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

[151] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-60.
[152] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-69.

CT #	Control Technology	RACT	Discussion
			have no moving parts and avoid the need for external FGR.[153] 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 #6), the CE = $21,960/ton. DAQ finds this control technology is not RACT because it is not cost-effective.
18	FRI2	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."[154] Reductions of 48–68% have been demonstrated on a utility boiler;[155] 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 already achieved by the LNB mean that the reductions that can be achieved by FRI2 would be lower. Assuming that the cost is about the same as that of an FGR retrofit (estimated at $94,920) and that the reduction achievable is 57% (assuming a reduction from 40 ppm down to 17 ppm), CE = $7,518/ton. DAQ finds this control technology is not RACT because it is not cost-effective.
19	BT	No	See OT (#20). BT appears to be similar to OT in terms of operation and costs.
20	OT	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.[156] An EPA publication mentions specific installations and 15–25% control.[157] These techniques, which are a form of LEA control, are often done in conjunction with other control techniques. Since the MGMRI boilers are already equipped with LNB, which generally are designed for LEA, there may be little or no benefit in trying to use OT or BT to reduce excess air further. There is little cost information, but one publication[158] 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; in 2022 dollars, this is $3,300 x ($824.5$_{2022}$/358.2_{1992}$) = $7,596. The report notes that the monitoring instrumentation (CEM) needed to ensure proper operation and safety could cost as

[153] Oland, C. B., ORNL/TM-2002/19, Guide To Low-Emission Boiler And Combustion Equipment Selection, April 2002, Prepared for the U.S. Department of Energy, Office of Industrial Technologies, p. 5-9.

[154] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-56.

[155] Reese, James L., et al., Demonstration of Fuel Injection Recirculation (FIR) for NO_x Emissions Control, 1994. https://collections.lib.utah.edu/ark:/87278/s6zg6vvv

[156] "Guide to Low-Emission Boiler and Combustion Equipment Selection," p. 5-5. Oland, C.B. ORNL/TM-2002/19, April 2002.

[157] Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, p. 5-64. EPA-453/R-94-022, March 1994.

[158] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 2-17.

CT #	Control Technology	RACT	Discussion
			much, so doubling the cost gives a capital cost of $15,192. Assuming $2,000 in annual maintenance, a 30-year life, and a 15% reduction in emissions, CE = $7,552/ton. DAQ finds this control technology is not RACT because it is not cost-effective.
21	BF	No	This is a process of biasing the fuel flow to different burners to create a lower peak temperature. Since the MGMRI boilers have only one burner, it is not an applicable control technique. DAQ finds this control technology is not RACT because it is not technically feasible.
22	NGR	No	This 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%.[159] However, a literature search did not result in any articles or reports on use of NGR in natural gas-fired boilers (just coal- and oil-fired), so this technology is considered not technically feasible for gas-fired boilers. DAQ finds this control technology is not RACT because it is not technically feasible.
23	CCB	No	This is another type of LNB, so cost is addressed under LNB/ULNB (#6). 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.[160] To achieve ultra-low NO_x 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 did result 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; however, no retrofit emissions data were obtained. Since achieving 20 ppm requires steam injection at the cost of efficiency and other ULNB can achieve 9–10 ppm without using steam injection, and assuming the cost of CCB is similar to other ULNB, DAQ finds this control technology is not RACT because it is not cost-effective.

Of the 23 boiler control technologies evaluated by DAQ, none appear to be both technically and economically feasible. CFB are not technically feasible (the boilers are too large for such burners), but if applicable, would appear to be economically feasible.[161] DAQ concludes that the existing controls and monitoring constitute RACT for the boilers.

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[159] "Guide to Low-Emission Boiler and Combustion Equipment Selection," p. 5-7. Oland, C.B. ORNL/TM-2002/19, April 2002.

[160] EPA-453/R-94-022, Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (lCI) Boilers, March 1994, p. 5-54.

[161] This technique has the benefit of increasing efficiency and saving fuel, so may actually be more cost-effective than preliminary analysis indicates: the CE without considering fuel savings is $5,143/ton, below the $5,500/ton threshold, while considering fuel savings results in a CE = -$25,661/ton (a cost savings). The reduction in actual emissions from equipping the two boilers with ceramic burners would be 2.08 tpy.

4.6.1.2 Emergency Generators

The other RACT analysis was conducted on the 46 emergency generators on various MGMRI properties that met the criteria for review. The diesel generators are rated from 1,180 to 3,701 hp and are all from the same manufacturer. The PTE for the generators ranges from 7.08 to 15.12 tpy. For all 46 units, the Title V OP limits operation to 500 hours per year per generator, including emergency use; only 100 hours per year of this 500 hours can be for nonemergency purposes, and only 50 of the 100 hours can be for nonemergency purposes other than testing and monitoring.[162] All 46 units are required to follow the manufacturer's O&M guidance, which is generally accepted as constituting GCP.[163] In addition, the OP requires all the units to have turbochargers and aftercoolers except:

- Turbochargers only: EX007-EX010 and NY27-NY29.
- Neither: TM01.

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

TM01 is the only unit where neither turbocharging nor aftercoolers are required by the Title V OP, but it is also the only unit specifically mentioned as subject to EPA's Tier Certification. More information is needed to determine the design and configuration of TM01, but it likely has some form of control built into the design because despite being the largest engine, its PTE at 500 hours is only 10.83 tpy NO_x compared to a higher (up to 15.12 tpy) PTE for smaller engines at the MGMRI properties.

MGMRI did not provide actual emissions information in its RACT analysis, so DAQ used data from five emergency generators at NAFB to estimate actual emissions from the MGMRI units. This was done by comparing the maximum actual NO_x emissions at each unit from 2017–2021 to the units' PTE. Unit 41 at NAFB had maximum actual emissions of 1.861 tpy compared to a PTE of 8.07 tpy, so actual emissions were 23.1% of the PTE. Taking the highest MGMRI unit PTE (15.12 tpy) times 0.231 yields an estimated maximum actual 3.49 tpy. This value was used for the CE calculations.

[162] For example, Condition III.A.4.a.: "The permittee shall limit the operation of the emergency generators and fire pumps (EUs: MG17 through MG24, MG26 through MG28, MG51, and MG113) 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 generator from other generators, per 40 CFR 60.4211.

[163] For example, Condition III.A.5.p.: "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)."

4.6.1.3 MGMRI RACT Analysis

The only technically feasible options listed by MGMRI for the generators were (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. One MGMRI unit (TM01, the largest, at Treasure Island) is certified; all the units were assumed to practice GCP, which was considered equivalent to the requirement in the Title V OP for all the MGMRI units to adhere to the manufacturers' O&M guidance. MGMRI also considered any add-on controls, like SCR, to be 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 generators. MGMRI did not address other control options, such as those in documents like EPA's 1978 ACT[164] for NO_x emissions.

4.6.1.4 DAQ RACT Analysis

DAQ has reviewed the MGMRI RACT analyses (Appendix 5), revised them as necessary, and conducted RACT analyses for control technologies not included in the MGMRI analysis. The analyses are summarized in Table 4.6-2; the actual CE calculations are in Appendix 9.

The emergency generators currently:

- Are all required to practice GCP and GMP; and
- Have and use turbochargers and aftercoolers except for the eight units (EX007–010 and NY 27–29, plus TM01) that are not required to have aftercoolers.
- For TM01, which is Tier Certified, meet the appropriate limit in 40 CFR Part 60, Subpart IIII.

DAQ has determined that the current control techniques (GCP/GMP, turbochargers, and aftercoolers (except as noted above)) constitute RACT for all emergency generators except TM01, for which tier certification emissions limits apply.

Table 4.6-2. Summary of DAQ RACT Analyses for MGMRI Emergency Generators

CT #	Control Technology	RACT?[165]	Discussion
1	SCR	No	MGMRI stated SCR may not be the best choice for emergency generators, per EPA, due to the brief steady-state operating time. SCR is considered technically feasible, with NO_x reductions up to 90%,[166] but even if it is technically feasible, it is not cost-effective. The capital cost is based on an estimate provided by W.W. Williams and other costs in the Caesars RACT analysis (Appendix 3). MGMRI did not provide any actual emissions, so DAQ used NAFB PTE-to-actual-emissions to get

[164] EPA-450/1-78-001, Control Techniques for Nitrogen Oxides Emissions from Stationary Sources-Second Edition, January 1978.

[165] Y = Yes; N = No; NA = Not Applicable or Not Available; A question mark (?) means that the determination is tentative pending additional information (usually, a cite from the manufacturer or source documenting a statement, such as a technology not being available for that make or model).

[166] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 2-22.

CT #	Control Technology	RACT?[165]	Discussion
			actual emissions estimates for MGMRI. Unit 41 had the highest NAFB actual/PTE ratio: 1.861/8.07 = 0.231 = 23.1%; 15.12 • 0.231 = 3.49 tpy. CE = $7,021/ton, so SCR was rejected as not cost-effective.
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 1600–2000°F and diesel engine exhaust gas ranges from 800–1200°F.[167] 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 4-2).[168]
3	DLN and SLN	NA	These technologies appear to be primarily for turbines, since no articles, documents, or websites indicated use of DLN or SLN on diesel engines.
4	Turbocharging	Yes	All but one of these units (TM01, but it is Tier-Certified) are already required to have a turbocharger, and all but seven (EX007–EX010 and NY27–NY29) are required to have an aftercooler.[169] Turbocharging alone doesn't appear to reduce NO_x emissions, but it may reduce other emissions; it is usually installed to increase output and can actually increase NO_x emissions if there is no aftercooler. Since compressing the air raises its temperature, engines with turbocharges usually also add aftercoolers to bring the temperature back down. Turbocharging combined with EGR does reduce NO_x emissions.[170]
5	GCP and GMP	Yes	These practices are the most common RACT determinations in the RBLC and are already being implemented through the Title V OP.[171]
6	Pre-stratified charge	No	EPA documents indicate that this technique is for spark ignition engines, not CI engines.[172]
7	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.[173] In addition, a study by NRDC on cleaning up diesel engine emissions found that EGR resulted in fuel penalties of 0–5%, was among the most costly of control options available, and increased PM emissions.[174] A web search turned up only a few companies offering EGR, and those often paired EGR with other controls (such as particulate), mainly on propulsion engines. EGR does not appear to be a viable RACT option.
8	ITR	No	If the engine already has an automated electronic control system for

[167] Marek Pronobis, Environmentally Oriented Modernization of Power Boilers, 2020, Chapter 4.4.2.

[168] Emission Factor Documentation, p. 2-18.

[169] The Title V permit requires, for example:

> Condition III.A.5.r. The permittee shall operate the diesel emergency generators with turbochargers and aftercoolers (EUs: MG17 through MG23), p. 25.

[170] Dond, DK, Gulhane, NP. Effect of a turbocharger and EGR on the performance and emission characteristics of a CRDI small diesel engine. *Heat Transfer*. 2022; 51: 1237- 1252. doi:10.1002/htj.22350

[171] For example, from the Title V permit (Condition III.A.5.p.): 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).

[172] EPA-453/R-93-032, Alternative Control Techniques Document-NO_x Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 5-14.

[173] Ibid, 5–85.

[174] Richard Kassel and Denise Bailey, Cleaning Up Today's Dirty Diesels, NRDC, 2005

CT #	Control Technology	RACT?[165]	Discussion
			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, CO, and HC. EPA literature backs up these concerns, including a 3% fuel penalty. If a unit is not already equipped for ITR, retrofit installation results in a CE = $6,674/ton, higher than the $5,500 threshold, making the technology not cost-effective.[175]
9	AFR adjustments	NA	DAQ makes no finding on its availability, but finds this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the benefits of potential emissions reductions.
10	Derating / increasing speed	No	DAQ finds this control technology does not qualify as RACT because the energy and collateral pollutant disbenefits outweigh the potential for RACT emissions reductions.
11	Inlet MAT adjustment / aftercooler	Y (if already on) No (if not already on)	DAQ estimates that the CE for retrofitting a cooler is about $15,000/ton based on the NAFB calculation for A03). DAQ concludes this control technology is available but not cost-effective and, therefore, does not qualify as RACT unless already required.
12	DWI	No	Assuming EPA's literature control level of 25–35% and using the midrange of 30%, the CE = $11,603/ton. This estimate does not include the potential fuel penalty. DAQ finds this control technology is not RACT because it is not cost-effective.
13	Water/fuel emulsions	No	DAQ estimates cost-effectiveness at $8,503/ton and concludes this control technology is not cost-effective.
14	EPMS	No	DAQ finds this control technology does not qualify as RACT because the amount of additional NO_x emissions reductions through its use is likely negligible.
15	High-pressure fuel injection	No	DAQ concludes this control technology does not qualify as RACT because its effect on reducing NO_x emissions, and the ability to retrofit it for existing emission units, is highly uncertain.
16	Conversion to natural gas (from diesel)	No	Switching to natural gas for emergency generators is usually impractical due to the need to have a dependable fuel supply available during emergencies (natural gas storage onsite is often either not technically feasible or prohibitively expensive). However, generators can be converted to dual fuel so natural gas can be used during all nonemergency use and diesel can be used during emergencies (see #17). Costs would be about the same.
17	Conversion to dual fuel (diesel/natural gas)	No	There are companies specializing in converting to dual fuels (e.g., see https://engeniousengineering.com/ and https://dwppon.com /wp-content/uploads/ 2020/06/bifuel _compressed.pdf). Costs would include converting the generator to dual fuel (or to natural gas only, see #16) and the piping needed to supply the unit with natural gas. If natural gas is already available at the properties, the piping cost would be relatively low. Conversion cost for small diesels with turbochargers ranges from $8,000 to $12,000,[176] but this is for small engines, so DAQ doubled it to $24,000. Reductions of 20–30% NO_x are expected.[177] EPA documents are in the same range, with an estimated 26.5% reduction in NO_x between diesel and dual fuel engines.[178] CE = $5,286/ton, which indicates this technology is barely cost-effective as RACT, but the actual conversion cost may be considerably higher than assumed. In addition, the

[175] Based on data from EPA's ACT for NO_X emissions from ICE engines, p. 2-42, Table 2-14.
[176] https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/
[177] Talus Park, Dual fuel conversion of a direct-injection diesel engine, West Virginia University Master's Thesis, 1999.
[178] EPA-453/R-93-032, Alternative Control Techniques Document-NO_X Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, p. 2-3.

CT #	Control Technology	RACT?[165]	Discussion
			estimate (1) includes only maintenance costs, and there are generally other annual costs; (2) assumes only $2,000 to hook up natural gas; (3) may not include direct and indirect costs in capital costs, and (4) does not address possible cost savings from using natural gas instead of diesel. Given the uncertainties, DAQ has determined that this technology will not be cost-effective.
18	Alternative fuels (other than natural gas)	NA	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 NO_x reductions can reach 60%. LNG requires huge investments for storage and installation and has high CO emissions.[179] DAQ finds that alternative fuels are not RACT for these emergency generators because the costs and potential collateral pollutant disbenefits outweigh the benefits of potential emissions reductions.

[179] Issa, M., Ibrahim, H., Ilinca, A. and Hayyani, M.Y. (2019) A Review and Economic Analysis of Different Emission Reduction Techniques for Marine Diesel Engines. Open Journal of Marine Science, 9, 148-171. https://doi.org/10.4236/ojms.2019.93012

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. l.~-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.

6.0 ELECTRIC UTILITY NO_x AND VOC RACT

6.1 INTRODUCTION

This section explains DAQ's case-by-case RACT determinations for NO_x and VOC for the two major sources in the electric utility sector. DAQ relied on information provided in the proposed RACT analyses for NV Energy (Appendix 7) and Saguaro Power Company (Appendix 8), supplementing these analyses where appropriate. Where the analyses provided cost estimates, DAQ adjusted calculation methodologies as needed, including equipment life and cost components, to assure a consistent approach.

This section does not repeat all the information from each source's proposed RACT analysis but highlights key information critical to the decision-making process. Refer to Appendices 7 and 8 (and supporting documentation) for the full scope of information considered in making the RACT determinations.

6.2 POTENTIALLY AVAILABLE CONTROL TECHNOLOGIES

Emission units at the affected electric utility sources include simple cycle combustion turbines (CTs), combined cycle units (CCUs), package boilers, cooling towers, emergency engines, and storage tanks; however, the only units that meet the VOC or NO_x RACT applicability thresholds are CTs, CCUs, and boilers. This section will thus be limited to NO_x and VOC control options for CTs and CCUs. With the exception of boilers, all other sources were below the DAQ applicability criteria (Section 4 provides a detailed discussion of boiler control technologies considered).

DAQ did not consider operating restrictions a viable control technology in identifying RACT because they do not usually control NO_x or VOC emissions during emission unit operations. They can, however, can be used to avoid applicability, including RACT requirements.

6.2.1 NO_x Control Technologies

6.2.1.1 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 to 2,100°F. At these temperatures, urea [$CO(NH_2)_2$] or ammonia [NH_3] reacts with NO_x, forming elemental nitrogen [N_2] 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 a SNCR system is the ability to contact the NO_x with the reagent as the concentration decreases without resulting in excessive ammonia slip and without 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 a technically feasible control technology for any of the CTs or CCUs.

6.2.1.2 Selective Catalytic Reduction

SCR is a post-combustion treatment of the flue gas that involves the injection of ammonia 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 catalyst allows the ammonia to reduce NO_X levels at lower exhaust temperatures than an alternative control technology called selective noncatalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400-1600°F, SCR can be utilized where exhaust gases are between 500°F and 1200°F, depending on the catalyst used" (Appendix 3, p. 2).

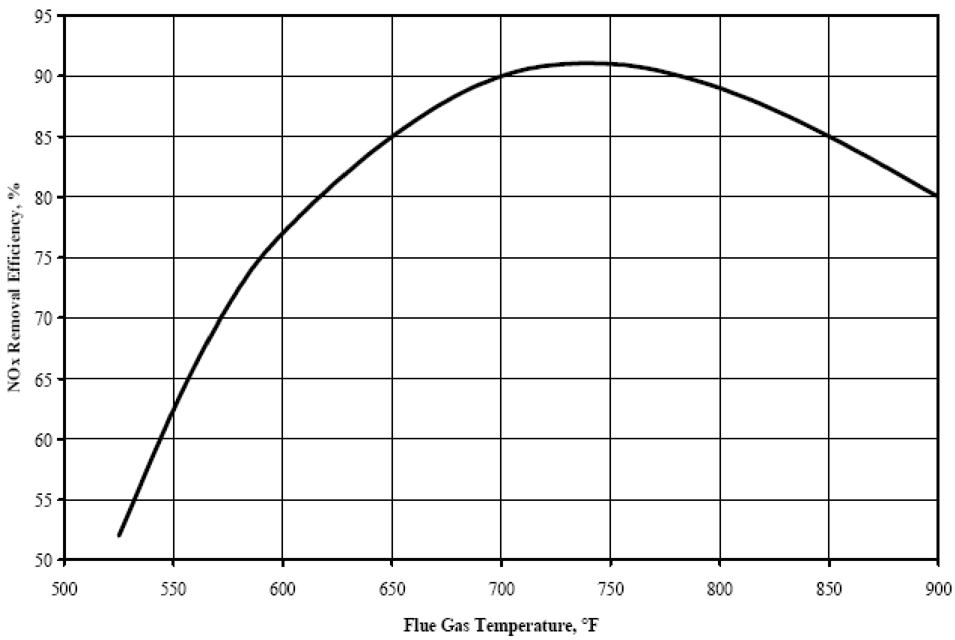

Figure 6-1. SCR-NO_X Removal versus Temperature[194]

6.2.1.3 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. Because the oxygen concentration in turbine exhaust is significantly higher (12–18% vol),[195] NSCR is not considered feasible for any of the CTs or CCUs.

6.2.1.4 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

[194] *Selective Catalytic Reduction*, Chapter 2. June 2019. J. Sorrels, D. Randall, K. Schaffner, and C. Fry.
[195] "GE Turbine Emission Control," R. Pavri and G. Moore. Document GER-4211, GE Energy Services.

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).[196]

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 it; therefore, this technology is not considered feasible for any of the CTs or CCUs.

6.2.1.5 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 being serviced on units already equipped with this technology.[197] EMx™ was eliminated from consideration because it is not commercially available.

6.2.1.6 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$_x$,[198] DAQ has 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.[199] Actual reduction will depend on combustor geometry, injection nozzle design, and fuel-bound nitrogen content.

Water injection can be installed as a retrofit on many existing turbines, depending on combustor design and the availability of high-purity, filtered water. Compared with other NO$_x$ control

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[196] Xonon Cool Combustion technology was developed by Catalytica Energy Systems, which merged with NZ Legacy to form Renergy in 2007. In 2007, the SCR technology services were sold to SCR-Tech LLC.
[197] Appendix 8
[198] Water injection is more effective because "the high latent heat of water acts as a strong thermal sink in reducing flame temperature" (GE, *ibid*).
[199] *CAM Technical Guidance Document*, *Water/Steam Injection*, Chapter B.17. EPA 1998.

technologies, capital costs are lower and operating costs are generally higher due to the need for a water treatment system.[200]

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.[201] However, all combustor designs are limited in the usability of WSI for NO_x control because increased injection rates reduce combustor operating stability and may eventually cause the combustor to flame out.

6.2.1.7 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 retrofit 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.

6.2.1.8 Good Combustion and 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 in accordance with the manufacturer's recommended settings and preventative maintenance schedules (Appendix 4, p. 2-2; Appendix 5, p. 2-3).

6.2.2 Potentially Available VOC Control Technologies

6.2.2.1 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. The catalyst is typically installed in a reactor with 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. 1. $$2CO + O_2 \rightarrow 2CO_2$$

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

[200] "Combustion Turbine NO_X Control Technologies Memo," January 2022. Project No. 13527-002, EPA.

[201] "Gas Turbine Emissions and Control," R. Pavri and G. Moore. GER-4211, GE Energy Services.

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 5 ppm@15% O_2 (1-hour) 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 Oxidation catalyst	30.96 tpy 5 ppm @ 15% O_2 (1-hour) 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.

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[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).

[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.

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[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 Units 11–22	5 ppm @ 15% O_2 (one-hour average)	GCP	CEMS (follow existing permit conditions)

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.

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[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)

<table>
<tr><th rowspan="2">Emission unit</th><th colspan="2">Emission Limitation/Work Practice</th><th rowspan="2">Monitoring Requirements</th></tr>
<tr><th>Normal Operation</th><th>Startup/Shutdown</th></tr>
<tr><td>Unit 4</td><td colspan="2">21.6 lb/hr
GCP</td><td rowspan="2">Unit 4</td></tr>
<tr><td>Units 5–8</td><td>5.01 lb/hr
GCP</td><td>GCP</td></tr>
</table>

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.

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

<table>
<tr><th rowspan="2">Emission Unit</th><th rowspan="2">Description</th><th rowspan="2">Date of Commercial Operation</th><th rowspan="2">Control(s)</th><th colspan="2">Emission Limits (all 3 units com-bined)</th></tr>
<tr><th>NO_x</th><th>VOC</th></tr>
<tr><td>A01
(Unit 3)</td><td>Natural gas/oil-fired CT
(84.5 MW)</td><td>1991</td><td>Water injection</td><td rowspan="3">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</td><td rowspan="3">Natural Gas[236]
3.59 tpy
2.06 lb/hr
#2 Oil[237]
4.94 tpy
4.50 lb/hr</td></tr>
<tr><td>A02
(Unit 4)</td><td>Natural gas/oil- fired CT
(84.5 MW)</td><td>1991</td><td>Water injection</td></tr>
<tr><td>A03
(Unit 5)</td><td>Natural gas/oil-fired CT
(84.5 MW)</td><td>1991</td><td>Water injection</td></tr>
</table>

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

- TCI includes initial capital investment (equipment cost only) and direct costs (direct installation cost only).
- Annualized TCI is based on the estimated equipment life of the various control options using CoST.[242] DAQ assumed an interest rate of 7.14% based on justification provided by NV Energy.[243]
- 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 (Appendix 9).

Total installed SCR costs are based on a vendor estimate provided by NV Energy. SCR catalyst replacement cost is based on estimated catalyst costs for CGS Unit 4.[244] LNB total installed cost is based on a vendor estimate for CGS Unit 4 and was scaled using the "six-tenths factor" methodology.

6.4.2.3.1 Control Equipment Performance

The achievable emissions level for the SCR (2 ppm @ 15% O_2) and DLNC (9 ppm @ 15% O_2) options are based on vendor data provided by NV Energy.[245] The achievable emissions level for the combination of SCR and DLNC is comparable to performance with SCR only, based on the vendor data. The lowest RBLC determination for a gas-fired simple cycle CT with SCR and DLNC is 2 ppm @ 15% O_2.[246]

6.4.2.3.2 Benefits/Disbenefits

SCR. SCR converts NO_x to nitrogen and oxygen by reacting the NO_x compounds with ammonia in the presence of a catalyst. However, 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 disposal of spent catalyst, which may contain 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

[242] *CoST* version 4.1
[243] Appendix 7
[244] Appendix 7a
[245] Appendix 7
[246] RBLC determinations for the period 2012–2022 for CTs equipped with SCR/DLNC range from 2-3.1 ppm @ 15% O_2 (see Appendix 10).

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.

Table 6.5-1. SPC RACT-Affected Units

Emission Unit	Description	Date of Commercial Operation	Control(s)	Emission Limits	
				NO_x	VOC
A01 (Unit 1)	Combustion Turbine Generator #1 (35 MW) with two fired HRSG (F05/05a)	1991	Steam Injection / SCR	Natural Gas: 15.20 lb/hr 10 ppm @ 15% O_2 (includes duct burners)	Natural Gas: 0.92 lb/hr
A02 (Unit 2)	Combustion Turbine Generator #2 (35 MW) with two fired HRSG (F06/06a)	1991			
F05	Supplemental Duct Burner (25 MMBtu/hr), Skid #1	1991			
F05a	Supplemental Duct Burner (25 MMBtu/hr), Skid #1	1991			
F06	Supplemental Duct Burner (25 MMBtu/hr), Skid #2	1991			
F06a	Supplemental Duct Burner (25 MMBtu/hr), Skid #2	1991			
A05 (Unit 5)	Auxiliary Boiler #1 (natural gas/hydrogen-fired, 218 MMBtu/hr)	1997	LNB / FGR / OC	13.94 tpy 3.18 lb/hr 12 ppm @ 3% O_2	4.47 tpy 1.02 lb/hr
A06 (Unit 6)	Auxiliary Boiler #2 (natural gas-fired, 86 MMBtu/hr)	1991	LNB	9.33 tpy 3.11 lb/hr 30 ppm @ 3% O_2	0.15 tpy 0.05 lb/hr

6.5.2 NO_x RACT Analysis

The following RACT analysis for NO_x was conducted using data and information in the RACT analysis provided by SPC,[248] as noted and where applicable.

6.5.2.1 Baseline Emissions

Baseline emissions establish the basis for the cost-effectiveness of each control option. Because Units 1 and 2 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.[249] Actual emissions data were used to determine the cost-effectiveness for all units because total emissions for the facility were well below 70% of PTE.

[248] Appendix 8

[249] Data provided by SPC for 2019-2021 by SPC. DAQ estimated 2017-2018 based on average NO_X emissions for 2019-2021 multiplied by the ratio of fuel usage as reported to EPA Mandatory Greenhouse Gas Reporting Program. The highest two-year average NO_X emissions for Units 1 and 2 is 54.60 tpy (Unit 27 - 2020-2021).

6.5.2.2 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. The operating permit was revised 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.

6.5.2.2.1 Control Equipment Evaluation

Table 6.5-2 shows the potential control technologies considered for each unit. These technologies are consistent with the potential retrofit options identified in EPA guidance for combustion turbines.[250] Certain technologies were not considered technically feasible so were eliminated from consideration, as discussed below.

Table 6.5-2. Technical Feasibility of NO_X Control Technologies (SPC)

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

The installation of DLNC is considered a feasible option for both units, although it would require the elimination of steam injection, which cannot be used simultaneously with DNLC. SPC included an SCR catalyst replacement option in their 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 the annual operating cost evaluation, which suggests that 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, although further investigation may be required.

6.5.2.2.2 Control Equipment Costs

All control equipment costs are based on vendor estimates provided by SPC[251] except as noted below. Estimates have been modified as follows to provide consistency between RACT determinations for the various units:

- TCI includes initial capital investment (equipment cost only) and direct costs (direct installation cost only).

[250] *Alternative Control Techniques Document – NO_X Emissions from Stationary Gas Turbines*, EPA, January 1993.
[251] Appendix 8

- Annualized TCI for DLNC is based on CoST.[252]
- Annualized TCI for the catalyst replacement assumes a five-year 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 in order to simplify the analysis.[253] Estimated costs are thus considered conservative and likely understate actual costs associated with each control option (Appendix 9).

6.5.2.2.3 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).[254] The achievable emissions level for the SCR catalyst replacement is based on the highest RBLC determination for a similarly equipped unit (3 ppm @ 15% O_2).[255] 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.

6.5.2.2.4 Disbenefits

SCR. SCR converts NO_x to nitrogen and oxygen by reacting the NO_x compounds with ammonia in the presence of a catalyst. However, 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 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

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[252] EPA *CoST* Version 4.1 Software (11/2022), https://www.cmascenter.org/cost/

[253] SPC also included annual remote tuning costs in their DLNC evaluation. DAQ excluded this cost from the evaluation for consistency with other DLNC evaluations.

[254] RBLC determinations for NO_X for the period 2012 – 2022 for CCUs equipped with SCR/LNB range from 2 - 3 ppm@15% O_2 (see Appendix 10) 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.

[255] RBLC determinations for NO_X for the period 2012 – 2022 for CCUs equipped with SCR (with and without water/steam injection) range from 2 - 3 ppm@15% O_2 (see Appendix 10). This is lower than the estimated level of performance (6 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.

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.

6.5.2.2.5 RACT Determination

Table 6.5-3 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 can be found in Appendix 9.

Table 6.5-3. NO_X RACT Summary (SPC CCUs)

Control Equipment	Incremental Control Efficiency (%)	Achievable Emissions (ppm @ 15% O_2)	Cost Effectiveness ($/ton)
Units 1 and 2			
DLNC (with existing SCR)	80%	2	9,650
SCR catalyst replacement	70%	3	9,360
SCR/steam injection (existing controls)	N/A	10	N/A

Table 6.5-4 summarizes the RACT determination for each unit.

Table 6.5-4. Proposed RACT-Based NO_X Emission Limitations (SPC CCUs)

Emission unit	Emission Limitation/Work Practice		Monitoring Requirements
	Normal Operation	Startup/Shutdown	
Units 1 & 2	10 ppm @ 15% O_2 (four-hour 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 due to excessive cost (> $9,400/ton for both units). Compliance will be demonstrated using CEMS according to the monitoring and reporting procedures in the source’s current Title V OP. RACT during startup, shutdown, and other non-normal operation is 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.

Since the current permit does not adequately reflect the monitoring, recordkeeping, and reporting requirements needed to ensure compliance with GCP, the permit will need to 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 these procedures are being implemented.

6.5.2.3 Auxiliary Boiler (Unit 5)

Unit 5 is an Indeck/Volcano (Model O-7-2000) watertube package boiler with a heat input rating of 218 MMBtu/hr. This boiler provides backup steam to nearby chemical manufacturing and food processing plants when the primary steam supply is offline. The boiler is permitted to fire natural gas and hydrogen from a nearby processing plant. Annual heat input is limited to 1,909,680 MMBtu/year. The hydrogen supply is variable, so the boiler must continuously adjust natural gas flow to maintain firing rate. The boiler was retrofit in 2014 with a Cleaver Brooks Natcom LNB with FGR and an OC system as part of the plant's cogeneration project to meet a NO_x emission limit of 12 ppm @ 3% O_2 and LAER CO emission limit of 1.2 ppm @ 3% O_2 while firing natural gas.

6.5.2.3.1 Control Equipment Evaluation

Section 4 provides an extensive list of potential boiler NO_x control technologies. These technologies can be generally classified as combustion or post-combustion controls. Most of the available control technologies are combustion controls that reduce NO_x formation using a variety of methods to optimize combustion air and/or improve fuel/air mixing. While NO_x reduction is the primary goal of these technologies, their implementation typically reduces combustion efficiency, which can cause increases of CO and VOC emissions. In this case, even minor increases in CO may cause Unit 5 to exceed the LAER CO emission limit, depending on the ability of the OC system to offset additional CO formation. Further evaluation is required to determine which technology may be technically feasible.

Two additional combustion-related control technologies were considered but deemed to be technically infeasible: installation of CFB and BOOS operation. However, the installation of CFB is not commercially available for a watertube boiler of this size,[256] and BOOS requires multiple burners but Unit 5 is equipped with only a single burner.

DAQ also considered the installation of SCR and SNCR on this boiler. However, the exhaust temperature (~325°F) is below the minimum temperature required for either technology.

Table 6.5-5 lists the technical feasibility of NO_x control technologies for SPC Unit 5, including whether it's possible to implement the technology and whether it's already equipped with the technology.

[256] Appendix 8a – Saguaro RACT Analysis- DAQ Supporting Documentation

Table 6.5-5. Technical Feasibility of NO_X Control Technologies (SPC Unit 5)

Control Technology	Unit 5
SNCR	No
SCR	No
CFB	No
BOOS	No
Other Combustion-Related Controls: • LNB upgrade • SCA • EAR / LEA • GFM	Possibly. Technical feasibility would require further evaluation of additional CO formation associated with each control technology and capabilities of existing CO OC system.
FGR	Already equipped
LNB	Already equipped
GCP	Already implemented

6.5.2.3.2 RACT Determination

DAQ was unable to identify any technically feasible upgrade operations without further analysis of combustion-related modifications and their effects on CO emissions. Although additional modifications may be possible, none of the technologies would be considered cost-effective due to the boiler's limited operation.[257]

DAQ concludes that the existing NO_x emission limit of 12 ppmvd @ 3% O_2 (4-hr average) while firing natural gas (excluding startup and shutdown operation) represents RACT based on the use of existing controls. Compliance shall be demonstrated using CEMS according to the current monitoring, recordkeeping, and reporting procedures in the source's current OP. RACT during startup, shutdown, and other non-normal operation is 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. While the source is already required to follow good combustion practices and maintain the boiler in accordance with the manufacturer's O&M manual,[258] the permittee shall ensure these procedures also address periods of startup, shutdown, and other non-normal operation.

Table 6.5-6 lists the proposed RACT-based NO_x emission limit for Unit 5 during normal and startup/shutdown modes of operation, and the corresponding monitoring requirements.

[257] Assuming a best-case scenario where the retrofit results in RACT-level NO_X emissions of 8.2 ppm @ 3% O_2 (based on lowest RBLC determination for combustion-related upgrades), the estimated total capital investment cost would need to be less than $6,500 in order for the retrofit to be considered cost effective based on the cost effectiveness threshold ($5,500/ton). There are no available technologies that can achieve such reductions for that cost (see Appendix 9).

[258] Condition E(1)(l) of Title V OP.

Table 6.5-6. Proposed RACT-Based NO_x Emission Limitations (SPC Unit 5)

Emission unit	Emission Limitation/Work Practice		Monitoring Requirements
	Normal Operation	Startup/Shutdown	
Unit 5	12 ppm @ 3% O_2 (4-hr average)	GCP	CEMS (follow existing permit requirements)

6.5.2.4 Auxiliary Boiler (Unit 6)

Unit 6 is a Nebraska watertube package boiler (Model NOS 2A/S-55) with a heat input rating of 86 MMBtu/hr. This boiler provides steam to the nearby Ocean Spray® manufacturing facility. The boiler is permitted to fire natural gas with an annual heat input limitation of 510,000 MMBtu/year and an annual operating limit of 6,000 hours in any consecutive 12 months. The unit is currently equipped with an LNB designed to meet a NO_x emission limit of 30 ppm @ 3% O_2.

6.5.2.4.1 Control Equipment Evaluation

The Unit 6 control equipment evaluation is based on the potential NO_x control technologies for boilers described in Section 4 of this report. Table 6.5-7 lists control technologies and an assessment of the technical feasibility of each.

Table 6.5-7. Technical Feasibility of NO_x Control Technologies (SPC Unit 6)

Control Technology	Technical Feasibility	Comments
SNCR	No	Boiler exhaust temperature is lower than required (500–200°F).
SCR	No	Boiler exhaust temperature is lower than required (1,400–1,600°F).
LNB Upgrade / FGR	Yes	
EAR / LEA	No	Boiler is already equipped with LNB and the plant conducts routine boiler tuning to optimize excess air flow.
ARA	No	Boiler is not currently equipped with OFA.
CFB / RCB	Yes	
GFFM	No	A literature search did not find articles or reports on the use of gas fuel flow modifiers on a gas-fired package boiler equipped with LNB. Since Unit 6 is already equipped with LNB, which incorporates air-fuel mixing strategies, this option likely will have little or no effect in reducing emissions.
WSI	No	A literature search did not find articles or reports suggesting addition of water or steam injection to boilers already equipped with LNB is technically feasible.
OFA	No	Unit 6 is a relatively small boiler that likely does not provide sufficient space to benefit from the use of OFA.[259]

[259] *NO_x Emissions Control from Stationary Sources Student Manual*, p. 6-10: "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." 2009. PLAN361-CI (formerly APTI Course 418), EPA.

Control Technology	Technical Feasibility	Comments
FIR	Possibly	FIR burners are commercially available for packaged watertube boilers from John Zink/Coen. For this evaluation, DAQ assumed that a FIR burner retrofit is technically feasible, although further investigation is required to confirm.
FIR2	Possibly	FIR2 has been demonstrated commercially in an industrial boiler, achieving NO_x emissions of 17 ppm, although this study is dated.[260] A literature search did not find articles or reports on this study, or any information suggesting FIR2 is a technically feasible retrofit option for this boiler, or whether this technology is even still commercially available. For this evaluation, DAQ assumed that FIR2 is technically feasible, but further investigation is required to confirm.
BT / OT	Already implemented	SPC required to conduct semiannual boiler inspections and tune-ups.[261]
NGR	No	NGR for industrial boilers has previously been limited to some coal- and municipal solid waste-fired boilers.[262] A literature search did not find articles or reports on NGR use in natural gas-fired, packaged watertube boilers, so this technology is not considered technically feasible.
CCB	No	CCB is considered an inferior technology compared with other LNBs. Available performance data shows NO_x emissions were reduced from 70 ppm to less than 20 ppm with a 5% boiler efficiency loss due to the injection of steam into the combustion zone; other LNB can achieve 9–10 ppm without using steam injection.
BOOS	No	This approach requires multiple burners. Unit 6 is equipped with only a single burner.
FGR	Possibly	DAQ will consider adding FGR to the existing LNB, although further investigation would be required to determine whether the existing burner would support it. DAQ will also consider replacing the existing LNB with a newer design that incorporates FGR.
GCP	Already implemented	SPC is required to conduct semiannual boiler inspections and tune-ups, and to follow manufacturer's O&M manual for GCP.[263]

6.5.2.4.2 Control Equipment Costs

Table 6.5-8 provides a summary of the cost assumptions associated with each technically feasible upgrade option. Control equipment costs include the following general assumptions:

- TCI includes initial capital investment (equipment cost only) and direct costs (direct installation cost only).
- Annualized TCI for all control operations is based on an estimated equipment life of 15 years (except as noted).[264]
- Interest rate used for calculating annualized TCI is based on DAQ RACT guidelines.

[260] "Alternative Control Techniques Document–NO_X Emissions from Industrial/Commercial/Institutional (ICI) Boilers," March 1994. EPA-453/R-94-022.
[261] Condition F(3)(g) of Title V OP.
[262] *Guide to Low Emission Boiler and Combustion Equipment Selection*, April 2002. ORNL/TM-2002/19.
[263] Condition F(3)(g) of Title V OP.
[264] Estimated equipment life for combustion-related upgrades = 15 years based on CoST version 4.1.

Cost estimates for certain options are based on vendor estimates provided by SPC. These estimates have been modified to reflect DAQ's cost assumptions for consistency with other RACT analyses. 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. Estimated costs are considered conservative and likely understate actual costs associated with each control option (Appendix 9).

Table 6.5-8. Control Equipment Costs (SPC Unit 6)

Control Technology	Comments
LNB Upgrade / FGR	Cost of LNB upgrade with FGR based on vendor estimate for ultra-low NO_x burner utilizing metal-fiber, surface-stabilized combustion technology.[265]
CFB	Capital cost ($0.78/1000 Btu (2011$)) based on a white paper.[266] In calculating annualized TCI, DAQ assumed a 10-year equipment life, which is shorter than other combustion options because the CFB are easily damaged.
FIR	Cost information was not readily available for FIR burner retrofit. DAQ assumed costs are similar to LNB replacement without FGR based on vendor estimate for LNB+FGR modified to reflect LNB replacement only.[267]
FIR2	Cost information was not readily available for FIR2 retrofit. DAQ assumed cost is the same as for an FGR retrofit with no burner replacement.
FGR	Cost of adding FGR to existing burner based on vendor estimate for LNB+FGR modified to reflect FGR only.[268]

6.5.2.4.3 Control Equipment Performance

Table 6.5-9 lists the assumptions used to determine the achievable emissions level for each of the technically feasible upgrade options. To the extent possible, DAQ applied the same performance assumptions used in the other boiler RACT analyses in this report.

Table 6.5-9. Control Equipment Performance (SPC Unit 6)

Control Technology	Comments
LNB Upgrade / FGR	Achievable emissions level of 5 ppm @ 3% O_2 based on vendor performance guarantee.[269]
CFB	Achievable emissions level of 15 ppm @ 3% O_2 based on vendor white paper.[270]
FIR	FIR vendor literature states that burners are capable of reaching single-digit NO_x concentrations and that performance is similar to LNB equipped with FGR. DAQ assumed an achievable emissions level of 9 ppm @ 3% O_2 based on vendor performance guarantee for LNB upgrade option with FGR.
FIR2	Limited information was available for NO_x control efficiency using FIR2. DAQ assumed a 58% incremental removal efficiency (13 ppm @ 3% O_2) based on the average removal

[265] Estimate provided was for a 35 MMBtu/hr fire-tube boiler burner that was modified based on the Unit 6 heat input rating. The cost estimate was based on a burner without FGR and, therefore, is considered conservative (see Appendix 8a).

[266] *Characterizing Costs, Savings, and Benefits of a Selection of Energy Efficient Emerging Technologies in the United States*, Xu, T., Lawrence Berkeley National Laboratory, 3/31/2011.

[267] Appendix 9

[268] Appendix 9

[269] Appendix 8a

[270] *Radiant Fiber Burners for Gas-Fired Appliances and Equipment*, John P. Kesselring, Robert M. Kendall, and Richard J. Schreiber, Alzeta Corporation.

Control Technology	Comments
	efficiency demonstrated in a utility boiler study.[271]
FGR	The achievable emissions level for the addition of FGR to the existing LNB is estimated to be 15 ppm @ 3% O_2. This assumes an incremental reduction of 50% from baseline emissions based on upper range of expected performance from other installations (i.e., 40–50% using 20–30% FGR).[272]

6.5.2.4.4 RACT Determination

Table 6.5-10 lists the incremental control efficiency, achievable level of emissions, and cost-effectiveness of each control option used in the RACT determination for Unit 6. Additional supporting calculations are in Appendix 9.

Table 6.5-10. NO_X RACT Summary (SPC Unit 6)

Control Equipment	Incremental Control Efficiency (%)	Achievable Emissions (ppm @ 3% O_2)	Cost Effectiveness ($/ton)
LNB Upgrade/FGR	83%	5	34,300
FIR	70%	9	53,700
FIR2	58%	13	19,200
CFB	50%	15	18,500
FGR	50%	19	15,400
LNB (existing controls)	N/A	30	N/A

Table 6.5-11 summarizes the RACT determination for Unit 6. DAQ determines that the existing NO_X limit of 30 ppmvd @ 3% O_2 (excluding startup and shutdown operation) represents RACT based on the use of existing NO_X controls. All other technically feasible control options were eliminated due to excessive cost ($15,400–$53,700/ton). Compliance will be demonstrated by following the existing monitoring and recordkeeping requirements and operating restrictions in the current Title V OP. RACT during startup, shutdown, and other non-normal operation is 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. While the source is already required to follow good combustion practices and maintain the boiler in accordance with the manufacturer's O&M manual,[273] the permittee shall ensure these procedures also address periods of startup, shutdown, and other non-normal operation.

Table 6.5-11. Proposed RACT-Based NO_X Emission Limitations (SPC Unit 6)

Emission Unit	Emission Limitation/Work Practice		Monitoring Requirements
	Normal Operation	Startup/Shutdown	
Unit 6	30 ppmvd @ 3% O2	Follow good combustion practices	Follow existing permit conditions

[271] *Demonstration of Fuel Injection Recirculation (FIR) for NO_X Emissions Control*, Reese, James L., et al., 1994.

[272] APTI 418, Control of Nitrogen Oxides Emissions, p. 6-18. 2000.

[273] See Condition E(1)(l) of the current Title V operating permit.

Appendix 1

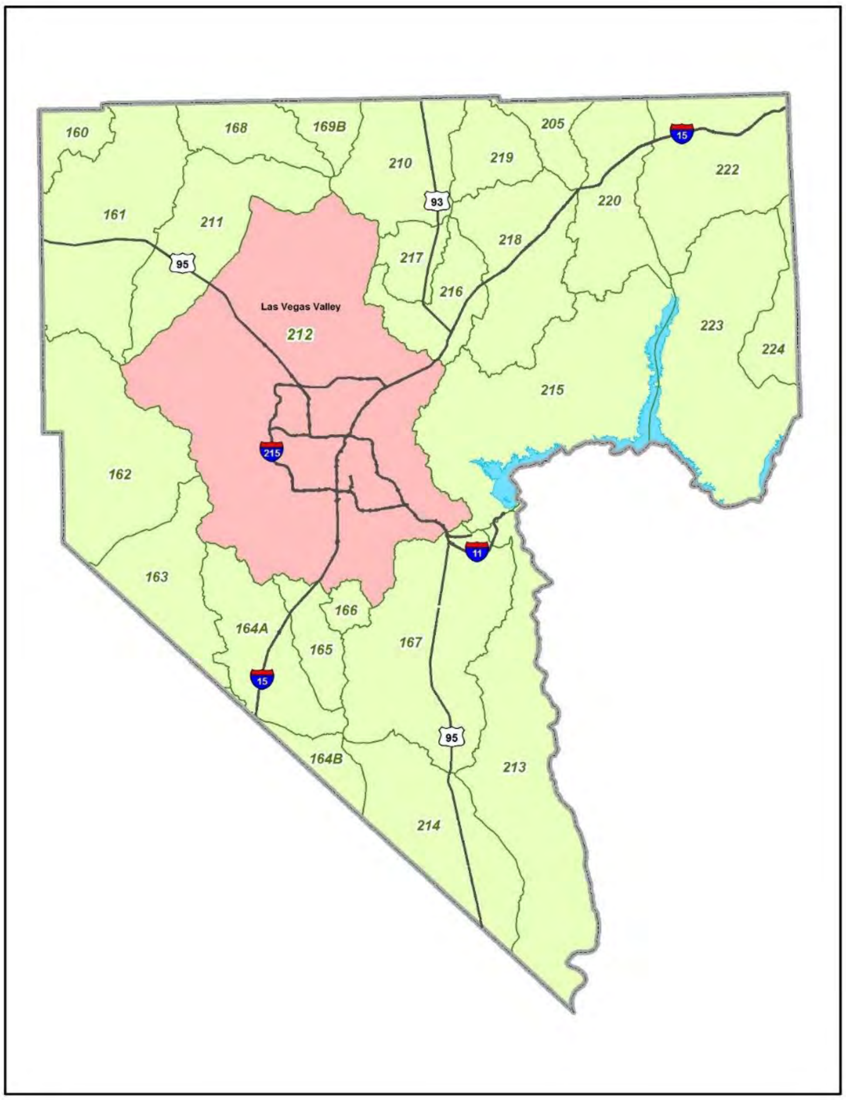
Final RACT Methodology for
HA 212 2015 8-hour Ozone NAAQS

FINAL RACT METHODOLOGY FOR HA 212 2015 8-HOUR OZONE NAAQS

I. INTRODUCTION

On June 4, 2018, EPA designated a portion of Clark County (hydrographic area 212) as a marginal nonattainment for the 2015 8-hour ozone National Ambient Air Quality Standards (NAAQS) based on a design value that exceeded the 0.07 ppm NAAQS. (83 FR 25776). HA 212 is located in a central location within Clark County and includes the Las Vegas Valley. *See* Figure 1.

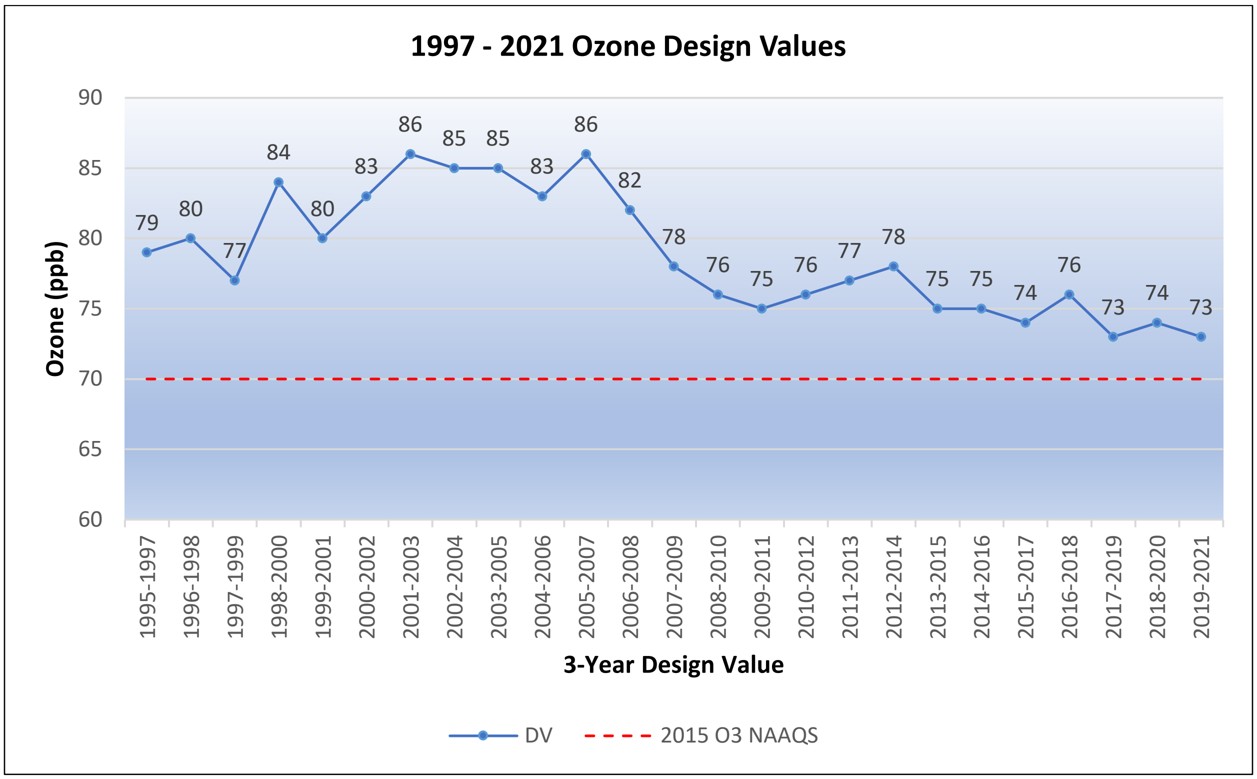
Figure 1. Nonattainment Area (Hydrographic Area 212) in Clark County, Nevada



II. OZONE IN CLARK COUNTY

The predominant source of NOx emissions in Clark County are from on-road mobile sources, while the predominant source of VOC emissions are biogenic. Point Sources of both NOx and VOC emissions comprise a very small portion of the total emissions inventory. In 2017, NO_x point sources contributed 1033 tons to the NO_x emissions inventory, while VOC point sources contributed a total of 447 tons to the VOC emissions inventory. Of these total point source emissions, NOx major sources represent only one third of the total inventory, while the VOC major sources comprise less than five percent (5%). During a typical summer day in 2017, NO_x major stationary sources collectively emitted less than 1 ton of NO_x, while VOCs major sources are below a tenth of a ton. This means that there may be fewer opportunities to implement cost-effective emissions controls on major sources.

Figure 2 – Ozone Trends in Clark County HA 212



III. ATTAINMENT DATE REQUIREMENTS

The effective date of the nonattainment designation for HA 212 occurred on August 3, 2018. EPA's implementation rule for the 2015 ozone NAAQS (40 CFR Part 51, Subpart CC) provides that a marginal nonattainment area must achieve attainment within three (3) years of the effective date of the nonattainment designation. Accordingly, HA 212's was required to achieve attainment of the 2015 8-hour Ozone NAAQS by August 3, 2021.

Whether HA 212 achieved attainment by this date is based on the 2018-2020 design value. DAQ identified 28 exceedance days at area monitors during this period that were likely caused by exceptional events such as wildfires or stratospheric ozone intrusions. In accordance with EPA's exceptional events rule (40 CFR 40 CFR §50.14), DAQ submitted 17 exceptional event demonstrations that included data, modeling, and other information to U.S. Environmental Protection Agency (EPA) Region 9 to support excluding monitoring data for these 28 event days from calculation of HA 212's ozone design value for the 2018-2020 ozone seasons.

After reviewing the data, Region 9 found that the weight of evidence did not support a finding that emissions from exceptional events caused exceedances of the ozone NAAQS in HA 212 on June 19-20, 2018, May 6, 2020, May 9, 2020, June 22, 2020, and June 26, 2020. Region 9 deferred reviewing the request for excluding monitoring data for other requested dates, because the Region determined that a finding on those dates would not affect a decision on HA 212's attainment status or qualification for a one-year extension for demonstrating attainment. Without excluding monitoring data for these dates from the design value calculation, HA 212's 2018-2020 design value equals 0.074 ppm. This value is above the 0.07 ppm design value required to demonstrate attainment of the 2015 8-hour ozone NAAQS (as required by 40 CFR §50.19) by HA 212's attainment date.

Under CAA Section 181(b), the EPA generally is required to reclassify a nonattainment area to the next higher ozone classification if the ozone nonattainment area fails to meet its attainment date. Thus, DAQ expects EPA to reclassify HA 212 from a marginal to a moderate nonattainment area for the 2015 8-hour ozone NAAQS (if EPA finalizes Region 9's nonoccurrence on DAQ's request to exclude certain dates of monitoring data from the 2018-2020 ozone design value calculation).

This redesignation will trigger additional state implementation plan (SIP) requirements for HA 212, including a requirement to impose reasonably available control technology requirements on certain stationary sources.

IV. RACT UNDER EXISTING DAQ REGULATIONS VS. NONATTAINMENT AREA RACT

DAQ's rules already require stationary sources to comply with RACT under Sections 12.1.3.6 and 12.4.3 of the permitting rules. DAQ defines RACT in Section 12.0 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...

This RACT requirement applies when a stationary source proposes to construct or modify an emissions unit and increase potential emissions at a minor stationary source by greater than significant and at a major stationary source by greater than the minor NSR Significant Level for a pollutant. For NO_x and VOC emissions increase, the significance levels are 20 tpy. (*See* Sections 12.1.1 and 12.4.2.1).

Although the DAQ's and EPA's definitions for "RACT" are consistent [1], the applicability of RACT to stationary sources under DAQ's current rules differs from the required applicability for RACT based on an area's nonattainment classification. The requirements for nonattainment areas are in Part D of the Clean Air Act. Section 172(c)(1) of Part D requires a nonattainment area to adopt reasonably available control measures including reasonably available control technology requirements for stationary sources.

CAA Section 182(b) adds additional information on meeting RACT requirements for moderate ozone nonattainment areas. Under Section 182, a moderate nonattainment area must apply RACT for VOC emissions to each source category for which EPA issued a control technology guideline (CTG). CTGs provide the "presumptive norm" for minimum VOC control requirements for specific categories of sources.[2] Sources falling into a source category for which EPA has published a CTG are referred to as "CTG sources." EPA recommends that air pollution control agencies adopt regulations that are consistent with the applicability thresholds and control level in these CTGs. Air pollution control agencies may, however, "judge the feasibility of imposing the recommended controls on particular sources, and adjust the controls accordingly."[3]

EPA has not issued CTGs for NO_x emissions from source categories, thus no RACT requirements apply to NO_x source categories by virtue of an EPA issued CTG. Instead, EPA issues Alternative Control Techniques (ACT) guidance for NO_x source categories. These guidance documents do not establish a presumptive level of emissions control, rather the documents provide information on potential control measures and costs. They provide a resource for determining RACT for individual major sources and for Reasonably Available Control Measure (RACM) requirements.

CAA Section 182(b)(1)(A)(ii)(II) also requires RACT for all major sources of ozone precursors, and Section 182(f) extends this major source requirement to NOx major sources. For a moderate nonattainment area such as HA 212, "major source" is defined as a stationary source that emits, or has the potential to emit at least 100 tons per year of either VOC or NO_x.

EPA codified these requirements for the 2015 ozone National Ambient Air Quality Standard (NAAQS) in its Ozone Implementation Rule found in 40 CFR Part 51, Subpart CC.[4]

The following outlines DAQ's process for satisfying CAA Sections 172(c)'s and 182(b)'s RACT requirements for CTG Sources and VOC and NOx major sources.

[1] Neither the CAA nor EPA's rules contain a codified definition of reasonably available control technology for purposes of implementing the CAA Part D RACT requirements. Instead, EPA has defined RACT in numerous guidance statements 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." EPA first set forth this definition in Memorandum from Roger Strelow, Assistant Administrator for Air and Waste Management to Regional Administrators, "Guidance for Determining Acceptability of SIP Regulations in Non-attainment Areas," (Dec. 9, 1976).

[2] 44 *Fed. Reg.* 53761 (Sept. 17, 1979)
[3] *Id.*
[4] 88 *Fed. Reg.* 62998 (

V. PROCESS FOR CTG SOURCES

Step 1 – Identify RACT CTG Sources

Attachment 2 includes a list of EPA's current VOC CTG source categories. DAQ will determine whether any stationary source within the source category is operating in the Clark County nonattainment area. DAQ will employ several search methods to identify whether CTG sources operate within the nonattainment area. These search methods may include, but are not necessarily limited to:

1. Review national emissions inventory information
2. Perform internet search using key terms from source category
3. Consult permitting and enforcement staff
4. Search business licenses issued through the Secretary of State
5. Public Outreach

Step 2 – Compare existing emission control requirements to CTG presumptive norm.

For each VOC CTG source category with an operating source in the HA 212 nonattainment area, DAQ will review EPA's CTG for that source category. Then, DAQ will review permits for the stationary source(s) and applicable Federal and SIP regulations to determine whether the permit or regulations already require a level of VOC emissions reduction consistent with EPA's presumptive norm for the CTG source category. As explained above, under DAQ's SIP-approved permitting program, sources may be subject to a VOC RACT requirement under Section 12.1.3.6 and 12.4.3 of DAQ's rules. In addition, CTG sources may be subject to VOC BACT or LAER requirements imposed under the requirements of Section 12.2 or 12.3, or a State SIP requirement or federal emissions standards such as New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants.

If a CTG source is subject to a RACT, BACT or LAER or federal or SIP requirement, DAQ will evaluate the required control level to determine if the control level satisfies EPA's presumptive norm for the source category. DAQ anticipates that one of four findings may result from this evaluation:

1. There is no operating CTG sources in a source category in the HA 212 nonattainment area;
2. CTG Source is subject to a RACT, BACT, LAER or federal or SIP requirements that is consistent with the emissions reduction achievable through application of the presumptive norm;
3. CTG Source is subject to RACT, BACT, LAER or federal or SIP requirement that is less stringent than the presumptive norm;
4. CTG Source is currently not subject to RACT, BACT, LAER or a federal or SIP rule.

Step 3 –Negative Declaration or Establish RACT

For any CTG source category for which DAQ fails to identify an operating source within the Clark County nonattainment area, DAQ will issue a negative declaration for the source category in its SIP submittal.

If the CTG source category currently is subject to a federal or SIP-approved regulation that is consistent with the emissions reductions that would be expected through application of EPA's presumptive norm, then DAQ will determine whether that rule is already part of the SIP. If that rule is not already adopted into the SIP, then DAQ will adopt the rule into the SIP to satisfy RACT requirements. In conducting this assessment, DAQ will also evaluate coverage of startup, shutdown, and malfunction (SSM) emissions under the existing rule. If the current rule includes an exemption for SSM emissions, then DAQ will consider separate regulations to establish RACT requirements for SSM emissions from the source category.

If a CTG source(s) is already subject to a permit-based, control requirement that is consistent with the presumptive norm, then DAQ will either submit the existing permits as a source-specific SIP requirement, or develop a SIP-approvable regulation specifying these applicable emission limitations for the CTG source through rule.

If one or more VOC CTG sources currently are subject to a permit or regulatory requirement, but the required VOC control level does not meet EPA's presumptive norm for the CTG source category, or if the CTG source(s) are not currently subject to VOC emissions control requirements, then DAQ will codify a regulation for that source category to satisfy VOC RACT requirements, or require a permit application submission for the CTG sources to establish case by case RACT in a permit. DAQ would likely use the permitting mechanism to establish RACT only if there are few CTG sources in a source category.

In establishing a categorical CTG source category regulation, or issuing a case-by-case RACT through issuance of a permit, DAQ will consider EPA's CTG for the source category as guidance for developing the RACT regulation, and also may consider regulations imposed by other states on the particular source category. DAQ envisions that any RACT requirement will be consistent with the applicability thresholds and control levels of the presumptive norm in the CTG unless DAQ finds that the presumptive norm is technically or economically infeasible for one or more CTG sources operating in the HA 212 nonattainment area.

VI. RACT FOR VOC AND NO_X MAJOR SOURCES RACT

As explained above, Section 182(b) requires DAQ to require RACT for all major stationary sources of VOC, and Section 182(f) requires DAQ to also apply RACT requirements to major stationary sources of NOx. EPA's guidance allows an air pollution control agency to establish a general RACT rule that applies to a category of stationary sources, or determine RACT for each emissions unit at a stationary source on a case-by-case basis. EPA also allows averaging between emissions units to demonstrate that, on whole, a RACT level of control is achieved by the emissions units. DAQ will consult with EPA before approving any averaging approach to satisfy BACT requirements.

Through a review of the 2017 National Emissions Inventory, DAQ preliminarily identified the following major sources that could be subject to the VOC or NOx RACT requirements. Table 1 identifies the major sources, and an inventory of emissions units for these major sources is contained in Attachment 1.

Table 1. Major Sources in HA 212 Nonattainment Areas

NOx Major Sources				
Facility ID	**Facility Name**	**Total Facility NOx PTE (tpy)**	**2017 NEI Emissions tpy**	**2017 NEI Emissions (tpd)**
7	Clark Generating Station	2465.9	115.40	0.32
114	Nellis AFB	199.0	19.81	0.05
257	Caesars Consolidated Properties	370.1	19.9	0.05
393	Saguaro Power Company	164.1	102.79	0.28
423	Sun Peak Generating Station	249.4	15.89	0.04
825	MGM Resorts International	767.1	65.07	0.18
16304	Switch, Ltd.	246.18	33.23	0.09
VOC Major Sources				
Facility ID	**Facility Name**	**Total Facility VOC PTE (tpy)**	**2017 NEI Emissions tpy**	**2017 NEI Emissions (tpd)**
13	Calnev Pipeline LLC	187.4	59.31	0.16
7	Clark Generating Station	216.5	14.12	0.04

Based on the limited number of major sources in HA 212's emissions inventory, DAQ believes that it is most appropriate to determine RACT for existing sources on a case-by-case basis for each major stationary source. DAQ does not believe it is necessary to determine RACT for all future new or replaced emissions units at this time. As explained above, DAQ rules already require RACT, BACT or LAER determinations for stationary sources that construct or modify above the minor NSR significant levels. Should a major source propose to construct a new VOC and NOx emissions unit above the RACT applicability threshold in the nonattainment area, then DAQ will request a RACT analysis with the construction permit application, and establish RACT requirements in the issued permit to the extent there are available emissions controls that are both technically and economically feasible.

Step 1 – Information Collection

As a first step in the case-by-case RACT process, DAQ will provide each major source the opportunity to submit a control technology analysis with a proposed RACT demonstration for its emissions units. Given the short period of time for DAQ to identify and implement RACT, it is important that DAQ focus both our major source resources and DAQ's resources on identifying opportunities for meaningful emissions reductions. To that end, DAQ advised major sources to submit RACT analysis information on each of their emissions units having a PTE equal to or greater than 5 tpy.

DAQ believes that 5 tpy represents an appropriate applicability threshold for evaluating potential RACT requirements and that excluding emissions units below this level from the information request represents a reasonable *de minimis* level. EPA allows states to establish a *de minimis* level for purposes of implementing RACT.[5]

A review of the individual emissions units located at our eight major sources (See Attachment 1) shows that applying this *de minimis* threshold would allow only small natural gas boilers (1-< 25 MMbtu/hr heat input); some emergency generators with actual emissions far below the emissions unit's PTE; and smaller emitting emissions units such as natural gas water heaters to avoid RACT applicability (0.01 tpy). The major contributors to each major source's actual emissions would be subject to the RACT review.

DAQ believes it is not cost-effective to regulate emissions from these smaller emissions units, because there are a lack of available, cost-effective control measures for these smaller emissions. The cost-effectiveness is further challenged by the reduced yearly emissions of the major source. As evident from the Table 1, the majority of major sources in HA 212 are emitting at orders of magnitude below the major source's PTE.

In addition, DAQ reviewed several existing State RACT requirements and found applicability thresholds for RACT requirements for industrial and commercial boilers, process heaters, and steam generators generally applied at greater than 50 mmBtu/hr heat input. San Diego County recently showed that applying lower applicability thresholds to these types of emissions units resulted in cost effectiveness values exceeding $12,000/ton. San Diego County, an area with air quality more impaired than HA 212, does not consider this cost per ton cost value cost-effective, and DAQ concurs in that finding.[6] DAQ believes that costs for major sources in HA 212 will be similar to those in San Diego County. Thus, we believe it will likely not be cost-effective to control emissions units with heat inputs lower than 50 mmBtu/hr. Nonetheless, we requested information and cost calculations at a value half of this amount. Likewise, we expect that emissions controls on smaller emergency generators, which operate infrequently, and water heaters that have negligible actual emissions would not be cost-effective.

Step 2 Information Needs

DAQ issued an invitation to major sources to submit information relative to a case-by-case RACT requirement. DAQ requested the following information:

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)

[5] *See* Memorandum from G.T. Helms, Group Leader Ozone Policy and Strategies Group to Air Branch Chief, Region 1-X, "De Minimis Values for NOx RACT," (Jan. 1, 1995)
[6] "2020 Reasonably Available Control Technology Demonstration for the National Ambient Air Quality Standards for Ozone in San Dieago County," County of San Diego Air Pollution Control District (October 2020).

6. Environmental, energy and other impacts (benefits and disbenefits); GHG, HAP or other
7. pollutants
8. Proposed RACT emissions limitation or averaging approach
9. Schedule for installing and operating the emissions control
10. Proposed testing, monitoring, recordkeeping, and reporting meeting periodic or CAM monitoring requirements.

To assure uniformity in the cost estimates between major sources, DAQ asked major sources to submit cost information using a 6% interest rate and the remaining useful life of the emissions unit (assuming an original useful life of 30 years unless the major source submits information justifying a different useful life.) The major source may also provide information on actual interest rates available to the major source, and DAQ will consider this information in determining RACT for the major source.

DAQ advised major sources that the baseline emissions for the cost effectiveness calculations should be based on the emissions unit's potential to emit (PTE) including consideration of existing, enforceable control technologies. Alternatively, if either the major source, or a particular emissions unit's actual emissions over a representative period of operations are less than 70% of the PTE, then the major source can elect to provide cost effectiveness information based on use of actual emissions. Actual emissions may be used as a baseline for all emissions units if the major source's actual emissions are 70% below its potential to emit, or for individual emissions units if a particular emissions unit's actual emissions are 70% below that emission unit's PTE.

Step 3 Information Verification

After receiving information from major sources, DAQ will review the information for thoroughness and reliability. DAQ will then determine whether it agrees with the major source's RACT recommendation.

In determining the suitability of a given control option for RACT, DAQ will be guided by cost effectiveness values DAQ approved in past control technology determinations, cost effectiveness guidance provided by EPA, and cost thresholds found acceptable by other states.

Step 4 Establish RACT Requirements

Once DAQ determines the appropriate control measures that qualify as RACT, it will determine the RACT emissions limitation. If DAQ determines that no control measure is cost-effective because of a reduced life expectancy, then DAQ will consider requiring the emissions unit to shutdown by a date certain. DAQ will also consider whether any interim measures are available to reduce emissions before the mandated shutdown date.

The RACT emissions limitation will represent the lowest achievable emissions level with which the emissions unit(s) can continuously comply using the proposed RACT control option. The proposed emissions limitation will also include requirements for startup, shutdown and malfunction periods (SSM) (with a proposed definition of SSM to govern these operations). The SSM provisions may be included in a single RACT emission limitation recommendation, or as a separate emissions limitation recommendation when including these SSM emissions in a generally applicability emission limitation would cause the proposed emissions limitation to be too lax during times of normal operations. DAQ will also consider work practice requirements when a numerical emissions limitation is not feasible.

DAQ will assess whether to issue the RACT determinations for the major sources through source category specific RACT regulations, or through individual permits for each major source. DAQ will then submit the rule or permit for EPA's approval into the SIP.

ATTACHMENT 1 – VOC and NOx EMISSIONS UNITS IN HA 212

This is a list of emissions units located at NOx and VOC major sources in HA 212. This list may be incomplete.

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
BA01	Natural Gas Boiler	16.8 MMBtu/hr	Kewanee	8,760 hr/yr	2.24	
BA02	Natural Gas Boiler	16.8 MMBtu/hr	Kewanee	8,760 hr/yr	2.24	
BA03	Natural Gas Boiler	25.106 MMBtu/hr	Kewanee	8,760 hr/yr	3.34	
BA04	Emergency Generator (#1) DOM: Pre- 2006	1,000 kW	Magna One	500 hr/yr	8.04	
		1,340 hp	Detroit Diesel			
BA05	Emergency Generator (#2) DOM: Pre- 2006	1,000 kW	Magna One	500 hr/yr	8.04	
		1,340 hp	Detroit Diesel			
BA06	Emergency Generator DOM: Pre- 2006	500 kW	Magna One	500 hr/yr	4.02	
		670 hp	Detroit Diesel			
BA07	Emergency Generator DOM: Pre- 2006	155 kW	Magna One	500 hr/yr	1.55	
		200 hp	Detroit Diesel			
BA11	Emergency Generator (#3) DOM: Pre- 2006	1,000 kW	Detroit	500 hr/yr	8.04	
		1,340 hp				
BA12	Emergency Generator (#4) DOM: Pre- 2006	1,000 kW	Detroit	500 hr/yr	8.04	
		1,340 hp				
BA17	Emergency Fire Pump DOM: 06/2011	526 hp	Clarke Fire Pump	500 hr/yr	0.76	
			John Deere Engine			
BA18	Emergency Fire Pump DOM: 04/2011	526 hp	Clarke Fire Pump	500 hr/yr	0.76	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
			John Deere Engine			
BA19	Cooling tower – 3 cells	18,000 GPM	Evapco	8,760 hr/yr	0.00	
BA20	Cooling tower – 3 cells	18,000 GPM	Evapco	8,760 hr/yr	0.00	
CR01	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR02	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR03	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR04	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR05	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR06	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	8,760 hr/yr	0.16	
CR07	Diesel Engine Emergency Generator DOM: 2013	1,500 kW	Caterpillar	500 hr/yr	10.18	
		3,634 hp	Caterpillar			
CR08	Diesel Engine Emergency Generator DOM: 2013	150 kW	Caterpillar	500 hr/yr	0.43	
		275 hp	Caterpillar			
CR09	Cooling Tower, 3-cell	5,400 gpm	Evapco	8,760 hr/yr	0.00	
PA12	Natural Gas Boiler #4	3.5 MMBtu/hr	Bryan	8,760 hr/yr	0.48	
PA13	Natural Gas Boiler #5	3.5 MMBtu/hr	Bryan	8,760 hr/yr	0.48	
PA14	Natural Gas Boiler #3	17.0 MMBtu/hr	Bryan	8,760 hr/yr	2.72	
PA15	Natural Gas Boiler #1	21.0 MMBtu/hr	Bryan	8,760 hr/yr	3.36	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
PA16	Natural Gas Boiler #2	21.0 MMBtu/hr	Bryan	8,760 hr/yr	3.36	
PA17	Emergency Generator #1 DOM: 03/25/1998	2,100kW	Cummins	500 hr/yr	16.90	
		2,816 hp				
PA18	Emergency Generator #2 DOM: 02/26/1998	2,100kW	Cummins	500 hr/yr	16.90	
		2,816 hp				
PA19	2-Cell Cooling Tower #1	4,725 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
PA20	2-Cell Cooling Tower #2	4,725 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
PA21	2-Cell Cooling Tower #3	4,725 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
PA22	2-Cell Cooling Tower #4	4,725 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
PA23	2-Cell Cooling Tower #5	4,725 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
PA28	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA29	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA30	Natural Gas Pool Heater	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA31	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA32	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA33	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA34	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
PA35	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.10	
PA36	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.84	
IP01	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	8,760 hr/yr	0.27	
IP02	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	8,760 hr/yr	0.27	
IP03	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	8,760 hr/yr	0.27	
IP04	Natural Gas Boiler	16.738 MMBtu/hr	Kewanee	8,760 hr/yr	3.59	
IP05	Natural Gas Boiler	16.738 MMBtu/hr	Kewanee	8,760 hr/yr	3.59	
IP06	Emergency Generator DOM: Pre-2006	470 kW	Caterpillar	500 hr/yr	4.08	
		680 hp				
IP07	Emergency Generator DOM: Pre-2006	500 kW	Caterpillar	500 hr/yr	4.53	
		755 hp				
IP08	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	500 hr/yr	5.34	
		890 hp				
IP09	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	500 hr/yr	5.34	
		890 hp				
IP10	Emergency Generator DOM: Pre-2006	280 kW	E.M. Generator	500 hr/yr	2.91	
		375 hp	Detroit			
IP11	Emergency Generator DOM: Pre-2006	500 kW	Marathon Electric	500 hr/yr	4.02	
		670 hp	Detroit			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
IP38	Emergency Generator DOM: 2019	500 kW	Caterpillar	500 hr/yr	2.07	
PH07	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	8,760 hr/yr	3.78	
PH08	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	8,760 hr/yr	3.78	
PH09	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	8,760 hr/yr	3.78	
PH10	Genset – Emergency	1,750 kW	Spectrum			
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	500 hr/yr	15.30	
PH11	Genset – Emergency	1,750 kW	Spectrum			
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	500 hr/yr	15.30	
PH12	Genset – Emergency	1,750 kW	Spectrum			
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	500 hr/yr	15.30	
PH13	Genset – Emergency	1,750 kW	MTU			
	Engine – Diesel DOM: 2008	2,561 hp	MTU/Detroit Diesel	500 hr/yr	6.40	
PH14	6-Cell Cooling Tower	33,360 gpm	Baltimore Aircoil Company	8,760 hr/yr	0.00	
LI01	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	8,760 hr/yr	0.24	
LI02	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	8,760 hr/yr	0.24	
LI03	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	8,760 hr/yr	0.24	
LI04	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	8,760 hr/yr	0.24	
LI05	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	8,760 hr/yr	0.24	
LI06	Emergency Generator DOM: 2012	2,000 kW	Caterpillar	500 hr/yr	10.80	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
		3,634 hp				
LI07	Emergency Generator DOM: 2012	2,000 kW	Caterpillar	500 hr/yr	10.80	
		3,634 hp				
LI08	Cooling Tower, 2 cell	6,000 gpm	Marley	8,760 hr/yr	0.00	
LI09	Cooling Tower, 2 cell	6,000 gpm	Marley	8,760 hr/yr	0.00	
LI10	Cooling Tower, 2 cell	6,000 gpm	Marley	8,760 hr/yr	0.00	
LI11	Natural Gas Water Heater	0.150 MMBtu/hr	AO Smith	8,760 hr/yr	0.01	
LI12	Emergency Engine DOM: 11/2012	180 kW	Deutz	500 hr/yr	0.20	
		241 hp				
LI13	Emergency Engine DOM: 11/2012	180 kW	Deutz	500 hr/yr	0.20	
		241 hp				
FMC01	Boiler	6.00 MMBtu/hr	Lochinvar	8,760 hr/yr	0.29	
FMC02	Boiler	6.00 MMBtu/hr	Lochinvar	8,760 hr/yr	0.29	
FMC03	Boiler	6.00 MMBtu/hr	Lochinvar	8,760 hr/yr	0.29	
FMC04	Boiler	6.00 MMBtu/hr	Lochinvar	8,760 hr/yr	0.29	
FMC05	Emergency Generator DOM: 1/21/2019	1,000 kW	Cummins	500 hr/yr	3.61	
		1,490 hp				
FMC06	Cooling Tower, 2-Cell	2,400 gpm/cell	Evapco	8,760 hr/yr	0.00	
FMC07	Cooling Tower, 2-Cell	2,400 gpm/cell	Evapco	8,760 hr/yr	0.00	
HA06	Natural Gas Boiler	4.50 MMBtu/hr	Bryan	8,760 hr/yr	0.22	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
HA07	Natural Gas Boiler	9.0 MMBtu/hr	Bryan	8,760 hr/yr	1.44	
HA08	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	8,760 hr/yr	0.54	
HA09	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	8,760 hr/yr	0.54	
HA10	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	8,760 hr/yr	0.54	
HA11	Natural Gas Boiler	4.80 MMBtu/hr	Universal Energy	8,760 hr/yr	0.77	
HA12	Emergency Fire Pump DOM: Pre-2006	276 kW	Fairbanks Morse Pump	500 hr/yr	2.87	
		370 hp	Caterpillar Engine			
HA13	Emergency Generator DOM: Pre-2006	800 kW	Marathon Electric Generator	500 hr/yr	7.39	
		1,232 hp	Detroit Diesel Engine			
HA14	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	500 hr/yr	5.34	
		890 hp				
HA15	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator	500 hr/yr	4.16	
		536 hp	Detroit Diesel Engine			
HA16	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator	500 hr/yr	4.16	
		536 hp	Detroit Diesel Engine	500 hr/yr	4.16	
HA17	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator			
		536 hp	Detroit Diesel Engine			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
HA18	Emergency Generator DOM: 1996	800 kW	Caterpillar	500 hr/yr	7.08	
		1,180 hp		8,760 hr/yr	0	
HA26	Cooling Tower, 2-Cells	4,200 gpm	Evapco			
HA27	Cooling Tower, 2-Cells	4,200 gpm	Evapco	8,760 hr/yr	0	
HA28	Cooling Tower, 2-Cells	4,200 gpm	Evapco	8,760 hr/yr	0	
FL01	Natural Gas Boiler	14.343 MMBtu/hr	Johnston	8,760 hr/yr	2.22	
FL02	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	8,760 hr/yr	3.13	
FL03	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	8,760 hr/yr	3.13	
FL04	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	8,760 hr/yr	3.13	
FL05	Natural Gas Boiler	8.165 MMBtu/hr	Cleaver Brooks	8,760 hr/yr	1.27	
FL06	Emergency Fire Pump DOM: Pre-2006	313 kW	Fairbanks Morse Pump	500 hr/yr	3.26	
		420 hp	Caterpillar Engine			
FL09	Emergency Generator DOM: 1999	750 kW	Caterpillar	500 hr/yr	6.66	
		1,109 hp				
FL10	Emergency Generator DOM: 1999	750 kW	Caterpillar	500 hr/yr	6.66	
		1,109 hp				
FL11	Emergency Generator DOM: Pre-2006	475 kW	Caterpillar	500 hr/yr	4.35	
		724 hp				
FL26	Emergency Generator DOM: 2010	600 kW	Caterpillar	500 hr/yr	3.13	
		923 hp				

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
FL28	Cooling Tower, 4-cells	9,600 gpm	Marley	8,760 hr/yr	0.00	
FL29	Cooling Tower, 2-Cells	3,800 gpm	Evapco	8,760 hr/yr	0.00	
FL30	Cooling Tower, 2-Cells	3,800 gpm	Evapco	8,760 hr/yr	0.00	
FL31	Cooling Tower, 2-Cells	3,800 gpm	Evapco	8,760 hr/yr	0.00	
CP01	Natural Gas Boiler	35.40 MMBtu/hr	Hurst	8,760 hr/yr	5.46	
CP02	Natural Gas Boiler	35.40 MMBtu/hr	Hurst	8,760 hr/yr	5.46	
CP03	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	8,760 hr/yr	5.35	
CP04	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	8,760 hr/yr	5.35	
CP05	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	8,760 hr/yr	5.35	
CP07	Natural Gas Boiler	1.0 MMBtu/hr	Gasmaster	8,760 hr/yr	0.07	
CP13	Emergency Generator DOM: 3/5/1997	2,000 kW	Caterpillar	500 hr/yr	17.26	
		2,876 hp				
CP14	Emergency Generator DOM: 3/3/1997	2,000 kW	Caterpillar	500 hr/yr	17.26	
		2,876 hp				
CP15	Emergency Generator DOM: 08/14/1996	1,750 kW	Caterpillar	500 hr/yr	15.12	
		2,520 hp				
CP16	Emergency Generator DOM: 04/18/1995	1,250 kW	Caterpillar	500 hr/yr	10.91	
		1,818 hp				
CP17	Emergency Generator DOM: 12/10/1997	2,000 kW	Caterpillar	500 hr/yr	17.26	
		2,876 hp				

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
CP19a	Cooling Tower, Cell 1 of 3	9,000 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP19b	Cooling Tower, Cell 2 of 3	9,000 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP19c	Cooling Tower, Cell 3 of 3	9,000 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP20	Cooling Tower	5,750 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP21	Cooling Tower	5,750 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP22	Cooling Tower	5,750 gpm	Baltimore Aircoil	8,760 hr/yr	0.00	
CP24	Natural Gas Boiler	1.5 MMBtu/hr	RBI Futera	8,760 hr/yr	0.08	
CP25	Natural Gas Boiler	1.5 MMBtu/hr	RBI Futera	8,760 hr/yr	0.08	
CP26	Natural Gas Boiler	24.0 MMBtu/hr	Unilux	8,760 hr/yr	1.16	
CP27	Natural Gas Boiler	24.0 MMBtu/hr	Unilux	8,760 hr/yr	1.16	
CP28	Emergency Generator DOM: 2008	2,000 kW	Caterpillar	500 hr/yr	10.47	
		3,634 hp				
CP29	Emergency Generator DOM: 2008	2,000 kW	Caterpillar	500 hr/yr	10.47	
		3,634 hp				
CP30a	Cooling Tower	5,600 gpm	Composite Cooling Solutions	8,760 hr/yr	0.00	
CP30b	Cooling Tower	5,600 gpm	Composite Cooling Solutions	8,760 hr/yr	0.00	
CP32	GDO with an AST and nozzles	1,000-gallon	Fireguard	18,000 gal/yr	0.00	
CP34	Diesel Fire Pump DOM: Post-2006	525 hp	Clarke Fire Pump	500 hr/yr	1.35	
			John Deere			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
CP35	Diesel Fire Pump DOM: Post-2006	525 hp	Clarke Fire Pump	500 hr/yr	1.35	
			John Deere			
CP37	Natural Gas Pool Heater	1.5 MMBtu/hr	RBI Futera II	8,760 hr/yr	0.08	
CP41	Natural Gas Water Heater	0.25 MMBtu/hr	A.O. Smith	8,760 hr/yr	0.10	
CP42	Natural Gas Water Heater	0.25 MMBtu/hr	A.O. Smith	8,760 hr/yr	0.10	
CP44	Natural Gas Water Heater	0.999 MMBtu/hr	Lochinvar	8,760 hr/yr	0.43	
A00704 D	Natural Gas-Fired Turbine (Unit 4); Simple Cycle	60 MW	General Electric		1,732.6	
A00701 A	Natural Gas-Fired Turbine (Unit 5); Combined Cycle	85 MW	Westinghouse		360[1]	
A00702 B	Natural Gas-Fired Turbine (Unit 6); Combined Cycle	85 MW	Westinghouse			
A00705	Natural Gas-Fired Turbine (Unit 7); Combined Cycle	85 MW	Westinghouse			
A00708	Natural Gas-Fired Turbine (Unit 8); Combined Cycle	85 MW	Westinghouse			
A00709	Lime Silo	3,700 cubic feet			--	
A00710	Soda Ash Silo (A)	4,160 cubic feet			--	
A00711	Soda Ash Silo (B)	4,160 cubic feet			--	
A00712	Cooling Tower; for Unit 9 Steam Turbine Generator	54,000 gpm			--	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
A00713	Cooling Tower; for Unit 10 Steam Turbine Generator	54,000 gpm			--	
A21	Emergency Genset	474 hp	Kohler		2.48	
	Diesel Engine; DOM: pre-1993		Detroit Diesel			
A27	Two (2) Natural Gas-Fired Turbines (Unit 11); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A28	Two (2) Natural Gas-Fired Turbines (Unit 12); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A29	Two (2) Natural Gas-Fired Turbines (Unit 13); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A30	Two (2) Natural Gas-Fired Turbines (Unit 14); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A31	Two (2) Natural Gas-Fired Turbines (Unit 15); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A32	Two (2) Natural Gas-Fired Turbines (Unit 16); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A33	Two (2) Natural Gas-Fired Turbines (Unit 17); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A34	Two (2) Natural Gas-Fired Turbines (Unit 18); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A35	Two (2) Natural Gas-Fired Turbines (Unit 19); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
A36	Two (2) Natural Gas-Fired Turbines (Unit 20); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A37	Two (2) Natural Gas-Fired Turbines (Unit 21); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A38	Two (2) Natural Gas-Fired Turbines (Unit 22); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney		30.96	
A43	Gasoline Dispensing Operation; Aboveground Storage Tank; One Product Nozzle; Regular Unleaded Gasoline	1,200 Gallon			0.00	
A45	Emergency Fire Pump	460 hp	Aurora		0.62	
	Diesel Engine; DOM: 2009		Cummins			
A01	Combustion Turbine Generator #1 with a fired HRSG	35 MW	GE	8,760 hr/yr combined fuel	69.24	
A02	Combustion Turbine Generator #2 with a fired HRSG	35 MW	GE			
A03	Detroit Diesel Starter Engine, Combustion Turbine Generator #1	520 hp	Detroit	8.760 hr/yr combined fuel	69.24	
A04	Detroit Diesel Starter Engine, Combustion Turbine Generator #2	520 hp	Detroit			
A05	Auxiliary Boiler #1	218 MMBtu/h	Indeck/ Volcano	125 hr/yr	1.01	
F05	Supplemental Duct Burner, Skid #1	25 MMBtu/hr	John Zink	125 hr/yr	1.01	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
F05a	Supplemental Duct Burner, Skid #1	25 MMBtu/hr	John Zink	8,760 hr/yr	13.94	
F06	Supplemental Duct Burner, Skid #2	25 MMBtu/hr	John Zink	6,000 hr/yr	9.33	
F06a	Supplemental Duct Burner, Skid #2	25 MMBtu/hr	John Zink			
A06	Auxiliary Boiler #2	86 MMBtu/hr	Nebraska			
A09a	Cooling Tower, 3 cells	7,666 gpm each	Thermal-Dynamics Towers Inc.			
A09b				8,760 hr/yr	0	
A09c						
A01	Gas-Fired Turbine (#3); Simple Cycle; natural gas fired; MEQ = 11.20	84.5 MW	General Electric	Natural Gas 3484 hr/yr Diesel Oil 2194 hr/yr	ng 249.11 oil 249.02	
	Gas-Fired Turbine (#3); Simple Cycle; #2 diesel oil fired; MEQ = 7.05					
A02	Gas-Fired Turbine (#4); Simple Cycle; natural gas fired; MEQ = 11.20	84.5 MW	General Electric			
	Gas-Fired Turbine (#4); Simple Cycle; #2 diesel oil fired; MEQ = 7.05					
A03	Gas-Fired Turbine (#5); Simple Cycle; natural gas fired; MEQ = 11.20	84.5 MW	General Electric			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
	Gas-Fired Turbine (#5); Simple Cycle; #2 diesel oil fired; MEQ = 7.05					
B01	Emergency Genset	50 kW	Taylor Power	0.32		
	Diesel Engine; DOM: 1991	81 hp	Perkins			
T01	Diesel Tank, AST	5,064,081-gallon capacity	Chicago Bridge and Iron Co.	0		
B11	Air Compressor	48hp	Ingersoll Rand			
	Diesel Engine; DOM: 2000		John Deer			
D02	Fire pump	208 hp	Peerless			
	Diesel Engine; DOM 1990		Cummins			
B10	Flare					
SR04	SVE and GW Treatment					
RB004a		1.5 MMBtu/hr	Patterson-Kelley			
RB004a	External Combustion	1.5	Patterson-Kelley	225 Million cfu natural gas/year	11.94	0.66
RB004b	External Combustion	1.5	Patterson-Kelley			
RB198	External Combustion	2.40	LAARS			
RB650	External Combustion	2.00	AERCO			
RB013a	External Combustion	2.5	Patterson-Kelley			
RB013b	External Combustion	2.5	Patterson-Kelley			
RB016	External Combustion	1.05	Rite			
RB024	External Combustion	1.75	RBI			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
RB389	External Combustion	1.5	Patterson-Kelley			
RB390	External Combustion	1.5	Patterson-Kelley			
RB655	External Combustion	4.50	Weather-Rite			
RB656	External Combustion	4.50	Weather-Rite			
RB657	External Combustion	4.77	Weather-Rite			
RB658	External Combustion	4.77	Weather-Rite			
RB036	External Combustion	3.30	Weather-Rite			
RB037	External Combustion	3.30	Weather-Rite			
RB396	External Combustion	1.5	Patterson-Kelley			
RB397	External Combustion	1.5	Patterson-Kelley			
RB558	External Combustion	2.365	JBI			
RB559	External Combustion	2.365	JBI			
RB651	External Combustion	1.500	Raypak			
RB402	External Combustion	2	Raypak			
RB403	External Combustion	2	Raypak			
RB040	External Combustion	2	Patterson-Kelley			
RB406	External Combustion	2	Patterson-Kelley			
RB049	External Combustion	2	Parker			
RB414	External Combustion	1.5	Patterson Kelley			
RB419	External Combustion	1.5	Patterson-Kelley			
RB421	External Combustion	1.8	Rite			
RB149	External Combustion	1.35	RBI			
RB426	External Combustion	1.75	RBI			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
RB427	External Combustion	1.75	RBI			
RB581	External Combustion	1.15	Modine			
RB065a	External Combustion	4	Patterson-Kelley			
RB659	External Combustion	4.00	Patterson Kelly			
RB144	External Combustion	1.25	Patterson-Kelley			
RB439	External Combustion	1.50	Patterson-Kelley			
RB440	External Combustion	1.05	Patterson-Kelley			
RB077a	External Combustion	3	Patterson Kelley			
RB078a	External Combustion	3	Patterson Kelley			
RB079a	External Combustion	3	Patterson Kelley			
RB080	External Combustion	1.5	Patterson-Kelley			
RB081	External Combustion	1.5	Patterson-Kelley			
RB086	External Combustion	2	Patterson- Kelly			
RB094	External Combustion	1.6	Camus			
RB456	External Combustion	1.05	Patterson-Kelley			
RB457	External Combustion	1.05	Patterson-Kelley			
RB236	External Combustion	1.2205	Raypak			
RB460	External Combustion	1.63	Raypak			
RB466	External Combustion	1.7	Lochinvar			
RB467	External Combustion	1.7	Lochinvar			
RB471	External Combustion	1.65	RBI			

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
RB473	External Combustion	1.5	Patterson-Kelley			
RB482	External Combustion	3.025	Rupp Industries			
RB493	External Combustion	1.5	Thermal Solutions			
RB494	External Combustion	1.5	Thermal Solutions			
RB495	External Combustion	2	Thermal Solutions			
RB496	External Combustion	2	Thermal Solutions			
RB112[1]	External Combustion	2.392	Fulton			
RB113[1]	External Combustion	2.392	Fulton			
RB114[1]	External Combustion	2.392	Fulton			
RB620	External Combustion	1	Raypak			
RB621	External Combustion	2	Patterson Kelly			
RB622	External Combustion	2	Patterson Kelly			
RB623	External Combustion	2	Patterson Kelly			
RB660	External Combustion	1.728	Rupp Air			
RB135	External Combustion	1.8	Lochinvar			
RB136	External Combustion	1.8	Lochinvar			
RB150	External Combustion	1.26	Raypak			
RB652	External Combustion	1.050	Patterson Kelley			
RB653	External Combustion	1.680	Parker			
RB516	External Combustion	1.05	Patterson-Kelley			
RB654[2]	Various	<1.00	Various			
G001	Generator or Fire Pump	68	Cummins	10/2001	0.28	0.01
	Generator or Fire Pump					

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
G002	Generator or Fire Pump	317	Cummins	6/2003	0.64	0.01
G003	Generator or Fire Pump	99	Cummins	3/2004	0.50	0.01
	Generator or Fire Pump					
G139	Generator or Fire Pump	896	MTU	12/2015	2.51	0.01
G004	Generator or Fire Pump	287	Caterpillar	3/1989	2.22	0.01
G005	Generator or Fire Pump	535	Cummins	10/1995	2.73	0.01
G006	Generator or Fire Pump	535	Cummins	4/1996	2.73	0.01
G007	Generator or Fire Pump	535	Cummins	8/2003	2.73	0.01
G008	Generator or Fire Pump	1750	Detroit Diesel	6/1995	10.50	0.01
G009	Generator or Fire Pump	1635	Energy Now		9.81	0.01
	Generator or Fire Pump		Mitsubishi			
G090	Generator or Fire Pump	324	Cummins	5/2012	0.66	0.01
	Generator or Fire Pump					
G010	Generator or Fire Pump	1350	Cummins	3/2003	5.64	0.01
G011	Generator or Fire Pump	380	Cummins	8/1997	1.95	0.01
G012	Generator or Fire Pump	535	Cummins	10/2002	2.73	0.01
G121	Generator or Fire Pump	260	Patterson	2010	2.02	0.01
	Generator or Fire Pump		Cummins			
G014	Generator or Fire Pump	676	Caterpillar	8/1993	4.06	0.01
G091	Generator or Fire Pump	145	Cummins	4/2011	0.19	0.01
G092	Generator or Fire Pump	145	Cummins	10/2010	0.19	0.01
G085	Generator or Fire Pump	27	Kubota	11/2011	0.05	0.01
G081	Generator or Fire Pump	149	Clarke	2/2010	0.41	0.01
G130	Generator or Fire Pump	324	Cummins	4/2013	0.35	0.01
G131	Generator or Fire Pump	755	Cummins	8/2012	2.02	0.01
G017	Generator or Fire Pump	91	Detroit Diesel	9/1995	0.71	0.01
	Generator or Fire Pump					
G021	Generator or Fire Pump	317	Cummins	2/2004	0.64	0.01
G064	Generator or Fire Pump	755	Cummins	7/2008	2.02	0.01

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
G095	Generator or Fire Pump	99	Cummins	10/2005	0.50	0.01
G140	Generator or Fire Pump	20 kW	Cummins		0.14	0.01
	Generator or Fire Pump	27 hp	Kubota			
G122	Generator or Fire Pump	44.8	Kubota	9/1999	0.35	0.01
G167	Generator or Fire Pump	25 kW	Cummins	2/2019	0.13	0.01
	Generator or Fire Pump	69 hp	Cummins			
G094	Generator or Fire Pump	1,490	Cummins	11/2010	3.28	0.01
	Generator or Fire Pump					
G022a	Generator or Fire Pump	45	Kubota	5/2001	0.35	0.01
G086	Generator or Fire Pump	27	Kubota	1/2011	0.05	0.01
G165	Generator or Fire Pump	250 kW	Cummins	2009	0.53	0.01
	Generator or Fire Pump	399	Cummins			
G024	Generator or Fire Pump	56	Cummins	4/2002	0.12	0.01
G025	Generator or Fire Pump	35 kW	Cummins	6/2001		
	Generator or Fire Pump	68			0.28	0.01
G077	Generator or Fire Pump	145	Cummins	9/2008	0.16	0.01
G103	Generator or Fire Pump	130	Cummins	1/2006	1.01	0.01
G028	Generator or Fire Pump	102	Cummins	12/2000	0.51	0.01
G084	Generator or Fire Pump	27	Kubota	11/2011	0.05	0.01
G029	Generator or Fire Pump	99	Cummins	7/2004	0.50	0.01
G142	Generator or Fire Pump	350 kW	Cummins	11/2009	1.70	0.01
	Generator or Fire Pump	755 hp				
G069	Generator or Fire Pump	399	Cummins	12/2007	1.25	
G124	Generator or Fire Pump	27	Kubota	2013	0.21	
G102	Generator or Fire Pump	27	Kubota	11/2011	0.06	
G032	Generator or Fire Pump	1586	Caterpillar	2/1992	7.80	
G033	Generator or Fire Pump	1586	Caterpillar	2/1992	7.80	
G034	Generator or Fire Pump	68	Cummins	9/1998	0.28	
G035a	Generator or Fire Pump	145	Cummins	8/2010	0.16	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
G132	Generator or Fire Pump	250	Cummins	1/2011	0.27	
G125	Generator or Fire Pump	37	Kubota	7/1999	0.29	
G120	Generator or Fire Pump	27	Kubota	8/2004	0.21	
	Generator or Fire Pump					
G097	Generator or Fire Pump	157	Caterpillar	12/2010	1.22	
G080	Generator or Fire Pump	250	Cummins	6/2008	0.41	
G036	Generator or Fire Pump	67	Waukesha	9/1981	0.52	
G126	Generator or Fire Pump	27.7	Kubota	1/1999	0.21	
G038	Generator or Fire Pump	207	Cummins	6/2006	1.60	
G067	Generator or Fire Pump	364	Cummins	9/2007	2.82	
G127	Generator or Fire Pump	27	Kubota	6/2004	0.21	
G040	Generator or Fire Pump	102	Cummins	2/2000	0.51	
G068	Generator or Fire Pump	399	Cummins	12/2007	1.25	
G137	Generator or Fire Pump	755	Cummins	8/2011	3.57	
G128	Generator or Fire Pump	27	Kubota	1/2006	0.05	
G129	Generator or Fire Pump	27	Kubota	6/2006	0.05	
G154	Generator or Fire Pump	145	Cummins	6/2016	0.19	
G166	Generator or Fire Pump	15 kW	Cummins	2019	0.51	
	Generator or Fire Pump	324	Cummins			
G135	Generator or Fire Pump	27	Kubota	9/2004	0.21	
G169	Generator or Fire Pump	100 kw	Cummins	TBD	0.25	
	Generator or Fire Pump	173 hp	Cummins			
G073	Generator or Fire Pump	364	Cummins	12/2008	0.74	
G136	Generator or Fire Pump	50 kw	Cummins	11/2012	0.17	
	Generator or Fire Pump	145				
G041	Generator or Fire Pump	1,220	Cummins	11/1991	8.07	
G149	Generator or Fire Pump	157	John Deere	2016	0.25	
	Generator or Fire Pump					
A033[3]	Generator or Fire Pump	250 kW	Olympian	2002	1.79	

EU	Description	Rating	Make	Operating Conditions	NOx (tpy)	VOC (tpy)
	Generator or Fire Pump	325 bhp	International			
G141	Generator or Fire Pump	1,200	Cummins	11/2005	5.08	
G046	Generator or Fire Pump	170	Cummins	6/2004	0.84	
G047	Generator or Fire Pump	364	Cummins	8/2010	0.66	
G048	Generator or Fire Pump	182	Cummins	12/1993	0.61	
G049	Generator or Fire Pump	208	Cummins	4/2005	1.61	
G157	Generator or Fire Pump	86	Clarke	6/2014	0.26	
	Generator or Fire Pump		John Deere			
G050	Generator or Fire Pump	380	Cummins	10/2003	1.95	
G099	Generator or Fire Pump	105	John Deere	1/2004	0.29	
G160[3]	Generator or Fire Pump	150 hp (Diesel, Tier 4)	Caterpillar	2/2018	0.98	
G161[3]	Generator or Fire Pump	520 hp	Caterpillar	2018	0.16	
G162[3]	Generator or Fire Pump	111.3 hp	Caterpillar	2018	0.73	
G158[2]	Generator or Fire Pump	7.9 hp	Honda Motor Company	2014	0.38	
A032[3]	Generator or Fire Pump	250	Cummins	2013	8.06	
A076	Generator or Fire Pump	150 kW	CAT	8/2010	0.39	
	Generator or Fire Pump	201 hp	Perkins			
G164[2]	Generator or Fire Pump	16 hp	Briggs & Stratton	2016	0.77	
G159[2]	Generator or Fire Pump	16 hp	Briggs & Stratton	pre-2006	0.77	
A053	Generator or Fire Pump	581	Caterpillar	2012	0.96	
G155[1]	Generator or Fire Pump	64.5	Deutz	8/2016	0.05	
G156[1]	Generator or Fire Pump	64.5	Deutz	8/2016	0.05	
G051	Generator or Fire Pump	536	Caterpillar	2005	4.15	
G143[1]	Generator or Fire Pump	64.5	Deutz	11/2014	0.05	
G144[1]	Generator or Fire Pump	64.5	Deutz	11/2014	0.05	
G063[1,2]	Generator or Fire Pump	65	Wisconsin	8/2010	0.08	

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 *1975/11*	Design Criteria for Stage I Vapor Control Systems – Gasoline Service Stations (PDF 15 pp, 766KB) *Note – This document is regarded as a CTG although it was never published with an EPA document number.*
VOC	EPA-450/2-76-028 *1976/11*	Control of Volatile Organic Emissions from Existing Stationary Sources – Volume I: Control Methods for Surface Coating Operations (PDF 174 pp, 4.6MB) *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 *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 *1977/11*	Control of Volatile Organic Emissions from Solvent Metal Cleaning (PDF 229 pp, 7.0MB)
VOC	EPA-450/2-77-025 *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 *1977/10*	Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals (PDF 62 pp, 1.6MB)
VOC	EPA-450/2-77-032 *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 *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 *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 *1977/12*	Control of Volatile Organic Emissions from Bulk Gasoline Plants (PDF 49 pp, 1.3MB)
VOC	EPA-450/2-77-036 *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 *1977/12*	Control of Volatile Organic Emissions from Use of Cutback Asphalt (PDF 18 pp, 481KB)
VOC	EPA-450/2-78-022 *1978/05*	Control Techniques for Volatile Organic Emissions from Stationary Sources (PDF 580 pp, 21.9MB) *Note – This document is often listed with CTGs, but it does not define RACT for any particular source*
VOC	EPA-450/2-78-015 *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 *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 *1978/06*	Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment (PDF 78 pp, 6.0MB)
VOC	EPA-450/2-78-029 *1978/12*	Control of Volatile Organic Emissions from Manufacture of Synthesized Pharmaceutical Products (PDF 134 pp, 3.8MB)
VOC	EPA-450/2-78-030 *1978/12*	Control of Volatile Organic Emissions from Manufacture of Pneumatic Rubber Tires (PDF 72 pp, 1.6MB)
VOC	EPA-450/2-78-033 *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 *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 *1978/12*	Control of Volatile Organic Emissions from Perchloroethylene Dry Cleaning Systems (PDF 76 pp, 2.5MB) *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 *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 *1982/09*	Control of Volatile Organic Compound Emissions from Large Petroleum Dry Cleaners (PDF 174 pp, 5.0MB)
VOC	EPA-450/3-83-008 *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 *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 *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 *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 *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 *1996/04*	Control of Volatile Organic Compound Emissions from Wood Furniture Manufacturing Operations (PDF 288 pp, 13.8MB) *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 *1994/04*	Alternative Control Technology Document – Surface Coating Operations at Shipbuilding and Ship Repair Facilities (PDF 217 pp,

Pollutant	EPA Report	Description
		9.8MB) *Note – For CTG, see 61 FR-44050, August 27,1996*
VOC	61 FR-44050 8/27/96 *1996/08*	Control Techniques Guidelines for Shipbuilding and Ship Repair Operations (Surface Coating) (PDF 30 pp, 4.0MB) *Note – See also EPA-453/R-94-032.*
VOC	59 FR-29216 6/06/94 *1994/06*	Aerospace MACT (PDF 37 pp, 6MB) *Note – See also EPA-453/R-97-004.*
VOC	EPA-453/R-97-004 *1997/12*	Aerospace (CTG & MACT) (PDF 62 pp, 288KB) *Note – See also 59 FR-29216, June 6, 1994.*
VOC	EPA-453/R-06-001 *2006/09*	Control Techniques Guidelines for Industrial Cleaning Solvents (PDF 290 pp, 7.6MB)
VOC	EPA-453/R-06-002 *2006/09*	Control Techniques Guidelines for Offset Lithographic Printing and Letterpress Printing (PDF 52 pp, 349KB)
VOC	EPA-453/R-06-003 *2006/09*	Control Techniques Guidelines for Flexible Package Printing (PDF 33 pp, 216KB)
VOC	EPA-453/R-06-004 *2006/09*	Control Techniques Guidelines for Flat Wood Paneling Coatings (PDF 27 pp, 212KB)
VOC	EPA 453/R-07-003 *2007/09*	Control Techniques Guidelines for Paper, Film, and Foil Coatings (PDF 102 pp, 488KB)
VOC	EPA 453/R-07-004 *2007/09*	Control Techniques Guidelines for Large Appliance Coatings (PDF 44 pp, 374KB)
VOC	EPA 453/R-07-005 *2007/09*	Control Techniques Guidelines for Metal Furniture Coatings (PDF 100 pp, 293KB)
VOC	EPA 453/R-08-003 *2008/09*	Control Techniques Guidelines for Miscellaneous Metal and Plastic Parts Coatings (PDF 143 pp, 897KB)
VOC	EPA 453/R-08-004 *2008/09*	Control Techniques Guidelines for Fiberglass Boat Manufacturing Materials (PDF 41 pp, 336KB)
VOC	EPA 453/R-08-005 *2008/09*	Control Techniques Guidelines for Miscellaneous Industrial Adhesives (PDF 47 pp, 350KB)

Pollutant	EPA Report	Description
VOC	EPA 453/R-08-006 *2008/09*	Control Techniques Guidelines for Automobile and Light-Duty Truck Assembly Coatings (PDF 44 pp, 2.64MB) *Note – See also EPA-453/R-08-002.*
VOC	EPA 453/R-08-002 *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) *Note – See also EPA-453/R-08-006.*
VOC	EPA-453/B-16-001 *2016/10*	Control Techniques Guidelines for the Oil and Natural Gas Industry (343 pp, 1.6 MB)

Appendix 2

NAFB RACT Analysis

NELLIS AIR FORCE BASE, NEVADA
SOURCE 114

REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT) ANALYSIS

September 2022

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List of Appendices

Acronyms and Abbreviations

<	less than
≤	less than or equal to
AFB	Air Force Base
AFR	air-to-fuel ratio
AP-42	Compilation of Air Emission Factors
application	Authority to Construct Permit Application
ATC	Authority to Construct
BACT	Best Available Control Technology
CARB	California Air Resources Board
CFR	Code of Federal Regulations
CO	carbon monoxide
DAQ	(Clark County) Division of Air Quality
DLN	Dry Low NOx
EF	emission factor
EGR	Exhaust Gas Recirculation
EPA	U.S. Environmental Protection Agency
EU	emission unit
g	gram(s)
GHG	greenhouse gas
HA	hydrographic area
HAP	hazardous air pollutant
HC	Hydrocarbons
hp	horsepower
hr/yr	hour(s) per year
IC	internal combustion
ITR	Injection Timing Retard
kW	kilowatt(s)
LAER	Lowest Achievable Emission Rate
lb	pound(s)
lb/hp-hr	pound(s) per horsepower-hour
N/A	not applicable
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOx	nitrogen oxide
NSPS	New Source Performance Standards
PCC	Pre-ignition Chamber Combustion
permit	Source 114 Part 70 Operating Permit
PM	particulate matter
ppm	parts per million
PTE	potential to emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RICE	Reciprocating Internal Combustion Engine
SCC	Source Classification Code
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan

SLN	SoLoNOx
SNCR	Selective Non-Catalytic Reduction
TBD	to be determined
tpy	ton(s) per year

I. Introduction

A. Purpose

In 2018, the U.S. Environmental Protection Agency (EPA) designated hydrographic area (HA) 212 in Clark County, Nevada, 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, 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, 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 (ppm). 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).

EPA has not defined the term, RACT, by rule, but in guidance it describes the requirement as the lowest emissions an industrial source is capable of emitting through use of control technology that is reasonably available considering technological and economic feasibility. Currently, the DAQ has identified seven nitrogen oxide (NOx) major sources that could be subject to major source RACT requirements, including Nellis Air Force Base (Nellis). DAQ requests that these sources conduct a case-specific, initial evaluation to identify potential control options, evaluate feasibility and costs, and recommend emissions limitations that might satisfy the RACT requirement.

The DAQ has requested that Nellis submit an initial evaluation and recommend emissions limitations that might satisfy the RACT requirement for NOx control for specific sources no later than 03 October 2022.

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 ($/ton);
- Baseline and controlled tons-per-year (tpy) emissions estimates (and basis);
- Environmental, energy, and other impacts (benefits and disbenefits); greenhouse gases (GHGs), hazardous air pollutants (HAPs), 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 meeting 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 24 February 2022 and potential to emit (PTE) calculations. Many additional resources and references were consulted; see appendices for additional details.

C. Emission Units Evaluated

The emission units that met the evaluation criteria of having a NOx PTE greater than 5tpy are eight emergency engines, one non-emergency engine, and one aircraft engine test cell. All three of these groups of sources are included in the Nellis Part 70 Operating Permit. **Table 1-1** provides permitted maximum-potential operations and NOx emissions.

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

Source	Building Number	EU	EPA Engine Tier Rating	HP Rating	Potential Annual Hours of Operation (hr/yr)	NOx Potential to Emit (PTE) (tons/yr)
Non-Emergency Engine	Aggregate Plant	A032	Tier 2	250	2,080	8.06
Emergency Engine	202	G009	Tier 1	1,635	500	9.81
	217	G010	Tier 1	1,350	500	5.64
	1301	G032	Tier 1	1,586	500	7.80
	1301	G033	Tier 1	1,586	500	7.80
	10307	G041	Tier 1	1,220	500	8.07
	10706-1	G141	Tier 1	1,200	500	5.08
	201	G176	Tier 2	2,220	500	5.90
	1771	New	Tier 2	2,922	500	8.54
Aircraft Engine Test Cell	Hush House	N001&N002	N/A	61633/61637	-	46.42

EPA = Environmental Protection Agency
EU = emission unit
HP = horsepower
hr = hours
yr = year

The remainder of this document is organized as follows:

- Section II, Non-Emergency Stationary Engines, presents the RACT analysis for the one non-emergency engine;
- Section III, Emergency Engines, presents the RACT analysis for the eight emergency engines; and

- Section IV, Aircraft Engine Test Cell, presents the RACT analysis for one aircraft engine test cell

II. Non-Emergency Stationary Engines

A. Background Information on Source and Emission Point

EU A032 is a non-emergency generator which supports the aggregate plant. The engine specification for this unit is listed below in **Table 2-1.** The aggregate plant did not utilize this generator in 2021 and has no plans to operate it in 2022.

Table 2-1 Non-Emergency Generator Engine Data

Building Number	EU	Engine Data						
		Manufacturer	Model Number	Serial Number	Capacity (hp)	Date of Manufacture		Fuel Type
						Month	Year	
Aggregate Plant	A032	Cummins	M11	60425136	250	Unknown	2013	Diesel

The tables below (**Table 2-2** and **Table2-3**) show the actual NOx emissions and hourly usage for the last five years. As shown, A032 actual NOx emissions are well below the projected PTE emissions.

Table 2-2 Non-Emergency Generator NOx Emissions

EU	Actual NOx Emissions (tons/yr)							
	2017	2018	2019	2020	2021	Average	Max	Total
A032	0.31	0.39	0.19	0.17	0	0.21	0.39	1.06

Table 2-3 Non- Emergency Generator Usage

EU	Usage (hr/yr)				
	2017	2018	2019	2020	2021
A032	80	102	49	46	0

Existing NOx controls are:

- Annual operating limitations by permit (2,080 hr/yr);
- 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)
- Turbocharging
- Pre-stratified charge
- Exhaust Gas Recirculation (EGR)
- Injection Timing Retard (ITR)
- Air-to-Fuel Ratio (AFR) 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 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/BACT/LAER Clearinghouse (RBLC) search was conducted on 01 September 2022, for similar engines – both emergency and non-emergency units burning diesel fuel. Database review line items are provided in Appendix A.

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

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

- The unit is already equipped with turbocharging.
- The Air Force confirmed that the engine needs 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 these engines.
- Engine derating was removed because it was determined by engine manufacturers to not be technically beneficial in terms of grams NOx per hp-hr output for these particular engines.
- The purpose of this unit 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. This standby generator directive is being used in this case due to the limited operation of A032 which is more in ordnance with standby generator operations.
- The utilization of battery backup power is not allowed by the mission.
- Engine performance management systems were not found to substantially reduce NOx, and the operators utilize good maintenance and operations practices as established by the manufacturer. Intake air cooling could be adjusted (i.e., 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 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 quantifiable impact on potential NOx emissions in this study.

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. No examples could be found of applying this technology to these types of units.
- 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 A032 was 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 generally carries penalties of increased particulates, carbon monoxide (CO), Hydrocarbons (HC), 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 was determined by the manufacturer to not be applicable to or available for these engines, and no vendor offerings were found.

<u>SCR Concerns</u>

SCR as a control technology includes a reducer added to the exhaust flow where reactions in a catalytic chamber take place to remove NOx.

Retrofitting the existing engine with SCR is readily available as an add-on technology for stationary diesel engines. New replacement Tier 4 manufacturer-certified engines, designed for prime use, rely heavily on SCR for NOx control, and are also readily available.

However, Nellis feels add-on SCR by way of SCR retrofit or by way of replacement with Tier 4 engines to be an impractical option for EU A032. The emission unit operates intermittently with starts and stops similar to operations of emergency engines (as defined in federal air rules), and engines that operate intermittently spend much of their time in warm-up or cool-down mode, where the exhaust is not warm enough for SCR to function.

Therefore, Nellis feels that SCR retrofit and replacement with a Tier 4 engine be removed from further analysis because it is impractical as a control technology for EU A032.

Potential Control Technologies for Further Review and Evaluation

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

- Reduction in operating hours

Nellis would be willing to reduce the maximum engine run hours on this engine from 2,080 hours to 1,200, which would bring the PTE to below 5 tons per year at maximum capacity. As seen above, operating hours for the last five years have been below the current yearly limit and would still be below the new proposed PTE hours. Economically, this would be the most cost-effective option to bring this non-emergency generator below the initial RACT analysis guidelines of 5 tons of NOx per year.

C. Elimination of Technically Infeasible Options

As stated above, all other control technologies have been eliminated from analysis.

D. Calculation of Control Technology Cost

Reducing the PTE hourly limit for EU A032 is extremely cost-effective. This action will only cost Nellis AFB the ATC application and review fee of approximately $4,000 (this is variable based on the changing DAQ fee schedules).

E. RACT Recommendation

It is Nellis' position that reduction in operating hours is the most cost-effective NOx reduction. It is therefore proposed to limit the use of EU A032 to 1,200 hours. This will reduce the NOx PTE of EU A032 by 58%. The five-year actual average of NOx emissions is currently 97% less than the permitted PTE limit. The total sum of operating hours for the last five years is 276.83 hours, which is 77% less than the new proposed operating limit of 1,200 hours per year.

III. Emergency-Use Stationary Engines

A. Background Information on Source and Emission Point

Nellis operates eight emergency generators which exceed the 5 tons per year NOx threshold for RACT analysis. The generators support various buildings on Nellis. The engine specifications for these units are listed below in Table 3-1.

Limited data is available for EU G176, as it was newly installed in 2021 and has limited run time.

The new EU will eventually support Building 1771, which is a new facility currently under construction. An Authority to Construct (ATC) Permit has not been received from DAQ at this time.

EU G141 has no operating hours because it was never installed. The engine was not properly sized when purchased. Therefore, EU G141 is currently permitted to sit in the 820 Red Horse Power Production Shop storage yard, where it is used for spare parts. The Shop has no intention of installing this generator at a different building at this time. However, if that were to change, Nellis AFB would first submit an ATC to relocate this engine.

EU G176 and the new EU at Building 1771 are brand new units with the best available control technology (BACT) available to Nellis AFB and EU G141 is non-operational. Therefore, this analysis will only be performed on EUs G009, G010, G032, G033, and G041.

Table 3-1 Emergency Generator Engine Data

Building Number	EU	Engine Data						
		Manufacturer	Model Number	Serial Number	Capacity (hp)	Date of Manufacture		Fuel Type
						Month	Year	
202	G009	Mitsubishi	PS6	12588	1635	Unknown	Unknown	Diesel
217	G010	Cummins	QST30-G3	37205939	1350	3	2003	Diesel
1301 (Hospital)	G032	Caterpillar	3512	24Z04351	1586	2	1992	Diesel
1301 (Hospital)	G033	Caterpillar	3512	24Z04354	1586	2	1992	Diesel
10307	G041	Cummins	KTA38-G3	97494-6	1220	11	1991	Diesel
10706 -1	G141	Cummins	QSK23-G3	314180	1200	11	2005	Diesel
201	G176	Cummins	QSK-50-G4	25462291	2220	Unknown	2021	Diesel
1771	New	Cummins	QSK60-G6 NR2	TBD	2922	TBD	TBD	Diesel

The tables below (**Table 3-2** and **Table 3-3**) show the actual emergency and maintenance and testing hourly usage for the last five years.

Table 3-2 Emergency Generator Emergency Usage

EU	Emergency Usage (hr/yr)				
	2017	2018	2019	2020	2021
G009	1.2	0.2	0.7	0.6	11.9
G010	5.5	67.9	78.7	0.2	0.1
G032	3.3	0.0	6.2	0.2	2.0
G033	3.3	0.0	6.2	0.1	1.9
G041	37.0	51.2	57.6	13.0	5.3
G141	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed
G176	Not Installed	Not Installed	Not Installed	Not Installed	0.0
New	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed

Table 3-3 Emergency Generator Maintenance and Testing Usage

EU	Maintenance and Testing Usage (hr/yr)				
	2017	2018	2019	2020	2021
G009	16.5	12.5	15.3	14.2	14.0
G010	7.5	11.4	12.9	13.7	1.0
G032	37.2	35.5	35.6	17.2	24.5
G033	36.6	35.7	35.5	17.1	25.7
G041	9.1	11.1	64.1	12.0	25.1
G141	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed
G176	Not Installed	Not Installed	Not Installed	Not Installed	2.1
New	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed

Table 3-4 shows the actual NOx emissions for the last five years. As shown, actual NOx emissions are well below the projected PTE emissions in **Table 1-1**.

Table 3-4 Emergency Generator NOx Emissions

EU	Actual NOx Emissions (tons/yr)							
	2017	2018	2019	2020	2021	Average	Max	Total
G009	0.269	0.281	0.292	0.285	0.477	0.321	0.477	1.604
G010	0.191	0.911	1.042	0.013	0.026	0.437	1.042	2.183

EU	Actual NOx Emissions (tons/yr)							
	2017	2018	2019	2020	2021	Average	Max	Total
G032	0.605	0.555	0.365	0.385	0.731	0.528	0.731	2.641
G033	0.608	0.553	0.363	0.402	0.702	0.526	0.702	2.628
G041	0.776	1.861	1.123	0.610	0.279	0.930	1.861	4.649
G141	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed
G176	Not Installed	Not Installed	Not Installed	Not Installed	0.020	0.020	0.020	0.020
New	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed	Not Installed

Existing NOx controls are:

- Annual operating limitations by permit (500 hr/yr);
- 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)
- Turbocharging
- Pre-stratified charge
- Exhaust Gas Recirculation (EGR)
- Injection Timing Retard (ITR)
- Air-to-Fuel Ratio (AFR) 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 Tier 2 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/BACT/LAER Clearinghouse (RBLC) search was conducted on 01 September 2022, for similar engines – both emergency and non-emergency units burning diesel fuel. Database review line items are provided in Appendix A.

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

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

- The units are already equipped with turbocharging.
- 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 these engines.
- Engine derating was removed because it was determined by the manufacturer to not be technically beneficial in terms of grams 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 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 utilization of battery backup power is not allowed by the mission.
- 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 (i.e., 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 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 these types of diesel units.
- 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 were found. The conclusion was that EGR is not readily available, and it was removed from consideration.
- Pre-stratified charge is not applicable or available for these units, according to the manufacturer.
- Typically, ignition timing retard generally carries penalties of increased particulates, CO, HC, 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.

<u>SCR Concerns</u>

As mentioned above in the non-emergency engine section, SCR as a control technology and Tier 4 manufacturer-certified engines are not recommended by CARB 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.

<u>Potential Control Technologies for Further Review and Evaluation</u>

Based on the above analysis, there are two possible control options.

- Replacement with Tier 2 diesel engines
- Replacement with Tier 3 diesel engines

To estimate the theoretical percent reduction of NOx after replacement with Tier 2 diesel engines, the current emission factor from either the Compilation of Air Emission Factors (AP-42) or manufacturer data was compared to the Tier 2 NOx emission standard (6.4 g/kW-hr), to arrive at a percent reduction for each engine ranging from 37% to 60%, as shown in Appendix C.

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 g/kW-hr. So, if there were a corresponding Tier 3 standard for emergency use engines (despite Tier 3 not applicable at this capacity), theoretical reductions for each engine range from 61% to 75%, as shown in Appendix C.

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 2 or 3 standards would provide the power needed, using a reliable fuel source, with theoretical reduced NOx. This option is technically feasible.

D. Calculation of Control Technology Cost

Evaluation of cost follows, with detailed calculations located in Appendix C.

In estimating costs, there is generally a margin of error of plus or minus 30 percent, according to the *EPA Air Pollution Control Cost Manual,* EPA/452B-02-001, 6th edition January 2002; NOx- control SCR chapter updates August and December 2016. There are also general assumptions made for variables in the calculations which include pricing, equipment life, and interest rates.

DAQ indicated that the interest rate used should be no more than 6%. Therefore 6% interest rate is used in this report.

The cost analysis includes the capital (upfront) costs with capital recovery factored in to provide this in annualized form. Then annual operating costs are added to get the total cost per year.

Then the emission reduction is taken into account to determine the cost per ton reduced per year.

The results of the cost-estimating calculations are shown in Appendix C.

Note that estimated costs are provided as a study only for purposes of this analysis and do not represent commitments or final proposed costs from any particular vendor.

Replace with Tier 2 Diesel Engines; Cost 1,000 kW Units (Average, see Appendix C for individual costs)

- Total Annualized Cost: $34,161
- Annual Pollutant Reduction: 0.28 tpy
- Cost Effectiveness: $148,072/tpy

Replace with Tier 3 Diesel Engines; Cost (Average, see Appendix C for individual costs)

- Total Annualized Cost: $173,672
- Annual Pollutant Reduction: 0.38 tpy
- Cost Effectiveness: $516,552/tpy

E. RACT Recommendation

Because of economic unreasonableness (where the cost effectiveness is based on actual emissions, and as stated, true emission reductions are expected to be much lower as these are emergency use units), Nellis does not propose to install NOx controls on these units.

Therefore, the proposed RACT is no additional controls or practices but continuing to limit hours to the permitted 500 hours per year. Engines limited to less than 500 hours per year have 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.

Nellis proposes to document usage of emergency engines, as permitted and required by 40 Code of Federal Regulations (CFR) 63 Subpart ZZZZ.

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

IV. Aircraft Engine Test Cell

A. Background Information on Source and Emission Points

An aircraft engine hush house allows for off-wing aircraft engine diagnostics and testing. Aircraft engines, which have been removed from the aircraft, are placed on a permanent stand within the hush house for the testing.

At the hush house, the engines are tested in different operating modes, such as idle, military, and afterburner to ensure that the engines meet specific engineering requirements. These various operating modes are similar to mobile emissions from actual aircraft in the same modes.

Potential emissions in the permit are based on maximum possible test times in each test modes, while actual emissions are estimated based on actual test times and modes utilized during the year.

Table 4-1 shows the specific NO_x emission factors for the engine testing that takes place at the Hush House in Buildings 61633 and 61637, and **Table 4-2** shows the actual emission for the periods listed.

Table 4-1 Aircraft Engine Test Cell Emission Factors

Aircraft Engine	Mode	NO_x Emission Factor (lb/1,000 lb fuel)
F100-PW-220	Idle	4.61
	Military	29.60
	AB-5	8.20
F100-PW-229	Idle	3.80
	Military	29.29
	AB-1	14.30
F119-PW-100	Idle	3.01
	Military	19.81
	Afterburner	7.37

Table 4-2 Aircraft Engine Test Cell NOx Emissions

Time Period	Actual NOx Emissions (tons/yr)
2021	8.34
2020	7.81
2019	12.90
2018	9.88
2017	9.18
Average Yearly NOx Emissions	**9.622**
Annual Permit Allowable NOx	**46.42**

B. Review of Available Control Technologies

Aircraft Engine Testing control options from the RBLC, were pulled on 17 August 2022.

Tabulated RBLC results for N001 & N002 aircraft engine testing are shown in Appendix A. Three similar facilities were considered RACT with no additional controls or practices, other than the preventive requirement of good management practices.

There were no control measures located for aircraft engine testing or similar sources in the *EPA's Menu of Control Measures 2013*.

C. Elimination of Technologically Infeasible Options

No elimination step was necessary.

D. Calculation of Control Technology Cost

No estimating of costs was necessary.

E. RACT Recommendation

Based on the RBLC database search for similar facilities (showing that LAER/BACT is no controls; see Appendix A), and since the aircraft engines are required to be tested under operating conditions as similar as possible to their operation on aircraft, no add-on combustion controls are proposed for this facility. The allowable emissions of NOx are less than 46.42 tons per year. However, actual emissions are historically much lower, with only 8.34 tons of actual NOx emissions from the hush house in 2021. Adherence with permit limits will be consistently tracked and followed. Nellis AFB requests that continuing with these practices be considered RACT for this source.

Records of all actual test times and modes, which roll up monthly, will continue to be utilized to show compliance with annual permit limits.

Since the above is already being done for the units, this would be considered immediate RACT implementation.

No readily available control technologies were identified for evaluation, and therefore economic supporting information is not enclosed. The RBLC review confirms this, as no economic information was reviewed for the similar sources.

Appendix A RBLC Data Review

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_STATE	PERMIT_ISSUANCE_DATE	PROCESS_NAME	PROCESS_TYPE	PRIMARY_FUEL	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION	CASE-BY-CASE_BASIS	OTHER_APPLICABLE_REQUIREMENTS	OTHER_FACTORS	PERCENT_EFFICIENCY	COMPLIANCE_VERIFIED	EMISSION_LIMIT_2	EMISSION_LIMIT_2_UNIT	EMISSION_LIMIT_2_AVGERAGE_TIME_CONDITION	POLLUTANT_COMPLIANCE_NOTES
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Emergency Camp Generators	17.11	Ultra Low Sulfur Diesel	Three 2,695 hp ULSD-fired Standby Camp Generator Engines.	Nitrogen Oxides (NOx)	N		4.8	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Airstrip Generator Engine	17.21	Ultra Low Sulfur Diesel	One 490 hp Airstrip Generator Engine	Nitrogen Oxides (NOx)	N		4.8	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Agitator Generator Engine	17.21	Ultra Low Sulfur Diesel	ULSD-fired 98 hp Agitator Generator Engine	Nitrogen Oxides (NOx)	N		5.6	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Fine Water Pumps	17.11	Ultra Low Sulfur Diesel	Two ULSD-fired 610 hp Fine Water Pumps	Nitrogen Oxides (NOx)	N		3	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Bulk Tank Generator Engines	17.11	Ultra Low Sulfur Diesel	Two ULSD-fired 891 hp Bulk Tank Storage Area Generator Engines	Nitrogen Oxides (NOx)	N		4.8	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	06/30/2017 ACT	Black Start and Emergency Internal Cumbustion Engines	17.11	Diesel	Two (2) 600 kWe black start diesel generators and four (4) 1,500 kWe emergency diesel generators.	Nitrogen Oxides (NOx)	P	Good Combustion Practices	8	G/KW-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	U	0	U	0			8.0 g/kW-hr includes NOx and VOC emissions. NSPS Subpart IIII engines.

AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	06/30/2017 ACT	Fire Pump Diesel Internal Combustion Engines	17.21	Diesel	Three (3) 252 hp fire pump diesel internal combustion engines.	Nitrogen Oxides (NOx)	P	Good Combustion Practices	3.7	G/KW-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	U	0	U	0			83.70 g/kW-hr includes NOx and VOC emissions. NSPS Subpart IIII engines.
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	06/30/2017 ACT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	17.11	Diesel and Natural Gas	Twelve 17-MW Wartsila 18V50DF ULSD/Natural Gas-Fired Internal Combustion Engines. Each engine rated at: 143.5 MMBtu/hr on ULSD 141.4 MMBtu/hr on natural gas	Nitrogen Oxides (NOx)	B	Selective Catalytic Reduction (SCR) and Good Combustion Practices	0.53	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		U	95	U	0.08	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	Potential NOx emissions of 85.9 tpy for each engine (EU 1-12).
AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	08/13/2020 ACT	One (1) Black Start Generator Engine	17.11	ULSD	EU 39 is a 4,060 hp diesel generator.	Nitrogen Oxides (NOx)	P	Good combustion practices, limit operation to 500 hours per year.	3.3	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NSPS , NESHAP	U	0	U	0			EU 39 is an EPA Tier 4 Final Engine. 3.3 g/hp-hr limit includes 25% not to exceed factor of safety.
AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	08/13/2020 ACT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	17.21	ULSD	Three firewater pump engines (EUs 40 - 42) rated at 250 hp each with 14.47 gph diesel throughput. Dormitory Emergency Generator Engine (EU 43) rated at 335 hp with 19.4 gph of diesel throughput. Communications Tower Emergency Generator Engine (EU 44) rated at 200 hp with 11.64 gph of diesel throughput.	Nitrogen Oxides (NOx)	P	Good combustion practices, limit operation to 500 hours per year per engine	3.6	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NSPS , NESHAP	U	0	U	0			EUs 40 - 44 are required to achieve EPA Tier 3 emission status. 3.6 g/hp-hr limit is 95% of the total for NMHC + NOx and includes a 25% not to exceed factor of safety.

AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	07/07/2022 ACT	Diesel Fire Pump Engine	17.11	Diesel	EU 11 is a 575 hp diesel fire pump engine which is required to meet E.F.s from Table 4 of NSPS Subpart IIII, which is the equivalent to EPA Nonroad Tier 3. BACT E.F.s include not to exceed factor of safety as identified in 40 CFR 1039.101(e).	Nitrogen Oxides (NOx)	P	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII	3.6	G/HP-HR		BACT-PSD	NSPS	U	0	U	500	HRS/YR		NOx emissions from diesel firewater pump engine EU 11 will not exceed 3.6 g/hp-hr @ 15% O2 (95% of NMHC + NOx from Table 4 of NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety);
AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	07/07/2022 ACT	Auxiliary Air Compressor Engine	17.21	Diesel	EU 12 is a 300 hp diesel auxiliary air compressor engine which is required to meet EPA nonroad Tier 4 final E.F.s. BACT E.F.s include not to exceed factor of safety as identified in 40 CFR 1039.101(e).	Nitrogen Oxides (NOx)	P	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII	0.45	G/HP-HR		BACT-PSD	NSPS	U	0	U	500	HRS/YR		NOx emissions from the auxiliary air compressor diesel engine EU 12 will not exceed 0.45 g/hp-hr @ 15% O2 (EPA Tier 4 Final, includes 50% not to exceed factor of safety).
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	NUCOR STEEL TUSCALOOSA, INC.	AL	07/22/2014 ACT	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL		Nitrogen Oxides (NOx)	N		0.015	LB/HP-H		BACT-PSD	NSPS , MACT	N	0	N	0			
*AL-0318	TALLADEGA SAWMILL	GEORGIA PACIFIC WOOD PRODUCTS, LLC	AL	12/18/2017 ACT	250 Hp Emergency CI, Diesel-fired RICE	17.11	Diesel	Emergency Only	Nitrogen Oxides (NOx)	N		0			N/A		U	0	U	0			
AL-0328	PLANT BARRY	ALABAMA POWER COMPANY	AL	11/09/2020 ACT	Diesel Emergency Engines	17.11	Diesel		Nitrogen Oxides (NOx)	N		3	GR/BHP-HR	NMHC + NOX	BACT-PSD	NSPS , SIP , OPERATING PERMIT	U	0	N	0			
AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	09/23/2019 ACT	Emergency Engines	17.11	Diesel		Nitrogen Oxides (NOx)	P	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.4	G/KW-H		BACT-PSD		U	0	U	0			

AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	06/09/2019 ACT	Emergency Engines	17.11	Diesel	The emergency generators are diesel fired generators which provide electrical power in the event of power failure.	Nitrogen Oxides (NOx)	P	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	4.86	G/KW-HR		BACT-PSD		U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Main Propulsion Generator Diesel Engines	17.11	Diesel	Four 1998 Wartsila 18V32LNE 9910 hp and Two 1998 Wartsila 12V32LNE 6610 hp	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	12.7	G/KW-H	ROLLING 24 HOUR AVERAGE	BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Diesel Powered Forklift Engine	17.21	Diesel		Nitrogen Oxides (NOx)	P	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			

FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Wireline Diesel Engines	17.21	Diesel	Wireline engines, electric line engines, casing unit engines, tubing running engine, fluid filtration pump engine, powerpack engine, slickline powerpack engine, and CT pump engine	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Water Blasting Diesel Engine	17.21	Diesel		Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Well Evaluation Diesel Engine	17.21	Diesel		Nitrogen Oxides (NOx)	P	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			

FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Fast Rescue Craft Diesel Engine	17.21	Diesel		Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Escape Capsule Diesel Engine	17.21	Diesel		Nitrogen Oxides (NOx)	P	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Emergency Diesel Engine	17.11	Diesel	1998 Wartsila 6R32LNE	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			

FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Remotely Operated Vehicle Emergency Generator	17.21	Diesel	2004 Cummins QSM11-G2NR3	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0350	ANADARKO PETROLEUM, INC DIAMOND BLACKHAWK DRILLING PROJECT	ANADARKO PETROLEUM, INC.	FL	12/31/2014 ACT	Main Propulsion Generator Engines	17.11	Diesel	Six 2012 Hyundai-HiMsen 9H32/40V 6,035 hp and two 2012 Hyundai-HiMsen 18H32/40V diesel electric engines.	Nitrogen Oxides (NOx)	P	Use of good combustion practices based on the most recent manufacturer â€™s specifications issued for these engines at the time that the engines are operating under this permit	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			DR-ME-01 through DR-ME-08 Operating at 50% Load and Above: 10.57 g/kw-hr on a rolling 24-hour average basis. DR-ME-01 through DR-ME-06 Operating Below 50% Load: 57.3 lb/hr on a rolling 24-hour average basis. DR-MR-07 and DR-ME-08 Operating Below 50% Load: 103.5 lb/hr on a rolling 24-hour average basis.
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	07/27/2018 ACT	1,500 kW Emergency Diesel Generator	17.11	ULSD	The emergency generator will operate a combined total of 100 hr/yr for maintenance checks, and readiness testing, which includes a maximum 50 hr/yr for non-emergency operation.	Nitrogen Oxides (NOx)	P	Operate and maintain the engine according to the manufacturer's written instructions	6.4	G/KW-HOUR		BACT-PSD	NESHAP , NSPS	U	0	U	0			Standard equals Subpart IIII limit. Limit is for NOX and Non-Methane Hydrocarbons

FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	07/27/2018 ACT	Emergency Fire Pump Engine (347 HP)	17.21	ULSD	Limits equal Subpart IIII limits	Nitrogen Oxides (NOx)	P	Operate and maintain the engine according to the manufacturer's written instructions	4	G/KW-HR		BACT-PSD	NSPS , NESHAP	U	0	U	0			Certified engine, no testing required. Limit is for NOx + NMHC
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	06/07/2021 ACT	1,500 kW Emergency Diesel Generator	17.11	ULSD	The emergency generator will operate a combined total of 100 hr/yr for maintenance checks, and readiness testing, which includes a maximum 50 hr/yr for non-emergency operation.	Nitrogen Oxides (NOx)	N		6.4	G/KW-HOUR	FOR NMHC +NOX	BACT-PSD	NSPS	U	0	U	0			
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	06/07/2021 ACT	Emergency Fire Pump Engine (347 HP)	17.21	ULSD	Limits equal Subpart IIII limits	Nitrogen Oxides (NOx)	N		4	G/KW-HOUR	NMHC + NOX STANDARD	BACT-PSD	NSPS	U	0	U	0			
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012 ACT	Emergency Generator	17.11	diesel fuel	rated @ 2,000 KW	Nitrogen Oxides (NOx)	P	good combustion practices	6	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		U	0	U	6.61	TONS/YR	ROLLING 12 MONTH TOTAL	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012 ACT	Fire Pump	17.21	diesel fuel	rated @ 235 KW	Nitrogen Oxides (NOx)	P	good combustion practices	3.75	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		U	0	U	0.49	TONS/YR	ROLLING 12 MONTH TOTAL	
IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	09/05/2014 ACT	Emergency Generator	17.11	distillate fuel oil		Nitrogen Oxides (NOx)	P	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.67	G/KW-H		BACT-PSD		U	0	U	0			

IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	09/05/2014 ACT	Firewater Pump Engine	17.21	distillate fuel oil		Nitrogen Oxides (NOx)	P	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	3.5	G/KW-H		BACT-PSD		U	0	U	0			
IL-0129	CPV THREE RIVERS ENERGY CENTER	CPV THREE RIVERS, LLC	IL	07/30/2018 ACT	Emergency Engines	17.11	Ultra-low sulfur diesel	Two emergency engine-generators. One large emergency engine-generator, 1500 kW output, will provide emergency power to the plant. One small emergency engine-generator, 125 kW output, will provide emergency power to the switchyard. Fuel used in the emergency engines must meet the requirements of 40 CFR 80.510(b), pursuant to 40 CFR 60.4207(b).	Nitrogen Oxides (NOx)	N		0			LAER	NSPS	U	0	U	0			Limits of the NSPS, 40 CFR 60 Subpart IIII, are LAER for NOx. For the large engine: 6.4 g/kW-hr For the small engine: 4.0 g/kW-hr Permit limits are as follows: For the large engine: 23.0 lb/hr and 1.7 ton/yr For the small engine: 1.2 lb/hr and 0.09 ton/yr
IL-0129	CPV THREE RIVERS ENERGY CENTER	CPV THREE RIVERS, LLC	IL	07/30/2018 ACT	Firewater Pump Engine	17.21	Ultra-low sulfur diesel	A 422 horsepower engine will power the pump in the firewater system. Fuel must meet the requirements of 40 CFR 80.510(b), pursuant to 40 CFR 60.4207(b).	Nitrogen Oxides (NOx)	N		0			LAER	NSPS	U	0	U	0			Limits of the NSPS, 40 CFR 60 Subpart IIII, are LAER for NOx. For NOx: 4.0 g/kW-hr
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	IL	12/31/2018 ACT	Firewater Pump Engine	17.21	Ultra-Low Sulfur Diesel	One engine will power the pump in the firewater system. The fuel must meet the requirements of 40 CFR 80.510(b) pursuant to 40 CFR 60.4207(b).	Nitrogen Oxides (NOx)	N		4	G/KW-HR		LAER	NSPS	N	0	U	0			NSPS Subpart IIII limit of 4.0 g/kW-hr is LAER

IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	IL	12/31/2018 ACT	Emergency Engine	17.11	Ultra-Low Sulfur Diesel	One large emergency engine-generator at the plant; one small emergency engine-generator at the switchyard. Fuel must meet the requirements at 40 CFR 80.510(b) pursuant to 40 CFR 60.4207(b)	Nitrogen Oxides (NOx)	N		6.4	G/KW-HR		LAER	NSPS	U	0	U	0			NSPS Subpart IIII limit of 6.4 g/kW-hr is LAER
*IL-0133	LINCOLN LAND ENERGY CENTER	LINCOLN LAND ENERGY CENTER (A/K/A EMBERCLEAR)	IL	07/29/2022 ACT	Emergency Engines	17.11	Ultra-Low Sulfur Diesel	Two engine-generators will power an electrical generator to provide power to critical equipment during power outages. Ultra-low sulfur diesel fuel (sulfur content <15 part per million (ppm)) will be used as fuel	Nitrogen Oxides (NOx)	N		6.4	GRAMS	KILOWATT-HOUR	BACT-PSD	NSPS	U	0	U	0			Limit 1 includes non-methane hydrocarbons (NMHC), i.e. NOx + NMHC, consistent with the NSPS, 40 CFR 60 Subpart IIII.
*IL-0133	LINCOLN LAND ENERGY CENTER	LINCOLN LAND ENERGY CENTER (A/K/A EMBERCLEAR)	IL	07/29/2022 ACT	Fire Water Pump Engine	17.21	Ultra-Low Sulfur Diesel	The fire water pump engine will power the pump in the plant's fire water system	Nitrogen Oxides (NOx)	N		4	GRAMS	KILOWATT-HOUR	BACT-PSD	NSPS	U	0	U	0			Limit 1 includes non-methane hydrocarbons (NMHC), i.e., NOx + NMHC, consistent with the NSPS, 40 CFR 60 Subpart IIII.
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	12/03/2012 ACT	TWO (2) FIREWATER PUMP DIESEL ENGINES	17.21	DIESEL	THE TWO FIREWATER PUMP ENGINES, IDENTIFIED AS FP01 AND FP02, EXHAUSTING THROUGH TWO (2) VENTS.	Nitrogen Oxides (NOx)	P	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	3	G/HP-H	3 HOURS	BACT-PSD			0		500	HOURS OF OPERATION	YEARLY	LIMIT TWO IS FOR EACH FIREWATER PUMP ENGINE
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	12/03/2012 ACT	TWO (2) EMERGENCY DIESEL GENERATORS	17.11	DIESEL	THE TWO INTERNAL COMBUSTION ENGINES, IDENTIFIED AS EG01 AND EG02, EXHAUST THROUGH TWO (2) VENTS.	Nitrogen Oxides (NOx)	P	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	3 HOURS	BACT-PSD			0		500	HOURS OF OPERATION	YEALRY	LIMIT ONE AND TWO ARE FOR EACH GENERATOR
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	12/03/2012 ACT	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	THIS ONE (1) INTERNAL COMBUSTION ENGINE, IDENTIFIED AS EG03, EXHAUSTS THROUGH ONE (1) VENT.	Nitrogen Oxides (NOx)	A	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	3 HOURS	BACT-PSD			0		500	HOURS OF OPERATION	YEARLY	LIMIT ONE AND TWO ARE FOR EACH GENERATOR

IN-0173	MIDWEST FERTILIZER CORPORA TION	MIDWEST FERTILIZER CORPORA TION	IN	06/04/201 4 ACT	DIESEL FIRED EMERGEN CY GENERATO R	17.11	NO. 2, DIESEL	ANNUAL OPERATING HOURS SHALL NOT EXCEED 500 HOURS. INSIGNIFICANT ACTIVITY WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTIO N PRACTICES	4.46	G/BHP-H	3-HR AVERA GE	BACT-PSD		N	0		0			
IN-0173	MIDWEST FERTILIZER CORPORA TION	MIDWEST FERTILIZER CORPORA TION	IN	06/04/201 4 ACT	FIRE PUMP	17.21		OPERATION LIMITED TO 500 HOURS PER YEAR. INSIGNIFICANT ACTIVITY, WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTIO N PRACTICES	2.83	G/BHP-H	3-HR AVERA GE	BACT-PSD		N	0		0			
IN-0173	MIDWEST FERTILIZER CORPORA TION	MIDWEST FERTILIZER CORPORA TION	IN	06/04/201 4 ACT	RAW WATER PUMP	17.21	DIESEL, NO. 2	OPERATION NOT TO EXCEED 500 HOURS PER YEAR. INSIGNIFICANT ACTIVITY, WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTIO N PRACTICES	2.83	G/BHP-H	3-HR AVERA GE	BACT-PSD		N	0		0			
IN-0179	OHIO VALLEY RESOURCE S, LLC	OHIO VALLEY RESOURCE S, LLC	IN	09/25/201 3 ACT	DIESEL-FIRED EMERGEN CY GENERATO R	17.11	NO. 2 FUEL OIL	ANNUAL HOURS OF OPERATION NOT TO EXCEED 200 HOURS.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTIO N PRACTICES	4.46	G/B-HP-H	3-HR AVERA GE	BACT-PSD		N	0		0			ADD ON CONTROLS ARE NOT NORMALLY REQUIRED FOR LIMITED USE EMISSION UNITS.
IN-0179	OHIO VALLEY RESOURCE S, LLC	OHIO VALLEY RESOURCE S, LLC	IN	09/25/201 3 ACT	DIESEL-FIRED EMERGEN CY WATER PUMP	17.21	NO. 2 FUEL OIL	ANNUAL OPERATION LIMITED TO 200 HR,	Nitrogen Oxides (NOx)	P	GOOD COMBUSTIO N PRACTICES	2.86	G/B-HP-H	3-HR AVERA GE	BACT-PSD		N	0		0			ADD ON CONTROLS ARE NOT NORMALLY REQUIRED FOR LIMITED USE EMISSION UNITS.
IN-0180	MIDWEST FERTILIZER CORPORA TION	MIDWEST FERTILIZER CORPORA TION	IN	06/04/201 4 ACT	DIESEL FIRED EMERGEN CY GENERATO R	17.11	NO. 2, DIESEL	ANNUAL OPERATING HOURS SHALL NOT EXCEED 500 HOURS. INSIGNIFICANT ACTIVITY WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTIO N PRACTICES	4.46	G/B-HP-H	3-HR AVERA GE	BACT-PSD		N	0		0			
IN-0180	MIDWEST FERTILIZER CORPORA TION	MIDWEST FERTILIZER CORPORA TION	IN	06/04/201 4 ACT	FIRE PUMP	17.21		OPERATION LIMITED TO 500 HOURS PER YEAR. INSIGNIFICANT ACTIVITY, WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTIO N PRACTICES	2.83	G/B-HP-H	3-HR AVERA GE	BACT-PSD		N	0		0			
IN-0180	MIDWEST FERTILIZER CORPORA TION	MIDWEST FERTILIZER CORPORA TION	IN	06/04/201 4 ACT	RAW WATER PUMP	17.21	DIESEL, NO. 2	OPERATION NOT TO EXCEED 500 HOURS PER YEAR. INSIGNIFICANT ACTIVITY, WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTIO N PRACTICES	2.83	G/B-HP-H	3-HR AVERA GE	BACT-PSD		N	0		0			

IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	04/24/2014 ACT	DIESEL FIRE PUMP	17.11	DIESEL		Nitrogen Oxides (NOx)	N		3	G/HP-H		BACT-PSD			0		500	H		RESTRICTED USE OF ONLY NATURAL GAS, THE USE OF GOOD COMBUSTION PRACTICES
IN-0263	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	03/23/2017 ACT	EMERGENCY GENERATORS (EU014A AND EU-014B)	17.11	DISTILLATE OIL		Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.42	G/HP-H EACH	3 HOUR AVERAGE	BACT-PSD		N	0		500	H/YR EACH		
IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	06/11/2019 ACT	Emergency generator EU-6006	17.11	Diesel		Nitrogen Oxides (NOx)	P	Tier II diesel engine	6.4	G/KWH	TIER II NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	U	0	U	0			Unit shall use good combustion practices and energy efficiency as defined in the permit. 40 CFR 60, subpart IIII 40 CFR 63, subpart ZZZZ
IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	06/11/2019 ACT	Emergency fire pump EU-6008	17.11	Diesel		Nitrogen Oxides (NOx)	P	Engine that complies with Table 4 to Subpart IIII of Part 60	4	G/KWH	COMBINED NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	U	0	U	0			Unit shall use good combustion practices and energy efficiency as defined in the permit. 40 CFR 60, subpart IIII 40 CFR 63, subpart ZZZZ
IN-0324	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	05/06/2022 ACT	emergency generator EU 014a	17.11	distillate oil		Nitrogen Oxides (NOx)	N		4.42	G/HP-HR		BACT-PSD		U	0	U	500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	NOx emissions from the diesel-fired emergency generator (EU-014a) shall be controlled by exercising good combustion practices
IN-0324	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	05/06/2022 ACT	fire water pump EU-015	17.11			Nitrogen Oxides (NOx)	N		2.83	G/HP-HR		BACT-PSD		U	0	U	500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	NOx emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices

*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	03/18/2013 ACT	Caterpillar C18DITA Diesel Engine Generator	17.11	No. 2 Distillate Fuel Oil		Nitrogen Oxides (NOx)	P	utilize efficient combustion/ design technology	14	LB/HR		BACT-PSD		U	0	U	0			
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	03/18/2013 ACT	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	17.21	No. 2 Fuel Oil		Nitrogen Oxides (NOx)	P	utilize efficient combustion/ design technology	2	LB/HR	AT FULL LOAD	BACT-PSD		U	0	U	0			
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-02 - North Water System Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-02, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-03 - South Water System Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-03, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-04 - Emergency Fire Water Pump	17.11	Diesel	Diesel emergency fire water pump used to provide emergency fire water supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-04, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 11-01 - Melt Shop Emergency Generator	17.21	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 11-01, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 11-02 - Reheat Furnace Emergency Generator	17.21	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 11-02, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-07 - Air Separation Plant Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare and maintain for EP 10-07, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-01 - Caster Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS	N	0	U	0			prepare and maintain for EP 10-01, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 11-03 - Rolling Mill Emergency Generator	17.21	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 11-03, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 11-04 - IT Emergency Generator	17.21	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 11-04, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 11-05 - Radio Tower Emergency Generator	17.21	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	3.5	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 11-05, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	17.11	Diesel	No controls.	Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Tunnel Furnace Emergency Generator (EP 08-06)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Caster B Emergency Generator (EP 08-07)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Air Separation Unit Emergency Generator (EP 08-08)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Cold Mill Complex Emergency Generator (EP 09-05)	17.21	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	05/23/2014 ACT	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	17.11			Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	27.37	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	1.37	TPY	ANNUAL MAXIMUM	BACT is determined to be compliance with the limitations imposed by 40 CFR 60 Subpart IIII and its associated monitoring, recordkeeping, and reporting requirements; and operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage. Limit NOx + NMHC to 6.4 g/kW-hr.
LA-0292	HOLBROOK COMPRESSOR STATION	CAMERON INTERSTATE PIPELINE LLC	LA	01/22/2016 ACT	Emergency Generators No. 1 & No. 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart	14.16	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.71	TPY	ANNUAL MAXIMUM	Emergency generators are also subject to a BACT limit of 1.51 lb NOx/MM Btu.

LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	LA	05/23/2014 ACT	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	17.11	Diesel	Non-emergency use is limited to 100 hours per year.	Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer â€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	27.37	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT , NSPS	U	0	U	1.37	TPY	ANNUAL MAXIMUM	NOx + NMHC limit is 6.40 g/kW-hr. BACT is determined to be compliance with the limitations imposed by 40 CFR 60 Subpart IIII and its associated monitoring, recordkeeping, and reporting requirements; and operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	06/30/2016 ACT	Diesel Engines (Emergency)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0307	MAGNOLIA LNG FACILITY	MAGNOLIA LNG, LLC	LA	03/21/2016 ACT	Diesel Engines	17.11	Diesel	Water Pumps (2 units) = 355 hp Tank Deluge Pumps (2 units) = 800 hp Generator = 1340 hp	Nitrogen Oxides (NOx)	P	combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	09/26/2013 ACT	2000 KW Diesel Fired Emergency Generator Engine	17.11	Diesel		Nitrogen Oxides (NOx)	P	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	33.07	LB/H	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	U	0	U	1.38	T/YR	ANNUAL MAXIMUM	

LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	09/26/2013 ACT	380 HP Diesel Fired Pump Engine	17.21	Diesel		Nitrogen Oxides (NOx)	P	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	2.92	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.12	T/YR	ANNUAL MAXIMUM	
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	06/04/2015 ACT	Firewater Pump Engines	17.21	Diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	3	G/BHP-HR		BACT-PSD		U	0	U	0			
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	06/04/2015 ACT	Emergency Generator Engines	17.11	Diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	6.4	G/KW-HR		BACT-PSD		U	0	U	0			
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	06/30/2017 ACT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	17.11	Diesel	Operating hour limit: 100 hr/yr	Nitrogen Oxides (NOx)	P	Compliance with NSPS Subpart IIII	6.6	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Limit: 3.84 g/hp-hr
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	06/30/2017 ACT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	17.11	Diesel	Operating hours limit: 100 hr/yr.	Nitrogen Oxides (NOx)	P	Compliance with NSPS Subpart IIII	19.23	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Limit: 4.93 g/hp-hr

LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	LA	08/31/2016 ACT	SCPS Emergency Diesel Generator 1	17.11	Diesel		Nitrogen Oxides (NOx)	B	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	BACT-PSD	NSPS, OPERATING PERMIT	U	0	U	6.84	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.8 G/BHP-HR (NMHC + NOx)
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	LA	08/31/2016 ACT	SCPS Emergency Diesel Firewater Pump 1	17.21	Diesel		Nitrogen Oxides (NOx)	B	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	BACT-PSD	NSPS, OPERATING PERMIT	U	0	U	0.47	T/YR	ANNUAL MAXIMUM	BACT Limit = 3.0 G/BHP-HR (NMHC + NOx)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Emergency Diesel Generator 1	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS, OPERATING PERMIT	U	0	U	2.63	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.4 G/KW-H) (12-Month Rolling Average)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Emergency Diesel Generator 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS, OPERATING PERMIT	U	0	U	2.63	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.4 G/KW-H) (12-Month Rolling Average)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Fire Pump Diesel Engine 1	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS, OPERATING PERMIT	U	0	U	0.23	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.40 G/KW-H) (12-Month Rolling Average)

*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Fire Pump Diesel Engine 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.23	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.8 G/BHP-H (6.40 G/KW-H) (12-Month Rolling Average)
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	02/17/2017 ACT	emergency generator engines (6 units)	17.11	diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	12/22/2016 ACT	Emergency Generator Engines (4 units)	17.11	Diesel	I-GDE-1201, II-GDE-1201 = 2346 hp I-GDE-1202 = 755 hp I-GDE-1203 = 1193 hp	Nitrogen Oxides (NOx)	P	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			BACT = LAER (Permit 0180-00210-V4, dated 12/22/2016)
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	12/22/2016 ACT	Firewater pump Engines (4 units)	17.11	diesel		Nitrogen Oxides (NOx)	P	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			BACT = LAER (Permit 0180-00210-V4, dated 12/22/2016)
LA-0318	FLOPAM FACILITY	FLOPAM, INC.	LA	01/07/2016 ACT	Diesel Engines	17.11			Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	01/09/2017 ACT	Fire Water Diesel Pump No. 3 Engine	17.11	Diesel Fuel	Emergency engine with a limit of 100 hours/yr on operating hours for ready testing.	Nitrogen Oxides (NOx)	P	operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			

LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	01/09/2017 ACT	Fire Water Diesel Pump No. 4 Engine	17.11	Diesel Fuel	Emergency Engine limited to 100 hours/yr for ready tests	Nitrogen Oxides (NOx)	P	operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	01/09/2017 ACT	Standby Generator No. 9 Engine	17.21	Diesel Fuel	Operating hours limited to 100 hours/yr for ready testing.	Nitrogen Oxides (NOx)	P	operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	09/21/2018 ACT	Firewater Pumps	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	Good Combustion and Operating Practices.	3.1	G/HP-H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Comply with 40 CFR 60 Subpart IIII and limiting normal operations to 50 h/yr.
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	09/21/2018 ACT	Large Emergency Engines (>50kW)	17.11	Diesel Fuel	Three emergency black-start engines and two emergency generators	Nitrogen Oxides (NOx)	P	Good Combustion and Operating Practices	5.6	G/KW-H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Comply with 40 CFR 60 Subpart IIII and limiting normal operations to 100 hr/yr.
LA-0346	GULF COAST METHANOL COMPLEX	IGP METHANOL LLC	LA	01/04/2018 ACT	emergency generators (4 units)	17.11	natural gas		Nitrogen Oxides (NOx)	P	Comply with standards of 40 CFR 60 Subpart JJJJ	2	G/BHP-HR		BACT-PSD	NSPS	U	0	U	0			
LA-0350	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	03/28/2018 ACT	emergency generators (3 units) EQT0039, EQT0040, EQT0041	17.11			Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			

LA-0364	FG LA COMPLEX	FG LA LLC	LA	01/06/2020 ACT	Emergency Generator Diesel Engines	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	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	NSPS , NESHAP	U	0	U	0			Engines are limited to 100 hours of non-emergency use.

LA-0364	FG LA COMPLEX	FG LA LLC	LA	01/06/2020 ACT	Emergency Fire Water Pumps	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	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	NSPS , NESHAP	U	0	U	0			Engines are limited to 100 hours of non-emergency use.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	VCM Unit Emergency Generator A	17.11	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	PVC Emergency Combustion Equipment A	17.21	Diesel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	C/A Emergency Generator B	17.11	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	VCM Unit Emergency Generator B	17.21	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			

LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	VCM Unit Emergency Cooling Water Pumps	17.21	Gaseous fuel	Maximum horsepower rating. Three engines total of the same model.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	2.98	G/KW-HR		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	PVC Emergency Combustion Equipment B	17.21	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	4.41	LB/MMBTU		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	PVC Emergency Combustion Equipment 2A and 2B	17.21	Diesel	Maximum horsepower rating. Two engines of the same model.	Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII.	0.4	G/KW-HR		BACT-PSD	NSPS	U	0	U	0			BACT limit in terms of non-methane hydrocarbon (NMHC) + NOx.
LA-0382	BIG LAKE FUELS METHANOL PLANT	BIG LAKE FUELS LLC	LA	04/25/2019 ACT	Emergency Engines (EQT0014 - EQT0017)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Comply with standards of 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	LA	09/03/2020 ACT	Emergency Engines (EQT0011 - EQT0016)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	MA	01/30/2014 ACT	Emergency Engine/Generator	17.11	ULSD	â‰¤ 300 hours of operation per 12-month rolling period S in ULSD: â‰¤0.0015% by weight	Nitrogen Oxides (NOx)	N		4.8	GM/BHP-H	1 HR BLOCK AVG	LAER	NSPS, NESHAP, SIP, OPERATING PERMIT	U	0	U	11.6	LB/H	1 HR BLOCK AVG	emission limits are for NOx and VOC combined total. the project is subject LAER for NOx as ozone precursor, and BACT-PSD for NOx as NO2 precursor.

MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	MA	01/30/2014 ACT	Fire Pump Engine	17.21	ULSD	â‰¤ 300 hours of operation per 12-month rolling period S in ULSD: â‰¤0.0015% by weight	Nitrogen Oxides (NOx)	N		3	GM/BHP-H	1 HR BLOCK AVG	LAER	NSPS , NESHAP , SIP , OPERATING PERMIT	U	0	U	2.44	LB/H	1 HR BLOCK AVG	emission limits are for NOx and VOC combined total. the project is subject LAER for NOx as ozone precursor, and BACT-PSD for NOx as NO2 precursor.
MA-0043	MIT CENTRAL UTILITY PLANT	MASSACHUSETTS INSTITUTE OF TECHNOLOGY	MA	06/21/2017 ACT	Cold Start Engine	17.11	ULSD	CAT DM8263 or equivalent. â‰¤ 8 hours of operation per day, â‰¤ 300 hours of operation per consecutive 12-month period, S in ULSD: â‰¤0.0015% by weight.	Nitrogen Oxides (NOx)	N		35.09	LB/HR	1 HR BLOCK AVG	OTHER CASE-BY-CASE	NESHAP , SIP , OPERATING PERMIT , NSPS	U	0	U	5.3	TONS/ C12MP	CONSECUTIVE TWELVE MONTH PERIOD	
MD-0042	WILDCAT POINT GENERATION FACILITY	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	04/08/2014 ACT	EMERGENCY GENERATOR 1	17.11	ULTRA LOW SULFU DIESEL	40 CFR 60 SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	LIMITED OPERATING HOURS, USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.8	G/HP-H		LAER	NSPS		0		6.4	G/KW-H		COMBINED NOX AND NMHC
MD-0042	WILDCAT POINT GENERATION FACILITY	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	04/08/2014 ACT	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRA LOW SULFUR DIESEL	40 CFR 60, SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	LIMITED OPERATING HOURS, USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	3	G/HP-H		LAER	NSPS		0		4	G/KW-H		COMBINED NOX AND NMHC

MD-0043	PERRYMAN GENERATING STATION	CONSTELLATION POWER SOURCE GENERATION, INC.	MD	07/01/2014 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	40 CFR 60 SUBPART IIII, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	4.8	G/HP-H		LAER	NSPS		0		6.4	G/KW-H		NSPS 40 CFR 60 SUBPART IIII
MD-0043	PERRYMAN GENERATING STATION	CONSTELLATION POWER SOURCE GENERATION, INC.	MD	07/01/2014 ACT	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRAL LOW SULFUR DIESEL	40 CFR 60, SUBPART IIII, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	3	G/HP-H		LAER	NSPS		0		4	G/KW-H		NSPS 40 CFR 60 SUBPART IIII
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	06/09/2014 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	40 CFR 60, SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.8	G/HP-H	COMBINED NOX + NMHC	LAER	NSPS		0		6.4	G/KW-H	COMBINED NOX + NMHC	NSPS 40 CFR 60 SUBPART IIII
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	06/09/2014 ACT	5 EMERGENCY FIRE WATER PUMP ENGINES	17.21	ULTRA LOW SULFUR DIESEL	40 CFR 60, SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	3	G/HP-H	NOX + NMHC	LAER	NSPS		0		4	G/KW-H	NOX + NMHC	NSPS 40 CFR 60 SUBPART IIII

MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MI	11/01/2013 ACT	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	17.11	Diesel	1,000 kW (1,502 hp) each; hours restriction = 500 hours each per year.	Nitrogen Oxides (NOx)	P	Good combustion practices	4.8	G/B-HP-H	TEST PROTOCOL; EACH UNIT	BACT-PSD	SIP	N	0	N	0			The NOx limit of 4.8 g/bhp-hr applies to each unit.
MI-0418	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER - WARREN	MI	01/14/2015 ACT	FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines)	17.11	Diesel	DRUPS emergency engines identified as the following: EUDRUPS1, EUDRUPS2, EUDRUPS3, EUDRUPS4, EUDRUPS5, EUDRUPS6, EUDRUPS7, EUDRUPS8, EUDRUPS9 permitted within the flexible group that is identified as FG-BACKUPGENS. Each engine is 3490KW each. DRUPS stands for Diesel Rotary Uninterruptable Power supply system. The system provides for zero down-time in electrical energy supply at the onset of a power outage. The system stores energy in a fly-wheel that powers the generator until the diesel engine starts up. Two DRUP engines connect to one	Nitrogen Oxides (NOx)	P	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)	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	N	0	U	0			The emission limit is for each DRUP engine. No add-on controls were technically feasible for these emergency engines, so a cost analysis was not necessary.

MI-0418	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER - WARREN	MI	01/14/2015 ACT	Four (4) emergency engines in FG-BACKUPGENS	17.11	Diesel	There are four (4) emergency engines identified as EUGENERATOR1, EUGENERATOR2, EUGENERATOR3, and EUGENERATOR4 in the flexible group identified in the permit as FG-BACKUPGENS. Each engine is 2710 KW. Two engines connect to one standard generator set.	Nitrogen Oxides (NOx)	P	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)	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	N	0	U	0			The emission limit is per engine. No add-on controls were technically feasible for these emergency engines so a cost analysis was not necessary.
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	08/26/2016 ACT	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 1600 kW (EUEMRGRICE in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	22.6	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	08/26/2016 ACT	Dieself fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (identified as EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	3.53	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add on control would not be cost effective.

MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	01/04/2017 ACT	EUEMENGINE (Diesel fuel emergency engine)	17.11	Diesel Fuel	a 2,922 horsepower (HP) (2,179 kilowatts (kW)) diesel fueled emergency engine manufactured in 2011 or later and a displacement of <10 liters/cylinder. Restricted to 4 hours/day, except during emergency conditions and stack testing, and 500 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC + NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	01/04/2017 ACT	EUFPENGINE (Emergency engine--diesel fire pump)	17.21	Diesel	A 260 brake horsepower (bhp) diesel-fueled emergency engine manufactured in 2011 or later and a displacement of <10 liters/cylinder. Powers a fire pump used for a back up during an emergency (EUFPENGINE). Restricted to 1 hour/day, except during emergency conditions and stack testing, and 100 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	G/BHP-H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC + NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE1 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	21.2	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.

MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE2 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours	4.4	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUFIREPUMP in FGRICE (Diesel fire pump engine)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines. Limited operating hours.	3.53	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUFPENGINE (South Plant): Fire pump engine	17.21	Diesel	A 300 HP diesel-fired emergency fire pump engine with a model year of 2011 or later, and a displacement of <30 liters/cylinder. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	G/BHP-H	HOURLY	BACT-PSD	SIP	N	0	N	0			The limit is actually in ‘‘NMHC + NOx‘‘ (nonmethane hydrocarbon plus NOx) which is what is required in the NSPS.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUEMENGINE (North Plant): Emergency Engine	17.11	Diesel	A 1,341 HP (1,000 kilowatts (KW)) diesel-fired emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is designed to be compliant with Tier IV emission standards. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS Subpart IIII requirements.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+ NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUFPENGINE (North Plant): Fire pump engine	17.21	Diesel	A 300 HP diesel-fired emergency fire pump engine with a model year of 2011 or later, and a displacement of <30 liters/cylinder. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	G/BHP-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+ NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.

MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUEMENGINE (South Plant): Emergency Engine	17.11	Diesel	A 1,341 HP (1,000 kilowatts (kW)) diesel-fired emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is designed to be compliant with Tier IV emission standards. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0434	FLAT ROCK ASSEMBLY PLANT	FORD MOTOR COMPANY	MI	03/22/2018 ACT	EUENGINE 01 through EUENGINE 08	17.11	Diesel	Eight (8) diesel-fueled emergency engine/generators rated at 2,500 kilowatt (kW) / 3,633 brake horsepower (BHP), two (2) emergency fire pump engines rated at 250 BHP and an emergency engine rated at 500 kW. No add-on control.	Nitrogen Oxides (NOx)	P	Good combustion practices.	6.4	G/KW-H	HOURLY; EACH ENGINE; NMHC +NOX	BACT-PSD	NSPS , SIP	N	0	N	42.6	LB/H	HOURLY; EACH ENGINE ; NOX	The first emission limit above is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx) and is 6.4 G/KW-H for each engine. The limit is based on NSPS IIII. The second emission limit above is actually in NOx and is 42.6 LB/H for each engine.
MI-0434	FLAT ROCK ASSEMBLY PLANT	FORD MOTOR COMPANY	MI	03/22/2018 ACT	EUFIREPUMPENGS (2 emergency fire pump engines)	17.21	Diesel	EUFIREPUMPENGS - Two (2) diesel-fueled emergency fire pump engines rated at 250 brake horsepower (BHP). No add-on control.	Nitrogen Oxides (NOx)	P	Good combustion practices.	3	G/B-HP-H	HOURLY; EACH ENGINE (NMHC +NOX)	BACT-PSD	NSPS , SIP	U	0	N	2.8	LB/H	HOURLY; EACH ENGINE (NOX)	Emission limit 1 above is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx) and is 3.0 G/B-HP-H for each engine and is based upon NSPS IIII. Emission limit 2 is actually a NOx limit and is 2.8 LB/H for each engine.

MI-0434	FLAT ROCK ASSEMBLY PLANT	FORD MOTOR COMPANY	MI	03/22/2018 ACT	EULIFESAFETYENG - One diesel-fueled emergency engine/generator	17.21	Diesel	EULIFESAFETYENG - One (1) diesel-fueled emergency engine/generator rated at 500 KW. No add-on control.	Nitrogen Oxides (NOx)	P	Good combustion practices.	4	G/KW-H	HOURLY; NMHC +NOX	BACT-PSD	NSPS , SIP	N	0	N	8.47	LB/H	HOURLY; NOX	Emission limit 1 above is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx) and is 4.0 G/KW-H based upon NSPS IIII. Emission limit 2 is actually NOx and is 8.47 LB/H.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	MI	07/16/2018 ACT	EUEMENGINE: Emergency engine	17.11	Diesel	A nominal 2 MW diesel-fueled emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is an EPA Tier 2 certified engine subject to NSPS IIII.	Nitrogen Oxides (NOx)	P	State of the art combustion design.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	MI	07/16/2018 ACT	EUFPENGINE: Fire pump engine	17.21	Diesel	A 399 brake HP diesel-fueled emergency fire pump engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is an EPA Tier 3 certified engine subject to NSPS IIII.	Nitrogen Oxides (NOx)	P	State of the art combustion design.	4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx) which is what is required in the NSPS.
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	12/21/2018 ACT	EUEMGD1--A 1500 HP diesel fueled emergency engine	17.11	Diesel	A 1500 HP diesel-fueled emergency engine manufactured after 2006 serving a 1,000 kW engine generator with associated fuel oil tank. The engine generator is used to charge the batteries in the uninterruptible power supply battery system.	Nitrogen Oxides (NOx)	P	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	U	0			Emission limit is for NMHC+NOx. Did not consider the additional control to be technically feasible since many controls don't function properly for small emitters and intermittent sources.

MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	12/21/2018 ACT	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	17.11	Diesel	A 6000 HP diesel-fueled emergency engine manufactured after 2006 serving a 4000 kW generator with associated fuel oil tank. The engine generator is used to facilitate operations during idling of the plan for routine maintenance checks and readiness testing.	Nitrogen Oxides (NOx)	P	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	U	0			Emission limit is for NMHC+NOx. Did not consider the additional control to be technically feasible since many controls don't function properly for small emitters and intermittent sources.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	MI	08/21/2019 ACT	FGEMENGINE	17.11	Diesel	Two (2) diesel-fired emergency engines, each 1,474 HP (1,100 kW) with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engines are designed to be compliant with Tier 2 emission standards.	Nitrogen Oxides (NOx)	N		5.3	G/HP-H	HOURLY; EACH ENGINE	BACT-PSD	NSPS	N	0	U	0			permit also with a limit of 6.4 G/KW-H, is hourly and applies to each engine. This emission limit is for certified engines; if testing becomes required to demonstrate compliance, then the tested values must be compared to the Not to Exceed (NTE) requirements determined through 40 CFR 60.4212(c). SCR is not technically feasible for emergency engines, which will be small, intermittent sources, only operated for maintenance and testing and in case of a true emergency. Other add-on controls are not considered technically or

*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	MI	11/26/2019 ACT	EUFPENGINE (Emergency engine-diesel fire pump	17.21	diesel fuel	A 260 brake horsepower (bhp) diesel-fueled emergency engine manufactured in 2011 or later and a displacement of <10 Liters/cylinder. Powers a fire pump used for back up during an emergency (EUFPENGINE). Restricted to 1 hours/day, except during emergency conditions and stack testing, and 100 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good Combustion Practices and meeting NSPS Subpart IIII requirements	3	G/BHP-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in â€œNMHC+NOxâ€ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	MI	11/26/2019 ACT	EUEMENGINE (diesel fuel emergency engine)	17.11	diesel fuel	A 2,922 horsepower (HP) (2,179 kilowatts (kW)) natural gas-fueled emergency engine (EUEMENGINE) manufactured in 2011 or later and a displacement of <10 Liters/cylinder. Restricted to 4 hours/day, except during emergency conditions and stack testing, and 500 hours/year on a 12-month rolling time period basis	Nitrogen Oxides (NOx)	P	Good Combustion Practices and meeting NSPS Subpart IIII requirements	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in â€œNMHC+NOxâ€ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE1 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours	21.2	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.

MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 500 KW (EUEMRGRICE2 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified Engines, Limited Operating Hours	4.4	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.
MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Diesel fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified Engines, Limited Operating Hours	3.53	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	NJ	11/01/2012 ACT	Emergency Generator	17.11	ULSD		Nitrogen Oxides (NOx)	P	use of ultra low sulfur diesel (ULSD) a clean fuel	18.53	LB/H		LAER	NSPS , OPERATING PERMIT	U	0	U	0			
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	NJ	03/10/2016 ACT	Diesel Fired Emergency Generator	17.11	ULSD		Nitrogen Oxides (NOx)	P	use of ultra low sulfur diesel a clean burning fuel.	42.3	LB/H		LAER	NSPS , OPERATING PERMIT	N	0	N	0			
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	NJ	03/10/2016 ACT	Emergency Diesel Fire Pump	17.21	ULSD	Maximum heat Input Rate = 2.6 MMBtu/hr	Nitrogen Oxides (NOx)	P	use of ULSD a clean burning fuel, and limited hours of operation	1.7	LB/H		LAER	NSPS , OPERATING PERMIT	N	0	N	0			

NY-0103	CRICKET VALLEY ENERGY CENTER	CRICKET VALLEY ENERGY CENTER LLC	NY	02/03/2016 ACT	Black start generator	17.11	ultra low sulfur diesel		Nitrogen Oxides (NOx)	B	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	LAER		U	0	U	0			
NY-0103	CRICKET VALLEY ENERGY CENTER	CRICKET VALLEY ENERGY CENTER LLC	NY	02/03/2016 ACT	Emergency fire pump	17.21	ultra low sulfur diesel		Nitrogen Oxides (NOx)	P	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.6	G/BHP-H	1 H	LAER		U	0	U	0			
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	06/18/2013 ACT	Emergency fire pump engine	17.21	diesel	223.8 kW. Emergency fire pump engine restricted to 500 hours of operation per rolling 12 months.	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	1.7	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.43	T/YR	PER ROLLING 12-MONTHS	Additional limits: 3.5 g NOx/kW-H; and 4.0 g NMHC + NOx/kW-hr, the standard from Subpart IIII. Method 7E if required.
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	06/18/2013 ACT	Emergency generator	17.11	diesel	Emergency diesel fired generator restricted to 500 hours of operation per rolling 12-months.	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	27.8	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	6.95	T/YR	PER ROLLING 12-MONTHS	Additional limits: 5.61 g NOx/kW-H; and 6.4 g NMHC + NOx/kW-hr, the standard from Subpart IIII. Method 7E if required.

OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	GENERAL ELECTRIC	OH	05/07/2013 ACT	Test Cell 1 for Aircraft Engines and Turbines	17.11	JET FUEL	Fuels tested include jet fuel, diesel fuel, biofuels and gaseous fuels. Size of engine turbine varies, none specified. Installed with a continuous fuel flow monitor.	Nitrogen Oxides (NOx)	N		1.7	LB/MMBTU	LAER AND PSD LIMIN	LAER	SIP	U	0	U	92	T/YR	PER ROLLING 12 MONTHS	The emission limit of 1.70 LB NOX/MMBtu is considered LAER, based on design emission levels. Must develop an Emissions Protocol Document on the potential to emit.
OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	GENERAL ELECTRIC	OH	05/07/2013 ACT	Test Cell 2 for Aircraft Engines and Turbines	17.11	JET FUEL	Fuels tested include jet fuel, diesel fuel, biofuels and gaseous fuels. Size of engine turbine varies, none specified. Installed with a continuous fuel flow monitor.	Nitrogen Oxides (NOx)	N		4.4	LB/MMBTU		LAER	SIP	U	0	U	80	T/YR	PER ROLLING 12 MONTHS	The emission limit of 4.4 LB NOX/MMBtu is considered LAER, based on design emission levels. Must develop an Emissions Protocol Document on the potential to emit.
OH-0360	CARROLL COUNTY ENERGY	CARROLL COUNTY ENERGY	OH	11/05/2013 ACT	Emergency generator (P003)	17.11	diesel	1,112 kW emergency diesel fired generator.	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	13.74	LB/H		BACT-PSD	NSPS	U	0	U	3.44	T/YR	PER ROLLING 12 MONTH PERIOD	Additional limits: 5.61 g NOx/kW-H; and 6.4 g NMHC + NOx/kW-hr, the standard from Subpart IIII.
OH-0360	CARROLL COUNTY ENERGY	CARROLL COUNTY ENERGY	OH	11/05/2013 ACT	Emergency fire pump engine (P004)	17.21	diesel	400 hp (298 kW) emergency diesel-fired fire pump engine	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	2.3	LB/H		BACT-PSD	NSPS	U	0	U	0.57	T/YR	PER ROLLING 12 MONTH PERIOD	Additional limits: 3.5 g NOx/kW-H; and 4.0 g NMHC+NOx/kW-h (3.0 g/hp-h), the standard from Subpart IIII.
OH-0363	NTE OHIO, LLC		OH	11/05/2014 ACT	Emergency generator (P002)	17.11	Diesel fuel	Emergency diesel engine powered standby generator, rated at 1,100 kilowatts.	Nitrogen Oxides (NOx)	P	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	29.01	LB/H		BACT-PSD	NSPS	U	0	U	7.25	T/YR	PER ROLLING 12 MONTH PERIOD	

OH-0363	NTE OHIO, LLC		OH	11/05/2014 ACT	Emergency Fire Pump Engine (P003)	17.21	Diesel fuel	Emergency diesel fire pump engine is rated at a maximum 260 BHP.	Nitrogen Oxides (NOx)	P	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	1.72	LB/H		BACT-PSD	NSPS	U	0	U	0.43	T/YR	PER ROLLING 12 MONTH PERIOD	NSPS Subpart IIII: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 3.0 g/hp-hr.
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	08/25/2015 ACT	Emergency fire pump engine (P004)	17.21	Diesel fuel	140 hp (104.5 kW) emergency diesel-fired fire pump engine	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	0.81	LB/H		BACT-PSD	NSPS	U	0	U	0.2	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 3.5 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 4.0 g/kW-hr.
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	08/25/2015 ACT	Emergency generator (P003)	17.11	Diesel fuel	1,750 kW (2,346 hp) emergency generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	21.6	LB/H		BACT-PSD	NSPS	U	0	U	5.41	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 5.61 g/kW-hr and Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	OH	09/23/2016 ACT	Emergency fire pump engine (P004)	17.21	Diesel fuel	311 hp (232.1 kW mechanical) emergency fire pump	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	1.79	LB/H		BACT-PSD	NSPS	U	0	U	0.45	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 3.5 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 4.0 g/kW-hr.
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	OH	09/23/2016 ACT	Emergency generator (P003)	17.11	Diesel fuel	2,000 kW electric, 2,198 kW mechanical (2,947 hp) emergency diesel generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	27.18	LB/H		BACT-PSD	NSPS	U	0	U	6.8	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 5.61 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.

OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	04/19/2017 ACT	Emergency Fire Pump Diesel Engine (P008)	17.21	Diesel fuel	460 HP - 343 kW Emergency Fire Pump Diesel Engine	Nitrogen Oxides (NOx)	P	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	NSPS	U	0	U	0.02	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 0.4 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	04/19/2017 ACT	Emergency Generator (P009)	17.11	Diesel fuel	5,000 HP â€“ 3,729 kW Emergency Generator Diesel Engine	Nitrogen Oxides (NOx)	P	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	NSPS	U	0	U	0.3	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 0.67 g/kW-hr. NSPS limit is NMHC + NOx emissions shall not exceed 6.4 g/kW-hr (3.0 g/hp-hr).
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	OH	09/07/2017 ACT	Emergency generator (P003)	17.11	Diesel fuel	Emergency Generator 1000 kW (electrical), 1,140 kW (mechanical), 1,529 hp	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	16.07	LB/H		BACT-PSD	NSPS	U	0	U	4.02	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 6.4 g/kW-hr. NSPS limit is Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	OH	09/07/2017 ACT	Emergency fire pump engine (P004)	17.21	Diesel fuel	Emergency Fire Pump 300 hp (224 kW mechanical)	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	1.97	LB/H		BACT-PSD	NSPS	U	0	U	0.49	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 4.0 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 4.0 g/kW-hr.
OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	OH	09/27/2017 ACT	Emergency generator (P003)	17.11	Diesel fuel	1,000 kWe (1,140 kW mechanical) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	16.1	LB/H		BACT-PSD	NSPS	U	0	U	4.02	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 6.4 g/kW-hr (4.8 g/hp-hr). NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr.

OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	OH	09/27/2017 ACT	Emergency fire pump engine (P004)	17.21	Diesel fuel	300 hp emergency diesel-fired fire pump	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	1.97	LB/H		BACT-PSD	NSPS	U	0	U	0.49	T/YR	PER ROLLIN G 12 MONTH PERIOD	Standard limit is 4.0 g/kW-hr (3.0 g/hp-hr). NSPS is Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	10/23/2017 ACT	Emergency Generators (2 identical, P004 and P005)	17.11	Diesel fuel	Two identical Emergency Generators; 1,645 kW (2,206 HP) emergency diesel-fired generator to provide on-site emergency power capabilities independent of the utility grid. Throughputs and limits are for a single generator except as noted.	Nitrogen Oxides (NOx)	P	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 â€™s operating manual.	23.21	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.16	T/YR	NMHC+ NOX. SEE NOTES.	Non-methane hydrocarbon plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 6.40 g/kW-hour (4.77 G/BHP-H), 23.21 pounds per hour and 1.16 tons per rolling, 12-month period.
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	10/23/2017 ACT	Emergency Fire Pump (P006)	17.21	Diesel fuel	410 HP emergency diesel-fired fire pump to provide on-site firefighting capabilities independent of the utility grid	Nitrogen Oxides (NOx)	P	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer â€™s operating manual	2.7	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.14	T/YR	NMHC+ NOX. SEE NOTES.	Nonmethane hydrocarbons plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 4.0 g/kW-hour (3.0 g/bhp-h), 2.70 pounds per hour and 0.14 ton per rolling, 12-month period.

OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/07/2017 ACT	Emergency Diesel Generator Engine (P001)	17.11	Diesel fuel	1,645 kW (2,206 HP) emergency diesel-fired generator to provide on-site emergency power capabilities independent of the utility grid.	Nitrogen Oxides (NOx)	P	Good combustion design	24.71	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.24	T/YR	NMHC+ NOX. SEE NOTES.	Non-methane hydrocarbon plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 6.40 g/kW-h (4.8 g/hp-h), 24.71 lb/h and 1.24 t/yr per rolling, 12-month period.
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/07/2017 ACT	Emergency Diesel Fire Pump Engine (P002)	17.11	Diesel fuel	700 hp emergency diesel-fired fire pump to provide on-site firefighting capabilities independent of the utility grid	Nitrogen Oxides (NOx)	P	Good combustion design	4.97	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.25	T/YR	NMHC+ NOX. SEE NOTES.	Nonmethane hydrocarbons plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 4.0 g/kW-hour, 4.97 pounds per hour and 0.25 ton per rolling, 12-month period. NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	OH	02/09/2018 ACT	Emergency diesel-fueled fire pump (P006)	17.21	Diesel fuel	250 hp emergency diesel-fueled fire pump	Nitrogen Oxides (NOx)	P	Comply with NSPS 40 CFR 60 Subpart IIII	1.6	LB/H		BACT-PSD	NSPS	U	0	U	0.41	T/YR	PER ROLLING 12 MONTH PERIOD	NOx Standard limit is 4.0 g/kW-hr (3.0 g/hp-hr). NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	OH	02/09/2018 ACT	Emergency diesel-fired generator (P007)	17.11	Diesel fuel	2,000 kW (2,682 hp) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	Comply with NSPS 40 CFR 60 Subpart IIII	28.2	LB/H		BACT-PSD	NSPS	U	0	U	7.05	T/YR	PER ROLLING 12 MONTH PERIOD	NOx Standard limit is 6.4 g/kW-hr (4.8 g/hp-hr). NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr (4.8 g/hp-hr).

OH-0377	HARRISON POWER	HARRISON POWER	OH	04/19/2018 ACT	Emergency Diesel Generator (P003)	17.11	Diesel fuel	1,387 KW (1,860 HP) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	19.68	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.98	T/YR	NMHC+ NOX. SEE NOTES.	All emissions limits are for Non-methane hydrocarbon (NMHC) + NOX emissions. 0.98 t/yr per rolling, 12-month period. NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr (4.8 g/hp-hr).
OH-0377	HARRISON POWER	HARRISON POWER	OH	04/19/2018 ACT	Emergency Fire Pump (P004)	17.21	Diesel fuel	238.6 KW (320 HP) emergency diesel-fired firewater pump	Nitrogen Oxides (NOx)	P	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	2.12	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.11	T/YR	NMHC+ NOX. SEE NOTES.	All emissions limits are for Non-methane hydrocarbon (NMHC) + NOX emissions. 0.11 t/yr per rolling, 12-month period. NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018 ACT	Firewater Pumps (P005 and P006)	17.21	Diesel fuel	Two identical Firewater Pumps 1 and 2; 300 kW (402 HP) emergency diesel-fired firewater pump engine. Limits are for single pump except as noted.	Nitrogen Oxides (NOx)	P	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 â€™s operating manual	2.64	LB/H	SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.13	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	Emission limits are for non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx). Non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx) emissions shall not exceed 4.0 g/kW-hour (3.0 g/HP-hour), 2.64 pounds per hour and 0.13 ton per rolling, 12-month period.

OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018 ACT	Emergency Diesel-fired Generator Engine (P007)	17.11	Diesel fuel	2,500 kW (3,353 HP) emergency diesel-fired generator engine	Nitrogen Oxides (NOx)	P	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 â€™s operating manual	37.41	LB/H	SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.87	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	Emission limits are for non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx). Non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx) emissions shall not exceed 6.4 g/kW-hour (4.8 g/HP-hour), 37.41 pounds per hour and 1.87 tons per rolling, 12-month period.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018 ACT	1,000 kW Emergency Generators (P008 - P010)	17.11	Diesel fuel	Three identical ECU Generators 1 to 3; 1,000 kW (1,341 HP) emergency diesel-fired generator engine. Limits are for single generator except as noted.	Nitrogen Oxides (NOx)	P	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 â€™s operating manual	14.96	LB/H	SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.75	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	Emission limits are for non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx). Non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx) emissions shall not exceed 6.4 g/kW-hour (4.8 g/HP-hour), 14.96 pounds per hour and 0.75 ton per rolling, 12-month period.
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	02/06/2019 ACT	Black Start Generator (P007)	17.21	Diesel fuel	Black start generator, 158 HP diesel engine.	Nitrogen Oxides (NOx)	P	Tier IV engine Tier IV NSPS standards certified by engine manufacturer.	0.104	LB/H		BACT-PSD	NSPS	U	0	U	5.2	X10-3 T/YR		

OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	02/06/2019 ACT	Emergency Generators (P005 and P006)	17.11	Diesel fuel	Two identical Emergency generators, 3131 HP diesel engines. Throughputs and limits are for one generator, except as noted.	Nitrogen Oxides (NOx)	P	Tier IV engine Tier IV NSPS standards certified by engine manufacturer.	3.45	LB/H		BACT-PSD	NSPS	U	0	U	0.17	T/YR		NSPS: 4.8 grams NOx + NMHC/bhp-hr
OH-0383	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	07/17/2020 ACT	Diesel-fired emergency fire pumps (2) (P009 and P010)	17.11	Diesel fuel	Two identical fire pump 3131 HP diesel engines. Throughputs and limits are for one engine, except as noted.	Nitrogen Oxides (NOx)	P	Tier IV NSPS standards certified by engine manufacturer.	0			BACT-PSD	NSPS	U	0	U	0			
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	07/02/2013 ACT	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	17.11	DIESEL	<100 HR/YR OPERATION.	Nitrogen Oxides (NOx)	P	COMBUSTION CONTROL	0.011	LB/HP-HR		BACT-PSD	NSPS	U	0	U	0			
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	10/10/2012 ACT	Emergency Generator	17.11	Diesel	The emergency generator will be restricted to operate not more than 100 hr/yr.	Nitrogen Oxides (NOx)	N		4.93	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	U	0	U	0			
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	10/10/2012 ACT	Fire Pump	17.21	Diesel	The fire pump will be restricted to operate not more than 100 hr/yr.	Nitrogen Oxides (NOx)	N		2.6	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	U	0	U	2.6	LB/H		Expressed as NO2. Other Limit: 0.13 T/YR
PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	PA	04/23/2013 ACT	EMERGENCY FIREWATER PUMP	17.21	LOW SULFUR DISTILLATE	EMERGENCY FIREWATER PUMP (450 BHP)	Nitrogen Oxides (NOx)	N		1.86	LB/H		OTHER CASE-BY-CASE	OTHER	U	0	U	0.09	T/YR	12 MONTH ROLLING TOTAL	
PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	PA	04/23/2013 ACT	EMERGENCY GENERATOR	17.11	Ultra Low sulfur Distillate	EMERGENCY GENERATOR (1,135 BHP - 750 KW)	Nitrogen Oxides (NOx)	N		9.89	LB/H		OTHER CASE-BY-CASE	OTHER	U	0	U	0.49	T/YR	12-MONTH ROLLING TOTAL	
PA-0309	NNA ENERGY CTR/JESSUP	NNA ENERGY CENTER, LLC	PA	12/23/2015 ACT	Fire pump engine	17.21	Ultra-low sulfur diesel		Nitrogen Oxides (NOx)	N		3	GM/HP-HR		LAER		U	0	U	0.05	TONS	12-MONTH ROLLING BASIS	

PA-0309	LACKAWANNA ENERGY CTR/JESSU	LACKAWANNA ENERGY CENTER,	PA	12/23/2015 ACT	2000 kW Emergency Generator	17.11	Ultra-low sulfur Diesel	To allow maintenance of vital plant loads during power outages or maintenance of the	Nitrogen Oxides (NOx)	N		5.45	GM/HP-HR		LAER		U	0	U	0.81	TONS	12-MONTH ROLLING BASIS	
PA-0310	CPV FAIRVIEW ENERGY CENTER	CPV FAIRVIEW, LLC	PA	09/02/2016 ACT	Emergency Generator Engines	17.11	ULSD	(2) 1500 kW emergency diesel genset. Emission limitations are for each genset and fuel is restricted to ULSD (15 ppm) and each is restricted to 100 hrs on a 12-month rolling basis.	Nitrogen Oxides (NOx)	N		4.8	G/BHP-HR		LAER	NSPS	U	0	U	0			
PA-0310	CPV FAIRVIEW ENERGY CENTER	CPV FAIRVIEW, LLC	PA	09/02/2016 ACT	Emergency Fire Pump Engine	17.21	ULSD	Sulfur content of diesel fuel shall not exceed 15 ppm, operation of engine shall not exceed 100 hr on a 12-month rolling basis.	Nitrogen Oxides (NOx)	N		3	G/BHP-HR		LAER	NSPS	U	0	U	0			
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	09/01/2015 ACT	Emergency Generator	17.11		Sulfur content of the diesel fuel combusted by the emergency diesel generator shall not exceed 15 ppm. Shall maintain and operate the source in accordance with good engineering practice.	Nitrogen Oxides (NOx)	N		4.93	G/HP-HR		LAER	NSPS	U	0	U	0.4	TPY	12-MONTH ROLLING BASIS	
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	09/01/2015 ACT	Fire Pump Engine	17.11	diesel	Sulfur content of the diesel fuel combusted by the fire engine pump shall not exceed 15 ppm. Shall maintain and operate the source in accordance with good	Nitrogen Oxides (NOx)	N		3	G/HP-HR		LAER	NSPS	U	0	U	0.08	TPY	12-MONTH ROLLING BASIS	
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	ENERGY ANSWERS ARECIBO, LLC	PR	04/10/2014 ACT	Emergency Diesel Fire Pump	17.21	ULSD Fuel Oil #2	The Emergency Fire Pump is rated at 335 BHP and limited to 500 hr/yr (emergency operations and testing and maintenance, combined).	Nitrogen Oxides (NOx)	N		2.85	G/B-HP-H		BACT-PSD		U	0	U	2.1	LB/H		

PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	ENERGY ANSWERS ARECIBO, LLC	PR	04/10/2014 ACT	Emergency Diesel Generator	17.11	ULSD Fuel oil # 2	Emergency Generator is rated at 670 BHP and is limited to 500 hr per year (emergency and testing and maintenance, combined)	Nitrogen Oxides (NOx)	N		2.85	G/B-HP-H		BACT-PSD		U	0	U	4.2	LB/H		
TX-0671	PROJECT JUMBO	M&G RESINS USA, LLC	TX	12/01/2014 ACT	Engines	17.11	ultra low sulfur diesel fuel	fired generators proposed. Each engine will be 4000 kW. Ultra low sulfur fuel is burned in the engines to meet the sulfur requirement of 15 ppm in 40CFR80.510(b). Each emergency engine is being permitted for maintenance and testing for maximum 100 hrs/yr. They are not being permitted for the actual emergency emissions	Nitrogen Oxides (NOx)	P	Each emergency generator's emission factor is based on EPA's Tier 2 standards at 40CFR89.112 for NOx	5.43	G/KW-H		BACT-PSD	NSPS	U	0	U	2.39	T/YR		

TX-0728	PEONY CHEMICAL MANUFAC TURING FACILITY	BASF	TX	04/01/2015 ACT	Emergency Diesel Generator	17.11	Diesel	generator (EPN 17-1-4) at the site is diesel fired and rated at 1500 horsepower (hp). Lowest Achievable Emission Rates (LAER) for nitrogen oxides (NOx) is the use of a 40 Code Federal Rules (CFR) Part 89 Tier 2 engine and limited hours of operation. Emissions from the engine shall not exceed 0.0218 grams per horsepower-hour (g/hp-hr) of nitrogen oxides (NOx). The engine is limited to 52 hours per year of non-emergency operation. Emissions from the engine shall not exceed 0.01256 g/hp hr of carbon monoxide (CO). The fuel for the engine is limited to 15 parts per million sulfur by weight (ultra-low sulfur diesel).	Nitrogen Oxides (NOx)	P	Minimized hours of operations Tier II engine	0.0218	G/HP HR		LAER	NSPS , MACT	N	0	U	0.35	TPY		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRIS E LLC	TX	02/06/2020 ACT	Emergency generator	17.11	DIESEL	Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	N	0	U	0			NSPS IIII, MACT ZZZZ

TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	02/06/2020 ACT	Emergency firewater pumps	17.11		Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency	0			BACT-PSD	NSPS , MACT	N	0	U	0			
TX-0879	MOTIVA PORT ARTHUR TERMINAL	MOTIVA ENTERPRISES LLC	TX	02/19/2020 ACT	Emergency Firewater Engine	17.11	Ultra-low sulfur diesel	Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	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	NSPS , MACT	N	0	U	0			NSPS IIII MACT ZZZZ
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	04/23/2020 ACT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	17.11	Ultra-low Sulfur Diesel		Nitrogen Oxides (NOx)	P	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0			BACT-PSD	NSPS , MACT	N	0	U	0			

TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		TX	09/09/2020 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL		Nitrogen Oxides (NOx)	P	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0			BACT-PSD		N	0	U	0			
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	TX	09/16/2020 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL		Nitrogen Oxides (NOx)	P	limited to 100 hours per year of non-emergency operation	0			BACT-PSD		N	0	U	0			
TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	11/17/2021 ACT	Emergency Generators	17.11	Ultra-low sulfur diesel (no more than 15		Nitrogen Oxides (NOx)	P	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission	0			BACT-PSD		N	0	U	0			
VA-0325	GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	06/17/2016 ACT	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	17.11	DIESEL FUEL		Nitrogen Oxides (NOx)	P	Good Combustion Practices/Maintenance	6.4	G/KW	PER HR	N/A		U	0	U	10.6	T/YR	12 MO ROLLING TOTAL	
VA-0325	GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	06/17/2016 ACT	DIESEL-FIRED WATER PUMP 376 bph (1)	17.21	DIESEL FUEL	FWP-1: 104.0 tons/year (12-month rolling total)	Nitrogen Oxides (NOx)	P	Good Combustion Practices/Maintenance	0			N/A		U	0	U	0			EMISSION LIMIT: 1 3.0 g/hp-hr NOx + NMHC (4.0 g/kW-hr NOx + NMHC)

VA-0328	C4GT, LLC	NOVI ENERGY	VA	04/26/2018 ACT	Emergency Diesel GEN	17.11	Ultra Low Sulfur Diesel		Nitrogen Oxides (NOx)	P	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	NSPS , SIP	N	0	N	9.6	T/YR	12 MO ROLLING AV	NOX + NMHC
VA-0328	C4GT, LLC	NOVI ENERGY	VA	04/26/2018 ACT	Emergency Fire Water Pump	17.21	Ultra Low Sulfur Diesel	315 BHP	Nitrogen Oxides (NOx)	P	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	SIP , NSPS	U	0	N	0			
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	06/24/2019 ACT	Emergency Diesel Generator - 300 kW	17.11	Ultra Low Sulfur Diesel		Nitrogen Oxides (NOx)	P	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	NSPS , SIP	N	0	N	11.7	T/YR	12 MO ROLLING AVG	Emission Limit 3: 4.8 G/HP - HR

VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	06/24/2019 ACT	Emegency Fire Water Pump	17.21	Ultra Low Sulfur Diesel		Nitrogen Oxides (NOx)	P	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	NSPS , SIP	N	0	N	0.7	T/YR		
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT		WI	04/24/2018 ACT	Diesel-Fired Emergency Generators	17.11	Diesel Fuel	Ten, 2,180kW Diesel-Fired Emergency Generators.	Nitrogen Oxides (NOx)	P	The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices	5.36	G/KWH		BACT-PSD	NSPS , NESHAP	N	0	U	0			BACT is Total hours of operation for each generator is 200 hours over a 12 month period. Ultra-low sulfur fuel contains less than 15 ppm sulfur. Good combustion practices are defined as maintaining the stationary compression ignition internal combustion engine according to each manufacturerâ€™s emission-related instructions.

WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	SIO INTERNATIONAL	WI	04/24/2018 ACT	P42 -Diesel Fired Emergency Generator	17.11	Diesel Fuel	Maximum Continuous Rating: 1,750 kW or 2,346 bhp	Nitrogen Oxides (NOx)	P	Good Combustion Practices, The Use of an Engine Turbocharger and Aftercooler.	5.36	G/KWH		BACT-PSD	NSPS , NESHAP	N	0	U	0			BACT is Good combustion practices are defined as maintaining the stationary compression ignition internal combustion engine according to the manufacturerâ€™s emission-related written instructions. The total hours of operation of the emergency generator may not exceed 200 hours during each consecutive 12-month period.
*WI-0300	NEMADJI TRAIL ENERGY CENTER	NEMADJI TRAIL ENERGY CENTER	WI	09/01/2020 ACT	Emergency Diesel Fire Pump (P06)	17.21	Diesel		Nitrogen Oxides (NOx)	P	Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturerâ€™s recommendations.	3	G/HP-H		BACT-PSD		U	0	U	0			
*WI-0300	NEMADJI TRAIL ENERGY CENTER	NEMADJI TRAIL ENERGY CENTER	WI	09/01/2020 ACT	Emergency Diesel Generator (P07)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Operation limited to 500 hours/year and operate and maintain according to the manufacturerâ€™s recommendations.	4.8	G/HP-H		BACT-PSD		U	0	U	0			

WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	11/21/2014 ACT	Emergency Generator	17.11	Diesel	Nominal 1,500 kW. Limited to 100 hours/year.	Nitrogen Oxides (NOx)	N		0			BACT-PSD	NSPS	U	0	U	0			
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	11/21/2014 ACT	Fire Pump Engine	17.21	Diesel	Limited to 100 Hours/year.	Nitrogen Oxides (NOx)	N		0			BACT-PSD	NSPS	U	0	U	0			
WV-0027	INWOOD	KNAUF INSULATION INC.	WV	09/15/2017 ACT	Emergency Generator - ESDG14	17.11	ULSD	Used to supply power to the facility in the event of power loss	Nitrogen Oxides (NOx)	P	Engine Design	4.77	G/HP-HR		BACT-PSD	NSPS , MACT	U	0	U	0			Engine is limited to 100 hours of non-emergency use per year.
*WV-0033	MAIDSVILLE	MOUNTAIN STATE CLEAN ENERGY, LLC	WV	01/05/2022 ACT	Emergency Generator	17.11	ULSD	4SLB Diesel-Fired Emergency Engine - Subpart IIII	Nitrogen Oxides (NOx)	P	Combustion Control (retarded timing and/or lean burn)	24.6	LB/HR		BACT-PSD	NSPS	N	0	U	6.4	G/BKW	NMHC+ NOX	Certified Engine
*WV-0033	MAIDSVILLE	MOUNTAIN STATE CLEAN ENERGY, LLC	WV	01/05/2022 ACT	Fire Water Pump	17.11	ULSD	4SLB Diesel-Fired Emergency Engine - Subpart IIII.	Nitrogen Oxides (NOx)	P	Combustion control (retarded timing and/or lean burn)	1.59	LB/HR		BACT-PSD	NSPS	U	0	U	4	G/BKW		Certified Engine

Nellis AFB
RACT Analysis
RBLC Search

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_STATE	PERMIT_ISSUANCE_DATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION	CASE-BY-CASE_BASIS	OTHER_APPLICABLE_REQUIREMENTS	OTHER_FACTORS	PERCENT_EFFICIENCY	COMPLIANCE_VERIFIED	EMISSION_LIMIT_2	EMISSION_LIMIT_2_UNIT	EMISSION_LIMIT_2_AVGERAGE_TIME_CONDITION	POLLUTANT_COMPLIANCE_NOTES
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Emergency Camp Generators	17.11	Ultra Low Sulfur Diesel	Three 2,695 hp ULSD-fired Standby Camp Generator Engines.	Nitrogen Oxides (NOx)	N		4.8	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Fine Water Pumps	17.11	Ultra Low Sulfur Diesel	Two ULSD-fired 610 hp Fine Water Pumps	Nitrogen Oxides (NOx)	N		3	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	01/23/2015 ACT	Bulk Tank Generator Engines	17.11	Ultra Low Sulfur Diesel	Two ULSD-fired 891 hp Bulk Tank Storage Area Generator Engines	Nitrogen Oxides (NOx)	N		4.8	GRAMS/HP-H		BACT-PSD		U	0	U	0			
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	06/30/2017 ACT	Black Start and Emergency Internal Cumbustion Engines	17.11	Diesel	Two (2) 600 kWe black start diesel generators and four (4) 1,500 kWe emergency diesel generators.	Nitrogen Oxides (NOx)	P	Good Combustion Practices	8	G/KW-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	U	0	U	0			8.0 g/kW-hr includes NOx and VOC emissions. NSPS Subpart IIII engines.
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	06/30/2017 ACT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	17.11	Diesel and Natural Gas	Twelve 17-MW Wartsila 18V50DF ULSD/Natural Gas-Fired Internal Combustion Engines. Each engine rated at: 143.5 MMBtu/hr on ULSD 141.4 MMBtu/hr on natural gas	Nitrogen Oxides (NOx)	B	Selective Catalytic Reduction (SCR) and Good Combustion Practices	0.53	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		U	95	U	0.08	G/KW-HR (NATURAL GAS)	3-HOUR AVERAGE	Potential NOx emissions of 85.9 tpy for each engine (EU 1-12).

AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	08/13/2020 ACT	One (1) Black Start Generator Engine	17.11	ULSD	EU 39 is a 4,060 hp diesel generator.	Nitrogen Oxides (NOx)	P	Good combustion practices, limit operation to 500 hours per year.	3.3	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NSPS , NESHAP	U	0	U	0			EU 39 is an EPA Tier 4 Final Engine. 3.3 g/hp-hr limit includes 25% not to exceed factor of safety.
AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	07/07/2022 ACT	Diesel Fire Pump Engine	17.11	Diesel	EU 11 is a 575 hp diesel fire pump engine which is required to meet E.F.s from Table 4 of NSPS Subpart IIII, which is the equivalent to EPA Nonroad Tier 3. BACT E.F.s include not to exceed factor of safety as identified in 40 CFR 1039.101(e).	Nitrogen Oxides (NOx)	P	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII	3.6	G/HP-HR		BACT-PSD	NSPS	U	0	U	500	HRS/YR		NOx emissions from diesel firewater pump engine EU 11 will not exceed 3.6 g/hp-hr @ 15% O2 (95% of NMHC + NOx from Table 4 of NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety);
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	NUCOR STEEL TUSCALOOSA, INC.	AL	07/22/2014 ACT	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL		Nitrogen Oxides (NOx)	N		0.015	LB/HP-H		BACT-PSD	NSPS , MACT	N	0	N	0			
*AL-0318	TALLADEGA SAWMILL	GEORGIA PACIFIC WOOD PRODUCTS, LLC	AL	12/18/2017 ACT	250 Hp Emergency CI, Diesel-fired RICE	17.11	Diesel	Emergency Only	Nitrogen Oxides (NOx)	N		0			N/A		U	0	U	0			
AL-0328	PLANT BARRY	ALABAMA POWER COMPANY	AL	11/09/2020 ACT	Diesel Emergency Engines	17.11	Diesel		Nitrogen Oxides (NOx)	N		3	GR/BHP-HR	NMHC + NOX	BACT-PSD	NSPS , SIP , OPERATING PERMIT	U	0	N	0			
AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	09/23/2019 ACT	Emergency Engines	17.11	Diesel		Nitrogen Oxides (NOx)	P	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.4	G/KW-H		BACT-PSD		U	0	U	0			

AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	06/09/2019 ACT	Emergency Engines	17.11	Diesel	The emergency generators are diesel fired generators which provide electrical power in the event of power failure.	Nitrogen Oxides (NOx)	P	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	4.86	G/KW-HR		BACT-PSD		U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Main Propulsion Generator Diesel Engines	17.11	Diesel	Four 1998 Wartsila 18V32LNE 9910 hp and Two 1998 Wartsila 12V32LNE 6610 hp	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	12.7	G/KW-H	ROLLING 24 HOUR AVERAGE	BACT-PSD	OPERATING PERMIT	U	0	U	0			
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	09/16/2014 ACT	Emergency Diesel Engine	17.11	Diesel	1998 Wartsila 6R32LNE	Nitrogen Oxides (NOx)	B	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			

FL-0350	ANADARKO PETROLEUM, INC DIAMOND BLACKHAWK DRILLING PROJECT	ANADARKO PETROLEUM, INC.	FL	12/31/2014 ACT	Main Propulsion Generator Engines	17.11	Diesel	Six 2012 Hyundai-HiMsen 9H32/40V 6,035 hp and two 2012 Hyundai-HiMsen 18H32/40V diesel electric engines.	Nitrogen Oxides (NOx)	P	Use of good combustion practices based on the most recent manufacturer â€™s specifications issued for these engines at the time that the engines are operating under this permit	0			BACT-PSD	OPERATING PERMIT	U	0	U	0			DR-ME-01 through DR-ME-08 Operating at 50% Load and Above: 10.57 g/kw-hr on a rolling 24-hour average basis. DR-ME-01 through DR-ME-06 Operating Below 50% Load: 57.3 lb/hr on a rolling 24-hour average basis. DR-MR-07 and DR-ME-08 Operating Below 50% Load: 103.5 lb/hr on a rolling 24-hour average basis.
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	07/27/2018 ACT	1,500 kW Emergency Diesel Generator	17.11	ULSD	The emergency generator will operate a combined total of 100 hr/yr for maintenance checks, and readiness testing, which includes a maximum 50 hr/yr for non-emergency operation.	Nitrogen Oxides (NOx)	P	Operate and maintain the engine according to the manufacturer's written instructions	6.4	G/KW-HOUR		BACT-PSD	NESHAP , NSPS	U	0	U	0			Standard equals Subpart IIII limit. Limit is for NOX and Non-Methane Hydrocarbons
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	FL	06/07/2021 ACT	1,500 kW Emergency Diesel Generator	17.11	ULSD	The emergency generator will operate a combined total of 100 hr/yr for maintenance checks, and readiness testing, which includes a maximum 50 hr/yr for non-emergency operation.	Nitrogen Oxides (NOx)	N		6.4	G/KW-HOUR	FOR NMHC +NOX	BACT-PSD	NSPS	U	0	U	0			
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012 ACT	Emergency Generator	17.11	diesel fuel	rated @ 2,000 KW	Nitrogen Oxides (NOx)	P	good combustion practices	6	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		U	0	U	6.61	TONS/YR	ROLLING 12 MONTH TOTAL	

IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	09/05/2014 ACT	Emergency Generator	17.11	distillate fuel oil		Nitrogen Oxides (NOx)	P	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.67	G/KW-H		BACT-PSD		U	0	U	0			
IL-0129	CPV THREE RIVERS ENERGY CENTER	CPV THREE RIVERS, LLC	IL	07/30/2018 ACT	Emergency Engines	17.11	Ultra-low sulfur diesel	Two emergency engine-generators. One large emergency engine-generator, 1500 kW output, will provide emergency power to the plant. One small emergency engine-generator, 125 kW output, will provide emergency power to the switchyard. Fuel used in the emergency engines must meet the requirements of 40 CFR 80.510(b), pursuant to 40 CFR 60.4207(b).	Nitrogen Oxides (NOx)	N		0			LAER	NSPS	U	0	U	0			Limits of the NSPS, 40 CFR 60 Subpart IIII, are LAER for NOx. For the large engine: 6.4 g/kW-hr For the small engine: 4.0 g/kW-hr Permit limits are as follows: For the large engine: 23.0 lb/hr and 1.7 ton/yr For the small engine: 1.2 lb/hr and 0.09 ton/yr
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	IL	12/31/2018 ACT	Emergency Engine	17.11	Ultra-Low Sulfur Diesel	One large emergency engine-generator at the plant; one small emergency engine-generator at the switchyard. Fuel must meet the requirements at 40 CFR 80.510(b) pursuant to 40 CFR 60.4207(b)	Nitrogen Oxides (NOx)	N		6.4	G/KW-HR		LAER	NSPS	U	0	U	0			NSPS Subpart IIII limit of 6.4 g/kW-hr is LAER

*IL-0133	LINCOLN LAND ENERGY CENTER	LINCOLN LAND ENERGY CENTER (A/K/A EMBERCLEAR)	IL	07/29/2022 ACT	Emergency Engines	17.11	Ultra-Low Sulfur Diesel	Two engine-generators will power an electrical generator to provide power to critical equipment during power outages. Ultra-low sulfur diesel fuel (sulfur content <15 part per million (ppm)) will be used as fuel	Nitrogen Oxides (NOx)	N		6.4	GRAMS	KILOWATT-HOUR	BACT-PSD	NSPS	U	0	U	0			Limit 1 includes non-methane hydrocarbons (NMHC), i.e. NOx + NMHC, consistent with the NSPS, 40 CFR 60 Subpart IIII.
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	12/03/2012 ACT	TWO (2) EMERGENCY DIESEL GENERATORS	17.11	DIESEL	THE TWO INTERNAL COMBUSTION ENGINES, IDENTIFIED AS EG01 AND EG02, EXHAUST THROUGH TWO (2) VENTS.	Nitrogen Oxides (NOx)	P	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	3 HOURS	BACT-PSD			0		500	HOURS OF OPERATION	YEALRY	LIMIT ONE AND TWO ARE FOR EACH GENERATOR
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	12/03/2012 ACT	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	THIS ONE (1) INTERNAL COMBUSTION ENGINE, IDENTIFIED AS EG03, EXHAUSTS THROUGH ONE (1) VENT.	Nitrogen Oxides (NOx)	A	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	3 HOURS	BACT-PSD			0		500	HOURS OF OPERATION	YEARLY	LIMIT ONE AND TWO ARE FOR EACH GENERATOR
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	06/04/2014 ACT	DIESEL FIRED EMERGENCY GENERATOR	17.11	NO. 2, DIESEL	ANNUAL OPERATING HOURS SHALL NOT EXCEED 500 HOURS. INSIGNIFICANT ACTIVITY WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.46	G/BHP-H	3-HR AVERAGE	BACT-PSD		N	0		0			
IN-0179	OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	09/25/2013 ACT	DIESEL-FIRED EMERGENCY GENERATOR	17.11	NO. 2 FUEL OIL	ANNUAL HOURS OF OPERATION NOT TO EXCEED 200 HOURS.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	3-HR AVERAGE	BACT-PSD		N	0		0			ADD ON CONTROLS ARE NOT NORMALLY REQUIRED FOR LIMITED USE EMISSION UNITS.
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	06/04/2014 ACT	DIESEL FIRED EMERGENCY GENERATOR	17.11	NO. 2, DIESEL	ANNUAL OPERATING HOURS SHALL NOT EXCEED 500 HOURS. INSIGNIFICANT ACTIVITY WILL NOT BE TESTED.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	3-HR AVERAGE	BACT-PSD		N	0		0			
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	04/24/2014 ACT	DIESEL FIRE PUMP	17.11	DIESEL		Nitrogen Oxides (NOx)	N		3	G/HP-H		BACT-PSD			0		500	H		RESTRICTED USE OF ONLY NATURAL GAS, THE USE OF GOOD COMBUSTION PRACTICES

IN-0263	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	03/23/2017 ACT	EMERGENCY GENERATORS (EU014A AND EU-014B)	17.11	DISTILLATE OIL		Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	4.42	G/HP-H EACH	3 HOUR AVERAGE	BACT-PSD		N	0		500	H/YR EACH		
IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	06/11/2019 ACT	Emergency generator EU-6006	17.11	Diesel		Nitrogen Oxides (NOx)	P	Tier II diesel engine	6.4	G/KWH	TIER II NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	U	0	U	0			Unit shall use good combustion practices and energy efficiency as defined in the permit. 40 CFR 60, subpart IIII 40 CFR 63, subpart ZZZZ
IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	06/11/2019 ACT	Emergency fire pump EU-6008	17.11	Diesel		Nitrogen Oxides (NOx)	P	Engine that complies with Table 4 to Subpart IIII of Part 60	4	G/KWH	COMBINED NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	U	0	U	0			Unit shall use good combustion practices and energy efficiency as defined in the permit. 40 CFR 60, subpart IIII 40 CFR 63, subpart ZZZZ
IN-0324	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	05/06/2022 ACT	emergency generator EU 014a	17.11	distillate oil		Nitrogen Oxides (NOx)	N		4.42	G/HP-HR		BACT-PSD		U	0	U	500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	NOx emissions from the diesel-fired emergency generator (EU-014a) shall be controlled by exercising good combustion practices
IN-0324	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	05/06/2022 ACT	fire water pump EU-015	17.11			Nitrogen Oxides (NOx)	N		2.83	G/HP-HR		BACT-PSD		U	0	U	500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	NOx emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices

*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	03/18/2013 ACT	Caterpillar C18DITA Diesel Engine Generator	17.11	No. 2 Distillate Fuel Oil		Nitrogen Oxides (NOx)	P	utilize efficient combustion/ design technology	14	LB/HR		BACT-PSD		U	0	U	0			
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-02 - North Water System Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-02, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-03 - South Water System Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-03, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-04 - Emergency Fire Water Pump	17.11	Diesel	Diesel emergency fire water pump used to provide emergency fire water supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	N	0	U	0			prepare and maintain for EP 10-04, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-07 - Air Separation Plant Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare and maintain for EP 10-07, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	07/23/2020 ACT	EP 10-01 - Caster Emergency Generator	17.11	Diesel	Diesel emergency generator used to provide emergency power supply for critical operations should the facility power supply be interrupted. This generator has a displacement of less than 30 liters per cylinder.	Nitrogen Oxides (NOx)	P	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS	N	0	U	0			prepare and maintain for EP 10-01, upon initial compliance demonstration but no later than 180 days after startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM, PM10, PM2.5, NOx, CO, SO2, VOC, and GHG emissions. Any revisions to the GCOP plan requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	17.11	Diesel	No controls.	Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Tunnel Furnace Emergency Generator (EP 08-06)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Caster B Emergency Generator (EP 08-07)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	04/19/2021 ACT	Air Separation Unit Emergency Generator (EP 08-08)	17.11	Diesel		Nitrogen Oxides (NOx)	P	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			prepare a good combustion and operations practices (GCOP) plan that defines, measures, and verifies the use of operational and design practices determined as BACT for minimizing emissions. Any revisions to the GCOP plan requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s

LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	05/23/2014 ACT	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	17.11			Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	27.37	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	1.37	TPY	ANNUAL MAXIMUM	BACT is determined to be compliance with the limitations imposed by 40 CFR 60 Subpart IIII and its associated monitoring, recordkeeping, and reporting requirements; and operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage. Limit NOx + NMHC to 6.4 g/kW-hr.
LA-0292	HOLBROOK COMPRESSOR STATION	CAMERON INTERSTATE PIPELINE LLC	LA	01/22/2016 ACT	Emergency Generators No. 1 & No. 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	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	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.71	TPY	ANNUAL MAXIMUM	Emergency generators are also subject to a BACT limit of 1.51 lb NOx/MM Btu.

LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	LA	05/23/2014 ACT	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	17.11	Diesel	Non-emergency use is limited to 100 hours per year.	Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	27.37	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT, NSPS	U	0	U	1.37	TPY	ANNUAL MAXIMUM	NOx + NMHC limit is 6.40 g/kW-hr. BACT is determined to be compliance with the limitations imposed by 40 CFR 60 Subpart IIII and its associated monitoring, recordkeeping, and reporting requirements; and operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	06/30/2016 ACT	Diesel Engines (Emergency)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0307	MAGNOLIA LNG FACILITY	MAGNOLIA LNG, LLC	LA	03/21/2016 ACT	Diesel Engines	17.11	Diesel	Water Pumps (2 units) = 355 hp Tank Deluge Pumps (2 units) = 800 hp Generator = 1340 hp	Nitrogen Oxides (NOx)	P	good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			

LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	09/26/2013 ACT	2000 KW Diesel Fired Emergency Generator Engine	17.11	Diesel		Nitrogen Oxides (NOx)	P	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	33.07	LB/H	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	U	0	U	1.38	T/YR	ANNUAL MAXIMUM	
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	06/04/2015 ACT	Emergency Generator Engines	17.11	Diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	6.4	G/KW-HR		BACT-PSD		U	0	U	0			
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	06/30/2017 ACT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	17.11	Diesel	Operating hour limit: 100 hr/yr	Nitrogen Oxides (NOx)	P	Compliance with NSPS Subpart IIII	6.6	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Limit: 3.84 g/hp-hr
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	06/30/2017 ACT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	17.11	Diesel	Operating hours limit: 100 hr/yr.	Nitrogen Oxides (NOx)	P	Compliance with NSPS Subpart IIII	19.23	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Limit: 4.93 g/hp-hr
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA , LLC	LA	08/31/2016 ACT	SCPS Emergency Diesel Generator 1	17.11	Diesel		Nitrogen Oxides (NOx)	B	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	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	6.84	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.8 G/BHP-HR (NMHC + NOx)

*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Emergency Diesel Generator 1	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	2.63	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.4 G/KW-H) (12-Month Rolling Average)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Emergency Diesel Generator 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	2.63	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.4 G/KW-H) (12-Month Rolling Average)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Fire Pump Diesel Engine 1	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.23	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.80 G/BHP-H (6.40 G/KW-H) (12-Month Rolling Average)
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	05/23/2014 ACT	Fire Pump Diesel Engine 2	17.11	Diesel		Nitrogen Oxides (NOx)	P	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0.23	T/YR	ANNUAL MAXIMUM	BACT Limit = 4.8 G/BHP-H (6.40 G/KW-H) (12-Month Rolling Average)
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	02/17/2017 ACT	emergency generator engines (6 units)	17.11	diesel		Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	12/22/2016 ACT	Emergency Generator Engines (4 units)	17.11	Diesel	I-GDE-1201, II-GDE-1201 = 2346 hp I-GDE-1202 = 755 hp I-GDE-1203 = 1193 hp	Nitrogen Oxides (NOx)	P	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			BACT = LAER (Permit 0180-00210-V4, dated 12/22/2016)
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	12/22/2016 ACT	Firewater pump Engines (4 units)	17.11	diesel		Nitrogen Oxides (NOx)	P	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	U	0	U	0			BACT = LAER (Permit 0180-00210-V4, dated 12/22/2016)
LA-0318	FLOPAM FACILITY	FLOPAM, INC.	LA	01/07/2016 ACT	Diesel Engines	17.11			Nitrogen Oxides (NOx)	P	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			

LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	01/09/2017 ACT	Fire Water Diesel Pump No. 3 Engine	17.11	Diesel Fuel	Emergency engine with a limit of 100 hours/yr on operating hours for ready testing.	Nitrogen Oxides (NOx)	P	Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	01/09/2017 ACT	Fire Water Diesel Pump No. 4 Engine	17.11	Diesel Fuel	Emergency Engine limited to 100 hours/yr for ready tests	Nitrogen Oxides (NOx)	P	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	09/21/2018 ACT	Firewater Pumps	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	Good Combustion and Operating Practices.	3.1	G/HP-H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Comply with 40 CFR 60 Subpart IIII and limiting normal operations to 50 h/yr.
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	09/21/2018 ACT	Large Emergency Engines (>50kW)	17.11	Diesel Fuel	Three emergency black-start engines and two emergency generators	Nitrogen Oxides (NOx)	P	Good Combustion and Operating Practices	5.6	G/KW-H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	0			Comply with 40 CFR 60 Subpart IIII and limiting normal operations to 100 hr/yr.
LA-0346	GULF COAST METHANOL COMPLEX	IGP METHANOL LLC	LA	01/04/2018 ACT	emergency generators (4 units)	17.11	natural gas		Nitrogen Oxides (NOx)	P	Comply with standards of 40 CFR 60 Subpart JJJJ	2	G/BHP-HR		BACT-PSD	NSPS	U	0	U	0			

LA-0350	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	03/28/2018 ACT	emergency generators (3 units) EQT0039, EQT0040, EQT0041	17.11			Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			
LA-0364	FG LA COMPLEX	FG LA LLC	LA	01/06/2020 ACT	Emergency Generator Diesel Engines	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	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	NSPS , NESHAP	U	0	U	0			Engines are limited to 100 hours of non-emergency use.

LA-0364	FG LA COMPLEX	FG LA LLC	LA	01/06/2020 ACT	Emergency Fire Water Pumps	17.11	Diesel Fuel		Nitrogen Oxides (NOx)	P	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	NSPS , NESHAP	U	0	U	0			Engines are limited to 100 hours of non-emergency use.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	VCM Unit Emergency Generator A	17.11	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			
LA-0379	SHINTECH PLAQUEMINES PLANT 1	SHINTECH LOUISIANA, LLC	LA	05/04/2021 ACT	C/A Emergency Generator B	17.11	Gaseous fuel	Maximum horsepower rating.	Nitrogen Oxides (NOx)	P	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR		BACT-PSD		U	0	U	0			
LA-0382	BIG LAKE FUELS METHANOL PLANT	BIG LAKE FUELS LLC	LA	04/25/2019 ACT	Emergency Engines (EQT0014 - EQT0017)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Comply with standards of 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	U	0	U	0			
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	LA	09/03/2020 ACT	Emergency Engines (EQT0011 - EQT0016)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		U	0	U	0			

MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	MA	01/30/2014 ACT	Emergency Engine/Generator	17.11	ULSD	â‰¤ 300 hours of operation per 12-month rolling period S in ULSD: â‰¤0.0015% by weight	Nitrogen Oxides (NOx)	N		4.8	GM/BHP-H	1 HR BLOCK AVG	LAER	NSPS , NESHAP , SIP , OPERATING PERMIT	U	0	U	11.6	LB/H	1 HR BLOCK AVG	emission limits are for NOx and VOC combined total. the project is subject LAER for NOx as ozone precursor, and BACT-PSD for NOx as NO2 precursor.
MA-0043	MIT CENTRAL UTILITY PLANT	MASSACHUSETTS INSTITUTE OF TECHNOLOGY	MA	06/21/2017 ACT	Cold Start Engine	17.11	ULSD	CAT DM8263 or equivalent. â‰¤ 8 hours of operation per day, â‰¤ 300 hours of operation per consecutive 12-month period, S in ULSD: â‰¤0.0015% by weight.	Nitrogen Oxides (NOx)	N		35.09	LB/HR	1 HR BLOCK AVG	OTHER CASE-BY-CASE	NESHAP , SIP , OPERATING PERMIT , NSPS	U	0	U	5.3	TONS/ C12MP	CONSECUTIVE TWELVE MONTH PERIOD	
MD-0042	WILDCAT POINT GENERATION FACILITY	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	04/08/2014 ACT	EMERGENCY GENERATOR 1	17.11	ULTRA LOW SULFU DIESEL	40 CFR 60 SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	LIMITED OPERATING HOURS, USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.8	G/HP-H		LAER	NSPS		0		6.4	G/KW-H		COMBINED NOX AND NMHC
MD-0043	PERRYMAN GENERATING STATION	CONSTELLATION POWER SOURCE GENERATION, INC.	MD	07/01/2014 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	40 CFR 60 SUBPART IIII, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	4.8	G/HP-H		LAER	NSPS		0		6.4	G/KW-H		NSPS 40 CFR 60 SUBPART IIII

MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	06/09/2014 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	40 CFR 60, SUBPART IIII, ULTRA LOW-SULFUR DIESEL FUEL, GOOD COMBUSTION PRACTICES	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.8	G/HP-H	COMBINED NOX + NMHC	LAER	NSPS		0		6.4	G/KW-H	COMBINED NOX + NMHC	NSPS 40 CFR 60 SUBPART IIII
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MI	11/01/2013 ACT	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	17.11	Diesel	1,000 kW (1,502 hp) each; hours restriction = 500 hours each per year.	Nitrogen Oxides (NOx)	P	Good combustion practices	4.8	G/B-HP-H	TEST PROTOCOL; EACH UNIT	BACT-PSD	SIP	N	0	N	0			The NOx limit of 4.8 g/bhp-hr applies to each unit.

MI-0418	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER - WARREN	MI	01/14/2015 ACT	FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines)	17.11	Diesel	DRUPS emergency engines identified as the following: EUDRUPS1, EUDRUPS2, EUDRUPS3, EUDRUPS4, EUDRUPS5, EUDRUPS6, EUDRUPS7, EUDRUPS8, EUDRUPS9 permitted within the flexible group that is identified as FG-BACKUPGENS. Each engine is 3490KW each. DRUPS stands for Diesel Rotary Uninterruptable Power supply system. The system provides for zero down-time in electrical energy supply at the onset of a power outage. The system stores energy in a fly-wheel that powers the generator until the diesel engine starts up. Two DRUP engines connect to one	Nitrogen Oxides (NOx)	P	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)	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	N	0	U	0			The emission limit is for each DRUP engine. No add-on controls were technically feasible for these emergency engines, so a cost analysis was not necessary.
MI-0418	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER - WARREN	MI	01/14/2015 ACT	Four (4) emergency engines in FG-BACKUPGENS	17.11	Diesel	There are four (4) emergency engines identified as EUGENERATOR1, EUGENERATOR2, EUGENERATOR3, and EUGENERATOR4 in the flexible group identified in the permit as FG-BACKUPGENS. Each engine is 2710 KW. Two engines connect to one standard generator set.	Nitrogen Oxides (NOx)	P	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)	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	N	0	U	0			The emission limit is per engine. No add-on controls were technically feasible for these emergency engines so a cost analysis was not necessary.

MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	08/26/2016 ACT	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 1600 kW (EUEMRGRICE in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	22.6	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	08/26/2016 ACT	Dieself fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (identified as EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	3.53	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add on control would not be cost effective.
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	01/04/2017 ACT	EUEMENGINE (Diesel fuel emergency engine)	17.11	Diesel Fuel	a 2,922 horsepower (HP) (2,179 kilowatts (kW)) diesel fueled emergency engine manufactured in 2011 or later and a displacement of <10 liters/cylinder. Restricted to 4 hours/day, except during emergency conditions and stack testing, and 500 hours/year on a 12-month rolling time period basis.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC + NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE1 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours.	21.2	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE2 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours	4.4	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.

MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	05/09/2017 ACT	EUFIREPUMP in FGRICE (Diesel fire pump engine)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines. Limited operating hours.	3.53	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	N	0	N	0			Based on the limited hours of operation, the company concluded that add-on control would not be cost effective.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUEMENGINE (North Plant): Emergency Engine	17.11	Diesel	A 1,341 HP (1,000 kilowatts (KW)) diesel-fired emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is designed to be compliant with Tier IV emission standards. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS Subpart IIII requirements.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	06/29/2018 ACT	EUEMENGINE (South Plant): Emergency Engine	17.11	Diesel	A 1,341 HP (1,000 kilowatts (kW)) diesel-fired emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is designed to be compliant with Tier IV emission standards. Equipped with a diesel particulate filter.	Nitrogen Oxides (NOx)	P	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.

MI-0434	FLAT ROCK ASSEMBLY PLANT	FORD MOTOR COMPANY	MI	03/22/2018 ACT	EUENGINE 01 through EUENGINE 08	17.11	Diesel	Eight (8) diesel-fueled emergency engine/generators rated at 2,500 kilowatt (kW) / 3,633 brake horsepower (BHP), two (2) emergency fire pump engines rated at 250 BHP and an emergency engine rated at 500 kW. No add-on control.	Nitrogen Oxides (NOx)	P	Good combustion practices.	6.4	G/KW-H	HOURLY; EACH ENGINE; NMHC +NOX	BACT-PSD	NSPS , SIP	N	0	N	42.6	LB/H	HOURLY; EACH ENGINE ; NOX	The first emission limit above is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx) and is 6.4 G/KW-H for each engine. The limit is based on NSPS IIII. The second emission limit above is actually in NOx and is 42.6 LB/H for each engine.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	MI	07/16/2018 ACT	EUEMENGINE: Emergency engine	17.11	Diesel	A nominal 2 MW diesel-fueled emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engine is an EPA Tier 2 certified engine subject to NSPS IIII.	Nitrogen Oxides (NOx)	P	State of the art combustion design.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in ‘‘NMHC+NOx‘‘ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	12/21/2018 ACT	EUEMGD1-- A 1500 HP diesel fueled emergency engine	17.11	Diesel	A 1500 HP diesel-fueled emergency engine manufactured after 2006 serving a 1,000 kW engine generator with associated fuel oil tank. The engine generator is used to charge the batteries in the uninterruptible power supply battery system.	Nitrogen Oxides (NOx)	P	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	U	0			Emission limit is for NMHC+NOx. Did not consider the additional control to be technically feasible since many controls don't function properly for small emitters and intermittent sources.

MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	12/21/2018 ACT	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	17.11	Diesel	A 6000 HP diesel-fueled emergency engine manufactured after 2006 serving a 4000 kW generator with associated fuel oil tank. The engine generator is used to facilitate operations during idling of the plan for routine maintenance checks and readiness testing.	Nitrogen Oxides (NOx)	P	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	U	0			Emission limit is for NMHC+NOx. Did not consider the additional control to be technically feasible since many controls don't function properly for small emitters and intermittent sources.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	MI	08/21/2019 ACT	FGEMENGINE	17.11	Diesel	Two (2) diesel-fired emergency engines, each 1,474 HP (1,100 kW) with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The engines are designed to be compliant with Tier 2 emission standards.	Nitrogen Oxides (NOx)	N		5.3	G/HP-H	HOURLY; EACH ENGINE	BACT-PSD	NSPS	N	0	U	0			permit also with a limit of 6.4 G/KW-H, is hourly and applies to each engine. This emission limit is for certified engines; if testing becomes required to demonstrate compliance, then the tested values must be compared to the Not to Exceed (NTE) requirements determined through 40 CFR 60.4212(c). SCR is not technically feasible for emergency engines, which will be small, intermittent sources, only operated for maintenance and testing and in case of a true emergency. Other add-on controls are not considered technically or

*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	MI	11/26/2019 ACT	EUEMENGINE (diesel fuel emergency engine)	17.11	diesel fuel	A 2,922 horsepower (HP) (2,179 kilowatts (kW)) natural gas-fueled emergency engine (EUEMENGINE) manufactured in 2011 or later and a displacement of <10 Liters/cylinder. Restricted to 4 hours/day, except during emergency conditions and stack testing, and 500 hours/year on a 12-month rolling time period basis	Nitrogen Oxides (NOx)	P	Good Combustion Practices and meeting NSPS Subpart IIII requirements	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	N	0	N	0			The limit is actually in â€œNMHC+NOxâ€ (nonmethane hydrocarbon plus NOx), which is what is required in the NSPS.
MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 1500 KW (EUEMRGRICE1 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified engines, limited operating hours	21.2	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.
MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	17.11	Diesel	One emergency diesel generator engine rated at 500 KW (EUEMRGRICE2 in FGRICE).	Nitrogen Oxides (NOx)	P	Certified Engines, Limited Operating Hours	4.4	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.
MI-0448	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	12/18/2020 ACT	Diesel fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	One diesel fire pump engine rated at 400 KW (EUFIREPUMP in FGRICE).	Nitrogen Oxides (NOx)	P	Certified Engines, Limited Operating Hours	3.53	LB/H	HOURLY	BACT-PSD		N	0	N	0			Based on the limited hours of operation, Arauco concluded that add-on control would not be cost effective.
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	NJ	11/01/2012 ACT	Emergency Generator	17.11	ULSD		Nitrogen Oxides (NOx)	P	use of ultra low sulfur diesel (ULSD) a clean fuel	18.53	LB/H		LAER	NSPS , OPERATING PERMIT	U	0	U	0			

NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	NJ	03/10/2016 ACT	Diesel Fired Emergency Generator	17.11	ULSD		Nitrogen Oxides (NOx)	P	use of ultra low sulfur diesel a clean burning fuel.	42.3	LB/H		LAER	NSPS , OPERATING PERMIT	N	0	N	0			
NY-0103	CRICKET VALLEY ENERGY CENTER	CRICKET VALLEY ENERGY CENTER LLC	NY	02/03/2016 ACT	Black start generator	17.11	ultra low sulfur diesel		Nitrogen Oxides (NOx)	B	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	LAER		U	0	U	0			
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	06/18/2013 ACT	Emergency generator	17.11	diesel	Emergency diesel fired generator restricted to 500 hours of operation per rolling 12-months.	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	27.8	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	U	0	U	6.95	T/YR	PER ROLLING 12-MONTHS	Additional limits: 5.61 g NOx/kW-H; and 6.4 g NMHC + NOx/kW-hr, the standard from Subpart IIII. Method 7E if required.
OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	GENERAL ELECTRIC	OH	05/07/2013 ACT	Test Cell 1 for Aircraft Engines and Turbines	17.11	JET FUEL	Fuels tested include jet fuel, diesel fuel, biofuels and gaseous fuels. Size of engine turbine varies, none specified. Installed with a continuous fuel flow monitor.	Nitrogen Oxides (NOx)	N		1.7	LB/MMBTU	LAER AND PSD LIMIN	LAER	SIP	U	0	U	92	T/YR	PER ROLLING 12 MONTHS	The emission limit of 1.70 LB NOX/MMBtu is considered LAER, based on design emission levels. Must develop an Emissions Protocol Document on the potential to emit.

OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	GENERAL ELECTRIC	OH	05/07/2013 ACT	Test Cell 2 for Aircraft Engines and Turbines	17.11	JET FUEL	Fuels tested include jet fuel, diesel fuel, biofuels and gaseous fuels. Size of engine turbine varies, none specified. Installed with a continuous fuel flow monitor.	Nitrogen Oxides (NOx)	N		4.4	LB/MMBTU		LAER	SIP	U	0	U	80	T/YR	PER ROLLING 12 MONTHS	The emission limit of 4.4 LB NOX/MMBtu is considered LAER, based on design emission levels. Must develop an Emissions Protocol Document on the potential to emit.
OH-0360	CARROLL COUNTY ENERGY	CARROLL COUNTY ENERGY	OH	11/05/2013 ACT	Emergency generator (P003)	17.11	diesel	1,112 kW emergency diesel fired generator.	Nitrogen Oxides (NOx)	P	Purchased certified to the standards in NSPS Subpart IIII	13.74	LB/H		BACT-PSD	NSPS	U	0	U	3.44	T/YR	PER ROLLING 12 MONTH PERIOD	Additional limits: 5.61 g NOx/kW-H; and 6.4 g NMHC + NOx/kW-hr, the standard from Subpart IIII.
OH-0363	NTE OHIO, LLC		OH	11/05/2014 ACT	Emergency generator (P002)	17.11	Diesel fuel	Emergency diesel engine powered standby generator, rated at 1,100 kilowatts.	Nitrogen Oxides (NOx)	P	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	29.01	LB/H		BACT-PSD	NSPS	U	0	U	7.25	T/YR	PER ROLLING 12 MONTH PERIOD	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	08/25/2015 ACT	Emergency generator (P003)	17.11	Diesel fuel	1,750 kW (2,346 hp) emergency generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	21.6	LB/H		BACT-PSD	NSPS	U	0	U	5.41	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 5.61 g/kW-hr and Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	OH	09/23/2016 ACT	Emergency generator (P003)	17.11	Diesel fuel	2,000 kW electric, 2,198 kW mechanical (2,947 hp) emergency diesel generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	27.18	LB/H		BACT-PSD	NSPS	U	0	U	6.8	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 5.61 g/kW-hr. NSPS: Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.

OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	04/19/2017 ACT	Emergency Generator (P009)	17.11	Diesel fuel	5,000 HP â€“ 3,729 kW Emergency Generator Diesel Engine	Nitrogen Oxides (NOx)	P	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	NSPS	U	0	U	0.3	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 0.67 g/kW-hr. NSPS limit is NMHC + NOx emissions shall not exceed 6.4 g/kW-hr (3.0 g/hp-hr).
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	OH	09/07/2017 ACT	Emergency generator (P003)	17.11	Diesel fuel	Emergency Generator 1000 kW (electrical), 1,140 kW (mechanical), 1,529 hp	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	16.07	LB/H		BACT-PSD	NSPS	U	0	U	4.02	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 6.4 g/kW-hr. NSPS limit is Non-methane hydrocarbon (NMHC) + NOx emissions shall not exceed 6.4 g/kW-hr.
OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	OH	09/27/2017 ACT	Emergency generator (P003)	17.11	Diesel fuel	1,000 kWe (1,140 kW mechanical) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	State-of-the-art combustion design	16.1	LB/H		BACT-PSD	NSPS	U	0	U	4.02	T/YR	PER ROLLING 12 MONTH PERIOD	Standard limit (metric) is 6.4 g/kW-hr (4.8 g/hp-hr). NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr.

OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	10/23/2017 ACT	Emergency Generators (2 identical, P004 and P005)	17.11	Diesel fuel	Two identical Emergency Generators; 1,645 kW (2,206 HP) emergency diesel-fired generator to provide on-site emergency power capabilities independent of the utility grid. Throughputs and limits are for a single generator except as noted.	Nitrogen Oxides (NOx)	P	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 â€™s operating manual.	23.21	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.16	T/YR	NMHC+ NOX. SEE NOTES.	Non-methane hydrocarbon plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 6.40 g/kW-hour (4.77 G/BHP-H), 23.21 pounds per hour and 1.16 tons per rolling, 12-month period.
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/07/2017 ACT	Emergency Diesel Generator Engine (P001)	17.11	Diesel fuel	1,645 kW (2,206 HP) emergency diesel-fired generator to provide on-site emergency power capabilities independent of the utility grid.	Nitrogen Oxides (NOx)	P	Good combustion design	24.71	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.24	T/YR	NMHC+ NOX. SEE NOTES.	Non-methane hydrocarbon plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 6.40 g/kW-h (4.8 g/hp-h), 24.71 lb/h and 1.24 t/yr per rolling, 12-month period.

OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/07/2017 ACT	Emergency Diesel Fire Pump Engine (P002)	17.11	Diesel fuel	700 hp emergency diesel-fired fire pump to provide on-site firefighting capabilities independent of the utility grid	Nitrogen Oxides (NOx)	P	Good combustion design	4.97	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.25	T/YR	NMHC+ NOX. SEE NOTES.	Nonmethane hydrocarbons plus nitrogen oxides (NMHC+NOx) emissions shall not exceed 4.0 g/kW-hour, 4.97 pounds per hour and 0.25 ton per rolling, 12-month period. NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	OH	02/09/2018 ACT	Emergency diesel-fired generator (P007)	17.11	Diesel fuel	2,000 kW (2,682 hp) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	Comply with NSPS 40 CFR 60 Subpart IIII	28.2	LB/H		BACT-PSD	NSPS	U	0	U	7.05	T/YR	PER ROLLING 12 MONTH PERIOD	NOx Standard limit is 6.4 g/kW-hr (4.8 g/hp-hr). NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr (4.8 g/hp-hr).
OH-0377	HARRISON POWER	HARRISON POWER	OH	04/19/2018 ACT	Emergency Diesel Generator (P003)	17.11	Diesel fuel	1,387 KW (1,860 HP) emergency diesel-fired generator	Nitrogen Oxides (NOx)	P	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	19.68	LB/H	NMHC +NOX. SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.98	T/YR	NMHC+ NOX. SEE NOTES.	All emissions limits are for Non-methane hydrocarbon (NMHC) + NOX emissions. 0.98 t/yr per rolling, 12-month period. NSPS: Non-methane hydrocarbon (NMHC) + NOX emissions shall not exceed 6.4 g/kW-hr (4.8 g/hp-hr).

OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018 ACT	Emergency Diesel-fired Generator Engine (P007)	17.11	Diesel fuel	2,500 kW (3,353 HP) emergency diesel-fired generator engine	Nitrogen Oxides (NOx)	P	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 â€™s operating manual	37.41	LB/H	SEE NOTES.	BACT-PSD	NSPS	U	0	U	1.87	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	Emission limits are for non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx). Non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx) emissions shall not exceed 6.4 g/kW-hour (4.8 g/HP-hour), 37.41 pounds per hour and 1.87 tons per rolling, 12-month period.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018 ACT	1,000 kW Emergency Generators (P008 - P010)	17.11	Diesel fuel	Three identical ECU Generators 1 to 3; 1,000 kW (1,341 HP) emergency diesel-fired generator engine. Limits are for single generator except as noted.	Nitrogen Oxides (NOx)	P	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 â€™s operating manual	14.96	LB/H	SEE NOTES.	BACT-PSD	NSPS	U	0	U	0.75	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	Emission limits are for non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx). Non-methane hydrocarbon plus nitrogen oxides (NMHC + NOx) emissions shall not exceed 6.4 g/kW-hour (4.8 g/HP-hour), 14.96 pounds per hour and 0.75 ton per rolling, 12-month period.
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	02/06/2019 ACT	Emergency Generators (P005 and P006)	17.11	Diesel fuel	Two identical Emergency generators, 3131 HP diesel engines. Throughputs and limits are for one generator, except as noted.	Nitrogen Oxides (NOx)	P	Tier IV engine Tier IV NSPS standards certified by engine manufacturer.	3.45	LB/H		BACT-PSD	NSPS	U	0	U	0.17	T/YR		NSPS: 4.8 grams NOx + NMHC/bhp-hr

OH-0383	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	07/17/2020 ACT	Diesel-fired emergency fire pumps (2) (P009 and P010)	17.11	Diesel fuel	Two identical fire pump 3131 HP diesel engines. Throughputs and limits are for one engine, except as noted.	Nitrogen Oxides (NOx)	P	Tier IV NSPS standards certified by engine manufacturer.	0			BACT-PSD	NSPS	U	0	U	0			
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	07/02/2013 ACT	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	17.11	DIESEL	<100 HR/YR OPERATION.	Nitrogen Oxides (NOx)	P	COMBUSTION CONTROL	0.011	LB/HP-HR		BACT-PSD	NSPS	U	0	U	0			
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	10/10/2012 ACT	Emergency Generator	17.11	Diesel	The emergency generator will be restricted to operate not more than 100 hr/yr.	Nitrogen Oxides (NOx)	N		4.93	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	U	0	U	0			
PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	PA	04/23/2013 ACT	EMERGENCY GENERATOR	17.11	Ultra Low sulfur Distillate	EMERGENCY GENERATOR (1,135 BHP - 750 KW)	Nitrogen Oxides (NOx)	N		9.89	LB/H		OTHER CASE-BY-CASE	OTHER	U	0	U	0.49	T/YR	12-MONTH ROLLING TOTAL	
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	12/23/2015 ACT	2000 kW Emergency Generator	17.11	Ultra-low sulfur Diesel	To allow maintenance of vital plant loads during power outages or maintenance of the switchyard.	Nitrogen Oxides (NOx)	N		5.45	GM/HP-HR		LAER		U	0	U	0.81	TONS	12-MONTH ROLLING BASIS	
PA-0310	CPV FAIRVIEW ENERGY CENTER	CPV FAIRVIEW, LLC	PA	09/02/2016 ACT	Emergency Generator Engines	17.11	ULSD	(2) 1500 kW emergency diesel genset. Emission limitations are for each genset and fuel is restricted to ULSD (15 ppm) and each is restricted to 100 hrs on a 12-month rolling basis.	Nitrogen Oxides (NOx)	N		4.8	G/BHP-HR		LAER	NSPS	U	0	U	0			

PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	09/01/2015 ACT	Emergency Generator	17.11		Sulfur content of the diesel fuel combusted by the emergency diesel generator shall not exceed 15 ppm. Shall maintain and operate the source in accordance with good engineering practice.	Nitrogen Oxides (NOx)	N		4.93	G/HP-HR		LAER	NSPS	U	0	U	0.4	TPY	12-MONTH ROLLING BASIS	
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	09/01/2015 ACT	Fire Pump Engine	17.11	diesel	Sulfur content of the diesel fuel combusted by the fire engine pump shall not exceed 15 ppm. Shall maintain and operate the source in accordance with good engineering practice.	Nitrogen Oxides (NOx)	N		3	G/HP-HR		LAER	NSPS	U	0	U	0.08	TPY	12-MONTH ROLLING BASIS	
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	ENERGY ANSWERS ARECIBO, LLC	PR	04/10/2014 ACT	Emergency Diesel Generator	17.11	ULSD Fuel oil # 2	Emergency Generator is rated at 670 BHP and is limited to 500 hr per year (emergency and testing and maintenance, combined)	Nitrogen Oxides (NOx)	N		2.85	G/B-HP-H		BACT-PSD		U	0	U	4.2	LB/H		
TX-0671	PROJECT JUMBO	M&G RESINS USA, LLC	TX	12/01/2014 ACT	Engines	17.11	ultra low sulfur diesel fuel	Two mergency diesel fired generators proposed. Each engine will be 4000 kW. Ultra low sulfur fuel is burned in the engines to meet the sulfur requirement of 15 ppm in 40CFR80.510(b). Each emergency engine is being permitted for maintenance and testing for maximum 100 hrs/yr. They are not being permitted for the actual emergency emissions	Nitrogen Oxides (NOx)	P	Each emergency generator's emission factor is based on EPA's Tier 2 standards at 40CFR89.112 for NOx	5.43	G/KW-H		BACT-PSD	NSPS	U	0	U	2.39	T/YR		

TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	TX	04/01/2015 ACT	Emergency Diesel Generator	17.11	Diesel	generator (EPN 17-1-4) at the site is diesel fired and rated at 1500 horsepower (hp). Lowest Achievable Emission Rates (LAER) for nitrogen oxides (NOx) is the use of a 40 Code Federal Rules (CFR) Part 89 Tier 2 engine and limited hours of operation. Emissions from the engine shall not exceed 0.0218 grams per horsepower-hour (g/hp-hr) of nitrogen oxides (NOx). The engine is limited to 52 hours per year of non-emergency operation. Emissions from the engine shall not exceed 0.01256 g/hp hr of carbon monoxide (CO). The fuel for the engine is limited to 15 parts per million sulfur by weight (ultra-low sulfur diesel).	Nitrogen Oxides (NOx)	P	Minimized hours of operations Tier II engine	0.0218	G/HP HR		LAER	NSPS , MACT	N	0	U	0.35	TPY		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	02/06/2020 ACT	Emergency generator	17.11	DIESEL	Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	N	0	U	0			NSPS IIII, MACT ZZZZ

TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	02/06/2020 ACT	Emergency firewater pumps	17.11		Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	N	0	U	0			
TX-0879	MOTIVA PORT ARTHUR TERMINAL	MOTIVA ENTERPRISES LLC	TX	02/19/2020 ACT	Emergency Firewater Engine	17.11	Ultra-low sulfur diesel	Ultra-low sulfur diesel containing no more than 15 ppmw total sulfur	Nitrogen Oxides (NOx)	P	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	NSPS , MACT	N	0	U	0			NSPS IIII MACT ZZZZ
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	04/23/2020 ACT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	17.11	Ultra-low Sulfur Diesel		Nitrogen Oxides (NOx)	P	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0			BACT-PSD	NSPS , MACT	N	0	U	0			

TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		TX	09/09/2020 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL		Nitrogen Oxides (NOx)	P	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0			BACT-PSD		N	0	U	0			
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	TX	09/16/2020 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL		Nitrogen Oxides (NOx)	P	limited to 100 hours per year of non-emergency operation	0			BACT-PSD		N	0	U	0			
TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	11/17/2021 ACT	Emergency Generators	17.11	Ultra-low sulfur diesel (no more than 15		Nitrogen Oxides (NOx)	P	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0			BACT-PSD		N	0	U	0			
VA-0325	GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	06/17/2016 ACT	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	17.11	DIESEL FUEL		Nitrogen Oxides (NOx)	P	Good Combustion Practices/Maintenance	6.4	G/KW	PER HR	N/A		U	0	U	10.6	T/YR	12 MO ROLLING TOTAL	

VA-0328	C4GT, LLC	NOVI ENERGY	VA	04/26/2018 ACT	Emergency Diesel GEN	17.11	Ultra Low Sulfur Diesel		Nitrogen Oxides (NOx)	P	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	NSPS , SIP	N	0	N	9.6	T/YR	12 MO ROLLING AV	NOX + NMHC
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	06/24/2019 ACT	Emergency Diesel Generator - 300 kW	17.11	Ultra Low Sulfur Diesel		Nitrogen Oxides (NOx)	P	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	NSPS , SIP	N	0	N	11.7	T/YR	12 MO ROLLING AVG	Emission Limit 3: 4.8 G/HP - HR

WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT		WI	04/24/2018 ACT	Diesel-Fired Emergency Generators	17.11	Diesel Fuel	Ten, 2,180kW Diesel-Fired Emergency Generators.	Nitrogen Oxides (NOx)	P	The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices	5.36	G/KWH		BACT-PSD	NSPS , NESHAP	N	0	U	0			BACT is Total hours of operation for each generator is 200 hours over a 12 month period. Ultra-low sulfur fuel contains less than 15 ppm sulfur. Good combustion practices are defined as maintaining the stationary compression ignition internal combustion engine according to each manufacturerâ€™s emission-related instructions.
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	SIO INTERNATIONAL	WI	04/24/2018 ACT	P42 -Diesel Fired Emergency Generator	17.11	Diesel Fuel	Maximum Continuous Rating: 1,750 kW or 2,346 bhp	Nitrogen Oxides (NOx)	P	Good Combustion Practices, The Use of an Engine Turbocharger and Aftercooler.	5.36	G/KWH		BACT-PSD	NSPS , NESHAP	N	0	U	0			BACT is Good combustion practices are defined as maintaining the stationary compression ignition internal combustion engine according to the manufacturerâ€™s emission-related written instructions. The total hours of operation of the emergency generator may not exceed 200 hours during each consecutive 12-month period.

*WI-0300	NEMADJI TRAIL ENERGY CENTER	NEMADJI TRAIL ENERGY CENTER	WI	09/01/2020 ACT	Emergency Diesel Generator (P07)	17.11	Diesel		Nitrogen Oxides (NOx)	P	Operation limited to 500 hours/year and operate and maintain according to the manufacturerâ€™s recommendations.	4.8	G/HP-H		BACT-PSD		U	0	U	0			
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	11/21/2014 ACT	Emergency Generator	17.11	Diesel	Nominal 1,500 kW. Limited to 100 hours/year.	Nitrogen Oxides (NOx)	N		0			BACT-PSD	NSPS	U	0	U	0			
WV-0027	INWOOD	KNAUF INSULATION INC.	WV	09/15/2017 ACT	Emergency Generator - ESDG14	17.11	ULSD	Used to supply power to the facility in the event of power loss	Nitrogen Oxides (NOx)	P	Engine Design	4.77	G/HP-HR		BACT-PSD	NSPS , MACT	U	0	U	0			Engine is limited to 100 hours of non-emergency use per year.
*WV-0033	MAIDSVILLE	MOUNTAIN STATE CLEAN ENERGY, LLC	WV	01/05/2022 ACT	Emergency Generator	17.11	ULSD	4SLB Diesel-Fired Emergency Engine - Subpart IIII	Nitrogen Oxides (NOx)	P	Combustion Control (retarded timing and/or lean burn)	24.6	LB/HR		BACT-PSD	NSPS	N	0	U	6.4	G/BKW	NMHC+NOX	Certified Engine
*WV-0033	MAIDSVILLE	MOUNTAIN STATE CLEAN ENERGY, LLC	WV	01/05/2022 ACT	Fire Water Pump	17.11	ULSD	4SLB Diesel-Fired Emergency Engine - Subpart IIII.	Nitrogen Oxides (NOx)	P	Combustion control (retarded timing and/or lean burn)	1.59	LB/HR		BACT-PSD	NSPS	U	0	U	4	G/BKW		Certified Engine

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.

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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

Appendix C Cost Analysis

Cost Analysis for EU G041 - Replacement with 1,000kW Tier 2 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	*16.09*
Maximum Run Time (hr/yr):	*500*
Capacity (kW):	*818*
PTE (tons/yr):	*8.07*
5-Year Actual Average NOx (tons/yr):	*0.93*
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	*30*
Annual Interest Rate (%):	*0.06*
Calculated Capital Recovery Factor:	*0.0726*
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	*16.09*
Tier 2 Emission Standard (incl NMVOC) (g/kW-hr):	*6.4*
5-Year Actual Average NOx (tons/yr):	*0.93*
Control Efficiency (%):	*60%*
Annual Emissions Reduced (tpy):	*0.56*
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 2 1,000kW engines:	*$299,500*
Material:	*incl.*
Structural Support:	*unkn.*
Construction (Direct)	
Instrumentation (10% Capital):	*$29,950*
Engineering (10% Capital):	*$29,950*
Construction and Field Cost (10% Capital):	*$29,950*
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	*$29,950*
Delivery (5% Capital):	*$14,975*
Other (Direct)	
Taxes (8% Capital):	*$23,960*
TOTAL DIRECT COST:	*$458,235*
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	*unkn.*
Catalyst Replacement	
Catalyst Replacement:	*N/A*
Install/Construction (10% of Original):	*N/A*
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	*unkn.*

Administration (2% of total capital investment- EPA Cost Manual):	*$5,990*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$2,995*
Insurance (1% of total capital investment- EPA Cost Manual):	*$2,995*
TOTAL INDIRECT COST:	*$11,980*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$33,290*
TOTAL ANNUALIZED INDIRECT COST:	*$870*
TOTAL ANNUALIZED COST:	*$34,161*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$60,987*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

$$\text{Capital Recovery Calculation :} \quad \frac{\text{interest rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$$

$$\text{Capital Recovery Factor, 30 yr} = \frac{0.06x(1+0.06)^{\wedge}30}{[(1+0.06)^{\wedge}30]-1}$$

$$= \frac{0.34460947}{4.743491173}$$

$$= 0.072648911$$

Cost Analysis for EU G041 - Replacement with Tier 3 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	16.09
Maximum Run Time (hr/yr):	500
Capacity (kW):	818
PTE (tons/yr):	8.07
5-Year Actual Average NOx (tons/yr):	0.93
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	30
Annual Interest Rate (%):	0.06
Calculated Capital Recovery Factor:	0.0726
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	16.09
Tier 3 Emission Standard (for lower capacity units) (g/kW-hr):	4.00
5-Year Actual Average NOx (tons/yr):	0.93
Control Efficiency (%):	75%
Annual Emissions Reduced (tpy):	0.70
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 3 engine (extrapolated cost, estimated)	$1,769,067
Material:	incl.
Structural Support:	unkn.
Construction (Direct)	
Instrumentation (10% Capital):	$176,907
Engineering (10% Capital):	$176,907
Construction and Field Cost (10% Capital):	$176,907
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	$176,907
Delivery (5% Capital):	$88,453
Other (Direct)	
Taxes (8% Capital):	$141,525
TOTAL DIRECT COST:	$2,706,673
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	unkn.
Catalyst Replacement	
Catalyst Replacement:	N/A
Install/Construction (10% of Original):	N/A
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	unkn.

Administration (2% of total capital investment- EPA Cost Manual):	*$35,381*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$17,691*
Insurance (1% of total capital investment- EPA Cost Manual):	*$17,691*
TOTAL INDIRECT COST:	*$70,763*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$196,637*
TOTAL ANNUALIZED INDIRECT COST:	*$5,141*
TOTAL ANNUALIZED COST:	*$201,778*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$288,737*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\dfrac{\text{interest rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$

Capital Recovery Factor, 30 yr = $\dfrac{0.06x(1+0.06)\hat{}30}{[(1+0.06)\hat{}30]-1}$

$= \dfrac{0.34460947}{4.743491173}$

$= 0.072648911$

Cost Analysis for EU G009 - Replacement with 1,000kW Tier 2 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	14.60
Maximum Run Time (hr/yr):	500
Capacity (kW):	1250
PTE (tons/yr):	9.81
5-Year Actual Average NOx (tons/yr):	0.321
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	30
Annual Interest Rate (%):	0.06
Calculated Capital Recovery Factor:	0.0726
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	14.60
Tier 2 Emission Standard (incl NMVOC) (g/kW-hr):	6.4
5-Year Actual Average NOx (tons/yr):	0.32
Control Efficiency (%):	56%
Annual Emissions Reduced (tpy):	0.18
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 2 1,000 kW engine:	$299,500
Material:	incl.
Structural Support:	unkn.
Construction (Direct)	
Instrumentation (10% Capital):	$29,950
Engineering (10% Capital):	$29,950
Construction and Field Cost (10% Capital):	$29,950
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip, 10%):	$29,950
Delivery (5% Capital):	$14,975
Other (Direct)	
Taxes (8% Capital):	$23,960
TOTAL DIRECT COST:	$458,235
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	unkn.
Catalyst Replacement	
Catalyst Replacement:	N/A
Install/Construction (10% of Original):	N/A
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	unkn.
Administration (2% of total capital investment-EPA Cost Manual):	$5,990

Property Taxes (1% of total capital investment- EPA Cost Manual):	*$2,995*
Insurance (1% of total capital investment- EPA Cost Manual):	*$2,995*
TOTAL INDIRECT COST:	*$11,980*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$33,290*
TOTAL ANNUALIZED INDIRECT COST:	*$870*
TOTAL ANNUALIZED COST:	*$34,161*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$189,492*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

$$\text{Capital Recovery Calculation} : \frac{\text{interest rate} \times (1+\text{interest rate})^{\text{Equipment Life}}}{[(1+\text{interest rate})^{\text{Equipment Life}}]-1}$$

$$\text{Capital Recovery Factor, 30 yr} = \frac{0.06x(1+0.06)^{30}}{[(1+0.06)^{30}]-1} = \frac{0.34460947}{4.743491173} = 0.072648911$$

Cost Analysis for EU G009 - Replacement with Tier 3 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	*14.60*
Maximum Run Time (hr/yr):	*500*
Capacity (kW):	*1250*
PTE (tons/yr):	*9.81*
5-Year Actual Average NOx (tons/yr):	*0.321*
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	*30*
Annual Interest Rate (%):	*0.06*
Calculated Capital Recovery Factor:	*0.0726*
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	*14.60*
Tier 3 Emission Standard (for lower capacity units) (g/kW-hr):	*4.00*
5-Year Actual Average NOx (tons/yr):	*0.32*
Control Efficiency (%):	*73%*
Annual Emissions Reduced (tpy):	*0.23*
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 3 engine (extrapolated cost, estimated):	*$1,769,067*
Material:	*incl.*
Structural Support:	*unkn.*
Construction (Direct)	
Instrumentation (10% Capital):	*$176,907*
Engineering (10% Capital):	*$176,907*
Construction and Field Cost (10% Capital):	*$176,907*
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	*$176,907*
Delivery (5% Capital):	*$88,453*
Other (Direct)	
Taxes (8% Capital):	*$141,525*
TOTAL DIRECT COST:	*$2,706,673*
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	*unkn.*
Catalyst Replacement	
Catalyst Replacement:	*N/A*
Install/Construction (10% of Original):	*N/A*
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	*unkn.*

Administration (2% of total capital investment- EPA Cost Manual):	*$35,381*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$17,691*
Insurance (1% of total capital investment- EPA Cost Manual):	*$17,691*
TOTAL INDIRECT COST:	*$70,763*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$162,400*
TOTAL ANNUALIZED INDIRECT COST:	*$4,246*
TOTAL ANNUALIZED COST:	*$166,646*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$715,076*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\frac{\text{interest rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$

Capital Recovery Factor, 30 yr = $\frac{0.06x(1+0.06)\text{^}30}{[(1+0.06)\text{^}30]-1}$

$= \frac{0.34460947}{4.743491173}$

$= 0.072648911$

Cost Analysis for EU G010 - Replacement with 1,000kW Tier 2 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	10.16
Maximum Run Time (hr/yr):	500
Capacity (kW):	900
PTE (tons/yr):	5.64
5-Year Actual Average NOx (tons/yr):	0.437
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	30
Annual Interest Rate (%):	0.06
Calculated Capital Recovery Factor	0.0726
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	10.16
Tier 2 Emission Standard (incl NMVOC) (g/kW-hr)	6.4
5-Year Actual Average NOx (tons/yr):	0.44
Control Efficiency (%):	37%
Annual Emissions Reduced (tpy):	0.16
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 2 1,000kW engine:	$299,500
Material:	incl.
Structural Support:	unkn.
Construction (Direct)	
Instrumentation (10% Capital):	$29,950
Engineering (10% Capital)	$29,950
Construction and Field Cost (10% Capital):	$29,950
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	$29,950
Delivery (5% Capital):	$14,975
Other (Direct)	
Taxes (8% Capital):	$23,960
TOTAL DIRECT COST:	$458,235
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	unkn.
Catalyst Replacement	
Catalyst Replacement:	N/A
Install/Construction (10% of Original):	N/A
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	unkn.
Administration (2% of total capital investment-EPA Cost Manual):	$5,990

Property Taxes (1% of total capital investment- EPA Cost Manual):	*$2,995*
Insurance (1% of total capital investment- EPA Cost Manual):	*$2,995*
TOTAL INDIRECT COST:	*$11,980*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$33,290*
TOTAL ANNUALIZED INDIRECT COST:	*$870*
TOTAL ANNUALIZED COST:	*$34,161*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$211,058*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\frac{\text{interest rate} \times (1+\text{interest rate})^{\text{Equipment Life}}}{[(1+\text{interest rate})^{\text{Equipment Life}}]-1}$

Capital Recovery Factor, 30 yr = $\frac{0.06 \times (1+0.06)^{30}}{[(1+0.06)^{30}]-1}$

$= \frac{0.34460947}{4.743491173}$

$= 0.072648911$

Cost Analysis for EU G010 - Replacement with Tier 3 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	*10.16*
Maximum Run Time (hr/yr):	*500*
Capacity (kW):	*900*
PTE (tons/yr):	*5.64*
5-Year Actual Average NOx (tons/yr):	*0.437*
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	*30*
Annual Interest Rate (%):	*0.06*
Calculated Capital Recovery Factor:	*0.0726*
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	*10.16*
Tier 3 Emission Standard (for lower capacity units) (g/kW-hr):	*4.00*
5-Year Actual Average NOx (tons/yr):	*0.44*
Control Efficiency (%):	*61%*
Annual Emissions Reduced (tpy):	*0.27*
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 3 engine (extrapolated cost, estimated):	*$1,769,067*
Material:	*incl.*
Structural Support:	*unkn.*
Construction (Direct)	
Instrumentation (10% Capital):	*$176,907*
Engineering (10% Capital):	*$176,907*
Construction and Field Cost (10% Capital):	*$176,907*
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	*$176,907*
Delivery (5% Capital):	*$88,453*
Other (Direct)	
Taxes (8% Capital):	*$141,525*
TOTAL DIRECT COST:	*$2,706,673*
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	*unkn.*
Catalyst Replacement	
Catalyst Replacement:	*N/A*
Install/Construction (10% of Original):	*N/A*
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	*unkn.*

Administration (2% of total capital investment- EPA Cost Manual):	*$35,381*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$17,691*
Insurance (1% of total capital investment- EPA Cost Manual):	*$17,691*
TOTAL INDIRECT COST:	*$70,763*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$162,400*
TOTAL ANNUALIZED INDIRECT COST:	*$4,246*
TOTAL ANNUALIZED COST:	*$166,646*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$628,773*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation :

$$\frac{\text{interest rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$$

Capital Recovery Factor, 30 yr =

$$\frac{0.06x(1+0.06)^\wedge30}{[(1+0.06)^\wedge30]-1}$$

$$= \frac{0.34460947}{4.743491173}$$

$$= 0.072648911$$

Cost Analysis for EU G032 - Replacement with 1,000kW Tier 2 Generator

Existing Source Information Per Generator	
Uncontrolled Nox Emission Factor (g/kW-hr):	*11.96*
Maximum Run Time (hr/yr):	*500*
Capacity (kW):	*1100*
PTE (tons/yr):	*7.8*
5-Year Actual Average NOx (tons/yr):	*0.528*
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	*30*
Annual Interest Rate (%):	*0.06*
Calculated Capital Recovery Factor:	*0.0726*
Emission Reduction Per Generator	
Uncontrolled Emission Factor (g/kW-hr)):	*11.96*
Tier 2 Emission Standard (incl NMVOC) (g/kW-hr):	*6.4*
5-Year Actual Average NOx (tons/yr):	*0.53*
Control Efficiency (%):	*46%*
Annual Emissions Reduced (tpy):	*0.25*
Direct Costs - Equipment, Construction Per Generator	
Capital (Direct)	
NPV, Tier 2 1,000kW engine:	*$299,500*
Material:	*incl.*
Structural Support:	*unkn.*
Construction (Direct)	
Instrumentation (10% Capital):	*$29,950*
Engineering (10% Capital):	*$29,950*
Construction and Field Cost (10% Capital):	*$29,950*
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	*$29,950*
Delivery (5% Capital):	*$14,975*
Other (Direct)	
Taxes (8% Capital):	*$23,960*
TOTAL DIRECT COST:	*$458,235*
Indirect Costs - Operating, Maintenance Per Generator	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	*unkn.*
Catalyst Replacement	
Catalyst Replacement:	*N/A*
Install/Construction (10% of Original):	*N/A*
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	*unkn.*

Administration (2% of total capital investment- EPA Cost Manual):	*$5,990*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$2,995*
Insurance (1% of total capital investment- EPA Cost Manual):	*$2,995*
TOTAL INDIRECT COST:	*$11,980*
Total Annualized Direct and Indirect Costs Per Generator	
TOTAL ANNUALIZED DIRECT COST:	*$33,290*
TOTAL ANNUALIZED INDIRECT COST:	*$870*
TOTAL ANNUALIZED COST:	*$34,161*
Cost Effectiveness Per Generator	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$139,148*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\dfrac{\text{intereste rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$

Capital Recovery Factor, 30 yr = $\dfrac{0.06x(1+0.06)^{\wedge}30}{[(1+0.06)^{\wedge}30]-1}$

$= \dfrac{0.34460947}{4.743491173}$

$= 0.072648911$

Cost Analysis for EU G032 - Replacement with Tier 3 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	11.96
Maximum Run Time (hr/yr):	500
Capacity (kW):	1100
PTE (tons/yr):	7.8
5-Year Actual Average NOx (tons/yr):	0.528
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	30
Annual Interest Rate (%):	0.06
Calculated Capital Recovery Factor:	0.0726
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	11.96
Tier 3 Emission Standard (for lower capacity units) (g/kW-hr):	4.00
5-Year Actual Average NOx (tons/yr):	0.53
Control Efficiency (%):	67%
Annual Emissions Reduced (tpy):	0.35
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 3 engine (extrapolated cost, estimated):	$1,769,067
Material:	incl.
Structural Support:	unkn.
Construction (Direct)	
Instrumentation (10% Capital):	$176,907
Engineering (10% Capital):	$176,907
Construction and Field Cost (10% Capital):	$176,907
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	$176,907
Delivery (5% Capital):	$88,453
Other (Direct)	
Taxes (8% Capital):	$141,525
TOTAL DIRECT COST:	$2,706,673
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	unkn.
Catalyst Replacement	
Catalyst Replacement:	N/A
Install/Construction (10% of Original):	N/A
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	unkn.

Administration (2% of total capital investment- EPA Cost Manual):	*$35,381*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$17,691*
Insurance (1% of total capital investment- EPA Cost Manual):	*$17,691*
TOTAL INDIRECT COST:	*$70,763*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$162,400*
TOTAL ANNUALIZED INDIRECT COST:	*$4,246*
TOTAL ANNUALIZED COST:	*$166,646*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$474,185*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\frac{\text{ntereste rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$

Capital Recovery Factor, 30 yr = $\frac{0.06x(1+0.06)^30}{[(1+0.06)^30]-1}$

$= \frac{0.34460947}{4.743491173}$

$= 0.072648911$

Cost Analysis for EU G033 - Replacement with 1,000kW Tier 2 Generator

Existing Source Information Per Generator	
Uncontrolled Nox Emission Factor (g/kW-hr):	*11.96*
Maximum Run Time (hr/yr):	*500*
Capacity (kW):	*1100*
PTE (tons/yr):	*7.8*
5-Year Actual Average NOx (tons/yr):	*0.526*
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	*30*
Annual Interest Rate (%):	*0.06*
Calculated Capital Recovery Factor:	*0.0726*
Emission Reduction Per Generator	
Uncontrolled Emission Factor (g/kW-hr)):	*11.96*
Tier 2 Emission Standard (incl NMVOC) (g/kW-hr):	*6.4*
5-Year Actual Average NOx (tons/yr):	*0.53*
Control Efficiency (%):	*46%*
Annual Emissions Reduced (tpy):	*0.24*
Direct Costs - Equipment, Construction Per Generator	
Capital (Direct)	
NPV, Tier 2 1,000kW engine:	*$299,500*
Material:	*incl.*
Structural Support:	*unkn.*
Construction (Direct)	
Instrumentation (10% Capital):	*$29,950*
Engineering (10% Capital):	*$29,950*
Construction and Field Cost (10% Capital):	*$29,950*
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	*$29,950*
Delivery (5% Capital):	*$14,975*
Other (Direct)	
Taxes (8% Capital):	*$23,960*
TOTAL DIRECT COST:	*$458,235*
Indirect Costs - Operating, Maintenance Per Generator	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	*unkn.*
Catalyst Replacement	
Catalyst Replacement:	*N/A*
Install/Construction (10% of Original):	*N/A*
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	*unkn.*

Administration (2% of total capital investment- EPA Cost Manual):	*$5,990*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$2,995*
Insurance (1% of total capital investment- EPA Cost Manual):	*$2,995*
TOTAL INDIRECT COST:	*$11,980*
Total Annualized Direct and Indirect Costs Per Generator	
TOTAL ANNUALIZED DIRECT COST:	*$33,290*
TOTAL ANNUALIZED INDIRECT COST:	*$870*
TOTAL ANNUALIZED COST:	*$34,161*
Cost Effectiveness Per Generator	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$139,677*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\frac{\text{intereste rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$

Capital Recovery Factor, 30 yr = $\frac{0.06x(1+0.06)^{\wedge}30}{[(1+0.06)^{\wedge}30]-1}$

$= \frac{0.34460947}{4.743491173}$

$= 0.072648911$

Cost Analysis for EU G033- Replacement with Tier 3 Generator

Existing Source Information	
Uncontrolled Nox Emission Factor (g/kW-hr):	11.96
Maximum Run Time (hr/yr):	500
Capacity (kW):	1100
PTE (tons/yr):	7.8
5-Year Actual Average NOx (tons/yr):	0.526
Equipment Life, Interest, Capital Recovery Factor	
Useful Life Equipment (years):	30
Annual Interest Rate (%):	0.06
Calculated Capital Recovery Factor:	0.0726
Emission Reduction	
Uncontrolled Emission Factor (g/kW-hr)):	11.96
Tier 3 Emission Standard (for lower capacity units) (g/kW-hr):	4.00
5-Year Actual Average NOx (tons/yr):	0.53
Control Efficiency (%):	67%
Annual Emissions Reduced (tpy):	0.35
Direct Costs - Equipment, Construction	
Capital (Direct)	
NPV, Tier 3 engine (extrapolated cost, estimated):	$1,769,067
Material:	incl.
Structural Support:	unkn.
Construction (Direct)	
Instrumentation (10% Capital):	$176,907
Engineering (10% Capital):	$176,907
Construction and Field Cost (10% Capital):	$176,907
Incidental & Miscellaneous (assume 10% Engr/Comm/Labor/Equip):	$176,907
Delivery (5% Capital):	$88,453
Other (Direct)	
Taxes (8% Capital):	$141,525
TOTAL DIRECT COST:	$2,706,673
Indirect Costs - Operating, Maintenance	
Maintenance & Monitoring	
Maintenance & Monitoring ($/yr):	unkn.
Catalyst Replacement	
Catalyst Replacement:	N/A
Install/Construction (10% of Original):	N/A
Other (Indirect)	
Overhead (60% of all labor plus maintenance materials-EPA Cost Manual):	unkn.

Administration (2% of total capital investment- EPA Cost Manual):	*$35,381*
Property Taxes (1% of total capital investment- EPA Cost Manual):	*$17,691*
Insurance (1% of total capital investment- EPA Cost Manual):	*$17,691*
TOTAL INDIRECT COST:	*$70,763*
Total Annualized Direct and Indirect Costs	
TOTAL ANNUALIZED DIRECT COST:	*$162,400*
TOTAL ANNUALIZED INDIRECT COST:	*$4,246*
TOTAL ANNUALIZED COST:	*$166,646*
Cost Effectiveness	
NOx control cost(Total Annualized Costs/Annual Nox Emissions Reduced):	*$475,988*

Notes:

**NPV rough estimate from Caterpillar (rough estimate only, not a quote) September 1, 2022*

**Useful life of engines assumed to be 30 years.*

** Control % estimated based on emission standards for replacement engine.*

** Items indicated as unknown were set to zero in order to be conservative.*

** Annual interest rate max set by DAQ.*

** Annualized costs estimated by multiplying line items times the calculated capital recovery factor.*

** Capital Recovery Factor calculation is illustrated below.*

Capital Recovery Calculation : $\frac{\text{ntereste rate x (1+interest rate) ^Equipment Life}}{\text{[(1+interest rate) ^ Equipment Life]-1}}$

Capital Recovery Factor, 30 yr = $\frac{0.06x(1+0.06)^30}{[(1+0.06)^30]-1}$

$= \frac{0.34460947}{4.743491173}$

$= 0.072648911$

Appendix 3

Caesars RACT Analysis

	For DAQ Use Only
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	

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:
00257	CAESARS CONSOLIDATED PROPERTIES

Certification

Name of Responsible Official:	Responsible Official's Title:	Company/Organization:
JERI RUSKOWITZ	DIRECTOR ENVIRONMENTAL COMPLIANCE	CAESARS ENTERTAINMENT, INC.

Jeri L Rusk	10/3/2022
Responsible Official's Signature	**Certification Date**

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

October 3, 2022

Prepared by:

BROADBENT
8 W. Pacific Avenue
Henderson, Nevada 89015

Project No. 13-01-207

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APPENDICES

1. Background

Clean Air Act (CAA) Section 181(a) includes a classification system for areas designated nonattainment for the ozone National Ambient Air Quality Standard (NAAQS). This classification system is based on the severity of the air quality as determined by the area's ozone design value and includes five categories: marginal, moderate, serious, severe and extreme. In 2018, the U.S. Environmental Protection Agency (EPA) designated hydrographic area (HA) 212 in Clark County, Nevada as nonattainment for the 2015 ozone NAAQS and assigned a classification of marginal to the area. The area was required to reach attainment of the 2015 ozone NAAQS by August 3, 2021. In July 2022, EPA determined that HA 212 failed to meet this deadline and, in addition, proposed to reclassify HA 212's attainment status classification to moderate based on its own ozone design value.

In response to this proposed EPA action, the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) is required to establish emissions control requirements in its State Implementation Plan (SIP) that include Reasonably Available Control Technology (RACT) requirements. RACT is defined by the EPA as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." A RACT analysis should, therefore, consider 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.

The CAA requires moderate ozone nonattainment areas to implement RACT for sources of ozone forming emissions. Ozone forming emissions include volatile organic compounds (VOC) and nitrogen oxides (NO_X). More specifically, the DAQ is required to adopt RACT level controls for sources subject to an EPA Control Techniques Guidelines (CTG) document (addressing sources of VOC) and for any other major sources of VOC and NO_X. The major source threshold for an area classified as moderate is 100 tons per year and is applied to a stationary source's potential to emit (PTE) to determine whether RACT requirements need to be evaluated for any particular stationary source. DAQ has determined that it will use a stationary source's PTE as applied in the major New Source Review program and Title V (Part 70) operating permits program to identify the major stationary sources subject to RACT. In addition, DAQ has requested that each major stationary source located in HA 212 make a determination as to whether it is to be considered a major stationary source subject to a RACT evaluation and, if so, perform the evaluation and submit the evaluation to DAQ for review and inclusion in the SIP revisions required as a result of the EPA's attainment area status reclassification action.

This report summarizes the RACT analysis performed by Caesars Consolidated Properties (Caesars) and contains its source specific recommendations for RACT.

2. 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.

- Bally's Las Vegas, 3645 S. Las Vegas Blvd.
- Caesars Palace, 3570 S. Las Vegas Blvd.
- The Cromwell Las Vegas, 3595 S. Las Vegas Blvd.
- Paris Casino Resort, 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.
- Battista's, 4041 Audrie St.
- 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. A copy of the current permit is included in Appendix A. Since the 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 Part 70 operating permit, the PTE for NO_X emissions is 440.10 tons per year and the PTE for VOC emissions is 26.76 tons per year so only NO_X emissions exceed both the Part 70 major source and moderate area major source thresholds. This analysis is therefore limited to emissions of NO_X.

3. Emission Units Subject to RACT

In their request for individual stationary source RACT analyses, DAQ further delineated the applicability requirement to a so-called Phase 1 level 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 for the Caesars properties that exceed this threshold.

Table 1 – Emission Units Subject to RACT

Emission Unit ID[1]	Description	Maximum Rating	Manufacturer	Model	Fuel Type	NO_X PTE[2,3,4] (tons/year)
Harrah's Las Vegas						
HA13	Emergency Generator DOM: Pre-2006	1,232 hp 800 kW	Detroit Diesel Engine Marathon Electric Generator	81637416 573RSL2056A-P266W	Diesel	7.39
HA14	Emergency Generator DOM: Pre-2006	890 hp 600 kW	Caterpillar Engine Caterpillar Generator	3412 SR4	Diesel	5.34
HA18	Emergency Generator DOM: 1996	1,180 hp 800 kW	Caterpillar Engine Caterpillar Generator	3412 SR-4B	Diesel	7.08

Emission Unit ID[1]	Description	Maximum Rating	Manufacturer	Model	Fuel Type	NO_X PTE[2,3,4] (tons/year)
Flamingo Las Vegas						
FL09	Emergency Generator DOM: 1999	1,109 hp 750 kW	Caterpillar Engine Caterpillar Generator	3412 SR4B	Diesel	6.66
FL10	Emergency Generator DOM: 1999	1,109 hp 750 kW	Caterpillar Engine Caterpillar Generator	3412 SR4B	Diesel	6.66
Bally's Las Vegas						
BA04	Emergency Generator (#1) DOM: Pre- 2006	1,340 hp 1,000 kW	Detroit Diesel Engine Magna One Generator	9163-7305 682FDR808 0AB-P667W	Diesel	8.04
BA05	Emergency Generator (#2) DOM: Pre- 2006	1,340 hp 1,000 kW	Detroit Diesel Engine Magna One Generator	9163-7305 682FDR808 0AB-P667W	Diesel	8.04
BA11	Emergency Generator (#3) DOM: Pre- 2006	1,340 hp 1,000 kW	Detroit Diesel Engine Detroit Diesel Generator	L18107 1000 DS	Diesel	8.04
BA12	Emergency Generator (#4) DOM: Pre- 2006	1,340 hp 1,000 kW	Detroit Diesel Engine Detroit Diesel Generator	L18127 1000 DS	Diesel	8.04
The Cromwell Las Vegas						
CR07	Diesel Engine Emergency Generator DOM: 2013	3,634 hp[5] 1,500 kW	Caterpillar Engine Caterpillar Generator	3512C SR4B-GD	Diesel	10.18
Caesars Palace						
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	3P80050GB NM	Natural gas	5.35
CP04	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	3P80050GB NM	Natural gas	5.35

Emission Unit ID[1]	Description	Maximum Rating	Manufacturer	Model	Fuel Type	NO_X PTE[2,3,4] (tons/year)
CP05	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	3P80050GB NM	Natural gas	5.35
CP13	Emergency Generator DOM: 3/5/1997	2,876 hp 2,000 kW	Caterpillar Engine Caterpillar Generator	3516 SR-4B	Diesel	17.26
CP14	Emergency Generator DOM: 3/3/1997	2,876 hp 2,000 kW	Caterpillar Engine Caterpillar Generator	3516 SR-4B	Diesel	17.26
CP15	Emergency Generator DOM: 08/14/1996	2,520 hp 1,750 kW	Caterpillar Engine Caterpillar Generator	3516 SR-4B	Diesel	15.12
CP16	Emergency Generator DOM: 04/18/1995	1,818 hp 1,250 kW	Caterpillar Engine Caterpillar Generator	3512 SR4	Diesel	10.91
CP17	Emergency Generator DOM: 12/10/1997	2,876 hp 2,000 kW	Caterpillar Engine Caterpillar Generator	3516 SR-4B	Diesel	17.26
CP28	Emergency Generator DOM: 2008	3,634 hp[5] 2,000 kW	Caterpillar Engine Caterpillar Generator	3516CDITA SR4B HV	Diesel	10.47
CP29	Emergency Generator DOM: 2008	3,634 hp[5] 2,000 kW	Caterpillar Engine Caterpillar Generator	3516CDITA SR4B HV	Diesel	10.47
Paris Casino Resort						
PA17	Emergency Generator #1 DOM: 03/25/1998	2,816 hp 2,100 kW	Cummins Engine Cummins Generator	CW-73-G QSW73	Diesel	16.90
PA18	Emergency Generator #2 DOM: 02/26/1998	2,816 hp 2,100 kW	Cummins Engine Cummins Generator	CW-73-G QSW73	Diesel	16.90

Emission Unit ID[1]	Description	Maximum Rating	Manufacturer	Model	Fuel Type	NO_X PTE[2,3,4] (tons/year)
The LINQ Hotel and Casino						
IP08	Emergency Generator DOM: Pre-2006	890 hp 600 kW	Caterpillar Engine Caterpillar Generator	3412 SR4	Diesel	5.34
IP09	Emergency Generator DOM: Pre-2006	890 hp 600 kW	Caterpillar Engine Caterpillar Generator	3412 SR4	Diesel	5.34
Planet Hollywood						
PH10	Emergency Generator DOM: 1999	2,550 hp 1,750 kW	MTU/Detroit Diesel Engine Spectrum Generator	T1637K16 1750DS4	Diesel	15.30
PH11	Emergency Generator DOM: 1999	2,550 hp 1,750 kW	MTU/Detroit Diesel Engine Spectrum Generator	T1637K16 1750DS4	Diesel	15.30
PH12	Emergency Generator DOM: 1999	2,550 hp 1,750 kW	MTU/Detroit Diesel Engine Spectrum Generator	T1637K16 1750DS4	Diesel	15.30
PH13	Emergency Generator DOM: 2008	2,561 hp 1,750 kW	MTU/Detroit Diesel Engine MTU Generator	T1238A36 1750RXC6D T2	Diesel	6.40
LINQ Complex						
LI06	Emergency Generator DOM: 2012	3,634 hp[5] 2,000 kW	Caterpillar Engine Caterpillar Generator	3516C SR4B-GD	Diesel	10.80
LI07	Emergency Generator DOM: 2012	3,634 hp[5] 2,000 kW	Caterpillar Engine Caterpillar Generator	3516C SR4B-GD	Diesel	10.80

Notes: [1] Emission Unit ID from Part 70 Operating Permit Tables III-A-1, B-1, C-1, D-1, E-1, F-1, G-1, H-1 and I-1
[2] PTE from Part 70 Operating Permit Tables III-A-2, B-2, C-2, D-2, E-2, F-2, G-2, H-2 and I-2

[3] Emissions for emergency generators based on 500 hours per year operation and an AP-42 emission factor except for EU's CR07, CP28, CP29, PH13, LI06 and LI07 which are based on manufacturer's specifications.
[4] Emissions for boilers based on 8,760 hours per year operation and emission factors derived from exhaust gas NO_X concentration limits.
[5] Based on manufacturer's performance data, the actual hp for these engines ranges from 2,206 hp (1,500 kW) to 2,937 hp (2,000 kW).

Each boiler listed in Table 1 has emission limits for exhaust gas NO_X concentrations in ppm. These additional limitations are summarized in Table 2.

Table 2 – Boiler 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

Each boiler is subject to performance testing every 5 years and must perform burner efficiency testing semiannually.

Emergency generators do not have specific emission limits. The permit contains general operation and maintenance requirements as follows:

- 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
- The permittee shall operate each of the diesel engines with turbochargers and aftercoolers

Engines subject to 40 CFR Part 60, Subpart IIII are also required to ensure that the diesel engines are in compliance with the regulation by meeting the following:

- Operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer
- Installation and configuration of the engine according to the manufacturer's specifications

In addition, each emergency generator is limited to 100 hours of operation for testing and maintenance annually.

Actual emissions of NO_X for the entire source and each emission unit for calendar years 2019-2021 are summarized in Table 3.

Table 3 – Actual NO_X Emissions 2019-2021

Emission Unit ID	Actual NO_X Emissions[1,2] (tons)			Maximum Annual 2019-2021 (tons)	NO_X PTE (tons/year)	Maximum Annual/PTE
	2019	2020	2021			
Entire Source	21.51	18.55	40.17	40.17	440.11	9.1%
HA13	0.21	0.20	0.20	0.21	7.39	2.8%
HA14	0.21	0.19	0.25	0.25	5.34	4.7%
HA18	0.29	0.24	0.34	0.34	7.08	4.8%
FL09	0.12	0.11	0.28	0.28	6.66	4.2%
FL10	0.08	0.11	0.12	0.12	6.66	1.8%
BA04	0.24	0.19	0.20	0.24	8.04	3.0%
BA05	0.26	0.20	0.20	0.26	8.04	3.2%
BA11	0.19	0.14	0.14	0.19	8.04	2.4%
BA12	0.22	0.14	0.19	0.22	8.04	2.7%
CR07	0.21	0.19	0.19	0.21	10.18	2.1%
CP01	1.58	2.23	0.29	2.23	5.46	40.8%
CP02	2.74	2.04	2.09	2.74	5.46	50.2%
CP03	2.35	0.39	1.20	2.35	5.35	43.9%
CP04	0.45	1.08	0.88	1.08	5.35	20.2%
CP05	1.73	1.08	2.49	2.49	5.35	46.5%
CP13	0.70	0.67	0.88	0.88	17.26	5.1%
CP14	0.74	0.67	0.92	0.92	17.26	5.3%
CP15	0.60	0.52	0.78	0.78	15.12	5.2%
CP16	0.43	0.36	0.67	0.67	10.91	6.1%
CP17	0.70	0.63	1.04	1.04	17.26	6.0%
CP28	0.56	0.39	0.52	0.56	10.47	5.3%
CP29	0.52	0.40	0.56	0.56	10.47	5.3%
PA17	0.32	0.45	0.34	0.45	16.9	2.7%
PA18	0.20	0.00	0.00	0.20	16.9	1.2%
IP08	0.14	0.15	0.22	0.22	5.34	4.1%
IP09	0.14	0.14	0.23	0.23	5.34	4.3%
PH10	-	-	0.30	0.30	15.3	2.0%
PH11	-	-	0.24	0.24	15.3	1.6%
PH12	-	-	0.26	0.26	15.3	1.7%
PH13	-	-	0.13	0.13	6.4	2.0%
LI06	0.03	0.16	0.26	0.26	10.8	2.4%
LI07	0.03	0.06	0.21	0.21	10.8	1.9%

Notes: [1] Entire source actual emissions based on 2019, 2020 and 2021 Emissions Inventories. Individual emission unit actual emissions based on maximum hourly emission rates and actual hours of operation.
[2] Includes emergency operations for generators.

As shown in Table 3, maximum actual emissions for the entire source are only 9.1% of the entire sources' PTE. Individual emission units' maximum actual emissions are between 20% and 50% of PTE for the boilers and between 1% and 6% for the emergency generators.

Actual hours of operation for each emission unit for calendar years 2019-2021 are summarized in Table 4.

Table 4 – Actual Hours of Operation 2019-2021

Emission Unit ID	Actual Operation (hours)					
	2019		2020		2021	
	Operation Normal	Operation Emergency	Operation Normal	Operation Emergency	Operation Normal	Operation Emergency
HA13	14.53	0.00	13.37	0.00	13.45	0.00
HA14	19.95	0.00	17.80	0.00	23.70	0.00
HA18	20.40	0.00	17.25	0.00	24.20	0.00
FL09	8.91	0.00	8.00	0.00	6.00	15.00
FL10	5.90	0.00	8.00	0.00	7.00	0.00
BA04	14.75	0.00	11.50	0.00	12.70	0.00
BA05	16.25	0.00	12.30	0.00	12.40	0.00
BA11	11.65	0.00	8.60	0.40	8.40	0.00
BA12	13.95	0.00	8.20	0.40	11.60	0.00
CR07	8.60	1.25	8.80	0.30	9.30	0.00
CP01	2523.80	na	3569.60	na	446.60	na
CP02	4384.50	na	3264.20	na	3233.20	na
CP03	3963.00	na	653.20	na	1962.00	na
CP04	764.20	na	1822.80	na	1436.90	na
CP05	2923.50	na	1832.90	na	4082.10	na
CP13	20.40	0.00	19.40	0.00	25.30	0.40
CP14	21.40	0.00	19.40	0.00	26.30	0.40
CP15	19.90	0.00	17.20	0.00	25.30	0.40
CP16	19.80	0.00	16.40	0.00	28.20	2.30
CP17	20.40	0.00	18.30	0.00	29.00	0.40
CP28	26.60	0.00	18.90	0.00	24.30	0.30
CP29	24.20	0.00	19.00	0.00	26.10	0.40
PA17	9.55	0.00	13.30	0.00	10.05	0.00
PA18	5.90	0.00	0.00	0.00	0.00	0.00
IP08	13.00	0.00	14.25	0.00	20.90	0.00
IP09	13.00	0.00	13.00	0.00	21.15	0.00
PH10	-	-	-	-	9.80	0.00
PH11	-	-	-	-	7.80	0.00
PH12	-	-	-	-	8.60	0.00
PH13	-	-	-	-	10.00	0.00
LI06	1.20	0.00	7.40	0.00	12.10	0.00
LI07	1.20	0.00	2.80	0.00	9.90	0.00

The boilers operate year-round with the most use occurring during the months of December through March. The emergency generators also operate year-round. In addition, operation of the emergency generators is almost exclusively related to testing and maintenance which must be performed on a routine monthly basis.

4. 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, DAQ has requested that major sources use a 6% interest rate to compute costs. This rate was used in all cost analyses contained in this report.

Regarding the base case for emissions, DAQ has stated that, if a major source's actual emissions over three consecutive, representative years are less than 70% of the major source's PTE, then the major source can elect to use actual emissions for the base case. Since this is the case for Caesars, the maximum actual annual emissions will be used for each emission unit evaluated for RACT in this report.

A detailed RACT analysis for each emission unit subject to RACT review identified above is included in Appendices B, and C.

5. Results

The results of each RACT determination are discussed in Section 3.0 of Appendices B and C. It should be noted that emission units that had similar ratings and/or emission concentrations were grouped for RACT determination purposes.

Appendix A

Part 70 Operating Permit

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: 257

Caesars Entertainment, Inc.,
Caesars Consolidated Properties

Harrah's Las Vegas, 3475 S. Las Vegas Blvd.
Flamingo Las Vegas, 3555 S. Las Vegas Blvd.
Bally's Las Vegas, 3645 S. Las Vegas Blvd.
Caesars Palace, 3570 S. Las Vegas Blvd.
The Cromwell Las Vegas, 3595 S. Las Vegas Blvd.
Paris Casino Resort, 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.
Battista's, 4041 Audrie St.
Forum Meeting Center, 3911 Koval Lane

ISSUED ON: September 23, 2021 **EXPIRES ON: September 22, 2026**

Revised: May 12, 2022

Current Action: Administrative Revision

Issued to:
Caesars Entertainment, Inc.
One Caesars Palace Drive
Las Vegas, Nevada 89109

Responsible Official:
Eric Dominguez
SVP Engineering & Asset Mgt.
PHONE: (702) 343-9501 FAX: (702) 407-6456
EMAIL: edominguez@caesars.com

NATURE OF BUSINESS:
SIC code 7011, "Hotels and Motels"
NAICS code 721120, "Casino Hotels"

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.

Theodore A. Lendis

Theodore A. Lendis, Permitting Manager

EXECUTIVE SUMMARY

Caesars Consolidated Properties (Caesars) is a major stationary source for nitrogen oxides (NO_x), a major Part 70 source for carbon monoxide (CO), and a minor source for particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), sulfur oxides (SO_x), volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). The source is also identified as a major source of greenhouse gases (GHGs). It is located on 1 Caesars Palace Drive, Las Vegas, Nevada, in the Las Vegas Valley airshed (Hydrographic Area (HA) 212). HA 212 is in attainment for all regulated air pollutants except ozone; effective August 3, 2018, the U.S. Environmental Protection Agency (EPA) designated HA 212 in marginal nonattainment for the 2015 ozone National Ambient Air Quality Standard (NAAQS). HA 212 is also subject to a maintenance plan for the CO and PM_{10} NAAQS.

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 is operating eleven facilities: Harrah’s Las Vegas, Flamingo Las Vegas, Bally’s Las Vegas, The Cromwell Las Vegas, Caesars Palace, Paris Casino Resort, The LINQ Hotel & Casino, Planet Hollywood, LINQ Complex – High Roller, Battista’s, and the Forum Meeting Center. Caesars is not classified as a categorical Stationary Source, as defined in Section 12.2.2(j) of the Clark County Air Quality Regulations (AQRs).

The table below summarizes the source-wide potential to emit (PTE) for each regulated air pollutant.

Source PTE (tons per year)

PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP	GHG
68.99	68.99	440.11	186.53	2.28	26.76	6.03	288,439.90

The Clark County Department of Environment and Sustainability (DES), Division of Air Quality (DAQ), issued a renewal Part 70 Operating Permit (OP) on March 28, 2016, with revisions issued on October 10, 2016; May 5, 2017; December 2, 2018; December 19, 2019; and June 23, 2021. This permitting action is based on all the revisions listed above, and the renewal application submitted on September 25, 2020.

Pursuant to AQR 12.5, all terms and conditions in Sections I–VII and the attachment in this permit are federally enforceable unless explicitly denoted otherwise.

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LIST OF TABLES

I. ACRONYMS

Table I-1: List of Acronyms

Term	Description
AQR	Clark County Air Quality Regulations
AST	aboveground storage tank
ATC	Authority to Construct
CARB	California Air Resources Board
CE	control efficiency
CF	control factor
CFR	United States Code of Federal Regulations
CO	carbon monoxide
EF	emission Factor
EMP	Environmental Management Portal
EO	Executive Order
EPA	United States Environmental Protection Agency
EU	emission unit
EVR	enhanced vapor recovery
FGR	flue gas recirculation
GDO	gasoline dispensing operation
HAP	hazardous air pollutant
hp	horsepower
kW	kilowatt
MMBtu	millions of British thermal units
NAC	Nevada Administrative Code
NO_X	nitrogen oxides
NESHAP	National Emission Standards for Hazardous Air Pollutants
NRS	Nevada Revised Statutes
NSPS	New Source Performance Standards
NSR	New Source Review
OP	Operating Permit
PM_{10}	particulate matter less than 10 microns
ppm	parts per million
PSD	Prevention of Significant Deterioration
PTE	potential to emit
scf	standard cubic feet
SIP	State Implementation Plan
SO_X	sulfur oxides
TSD	Technical Support Document
UST	underground storage tank
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compound

II. GENERAL CONDITIONS

A. GENERAL REQUIREMENTS

1. The permittee shall comply with all conditions of the Part 70 Operating Permit (OP). Any permit noncompliance may constitute a violation of the Clark County Air Quality Regulations (AQRs), Nevada law, and the Clean Air Act (Act), and is grounds for enforcement action; permit termination, revocation and reissuance, or revision; or denial of a permit 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 not be affected and shall 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 any 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; & AQR 12.5.2.8(b)]*

6. The permittee shall allow the Control Officer, upon presentation of credentials, to: *[AQR 4.1 & 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 any relevant facts, or who has submitted incorrect information in a permit application, shall, upon becoming aware of such failure or incorrect submittal, promptly submit to DAQ such supplementary facts or corrected information. In addition, the permittee shall also provide any additional information as necessary to address any requirements that become applicable to the source after the date a complete application was filed but before the 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 that is clearly visible and accessible to facility employees and DAQ representatives. *[AQR 12.5.2.6(m)]*

B. MODIFICATION, REVISION, 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 Authority to Construct (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 U.S. Environmental Protection Agency (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 EPA Administrator or the Control Officer determines that the permit must be revised or revoked to assure compliance with applicable requirements.

4. A permit, permit revision, or renewal may be approved only if all of 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 & 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)]*

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 six months, but not more than eighteen 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 Operating Permit (OP) until final action is taken on its application for a renewed Part 70 OP. *[AQR 12.5.2.1(a)(2)]*

C. REPORTING, NOTIFICATIONS, AND INFORMATION REQUIREMENTS

1. The permittee shall submit all compliance certifications to EPA and to the Control Officer. *[AQR 12.5.2.8(e)(4)]*

2. Any application form, report, or compliance certification submitted to the Control Officer pursuant to the OP or AQRs shall contain a certification by a responsible official, with an original signature, of truth, accuracy, and completeness. This certification (and any other certification 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)]*

3. 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 the permit requires keeping. The permittee may furnish records claimed to be confidential directly to the Administrator, along with a claim of confidentiality. *[AQR 12.5.2.6(g)(5)]*

4. Upon request of the Control Officer, the permittee shall provide information or analyses that will disclose the nature, extent, quantity, or degree of air contaminants that are or may be discharged by the source, along with the type or nature of control equipment in use. The Control Officer may require that 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 is authorized to inspect any article, machine, equipment, or other contrivance necessary to make the inspection and report. *[AQR 4.1]*

5. The permittee shall submit annual emissions inventory reports based on the following: *[AQR 18.6.1 and AQR 12.5.2.4]*

   a. The annual emissions inventory must be submitted to DAQ by March 31 of each calendar year (if March 31 falls on a Saturday or Sunday, or on a federal or Nevada holiday, 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).

6. Stationary sources that emit 25 tons or more of nitrogen oxide (NO_X) and/or emit 25 tons or more of volatile organic compounds (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 (aka Emissions Inventory). *[AQR 12.9.1]*

7. All report submissions shall be addressed to the attention of the Control Officer. *[AQR 12.5.2.6(d) & AQR 12.5.2.8]*

8. All reports shall contain the following: *[AQR 12.5.2.6(d) & AQR 12.5.2.8]*

   a. A certification statement on the first page, e.g., "I certify that, based on information and belief formed after reasonable inquiry, the statements contained in this document are true, accurate and complete." (A sample form is available from DAQ.)

   b. A certification signature from a responsible official of the company and the date of certification.

9. The permittee shall submit semiannual monitoring reports to DAQ. *[AQR 12.5.2.6(d) & AQR 12.5.2.8]*

10. The following requirements apply to semiannual reports: *[AQR 12.5.2.6(d) & AQR 12.5.2.8]*

    a. The report shall include a semiannual summary of each item listed in Sections III.A.7.b, III.B.7.b, III.C.7.b, III.D.7.b, III.E.7.b, III.F.7.b, III.G.7.b, III.H.7.b, III.I.7.b, III.J.7.b, and III.K.7.b of this OP.

    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.

11. Regardless of the date of issuance of this OP, the source shall comply with the schedule for report submissions outlined in Table II-C-1. *[AQR 12.5.2.6(d) & AQR 12.5.2.8]*

Table II-C-1: 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 Emission Inventory Report	Calendar year	March 31 each year[1]
Annual Emission 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
Report of Malfunctions, Startup, Shutdowns, or Deviations with Excess Emission	As required	Within 72 hours of the notification
Deviation Report without Excess Emissions	As required	Along with semiannual reports[1]
Excess Emissions that Pose a Potential Imminent and Substantial Danger	As required	Within 12 hours of the permittee learns of the event
Performance Testing Protocol	As required	No less than 45 days, but no more than 90 days, before the anticipated test date[1]
Performance Testing	As required	Within 60 days of end of test[1]

[1] If the due date falls on a Saturday, Sunday, or federal or Nevada holiday, the submittal is due on the next regularly scheduled business day.
[2] Required only for stationary sources that emit 25 tons or more of nitrogen oxide (NO_X) and/or emit 25 tons or more of volatile organic compounds (VOC) during a calendar year.

12. The Control Officer reserves the right to require additional reports and reporting to verify compliance with permit emission limits, applicable permit requirements, and requirements of applicable federal regulations. *[AQR 4.4]*

D. COMPLIANCE REQUIREMENTS

1. 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)]*

2. 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 other DAQ requirements 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]*

3. Any person aggrieved by an order issued pursuant to AQR 9.1 is entitled to a review, as provided in Chapter 233B of the Nevada Revised Statutes. *[AQR 9.12]*

4. 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)]*

5. The permittee shall certify compliance with the terms and conditions contained in the Part 70 OP, including emission limitations, standards, work practices, and the means for monitoring such compliance. *[AQR 12.5.2.8(e)]*

6. The permittee shall submit compliance certifications annually in writing to the Control Officer (4701 W. Russell Road, Suite 200, Las Vegas, Nevada 89118) and the Region 9 Administrator (Director, Air and Radiation Divisions, 75 Hawthorne St., San Francisco, California 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)]*

   a. The identification of each term or condition of the permit that is the basis of the certification;

   b. The identification of the methods or other means used by the permittee for determining the compliance status with each term and condition during the certification period. The 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 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 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 (b) above, and 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 is required and in which an excursion or exceedance, as defined under 40 CFR Part 64, occurred.

7. 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 limits set by regulations or this permit. The report shall be in two parts: *[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 paragraph (a) above, the permittee shall submit a detailed written report to DAQ containing the information required by AQR 25.6.3.

8. 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)]*

9. The owner or operator of any source required to obtain a permit under AQR 12 shall report to the Control Officer any 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]*

E. PERFORMANCE TESTING REQUIREMENTS

1. Upon request of the Control Officer, the permittee shall test or have tests performed to determine the emissions of air contaminants from any source whenever the Control Officer has reason to believe that an emission in excess of that allowed by the AQRs is occurring. The 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]*

2. Upon request of the Control Officer, 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]*

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, prior to the anticipated date of the performance test, unless otherwise specified in Sections, III.B.6, II.C.6, III.E.6, III.F.6, III.G.6, or III.H.6 of this permit. *[AQR 12.5.2.8]*

4. The permittee shall submit to EPA for approval any alternative test methods EPA has not already approved to demonstrate compliance with a requirement under 40 CFR Part 60. *[40 CFR Part 60.8(b)]*

5. 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 test. *[AQR 12.5.2.8]*

III. EMISSION UNITS AND APPLICABLE REQUIREMENTS

A. HARRAH'S LAS VEGAS

1. Emission Units

a. The stationary source activities at Harrah's Las Vegas covered by this Part 70 OP consist of the emission units (EUs) and associated appurtenances summarized in Table III-A-1. *[AQR 12.5.2.3; NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V 70 OP (03/28/2016) and (12/03/2018); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-A-1: Summary of EUs – Harrah's Las Vegas

EU	Description	Rating	Make	Model No.	Serial No.
HA06	Natural Gas Boiler	4.50 MMBtu/hr	Bryan	RV450-S-150-FDG	66726 (#5)
HA07	Natural Gas Boiler	9.0 MMBtu/hr	Bryan	LM900-S-15-FDG	66665 (#4)
HA08	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	CB.200-200	L-70272 (#1)
HA09	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	CB.200-200	L-70271 (#2)
HA10	Natural Gas Boiler	8.369 MMBtu/hr	Cleaver Brooks	CB.200-200	L-70270 (#3)
HA11	Natural Gas Boiler	4.80 MMBtu/hr	Universal Energy	BF108C	10341-1 (#6)
HA12	Emergency Fire Pump DOM: Pre-2006	276 kW	Fairbanks Morse Pump	5922F	3T1-020216
		370 hp	Caterpillar Engine	3406BD1	6TB06046
HA13	Emergency Generator DOM: Pre-2006	800 kW	Marathon Electric Generator	573RSL2056A-P266W	VE3575357
		1,232 hp	Detroit Diesel Engine	81637416	16VF007962
HA14	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	SR4	6FA06166
		890 hp		3412	81Z09924
HA15	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator	502FDR8056AB-L000W	KK-95206-3
		536 hp	Detroit Diesel Engine	71237305	12VA069124
HA16	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator	502FDR8056AB-L000W	KK-95206-1
		536 hp	Detroit Diesel Engine	71237305	12VA069593
HA17	Emergency Generator DOM: Pre-2006	400 kW	Magna One Generator	502FDR8056AB-L000W	KK-95206-2
		536 hp	Detroit Diesel Engine	71237305	12VA066655
HA18	Emergency Generator DOM: 1996	800 kW	Caterpillar	SR-4B	7AJ00864
		1,180 hp		3412	2WJ00740
HA26	Cooling Tower, 2-Cells	4,200 gpm	Evapco	USS 244-3O18	17-830216
HA27	Cooling Tower, 2-Cells	4,200 gpm	Evapco	USS 244-3O18	17-830217
HA28	Cooling Tower, 2-Cells	4,200 gpm	Evapco	USS 244-3O18	17-830218

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-A-2. *[AQR 12.5.2.3; NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V 70 OP (03/28/2016); and Title V 70 OP (12/03/2018)]*

Table III-A-2: PTE (tons per year) – Harrah's Las Vegas

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
HA06	8,760 hr/yr	0.15	0.15	0.22	0.73	0.01	0.11	0.04
HA07	8,760 hr/yr	0.30	0.30	1.44	1.46	0.02	0.21	0.07
HA08	8,760 hr/yr	0.27	0.27	0.54	1.36	0.02	0.2	0.07
HA09	8,760 hr/yr	0.27	0.27	0.54	1.36	0.02	0.2	0.07
HA10	8,760 hr/yr	0.27	0.27	0.54	1.36	0.02	0.2	0.07
HA11	8,760 hr/yr	0.16	0.16	0.77	0.78	0.01	0.11	0.04
HA12	500 hr/yr	0.20	0.20	2.87	0.62	0.01	0.23	0.01
HA13	500 hr/yr	0.22	0.22	7.39	1.70	0.01	0.22	0.01
HA14	500 hr/yr	0.16	0.16	5.34	1.23	0.01	0.16	0.01
HA15	500 hr/yr	0.30	0.30	4.16	0.90	0.01	0.34	0.01
HA16	500 hr/yr	0.30	0.30	4.16	0.90	0.01	0.34	0.01
HA17	500 hr/yr	0.30	0.30	4.16	0.90	0.01	0.34	0.01
HA18	500 hr/yr	0.21	0.21	7.08	1.62	0.01	0.21	0.01
HA26	8,760 hr/yr	0.22	0.22	0	0	0	0	0
HA27	8,760 hr/yr	0.22	0.22	0	0	0	0	0
HA28	8,760 hr/yr	0.22	0.22	0	0	0	0	0

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators and the fire pump for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators and the fire pump up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: HA12 through HA18). *[40 CFR Part 63.6640(f)(i)(ii)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's operations and maintenance (O&M) manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain the 4.5 MMBtu/hr boiler (EU: HA06) with burners that have a manufacturer's maximum emission concentration of 9 ppm NOx, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

d. The permittee shall operate and maintain the 4.5 MMBtu/hr boiler (EU: HA06) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

e. The permittee shall operate and maintain the 9.0 MMBtu/hr boiler (EU: HA07) with burners that have a manufacturer's maximum emission concentration of 30 ppm NOx, corrected to 3% oxygen, and flue gas recirculation control devices (FGR). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

f. The permittee shall operate and maintain the 9.0 MMBtu/hr boiler (EU: HA07) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

g. The permittee shall operate and maintain the 8.369 MMBtu/hr boilers (EUs: HA08 through HA10) with burners that have a manufacturer's maximum emission concentration of 12 ppm NOx, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate and maintain the 8.369 MMBtu/hr boilers (EUs: HA08 through HA10) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

i. The permittee shall operate and maintain the 4.80 MMBtu/hr boiler (EU: HA11) with burners that have a manufacturer's maximum emission concentration of 30 ppm NOx, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

j. The permittee shall operate and maintain the 4.80 MMBtu/hr boiler (EU: HA11) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

Diesel Generators/Fire Pumps

k. 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. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

l. The permittee shall operate the emergency fire pump with a turbocharger (EU: HA12). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

m. The permittee shall operate each generator with turbochargers (EUs: HA13 through HA18). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

Cooling Towers

n. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

o. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

p. The permittee shall operate the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EUs: HA26 through HA28). *[Title V 70 OP (12/03/2018)]*

q. The permittee shall limit the total dissolved solids (TDS) content of each cooling tower's circulation water to 5,000 ppm (EUs: HA26 through HA28). *[Title V 70 OP (12/03/2018)]*

Other

r. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall perform a burner efficiency test once each calendar year (EUs: HA06 through HA11). *[AQR 12.5.2.6(d)]*

b. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: HA06 through HA11). *[AQR 12.5.2.6(d)]*

c. The permittee shall not have to perform a burner efficiency test if the actual hours of operation are 0. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: HA06 through HA11). *[AQR 12.5.2.6(d)]*

d. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: HA06 through HA11). *[AQR 12.5.2.6(d)*

Diesel Generators/Fire Pumps

e. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters when operated for testing, maintenance, or during emergencies. (EUs: HA12 through HA18). *[AQR 12.5.2.6(d)]*

Visible Emissions

f. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

g. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator and fire pump while in operation. *[AQR 12.5.2.6(d)]*

h. 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. *[AQR 12.5.2.6(d)]*

i. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

    i. 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

    ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

        a. 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.

        b. 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.

        c. 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.

j. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

k. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee shall use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

6. Testing

No performance testing requirements have been identified. *[AQR 12.5.2.8(a)]*

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

   i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

   ii. Monthly TDS content of cooling tower circulation water;

   iii. Log book of all inspections, maintenance, and repairs, as specified in this document;

   iv. Records of burner efficiency, as specified in this permit; and

   v. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

   i. Date and duration of operation of emergency generators and the fire pump for testing, maintenance, and nonemergency use (EUs: HA12 through HA18); and

   ii. Date and duration of operation of emergency generators and the fire pump for emergency use, including documentation justifying use during the emergency (EUs: HA12 through HA18).

c. The permittee shall include, for all inspections, logs, visible emission checks, and tests required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

B. FLAMINGO LAS VEGAS

1. Emission Units

a. The stationary source activities at Flamingo Las Vegas, covered by this Part 70 OP, consist of the emission units and associated appurtenances summarized in Table III-B-1. *[AQR 12.5.2.3; NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); NSR ATC (02/23/11); and Title V OP (05/29/2013), (03/28/2016), and (12/03/2018)]*

Table III-B-1: Summary of EUs – Flamingo Las Vegas

EU	Description	Rating	Make	Model No.	Serial No.
FL01	Natural Gas Boiler	14.343 MMBtu/hr	Johnston	8786	9180-01
FL02	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	H3S-350-G	10016

EU	Description	Rating	Make	Model No.	Serial No.
FL03	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	H3S-350-G	10017
FL04	Natural Gas Boiler	14.645 MMBtu/hr	Kewanee	H3S-350-G	10476
FL05	Natural Gas Boiler	8.165 MMBtu/hr	Cleaver Brooks	CBI 700-200-150	0L104650
FL06	Emergency Fire Pump DOM: Pre-2006	313 kW	Fairbanks Morse Pump	5922	K3P1017265
		420 hp	Caterpillar Engine	3406	6TB02994
FL09	Emergency Generator DOM: 1999	750 kW	Caterpillar	SR4B	6EJ01215
		1,109 hp		3412	2WJ02515
FL10	Emergency Generator DOM: 1999	750 kW	Caterpillar	SR4B	6EJ01238
		1,109 hp		3412	2WJ02570
FL11	Emergency Generator DOM: Pre-2006	475 kW	Caterpillar	SR4	6EA01398
		724 hp		3412	81Z08892
FL26	Emergency Generator DOM: 2010	600 kW	Caterpillar	LC7	G7A03394
		923 hp		C18	EST01182
FL28	Cooling Tower, 4-cells	9,600 gpm	Marley	NC8411TAN4BGF	10050562-(A1-A4)
FL29	Cooling Tower, 2-Cells	3,800 gpm	Evapco	USS 244-3N18	17-833834
FL30	Cooling Tower, 2-Cells	3,800 gpm	Evapco	USS 244-3N18	17-833835
FL31	Cooling Tower, 2-Cells	3,800 gpm	Evapco	USS 244-3N18	17-833836

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-B-2. *[NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); NSR ATC (02/23/11); and Title V OP (05/29/2013), (03/28/2016), and (12/03/2018)]*

Table III-B-2: PTE (tons per year) – Flamingo Las Vegas

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
FL01	8,760 hr/yr	0.47	0.47	2.22	4.43	0.04	0.34	0.12
FL02	8,760 hr/yr	0.48	0.48	3.13	2.38	0.04	0.35	0.12
FL03	8,760 hr/yr	0.48	0.48	3.13	2.38	0.04	0.35	0.12
FL04	8,760 hr/yr	0.48	0.48	3.13	2.38	0.04	0.35	0.12
FL05	8,760 hr/yr	0.27	0.27	1.27	1.46	0.02	0.19	0.07
FL06	500 hr/yr	0.23	0.23	3.26	0.70	0.01	0.27	0.01
FL09	500 hr/yr	0.20	0.20	6.66	1.53	0.01	0.20	0.01
FL10	500 hr/yr	0.20	0.20	6.66	1.53	0.01	0.20	0.01
FL11	500 hr/yr	0.13	0.13	4.35	1.00	0.01	0.13	0.01
FL26	500 hr/yr	0.03	0.03	3.13	0.44	0.00	0.04	0.01
FL28	8,760 hr/yr	2.47	2.47	0.00	0.00	0.00	0.00	0.00

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
FL29	8,760 hr/yr	0.20	0.20	0.00	0.00	0.00	0.00	0.00
FL30	8,760 hr/yr	0.20	0.20	0.00	0.00	0.00	0.00	0.00
FL31	8,760 hr/yr	0.20	0.20	0.00	0.00	0.00	0.00	0.00

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-B-3. *[AQR 12.5.2.3 and NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

Table III-B-3: Emissions – Flamingo Las Vegas

EU	Rating	NO_x/CO (ppm)[1]	NO_x (lbs/hr)	CO (lbs/hr)
FL01	14.343 MMBtu/hr	NO_x 29/CO 95	0.51	1.01
FL02	14.645 MMBtu/hr	NO_x 40/CO 50	0.71	0.54
FL03	14.645 MMBtu/hr	NO_x 40/CO 50	0.71	0.54
FL04	14.645 MMBtu/hr	NO_x 40/CO 50	0.71	0.54

[1]Corrected to 3% oxygen.

c. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators and the fire pump for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators and the fire pump up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: FL06 and FL09 through FL11). *[40 CFR Part 63.6640(f)(i)(ii)]*

b. The permittee shall limit the operation of the diesel-fired emergency generator for testing and maintenance purposes to 100 hours per year. The permittee may operate the emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EU: FL26). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain the 14.343 MMBtu/hr boiler (EU: FL01) with burners that have a manufacturer's maximum emission concentration of 29 ppm NO_x, corrected to 3% oxygen, and FGR control devices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

d. The permittee shall operate and maintain the 14.343 MMBtu/hr boiler (EU: FL01) with burners that have a manufacturer's maximum emission concentration of 95 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

e. The permittee shall operate and maintain the three 14.645 MMBtu/hr boilers (EUs: FL02 through FL04) with burners that have a manufacturer's maximum emission concentration of 40 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

f. The permittee shall operate and maintain the three 14.645 MMBtu/hr boilers (EUs: FL02 through FL04) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

g. The permittee shall operate and maintain the 8.165 MMBtu/hr boiler (EU: FL05) with burners that have a manufacturer's maximum emission concentration of 29 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate and maintain the 8.165 MMBtu/hr boiler (EU: FL05) with burners that have a manufacturer's maximum emission concentration of 55 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

Diesel Generators/Fire Pumps

i. 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. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

j. The permittee shall operate each of the diesel engines with turbochargers (EUs: FL06, FL09 through FL11, and FL26). *[NSR ATC, Modification 10, Revision 0 (12/15/2008) and NSR ATC (02/23/2011)]*

k. The permittee shall ensure that the diesel engine is in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EU: FL26): *[40 CFR Part 60.4206]*

    i. Operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

    ii. Installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

l. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

m. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

n. The permittee shall operate the cooling tower with drift eliminators with a manufacturer's maximum drift rate of 0.005% (EUs: FL28). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

o. The permittee shall operate the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EUs: FL29 through FL31). *[Title V OP (12/03/2018)]*

p. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm (EUs: FL28 through FL31). *[Title V OP (12/03/2018)]*

Other

q. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: FL01 through FL04). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(1)]*

b. The permittee, when operating a boiler with a maximum heat input rating equal to or greater than 4.0 MMBtu/hr but less than 10.0 MMBtu/hr, shall perform a burner efficiency test once each calendar year (EU: FL05). *[AQR 12.5.2.6(d)]*

c. The permittee, when operating a boiler with a maximum heat input rating equal to or greater than 10.0 MMBtu/hr, shall perform a burner efficiency test twice each calendar year, at least five months apart, but no more than seven (EUs: FL01 through FL04). *[AQR 12.5.2.6(d)]*

d. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: FL01 through FL05). *[AQR 12.5.2.6(d)]*

e. The permittee may choose not to perform a burner efficiency test on a boiler during the calendar year if the documented actual hours of operation of that boiler, with a maximum heat input rating equal to or greater than 4.0 MMBtu/hr but less than 10.0 MMBtu/hr, are zero during a calendar year. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: FL05). *[AQR 12.5.2.6(d)]*

f. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: FL01 through FL04). *[AQR 12.5.2.6(d)]*

g. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: FL01 through FL05). *[AQR 12.5.2.6(d)]*

Diesel Generators/Fire Pumps

h. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters (EUs: FL06, FL09 through FL11, and FL26). *[AQR 12.5.2.6(d)]*

Visible Emissions

i. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

j. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator and fire pump while in operation. *[AQR 12.5.2.6(d)]*

k. 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. *[AQR 12.5.2.6(d)]*

l. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

   i. 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

   ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

      a. 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.

      b. 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.

c. 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.

m. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

n. The permittee shall continue to monitor the TDS in the cooling tower circulation water monthly. The permittee shall use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

6. Testing

Boiler Performance Tests

a. Performance testing shall be the instrument for determining compliance with emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: FL01 through FL04). *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

b. The permittee shall conduct performance tests on each boiler (EUs: FL01, FL02, FL03, and FL04) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

Table III-B-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this document;

iv. Records of burner efficiency testing, as specified in this OP;

v. Results of performance testing; and

vi. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: FL01 through FL04); *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of the emergency generators and the fire pump for testing, maintenance, and nonemergency use (EUs: FL06, FL09 through FL11, and FL26); and

iii. Date and duration of operation of the generators and fire pump for emergency use, including documentation justifying use during the emergency (EUs: FL06 through FL11 and FL26);

c. permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

C. BALLY'S LAS VEGAS

1. Emission Units

a. The stationary source activities at Bally's Las Vegas, covered by this Part 70 OP, consist of the emission units and associated appurtenances summarized in Table III-C-1. *[AQR 12.5.2.3; NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V OP (03/28/2016), (05/05/2017), and (12/19/2019); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-C-1: Summary of EUs – Bally's Las Vegas

EU	Description	Rating	Make	Model No.	Serial No.
BA01	Natural Gas Boiler	16.8 MMBtu/hr	Kewanee	H3S-750-G02	NB-24935
BA02	Natural Gas Boiler	16.8 MMBtu/hr	Kewanee	H3S-750-G02	NB-25232
BA03	Natural Gas Boiler	25.106 MMBtu/hr	Kewanee	H3S-750-G02	NB-24875

EU	Description	Rating	Make	Model No.	Serial No.
BA04	Emergency Generator (#1) DOM: Pre-2006	1,000 kW	Magna One	682FDR8080AB-P667W	LD95982-1
		1,340 hp	Detroit Diesel	9163-7305	16E0006591
BA05	Emergency Generator (#2) DOM: Pre-2006	1,000 kW	Magna One	682FDR8080AB-P667W	LD-95982-2
		1,340 hp	Detroit Diesel	9163-7305	16E0006592
BA06	Emergency Generator DOM: Pre-2006	500 kW	Magna One	500SR9E	66111
		670 hp	Detroit Diesel	7163-7305	16VA7496
BA07	Emergency Generator DOM: Pre-2006	155 kW	Magna One	440FDR8024GG-H000W	LD-94032
		200 hp	Detroit Diesel		
BA11	Emergency Generator (#3) DOM: Pre-2006	1,000 kW	Detroit	1000 DS	600214
		1,340 hp		L18107	24VA001710
BA12	Emergency Generator (#4) DOM: Pre-2006	1,000 kW	Detroit	1000 DS	600215
		1,340 hp		L18127	24VA001728
BA17	Emergency Fire Pump DOM: 06/2011	526 hp	Clarke Fire Pump	JX6H-UFADK0-D	RG6135L023246
			John Deere Engine	6135HFC48A	
BA18	Emergency Fire Pump DOM: 04/2011	526 hp	Clarke Fire Pump	JX6H-UFADK0-D	RG6135L022100
			John Deere Engine	6135HFC48A	
BA19	Cooling tower – 3 cells	18,000 GPM	Evapco	USS 314-4O72	16-804451
BA20	Cooling tower – 3 cells	18,000 GPM	Evapco	USS314-4O72	16-804450

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-C-2. *[NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V OP (03/28/2016), (05/05/2017), and (12/19/2019); Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-C-2: PTE (tons per year) – Bally's Las Vegas

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
BA01	8,760 hr/yr	0.55	0.55	2.24	1.25	0.04	0.40	0.14
BA02	8,760 hr/yr	0.55	0.55	2.24	1.25	0.04	0.40	0.14
BA03	8,760 hr/yr	0.82	0.82	3.34	1.87	0.07	0.59	0.21

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
BA04	500 hr/yr	0.24	0.24	8.04	1.84	0.01	0.24	0.01
BA05	500 hr/yr	0.24	0.24	8.04	1.84	0.01	0.24	0.01
BA06	500 hr/yr	0.12	0.12	4.02	0.92	0.01	0.12	0.01
BA07	500 hr/yr	0.11	0.11	1.55	0.34	0.01	0.13	0.00
BA11	500 hr/yr	0.24	0.24	8.04	1.84	0.01	0.24	0.01
BA12	500 hr/yr	0.24	0.24	8.04	1.84	0.01	0.24	0.01
BA17	500 hr/yr	0.01	0.01	0.76	0.12	0.01	0.03	0.01
BA18	500 hr/yr	0.01	0.01	0.76	0.12	0.01	0.03	0.01
BA19	8,760 hr/yr	0.93	0.93	0.00	0.00	0.00	0.00	0.00
BA20	8,760 hr/yr	0.93	0.93	0.00	0.00	0.00	0.00	0.00

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-C-3. *[AQR 12.5.2.3]*

Table III-C-3: Emissions – Bally's Las Vegas

EU	Rating	NO_x/CO (ppm)[1]	NO_x (lbs/hr)	CO (lbs/hr)
BA01	16.8 MMBtu/hr	NO_x 25/CO 23	0.51	0.29
BA02	16.8 MMBtu/hr	NO_x 25/CO 23	0.51	0.29
BA03	25.106 MMBtu/hr	NO_x 25/CO 23	0.77	0.43

[1]Corrected to 3% oxygen.

c. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: BA04 through BA07, BA11, and BA12). *[40 CFR Part 63.6640(f)(i)(ii)]*

b. The permittee shall limit the operation of each of the fire pumps for testing and maintenance purposes to 100 hours per year. The permittee may operate each fire pumps up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance (EUs: BA17 and BA18). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain each of the 16.8 MMBtu/hr boilers (EUs: BA01 and BA02) with burners that have a manufacturer's maximum emission concentration of 25 ppm NO_x, corrected to 3% oxygen, and FGR control devices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

d. The permittee shall operate and maintain each of the 16.8 MMBtu/hr boilers (EUs: BA01 and BA02) with burners that have a manufacturer's maximum emission concentration of 23 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

e. The permittee shall operate and maintain the 25.106 MMBtu/hr boiler (EU: BA03) with burners that have a manufacturer's maximum emission concentration of 25 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

f. The permittee shall operate and maintain the 25.106 MMBtu/hr boiler (EU: BA03) with burners that have a manufacturer's maximum emission concentration of 23 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

Diesel Generators/Fire Pumps

g. 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. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate each of the diesel engines with turbochargers (EUs: BA04 through BA07, BA11, and BA12). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

i. The permittee shall operate each of the diesel fire pumps with turbochargers and aftercoolers (EUs: BA17 and BA18). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

j. The permittee shall ensure that the diesel engines are in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EUs: BA17 and BA18): *[40 CFR Part 60.4211]*

   i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

   ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

k. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. *[Title V OP (05/05/2017)]*

l. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

m. The permittee shall operate the cooling tower with drift eliminators with a manufacturer's maximum drift rate of 0.001% (EU: BA19). *[Title V OP (05/05/2017)]*

n. The permittee shall operate the cooling tower with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EU: BA20). *[Title V OP (12/19/2019)]*

o. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm (EU: BA19). *[Title V OP (12/19/2019)]*

Other

p. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: BA01 through BA03). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(1)]*

b. The permittee shall perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven (EUs: BA01 through BA03). *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: BA01 through BA03). *[AQR 12.5.2.6(d)]*

d. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: BA01 through BA03). *[AQR 12.5.2.6(d)]*

e. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: BA01 through BA03). *[AQR 12.5.2.6(d)]*

Diesel Generators/Fire Pumps

f. The permittee shall install and utilize nonresettable hour meters such that the daily operating hours can be established for each applicable diesel engine (EUs: BA04 through BA07, BA11, BA12, BA17, and BA18). *[AQR 12.5.2.6(d)]*

Visible Emissions

g. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator and fire pump while in operation. *[AQR 12.5.2.6(d)]*

i. 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. *[AQR 12.5.2.6(d)]*

j. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

   i. 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

   ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

      a. 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.

      b. 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.

      c. 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.

k. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

l. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

6. Testing

a. Performance testing shall be the instrument for determining compliance with emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: BA01, BA02, and BA03). *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

b. The permittee shall conduct performance tests on each boiler (EUs: BA01, BA02, and BA03) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

Table III-C-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs as specified in this document;

iv. Results of performance testing; and

v. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: BA01, BA02 and BA03); *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of the emergency generators and the fire pump for testing, maintenance, and nonemergency use (EUs: BA04 through BA07, BA11, BA12, BA17, and BA18); and

Date and duration of operation of the generators and fire pumps for emergency use, including documentation justifying use during the emergency (EUs: BA04 through BA07, BA11, BA12, BA17, and BA18).

c. The permittee shall include, for all inspections, logs, visible emission checks, and tests required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

D. THE CROMWELL LAS VEGAS

1. Emission Units

a. The stationary source activities at The Cromwell Las Vegas, covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-D-1. *[AQR 12.5.2.3 and Title V OP (03/28/2016)]*

Table III-D-1: Summary of EUs – The Cromwell Las Vegas

EU	Description	Rating	Make	Model No.	Serial No.
CR01	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00252062
CR02	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00252063
CR03	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00252141
CR04	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00252065
CR05	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00251706
CR06	Natural Gas Boiler	3.0 MMBtu/hr	Lochinvar	FBN3000	G13H00252064
CR07	Diesel Engine Emergency Generator DOM: 2013	1,500 kW	Caterpillar	SR4B-GD	G4W01097
		3,634 hp	Caterpillar	3512C	EBG01274
CR08	Diesel Engine Emergency Generator DOM: 2013	150 kW	Caterpillar	D150-8	CAT00C66ALC600121
		275 hp	Caterpillar	C6.6	E6L00768
CR09	Cooling Tower, 3-cell	5,400 gpm	Evapco	USS-312-936	13-541894

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-D-2. *[Title V OP (03/28/2016) and (12/19/2019)]*

Table III-D-2: PTE (tons per year) – The Cromwell Las Vegas

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
CR01	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR02	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR03	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR04	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR05	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR06	8,760 hr/yr	0.10	0.10	0.16	0.49	0.01	0.07	0.02
CR07	500 hr/yr	0.06	0.06	10.18	0.88	0.01	0.22	0.03
CR08	500 hr/yr	0.02	0.02	0.43	0.09	0.01	0.17	0.01
CR09	8,760 hr/yr	0.28	0.28	0.00	0.00	0.00	0.00	0.00

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: CR07 and CR08). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[Title V OP (03/28/2016)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[Title V OP (03/28/2016)]*

c. The permittee shall operate and maintain the boilers (EUs: CR01 through CR06) with burners that have a manufacturer's maximum emission concentration of 10 ppm NO_x, corrected to 3% oxygen. *[Title V OP (03/28/2016)]*

d. The permittee shall operate and maintain the boilers (EUs: CR01 through CR06) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[Title V OP (03/28/2016)]*

Diesel Generators

e. The permittee shall operate and maintain all diesel generators in accordance with the manufacturer's O&M manual for emissions-related components. *[Title V OP (03/28/2016)]*

f. The permittee shall operate each of the diesel engines with turbochargers and aftercoolers (EUs: CR07 and CR08). *[Title V OP (03/28/2016)]*

g. The permittee shall ensure that the diesel engines are in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EUs: CR07 and CR08): *[40 CFR Part 60.4206]*

i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

h. The permittee shall operate and maintain the cooling tower in accordance with the manufacturer's O&M manual for emissions-related components. *[Title V OP (03/28/2016)]*

i. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

j. The permittee shall operate the cooling tower with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EU: CR09). *[Title V OP (03/28/2016)]*

k. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm (EU: CR09). *[Title V OP (12/19/2019)]*

Other

l. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Diesel Generators

a. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters when operated for testing, maintenance, or during emergencies. (EUs: CR07 and CR08). *[AQR 12.5.2.6(d)]*

Visible Emissions

b. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

d. 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. *[AQR 12.5.2.6(d)]*

e. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

i. 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

ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

a. 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.

b. 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.

c. 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.

f. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

g. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

6. Testing

No performance testing requirements have been identified. *[AQR 12.5.2.8(a)]*

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

   i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

   ii. Monthly TDS content of cooling tower circulation water;

   iii. Log book of all inspections, maintenance, and repairs, as specified in this document; and

   iv. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

   i. The date and duration of operation of emergency generators for testing, maintenance, and nonemergency use (EUs: CR07 and CR08); and

   ii. The date and duration of operation of generators for emergency use, including documentation justifying use during the emergency (EUs: CR07 and CR08).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)*

E. CAESARS PALACE

1. Emission Units

a. The stationary source activities at Caesars Palace covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-E-1. *[AQR 12.5.2.3; NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, NSR ATC, Modification 10, Revision 0 (12/15/2008); Modification 11, Revision 0 (02/19/2009); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V OP (03/28/2016); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-E-1: Summary of EUs – Caesars Palace

EU	Description	Rating	Make	Model No.	Serial No.
CP01	Natural Gas Boiler	35.40 MMBtu/hr	Hurst	S4-G-800-150	S4000-150-18
CP02	Natural Gas Boiler	35.40 MMBtu/hr	Hurst	S4-G-800-150	S4000-150-19
CP03	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	3P80050GBNM	12524
CP04	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	3P80050GBNM	12164

EU	Description	Rating	Make	Model No.	Serial No.
CP05	Natural Gas Boiler	33.475 MMBtu/hr	Burnham	3P80050GBNM	12238
CP07	Natural Gas Boiler	1.0 MMBtu/hr	Gasmaster	GMI1	221.02
CP13	Emergency Generator DOM: 3/5/1997	2,000 kW	Caterpillar	SR-4B	8DM00558
		2,876 hp		3516	6HN00155
CP14	Emergency Generator DOM: 3/3/1997	2,000 kW	Caterpillar	SR-4B	8DM00557
		2,876 hp		3516	6HN00154
CP15	Emergency Generator DOM: 08/14/1996	1,750 kW	Caterpillar	SR-4B	7GM00534
		2,520 hp		3516	25Z05223
CP16	Emergency Generator DOM: 04/18/1995	1,250 kW	Caterpillar	SR4	4DM00503
		1,818 hp		3512	24Z06413
CP17	Emergency Generator DOM: 12/10/1997	2,000 kW	Caterpillar	SR-4B	8DM00625
		2,876 hp		3516	6HN00199
CP19a	Cooling Tower, Cell 1 of 3	9,000 gpm	Baltimore Aircoil	4469-20-3W	92-4G-6184-P4
CP19b	Cooling Tower, Cell 2 of 3	9,000 gpm	Baltimore Aircoil	4469-20-3W	92-4G-6184-P4
CP19c	Cooling Tower, Cell 3 of 3	9,000 gpm	Baltimore Aircoil	4469-20-3W	92-4G-6184-P4
CP20	Cooling Tower	5,750 gpm	Baltimore Aircoil	3725A3	U040665201MAD
CP21	Cooling Tower	5,750 gpm	Baltimore Aircoil	3725A-4	U040665202MAD
CP22	Cooling Tower	5,750 gpm	Baltimore Aircoil	3725A-5	U040665203MAD
CP24	Natural Gas Boiler	1.5 MMBtu/hr	RBI Futera	FW1500	120644885
CP25	Natural Gas Boiler	1.5 MMBtu/hr	RBI Futera	FW1500	120644886
CP26	Natural Gas Boiler	24.0 MMBtu/hr	Unilux	ZF2500W-1-300/400	A1683
CP27	Natural Gas Boiler	24.0 MMBtu/hr	Unilux	ZF2500W-1-300/400	A1684
CP28	Emergency Generator DOM: 2008	2,000 kW	Caterpillar	SR4B HV	G3X00133
		3,634 hp		3516CDITA	SBJ00672
CP29	Emergency Generator DOM: 2008	2,000 kW	Caterpillar	SR4B HV	G3X00229
		3,634 hp		3516CDITA	SBJ00673
CP30a	Cooling Tower	5,600 gpm	Composite Cooling Solutions	FT-2828-75-P6IL	CT-7

EU	Description	Rating	Make	Model No.	Serial No.
CP30b	Cooling Tower	5,600 gpm	Composite Cooling Solutions	FT-2828-75-P6IL	CT-8
CP32	GDO with an AST and nozzles	1,000-gallon	Fireguard	MWCFG	
CP34	Diesel Fire Pump DOM: Post-2006	525 hp	Clarke Fire Pump	JX6H-UF60	FPVT-C084983-002
			John Deere	6125HF070	RG6125H063341
CP35	Diesel Fire Pump DOM: Post-2006	525 hp	Clarke Fire Pump	JX6H-UF60	FPVT-C084983-001
			John Deere	6125HF070	RG6125H063339
CP37	Natural Gas Pool Heater	1.5 MMBtu/hr	RBI Futera II	FW-1500	101984123
CP41	Natural Gas Water Heater	0.25 MMBtu/hr	A.O. Smith	BTH250A200	1615M000633
CP42	Natural Gas Water Heater	0.25 MMBtu/hr	A.O. Smith	BTH250A100	0826M001486
CP44	Natural Gas Water Heater	0.999 MMBtu/hr	Lochinvar	PBN1002	A15H00273568

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-E-2. *[NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, NSR ATC, Modification 10, Revision 0 (12/15/2008); Modification 11, Revision 0 (02/19/2009); NSR ATC, Modification 12, Revision 1 (08/20/2009); Title V OP (03/28/2016) and (12/19/2019); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-E-2: PTE (tons per year) – Caesars Palace

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
CP01	8,760 hr/yr	1.16	1.16	5.46	1.15	0.09	0.84	0.29
CP02	8,760 hr/yr	1.16	1.16	5.46	1.15	0.09	0.84	0.29
CP03	8,760 hr/yr	1.10	1.10	5.35	1.08	0.09	0.79	0.28
CP04	8,760 hr/yr	1.10	1.10	5.35	1.08	0.09	0.79	0.28
CP05	8,760 hr/yr	1.10	1.10	5.35	1.08	0.09	0.79	0.28
CP07	8,760 hr/yr	0.03	0.03	0.07	0.25	0.01	0.02	0.01
CP13	500 hr/yr	0.50	0.50	17.26	3.96	0.01	0.51	0.02
CP14	500 hr/yr	0.50	0.50	17.26	3.96	0.01	0.51	0.02
CP15	500 hr/yr	0.44	0.44	15.12	3.47	0.01	0.45	0.02
CP16	500 hr/yr	0.32	0.32	10.91	2.50	0.01	0.32	0.02
CP17	500 hr/yr	0.50	0.50	17.26	3.96	0.01	0.51	0.02
CP19a	8,760 hr/yr	2.32	2.32	0.00	0.00	0.00	0.00	0.00
CP19b	8,760 hr/yr	2.32	2.32	0.00	0.00	0.00	0.00	0.00
CP19c	8,760 hr/yr	2.32	2.32	0.00	0.00	0.00	0.00	0.00

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
CP20	8,760 hr/yr	1.48	1.48	0.00	0.00	0.00	0.00	0.00
CP21	8,760 hr/yr	1.48	1.48	0.00	0.00	0.00	0.00	0.00
CP22	8,760 hr/yr	1.48	1.48	0.00	0.00	0.00	0.00	0.00
CP24	8,760 hr/yr	0.05	0.05	0.08	0.24	0.01	0.04	0.01
CP25	8,760 hr/yr	0.05	0.05	0.08	0.24	0.01	0.04	0.01
CP26	8,760 hr/yr	0.79	0.79	1.16	3.9	0.06	0.57	0.2
CP27	8,760 hr/yr	0.79	0.79	1.16	3.9	0.06	0.57	0.2
CP28	500 hr/yr	0.06	0.06	10.47	0.86	0.01	0.03	0.03
CP29	500 hr/yr	0.06	0.06	10.47	0.86	0.01	0.03	0.03
CP30a	8,760 hr/yr	0.29	0.29	0.00	0.00	0.00	0.00	0.00
CP30b	8,760 hr/yr	0.29	0.29	0.00	0.00	0.00	0.00	0.00
CP32	18,000 gal/yr	0.00	0.00	0.00	0.00	0.00	0.15	0.01
CP34	500 hr/yr	0.02	0.02	1.35	0.09	0.01	0.04	0.01
CP35	500 hr/yr	0.02	0.02	1.35	0.09	0.01	0.04	0.01
CP37	8,760 hr/yr	0.05	0.05	0.08	0.24	0.01	0.04	0.01
CP41	8,760 hr/yr	0.01	0.01	0.10	0.04	0.01	0.01	0.01
CP42	8,760 hr/yr	0.01	0.01	0.10	0.04	0.01	0.01	0.01
CP44	8,760 hr/yr	0.03	0.03	0.43	0.36	0.01	0.02	0.01

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-E-3. *[AQR 12.5.2.3]*

Table III-E-3: Emissions – Caesars Palace

EU	Rating	NO_x/CO (ppm)[1]	NO_x (lbs/hr)	CO (lbs/hr)
CP01	35.4 MMBtu/hr	NO_x 29/CO 10	1.24	0.26
CP02	35.4 MMBtu/hr	NO_x 29/CO 10	1.24	0.26
CP03	33.475 MMBtu/hr	NO_x 30/CO 10	1.23	0.25
CP04	33.475 MMBtu/hr	NO_x 30/CO 10	1.23	0.25
CP05	33.475 MMBtu/hr	NO_x 30/CO 10	1.23	0.25
CP26	24.0 MMBtu/hr	NO_x 9/CO 50	0.26	0.89
CP27	24.0 MMBtu/hr	NO_x 9/CO 50	0.26	0.89

[1]Corrected to 3% oxygen.

c. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than 6 consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators and the fire pump for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators and the fire pump up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: CP13 through CP17). *[40 CFR Part 63.6640(f)(i)(ii)]*

b. The permittee shall limit the operation of each of the diesel-fired emergency generators and the fires pumps for testing and maintenance purposes to 100 hours per year. The permittee may operate each emergency generator and fire pump up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: CP28, CP29, CP34, and CP35). *[40 CFR Part 60.4211(f)]*

c. The permittee shall limit the maximum throughput of all gasoline products to 18,000 gallons per any consecutive 12 months (EU: CP32). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

4. Control Requirements

Boilers/Water Heaters [AQR 12.5.2.12]

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain the 35.4 MMBtu/hr boilers (EUs: CP01 and CP02) with burners that have a manufacturer's maximum emission concentration of 29 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

d. The permittee shall operate and maintain the 35.4 MMBtu/hr boilers (EUs: CP01 and CP02) with burners that have a manufacturer's maximum emission concentration of 10 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

e. The permittee shall operate and maintain the 33.475 MMBtu/hr boilers (EUs: CP03 through CP05) with burners that have a manufacturer's maximum emission concentration of 30 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

f. The permittee shall operate and maintain the 33.475 MMBtu/hr boilers (EUs: CP03 through CP05) with burners that have a manufacturer's maximum emission concentration of 10 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

g. The permittee shall operate and maintain the 1.0 MMBtu/hr boiler (EU: CP07) with burners that have a manufacturer's maximum emission concentration of 14 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate and maintain the 1.0 MMBtu/hr boiler (EU: CP07) with burners that have a manufacturer's maximum emission concentration of 77 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

i. The permittee shall operate and maintain the 1.50 MMBtu/hour boilers (EUs: CP24 and CP25) with burners that have a manufacturer's maximum emission concentration of 10 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

j. The permittee shall operate and maintain the 1.50 MMBtu/hour boilers (EUs: CP24 and CP25) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

k. The permittee shall operate and maintain the two 24.0 MMBtu/hr boilers (EUs: CP26 and CP27) with burners that have a manufacturer's maximum emission concentration of 9 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

l. The permittee shall operate and maintain the two 24.0 MMBtu/hr boilers (EUs: CP26 and CP27) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

m. The permittee shall operate and maintain the 1.5 MMBtu/hr boiler (EU: CP37) with burners that have a manufacturer's maximum emission concentration of 10 ppm NO_x, corrected to 3% oxygen. *[AQR 12.5.2.6]*

n. The permittee shall operate and maintain the 1.5 MMBtu/hr boiler (EU: CP37) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[AQR 12.5.2.6]*

Diesel Generators/Fire Pumps

o. 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. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

p. The permittee shall operate each of the diesel engines with turbochargers and aftercoolers (EUs: CP13 through CP17, CP28, CP29, CP34, and CP35). *[NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 11, Revision 0 (02/19/2009)]*

q. The permittee shall ensure that the diesel engines are in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EUs: CP28, CP29, CP34, and CP35): *[40 CFR Part 60.4206]*

    i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

r. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

s. The permittee shall operate the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.005% (EUs: CP19a through CP22). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

t. The permittee shall operate the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EUs: CP30a and CP30b). *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

u. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm. *[Title V OP (12/19/2019)]*

Gasoline Dispensing

v. The permittee shall implement control technology requirements on gasoline dispensing equipment (EU: CP32). *[40 CFR Part 63, Subpart CCCCCC]*

w. The permittee shall install and operate all Phase I vapor recovery equipment according to certifications specified by the manufacturer, and shall maintain the equipment to be leak-free, vapor-tight, and in proper working order. *[AQR 12.5.2.6]*

x. From October 1 to March 31 every year in the Las Vegas Valley, the Eldorado Valley, the Ivanpah Valley, the Boulder City limits, and any area within three miles of these areas, no gasoline intended as a final product for fueling motor vehicles shall be supplied or sold by any person; sold at retail; sold to a private or a municipal fleet for consumption; or introduced into any motor vehicle by any person unless the gasoline has at least 3.5 percent oxygen content by weight. *[AQR 53.1.1 & 53.2.1]*

y. If a gasoline storage tank in the Las Vegas Valley, the Eldorado Valley, the Ivanpah Valley, the Boulder City limits, and any area within three miles of these areas, receives its last gasoline delivery with less than 3.5 percent oxygen content by weight before September 15, gasoline dispensed from that tank will be exempt from enforcement of Section 53.2.1 until the first delivery date after October 1. *[AQR 53.5.1.1]*

z. The permittee shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Preventative measures to be taken include, but are not limited to, the following: *[40 CFR Parts 63.11116 and 63.11117]*

i. Minimize gasoline spills;

ii. Clean up spills as expeditiously as practicable;

iii. Cover all open gasoline containers and all gasoline storage tank fill pipes with a gasketed seal when not in use; and

iv. Only load gasoline into storage tanks using a submerged fill tube where the greatest distance from the bottom of the storage tank to the point of the fill tube opening is no more than six inches.

aa. The permittee shall install, maintain, and operate a Phase I vapor recovery system on all gasoline storage tanks (EU: CP32) that meets the following requirements: *[AQR 12.5.2.6]*

i. The Phase I vapor recovery system shall be rated with at least 90.0 percent control efficiency when in operation. This system shall be certified by an industry-recognized certification body, i.e., California Resources Air Board (CARB) or equivalent.

ii. The Phase I vapor recovery system shall be a dual-point vapor balance system, as defined by 40 CFR Part 63.11132, in which the storage tank is equipped with an entry port for a gasoline fill pipe and a separate exit port for a vapor connection.

iii. All Phase I vapor recovery equipment shall be installed and operated in accordance with manufacturer specifications and certification requirements.

iv. All Phase I vapor recovery equipment, including the vapor line from the gasoline storage tanks to the gasoline cargo tank, shall be maintained in good working order and vapor-tight, as defined in 40 CFR Part 63.11132.

v. All vapor connections and lines on storage tanks shall be equipped with closures that seal upon disconnect.

bb. The vapor balance system shall be designed so that the pressure in the cargo tank does not exceed 18 inches of water pressure or 5.9 inches of water vacuum during product transfer.

cc. Liquid fill and vapor return adapters for all systems shall be equipped and secured with vapor-tight caps after each delivery. *[AQR 12.5.2.6]*

dd. A pressure/vacuum (PV) vent valve on each gasoline storage tank system (EU: CP32) shall be installed, maintained, and operated in accordance with manufacturer's specifications.

i. The pressure specifications for PV vent valves shall be a positive pressure setting of 2.5 to 6.0 inches of water and a negative pressure setting of 6.0 to 10.0 inches of water.

ii. The total leak rate of all PV vent valves at the affected facility, including connections, shall not exceed 0.17 ft^3 per hour at a pressure of 2.0 inches of water and 0.63 ft^3 per hour at a vacuum of 4 inches of water. *[AQR 12.5.2.6]*

ee. The vapor balance system shall be capable of meeting the static pressure performance requirement in 40 CFR Part 63, Subpart CCCCCC. *[AQR 12.5.2.6]* ff. The permittee shall comply with good management practices during the unloading of gasoline cargo tanks, as follows: *[AQR 12.5.2.6]*

i. All hoses in the vapor balance system shall be properly connected.

ii. The adapters or couplers that attach to the vapor line on the storage tank shall have closures that seal upon disconnect.

iii. All vapor return hoses, couplers, and adapters used in the gasoline delivery shall be vapor-tight.

iv. All tank truck vapor return equipment shall be compatible in size and form a vapor-tight connection with the vapor balance equipment on the gasoline storage tank.

v. All hatches on the tank truck shall be closed and securely fastened.

vi. The filling of storage tanks shall be limited to unloading from vapor-tight gasoline cargo tanks carrying documentation onboard that the cargo tank has met the specifications of EPA Test Method 27.

Other

gg. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(1)]*

b. The permittee shall perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.6(d)]*

d. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.6(d)]*

e. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.6(d)]*

Diesel Generators/Fire Pumps

f. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters when operated for testing, maintenance, or during emergencies (EUs: CP13 through CP17, CP28, CP29, CP34, and CP35). *[AQR 12.5.2.6(d)]*

Visible Emissions

g. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator and fire pump while in operation. *[AQR 12.5.2.6(d)]*

i. 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. *[AQR 12.5.2.6(d)]*

j. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

   i. 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

   ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

      a. 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.

      b. 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.

      c. 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.

k. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

l. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

Gasoline Dispensing

m. The permittee shall monitor the combined throughput of gasoline each month (EU: CP32). *[AQR 12.5.2.6(d)]*

n. The permittee shall monitor the fuel storage and dispensing system (EU: CP32) to determine if components of the system are in compliance with the control requirements of this permit. The monitoring shall consist of, but not be limited to, the following: *[40 CFR Part 63.11125]*

i. The permittee shall inspect daily for gasoline spills, and record the times and dates the source became aware of a spill and cleaned it up.

ii. The permittee shall inspect covers on gasoline containers and fill-pipes after each delivery, and record the dates of fuel deliveries and corresponding inspections.

iii. The permittee shall record the date and approximate volume of gasoline sent to open waste collection systems that collect recyclable gasoline.

6. Testing

Performance Tests

a. Performance testing shall be the instrument for determining compliance with the emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: CP01 through CP05, CP26, and CP27). *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

b. The permittee shall conduct performance tests on each boiler (EUs: CP01 through CP05, CP26, and CP27) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

Table III-E-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

Gasoline Dispensing

c. The permittee shall conduct Phase I vapor recovery tests in accordance with the CARB-approved vapor recovery test procedures (as revised) listed in Table III-E-5, as applicable. *[AQR 12.5.2.8(a)]*

Table III-E-5: Vapor Recovery System Testing Procedures and Schedules

Type of Vapor Recovery System	Test Procedure	Frequency
Phase I Vapor Balance System	Pressure Decay/Leak test: TP201.3B (as revised for AST)	Initial and every three years thereafter
	Static Torque of Rotatable Phase I Adaptors CARB procedure TP-201.1B (With swivel adapters only)	Initial and every three years thereafter
	Leak Rate and Cracking Pressure of Pressure/Vacuum Vent Valves: CARB procedure TP-201.1E (as revised)	Initial and every three years thereafter
	Flow rate Test: CC_VRTP_1	Initial and every three years thereafter

d. The permittee shall submit, by mail, fax, or hand delivery, a Division of Air Quality (DAQ)-approved vapor recovery test notification form (available on the DAQ website) to schedule each vapor recovery test with the Stationary Sources Section supervisor at least 30 calendar days before the anticipated date of testing, unless otherwise specified in this permit. *[AQR 12.5.2.8(a)]*

e. Any prior approved scheduled vapor recovery system test cannot be canceled and/or rescheduled without the Control Officer's prior approval. *[AQR 12.5.2.8(a)]*

f. The permittee shall conduct Phase I vapor recovery system testing on affected gasoline dispensing equipment according to the following requirements: *[AQR 12.5.2.8(a)]*

   i. The permittee shall conduct and pass an initial vapor recovery system test within 180 days of startup of new equipment, or within 90 days after completion of repairs or reconstruction where the integrity of the vapor recovery system has been affected by the repair or reconstruction. Routine maintenance, including the replacement of hoses, nozzles, and efficiency compliance devices (e.g., bellows, face shield, splash guard, etc.), does not require an initial vapor recovery system test.

   ii. The permittee shall conduct and pass subsequent Phase I vapor recovery system tests on or before the anniversary date of the previous successful test at the frequency specified in Table III-E-5.

iii. Each vapor recovery system test may be witnessed by a DAQ inspector.

g. The permittee shall submit a Gasoline Dispensing Operation Certification of Vapor Recovery System Test Results Submittal Form (available on the DAQ website), along with associated test results, to the Control Officer after each vapor recovery system test. The submittal form shall be: *[AQR 12.5.2.8(a)]*

i. Complete and signed by the Responsible Official for the equipment being tested. The Responsible Official must certify that the test results are true, accurate, and complete.

ii. Submitted by mail, by fax, or in person.

iii. Submitted by the source, or by the permittee's testing company or consultant. However, the source is the responsible party and must ensure that the test report is delivered to DAQ within the applicable time frame.

h. If the source passes or fails the vapor recovery system test, the permittee shall submit the test results report to the Control Officer within 60 days of the date of the vapor recovery system test.

i. If the source fails a vapor recovery system test: *[Clark County Department of Air Quality Source Testing Guidelines (9/19/2019)]*

i. The permittee shall notify the Control Officer, by email or phone, within 24 hours of equipment test failure. If repairs can be made within five working days of the original scheduled test date, the permittee shall make the repairs and pass the required test(s).

ii. If the equipment cannot be repaired in five working days, the permittee shall make all necessary repairs and schedule a retest of the affected facility by submitting a new Test Notification Form to the Control Officer by mail, fax, or hand delivery no later than three business days before the new test date.

iii. After retesting (pass/fail), the owner/operator shall submit a Test Results Submittal Form (available on the DAQ website) and supporting test documents to the Control Officer within 15 days of completion.

iv. The permittee shall continue retesting until the affected facility successfully passes all aspects of the vapor recovery system test.

j. The Control Officer may require the permittee to conduct any test after a failed vapor recovery system test in the presence of a DAQ representative. *[AQR 12.5.2.8(a)]*

7. Recordkeeping

a. The permittee shall maintain records on site that include, at a minimum: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this document;

iv. Records of burner efficiency testing, as specified in this permit;

v. Results of performance testing;

vi. Records of location changes for nonroad engines, if applicable; and

vii. Gasoline-dispensing records shall contain, at a minimum (EU: CP32): *[AQR 12.5.2.6(d) and 40 CFR Part 63.11120]*

1. Equipment inspections, including findings and corrective actions;

2. Maintenance on storage and distribution equipment, including a general description of location(s) and part(s);

3. Date and time that storage and distribution equipment was taken out of service;

4. Date of repair or replacement of storage and distribution equipment/parts;

5. Deviations from permit requirements resulting in excess emissions;

6. Deviations from permit requirements not resulting in excess emissions (reported annually);

7. Daily total combined throughput of gasoline;

8. Monthly combined total throughput of gasoline; and

9. Calendar year annual emissions for the entire source (reported annually).

b. The permittee shall maintain records on site and report the following information semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: CP01 through CP05, CP26 and CP27). *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of generators and fire pumps for emergency use, including documentation justifying use during the emergency (EUs: CP13 through CP17, CP28, CP29, CP34 and CP35); and

iii. Date and duration of operation of generators and fire pumps for testing, maintenance, and nonemergency use (EUs: CP13 through CP17, CP28, CP29, CP34, and CP35); and

iv. Monthly, consecutive 12-month total of gasoline throughput *[40 CFR Part 63.11116(b)]*.

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

F. PARIS CASINO RESORT

1. Emission Units

a. The stationary source activities at Paris Casino Resort, covered by this Part 70 OP, consist of the emission units and associated appurtenances summarized in Table III-F-1. *[AQR 12.5.2.3; NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1, (08/20/2009); NSR ATC, Modification 14, (10/09/2009); NSR ATC, Modification 15, Revision 0 (03/20/2010); Title V 70 OP (05/29/2013), (03/28/2016), and (12/19/2019); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-F-1: Summary of EUs – Paris Casino Resort

EU	Description	Rating	Make	Model No.	Serial No.
PA12	Natural Gas Boiler #4	3.5 MMBtu/hr	Bryan	RV350S-150-FDG-LX	81362
PA13	Natural Gas Boiler #5	3.5 MMBtu/hr	Bryan	RV350S-150-FDG-LX	81349
PA14	Natural Gas Boiler #3	17.0 MMBtu/hr	Bryan	RW1700W-FDG-LX	81458
PA15	Natural Gas Boiler #1	21.0 MMBtu/hr	Bryan	RW2100W-FDG-LX	81444
PA16	Natural Gas Boiler #2	21.0 MMBtu/hr	Bryan	RW2100W-FDG-LX	81457
PA17	Emergency Generator #1 DOM: 03/25/1998	2,100kW 2,816 hp	Cummins	QSW73 CW73-G	79652 66300058
PA18	Emergency Generator #2 DOM: 02/26/1998	2,100kW 2,816 hp	Cummins	QSW73 CW73-G	79651 66300040
PA19	2-Cell Cooling Tower #1	4,725 gpm	Baltimore Aircoil	33758-2W	97221981 & 97222002
PA20	2-Cell Cooling Tower #2	4,725 gpm	Baltimore Aircoil	33758-2W	97222011 & 97222001
PA21	2-Cell Cooling Tower #3	4,725 gpm	Baltimore Aircoil	33758-2W	97222021 & 97221992
PA22	2-Cell Cooling Tower #4	4,725 gpm	Baltimore Aircoil	33758-2W	97221991 & 97222012
PA23	2-Cell Cooling Tower #5	4,725 gpm	Baltimore Aircoil	33758-2W	97222022 & 97221982
PA28	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	0409522881
PA29	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	092086486
PA30	Natural Gas Pool Heater	1.95 MMBtu/hr	RBI Futera II	FW1950	092084697
PA31	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	071983421

EU	Description	Rating	Make	Model No.	Serial No.
PA32	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	021261112
PA33	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	121160719
PA34	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	011260847
PA35	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	021982198
PA36	Natural Gas Boiler	1.95 MMBtu/hr	RBI Futera II	FW1950	051570836

2. Emission Limitations

The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-F-2. *[NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1, (08/20/2009); NSR ATC, Modification 14, (10/09/2009); NSR ATC, Modification 15, Revision 0 (03/20/2010); and Title V 70 OP (05/29/2013), (03/28/2016), and (12/19/2019)]*

Table III-F-2: PTE (tons per year) – Paris Casino Resort

EU	Conditions[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
PA12	8,760 hr/yr	0.13	0.13	0.48	1.27	0.01	0.09	0.04
PA13	8,760 hr/yr	0.13	0.13	0.48	1.27	0.01	0.09	0.04
PA14	8,760 hr/yr	0.56	0.56	2.72	6.28	0.04	0.40	0.14
PA15	8,760 hr/yr	0.69	0.69	3.36	7.75	0.06	0.50	0.17
PA16	8,760 hr/yr	0.69	0.69	3.36	7.75	0.06	0.50	0.17
PA17	500 hr/yr	0.49	0.49	16.90	3.87	0.01	0.50	0.02
PA18	500 hr/yr	0.49	0.49	16.90	3.87	0.01	0.50	0.02
PA19	8,760 hr/yr	1.22	1.22	0.00	0.00	0.00	0.00	0.00
PA20	8,760 hr/yr	1.22	1.22	0.00	0.00	0.00	0.00	0.00
PA21	8,760 hr/yr	1.22	1.22	0.00	0.00	0.00	0.00	0.00
PA22	8,760 hr/yr	1.22	1.22	0.00	0.00	0.00	0.00	0.00
PA23	8,760 hr/yr	1.22	1.22	0.00	0.00	0.00	0.00	0.00
PA28	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA29	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA30	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA31	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA32	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA33	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA34	8,760 hr/yr	0.06	0.06	0.10	0.32	0.01	0.05	0.02
PA35	8,760 hr/yr	0.06	0.06	0.10	0.70	0.01	0.05	0.02
PA36	8,760 hr/yr	0.06	0.06	0.84	0.70	0.01	0.05	0.02

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

a. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-F-3. *[Title V OP (05/29/2013)]*

Table III-F-3: Emissions – Paris Casino Resort

EU	Rating	NO_x/CO (ppm)[1]	NO_x (lbs/hr)	CO (lbs/hr)
PA14	17.0 MMBtu/hr	NO_x 30/CO 114	0.62	1.44
PA15	21.0 MMBtu/hr	NO_x 30/CO 114	0.77	1.78
PA16	21.0 MMBtu/hr	NO_x 30/CO 114	0.77	1.78

[1]Corrected to 3% oxygen.

b. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than 6 consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: PA17 and PA18). *[40 CFR Part 63.6640(f)(i)(ii)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain the 3.5 MMBtu/hour boilers (EUs: PA12 and PA13) with burners that have a manufacturer's maximum emission concentration of 26 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

d. The permittee shall operate and maintain the 3.5 MMBtu/hour boilers (EUs: PA12 and PA13) with burners that have a manufacturer's maximum emission concentration of 111 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

e. The permittee shall operate and maintain the 17.0 MMBtu/hr boiler (EU: PA14) with burners that have a manufacturer's maximum emission concentration of 30 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

f. The permittee shall operate and maintain the 17.0 MMBtu/hr boiler (EU: PA14) with burners that have a manufacturer's maximum emission concentration of 114 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

g. The permittee shall operate and maintain the 21.0 MMBtu/hr boilers (EUs: PA15 and PA16) with burners that have a manufacturer's maximum emission concentration of 30 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate and maintain the 21.0 MMBtu/hr boilers (EUs: PA15 and PA16) with burners that have a manufacturer's maximum emission concentration of 114 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

i. The permittee shall operate and maintain the 1.95 MMBtu/hr boilers (EUs: PA28 through PA34) with burners that have a manufacturer's maximum emission concentration of 10 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 15, Revision 0 (03/20/2010)]*

j. The permittee shall operate and maintain the 1.95 MMBtu/hr boilers (EUs: PA28 through PA34) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 15, Revision 0 (03/20/2010)]*

k. The permittee shall operate and maintain the 1.95 MMBtu/hr boiler (EU: PA35) with burners that have a manufacturer's maximum emission concentration of 10 ppm NO_x, corrected to 3% oxygen. *[Title V OP (12/19/2019)]*

Diesel Generators [AQR 12.5.2.6]

l. The permittee shall operate and maintain all diesel generators in accordance with the manufacturer's O&M manual for emissions-related components. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

m. The permittee shall operate each of the diesel engine with turbochargers (EUs: PA17 and PA18). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

Cooling Towers

n. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. No chromium-containing compounds shall be used for water treatment. *[40 CFR Part 63.402]*

o. The permittee shall operate each of the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.005% (EUs: PA19 through PA23). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

p. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm. *[Title V OP (12/19/2019)]*

Other

q. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(1)]*

b. The permittee shall perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.6(d)]*

d. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.6(d)]*

e. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.6(d)]*.

Diesel Generators

f. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters. (EUs: PA17 and PA18). *[AQR 12.5.2.6(d)]*

Visible Emissions

g. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

i. 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. *[AQR 12.5.2.6(d)]*

j. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

i. 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

ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

a. 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.

b. 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.

c. 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.

k. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

l. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee shall use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS. *[AQR 12.5.2.6(d)]*

6. Testing

a. Performance testing shall be the instrument for determining compliance with emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: PA14, PA15, and PA16). *[AQR 12.5.2.8(a) and Air Quality's Guidelines for Source Testing]*

b. The permittee shall conduct performance tests on each boiler (EUs: PA14, PA15, and PA16) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and Air Quality's Guidelines for Source Testing]*

Table III-F-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

7. Recordkeeping

a. The permittee shall maintain records on site that include, at a minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this permit;

iv. Records of burner efficiency testing;

v. Results of performance testing; and

vi. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: PA14, PA15, and PA16); *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of emergency generators for testing, maintenance, and nonemergency use (EUs: PA17 and PA18); and

iii. Date and duration of operation of emergency generators for emergency use, including documentation justifying use during the emergency (EUs: PA17 and PA18).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

G. THE LINQ HOTEL & CASINO

1. Emission Units

a. The stationary source activities at The LINQ Hotel & Casino covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-G-1. *[AQR 12.5.2.3; NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1, (08/20/2009); Title V OP (03/28/2016); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-G-1: Summary of EUs – The LINQ Hotel & Casino

EU	Description	Rating	Make	Model No.	Serial No.
IP01	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	WG-1250 D	82-34510
IP02	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	WG-1250 D	82-34507
IP03	Natural Gas Boiler	1.25 MMBtu/hr	Ajax	WG-1250 D	82-34502
IP04	Natural Gas Boiler	16.738 MMBtu/hr	Kewanee	H3S 400HP	R8190
IP05	Natural Gas Boiler	16.738 MMBtu/hr	Kewanee	H3S 400-G0	R8191
IP06	Emergency Generator DOM: Pre-2006	470 kW	Caterpillar	SR4	6EA00547
		680 hp		3412	81Z01351
IP07	Emergency Generator DOM: Pre-2006	500 kW	Caterpillar	SR4	5NA05002
		755 hp		3412	81Z04033
IP08	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	SR4	6FA04856
		890 hp		3412	81Z07511
IP09	Emergency Generator DOM: Pre-2006	600 kW	Caterpillar	SR4	6FA05404
		890 hp		3412	81Z08595
IP10	Emergency Generator DOM: Pre-2006	280 kW	E.M. Generator	7083-7305	263120414
		375 hp	Detroit		
IP11	Emergency Generator DOM: Pre-2006	500 kW	Marathon Electric	580FDF4036FFPD1W	JB-95613
		670 hp	Detroit	71637305	16VA015737
IP38	Emergency Generator DOM: 2019	500 kW	Caterpillar	LC6	G6B25666
		762 hp	Caterpillar	C15	FTE04081

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-G-2. *[NSR ATC, Modification 7, Revision 0 (01/29/2008); NSR ATC, Modification 10, Revision 0 (12/15/2008); NSR ATC, Modification 12, Revision 1, (08/20/2009); Title V OP (03/28/2016); and Application for Renewal of Part 70 OP (09/25/2020)]*

Table III-G-2: PTE (tons per year) – The LINQ Hotel & Casino

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
IP01	8,760 hr/yr	0.04	0.04	0.27	0.45	0.01	0.03	0.01
IP02	8,760 hr/yr	0.04	0.04	0.27	0.45	0.01	0.03	0.01
IP03	8,760 hr/yr	0.04	0.04	0.27	0.45	0.01	0.03	0.01
IP04	8,760 hr/yr	0.57	0.57	3.59	5.43	0.04	0.39	0.13
IP05	8,760 hr/yr	0.57	0.57	3.59	5.43	0.04	0.39	0.13
IP06	500 hr/yr	0.12	0.12	4.08	0.94	0.01	0.12	0.00
IP07	500 hr/yr	0.13	0.13	4.53	1.04	0.01	0.13	0.01
IP08	500 hr/yr	0.16	0.16	5.34	1.23	0.01	0.16	0.01
IP09	500 hr/yr	0.16	0.16	5.34	1.23	0.01	0.16	0.01
IP10	500 hr/yr	0.21	0.21	2.91	0.63	0.01	0.24	0.01
IP11	500 hr/yr	0.12	0.12	4.02	0.92	0.01	0.12	0.01
IP38	500 hr/yr	0.02	0.02	2.07	0.49	0.01	0.02	0.01

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-G-3. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

Table III-G-3: Emissions – The LINQ Hotel & Casino

EU	Rating	NO_x/CO (ppm)[1]	NOx (lbs/hr)	CO (lbs/hr)
IP04	16.738 MMBtu/hr	NO_x 40.2/CO 100	0.82	1.24
IP05	16.738 MMBtu/hr	NO_x 40.2/CO 100	0.82	1.24

[1]Corrected to 3% oxygen.

c. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than 6 consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: IP06 through IP11). *[40 CFR Part 63.6640(f)(i)(ii)]*

b. The permittee shall limit the operation of the diesel-fired emergency generator for testing and maintenance purposes to 100 hours per year. The permittee may operate the emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EU: IP38). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters [AQR 12.5.2.6]

a. The permittee shall combust only natural gas in all boilers/heaters. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

c. The permittee shall operate and maintain the 1.25 MMBtu/hr boilers (EUs: IP01 through IP03) with burners that have a manufacturer's maximum emission concentration of 40.2 ppm NO_x, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

d. The permittee shall operate and maintain the 1.25 MMBtu/hr boilers (EUs: IP01 through IP03) with burners that have a manufacturer's maximum emission concentration of 110.5 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

e. The permittee shall operate and maintain the 16.738 MMBtu/hr boilers (EUs: IP04 and IP05) with burners that have a manufacturer's maximum emission concentration of 40.2 ppm NO_x, corrected to 3% oxygen, and FGR control devices. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

f. The permittee shall operate and maintain the 16.738 MMBtu/hr boilers (EUs: IP04 and IP05) with burners that have a manufacturer's maximum emission concentration of 100 ppm CO, corrected to 3% oxygen. *[NSR ATC, Modification 7, Revision 0 (01/29/2008)]*

Diesel Generators

g. 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. *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

h. The permittee shall operate each of the emergency generators with turbochargers and aftercoolers (EUs: IP06 through IP09 and IP38). *[NSR ATC, Modification 10, Revision 0 (12/15/2008) and Application for Renewal of Part 70 OP (09/25/2020)]*

i. The permittee shall operate each of the emergency generators with turbochargers (EUs: IP10 and IP11). *[NSR ATC, Modification 10, Revision 0 (12/15/2008)]*

j. The permittee shall ensure that the diesel engine is in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EU: IP38): *[40 CFR Part 60.4206]*

    i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

    ii. installation and configuration of the engine according to the manufacturer's specifications.

Other

k. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: IP04 and IP05). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(1)]*

b. The permittee shall perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven (EUs: IP04 and IP05). *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: IP04 and IP05). *[AQR 12.5.2.6(d)]*

d. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: IP04 and IP05). *[AQR 12.5.2.6(d)]*

e. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: IP04 and IP05). *[AQR 12.5.2.6(d)]*

Diesel Generators

f. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters. (EUs: IP06 through IP11 and IP38). *[AQR 12.5.2.6(d)]*

Visible Emissions

g. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

i. 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. *[AQR 12.5.2.6(d)]*

j. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

    i. 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

ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

a. 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.

b. 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.

c. 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.

k. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

6. Testing

a. Performance testing shall be the instrument for determining compliance with the emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: IP04 and IP05). *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

b. The permittee shall conduct performance tests on each boiler (EUs: IP04 and IP05) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

Table III-G-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Log book of all inspections, maintenance, and repairs, as specified in this permit;

iii. Records of burner efficiency testing;

iv. Results of performance testing; and

v. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: IP04 and IP05); *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of emergency generators for testing, maintenance, and nonemergency use (EUs: IP06 through IP11 and IP38); and

iii. Date and duration of operation of emergency generators for emergency use, including documentation justifying use during the emergency (EUs: IP06 through IP11 and IP38).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

H. PLANET HOLLYWOOD

1. Emission Units

a. The stationary source activities at the Planet Hollywood covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-H-1. *[AQR 12.5.2.3 and Part 70 OP (06/23/2021)]*

Table III-H-1: Summary of EUs – Planet Hollywood

EU	Type	Rating	Manufacturer	Model No.	Serial No.
PH07	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	ZF2000W	2339
PH08	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	ZF2000W	2340
PH09	Natural Gas Boiler	23.65 MMBtu/hr	Unilux	ZF2000W	2341

EU	Type	Rating	Manufacturer	Model No.	Serial No.
PH10	Genset – Emergency	1,750 kW	Spectrum	1750DS4	0628031
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	T1637K16	5272000427
PH11	Genset – Emergency	1,750 kW	Spectrum	1750DS4	0628032
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	T1637K16	5272000397
PH12	Genset – Emergency	1,750 kW	Spectrum	1750DS4	0628033
	Engine – Diesel DOM: 1999	2,550 hp	MTU/Detroit Diesel	T1637K16	5272000421
PH13	Genset – Emergency	1,750 kW	MTU	1750RXC6DT2	301122-1-1-1208
	Engine – Diesel DOM: 2008	2,561 hp	MTU/Detroit Diesel	T1238A36	5262003725
PH14	6-Cell Cooling Tower	33,360 gpm	Baltimore Aircoil Company	PCS50-2424-100-12P3	PC2429

Note: DOM: date of manufacture; gpm: gallons per minute; hp: horsepower; kW: kilowatt; MMBtu: millions of British thermal units.

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-H-2. *[Part 70 OP (06/23/2021)]*

Table III-H-2: PTE (tons per year) – Planet Hollywood

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
PH07	8,760 hr/yr	0.78	0.78	3.78	7.67	0.06	0.56	0.20
PH08	8,760 hr/yr	0.78	0.78	3.78	7.67	0.06	0.56	0.20
PH09	8,760 hr/yr	0.78	0.78	3.78	7.67	0.06	0.56	0.20
PH10	500 hr/yr	0.45	0.45	15.30	3.51	0.01	0.45	0.01
PH11	500 hr/yr	0.45	0.45	15.30	3.51	0.01	0.45	0.01
PH12	500 hr/yr	0.45	0.45	15.30	3.51	0.01	0.45	0.01
PH13	500 hr/yr	0.21	0.21	6.40	3.68	0.01	0.34	0.01
PH14	8,760 hr/yr	8.58	8.58	0.00	0.00	0.00	0.00	0.00

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not allow actual emissions from the individual emission units to exceed the emission rates and emission concentrations listed in Table III-H-3. *[AQR 12.5.2.3 and Part 70 OP(06/23/2021)]*

Table III-H-3: Emissions – Planet Hollywood

EU	Rating	NO_x/CO (ppm)[1]	NO_x **(lbs/hr)**	CO **(lbs/hr)**
PH07	23.65 MMBtu/hr	NO_x 30/CO 100	0.86	1.75
PH08	23.65 MMBtu/hr	NO_x 30/CO 100	0.86	1.75
PH09	23.65 MMBtu/hr	NO_x 30/CO 100	0.86	1.75

[1]Corrected to 3% oxygen.

c. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each of the emergency generators up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: PH10 through PH12). *[40 CFR Part 63.6640(f)(i)(ii)]*

b. The permittee shall limit the operation of the diesel-fired emergency generator for testing and maintenance purposes to 100 hours per year. The permittee may operate the emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EU: PH13). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[Part 70 OP (06/23/2021)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[Part 70 OP (06/23/2021)]*

c. The permittee shall operate and maintain the boilers (EUs: PH07 through PH09) with burners that have a manufacturer's maximum emission concentration of 30 ppm NO_x, corrected to 3% oxygen. *[Part 70 OP (06/23/2021)]*

d. The permittee shall operate and maintain the boilers (EUs: PH07 through PH09) with burners that have a manufacturer's maximum emission concentration of 100 ppm CO, corrected to 3% oxygen. *[Part 70 OP (06/23/2021)]*

Diesel Generators

e. The permittee shall operate and maintain all diesel generators in accordance with the manufacturer's O&M manual for emissions-related components. *[Part 70 OP (06/23/2021)]*

f. The permittee shall operate each of the diesel engines with turbochargers and aftercoolers (EUs: PH10 through PH13). *[Part 70 OP (06/23/2021)]*

g. The permittee shall ensure that the diesel engine is in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EU: PH13): *[40 CFR Part 60.4206]*

i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

h. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. No chromium-containing compounds shall be used for water treatment (EU: PH14). *[Part 70 OP (06/23/2021)]*

i. The permittee shall operate the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.005% (EU: PH14). *[Part 70 OP (06/23/2021)]*

j. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm (EU: PH14). *[Part 70 OP (06/23/2021)]*

Other

k. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall install and utilize nonresettable fuel meters such that the daily consumption of natural gas can be established for each applicable boiler (EUs: PH07 through PH09). *[AQR 12.5.2.6(d) and 40 CFR Part 60.48c(g)(2)]*

b. The permittee shall perform a burner efficiency test twice each calendar year, at least five months apart but no more than seven (EUs: PH07 through PH09). *[AQR 12.5.2.6(d)]*

c. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: PH07 through PH09). *[AQR 12.5.2.6(d)]*

d. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: PH07 through PH09). *[AQR 12.5.2.6(d)]*

e. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: PH07 through PH09). *[AQR 12.5.2.6(d)]*

Diesel Generators

f. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters when operated for testing, maintenance, or during emergencies. (EUs: PH10 through PH13). *[AQR 12.5.2.6(d)]*

Visible Emissions

g. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

i. 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. *[AQR 12.5.2.6(d)]*

j. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

   i. 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

   ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

      a. 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.

      b. 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.

      c. 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.

k. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

l. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS (EU: PH14). *[AQR 12.5.2.6(d)]*

6. Testing

a. Performance testing shall be the instrument for determining compliance with the emission limitations set forth in this permit for all boilers that have a heat input rating equal to or greater than 10.0 MMBtu/hr (EUs: PH07 through PH09). *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

b. The permittee shall conduct performance tests on each boiler (EUs: PH07 through PH09) every five years, and no later than 90 days after the anniversary date of the last performance test. *[AQR 12.5.2.8(a) and DAQ's "Guidelines for Source Testing"]*

Table III-H-4: Performance Testing Protocol Requirements

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_x	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	—	EPA Methods 1, 2, 3A, and 4

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this permit;

iv. Records of burner efficiency testing, as specified in this permit;

v. Results of performance testing; and

vi. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Monthly amount of natural gas consumed (in MMBtu, scf, or therms) for each boiler (EUs: PH07 through PH09); *[40 CFR Part 60.48c(g)(1)]*

ii. Date and duration of operation of generators for emergency use, including documentation justifying use during the emergency (EUs: PH10 through PH13); and

iii. Date and duration of operation of emergency generators for testing, maintenance, and nonemergency use (EUs: PH10 through PH13).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

I. LINQ COMPLEX – HIGH ROLLER

1. Emission Units

a. The stationary source activities at the LINQ Complex – High Roller covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-I-1. *[AQR 12.5.2.3; Title V OP Significant Revision (05/29/13); and Title V OP (03/28/2016)]*

Table III-I-1: Summary of EU – LINQ Complex – High Roller

EU	Description	Rating	Make	Model No.	Serial No.
LI01	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	DNRH-5000-MSI	041215509
LI02	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	DNRH-5000-MSI	041215507
LI03	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	DNRH-5000-MSI	041215508
LI04	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	DNRH-5000-MSI	041215506
LI05	Natural Gas Boiler	5.0 MMBtu/hr	CAMUS	DNRH-5000-MSI	041215505
LI06	Emergency Generator DOM: 2012	2,000 kW	Caterpillar	SR4B-GD	G4Z00115
		3,634 hp		3516C	SBJ01461
LI07	Emergency Generator DOM: 2012	2,000 kW	Caterpillar	SR4B-GD	G4Z00116
		3,634 hp		3516C	SBJ01460
LI08	Cooling Tower, 2 cell	6,000 gpm	Marley	NC8413VAN2BGF	NC-10054867-B1&B2
LI09	Cooling Tower, 2 cell	6,000 gpm	Marley	NC8413VAN2BGF	NC-10054867-C1&C2
LI10	Cooling Tower, 2 cell	6,000 gpm	Marley	NC8413VAN2BGF	NC-10054867-A1&A2
LI11	Natural Gas Water Heater	0.150 MMBtu/hr	AO Smith	BTH-150-100	1304M002358

EU	Description	Rating	Make	Model No.	Serial No.
LI12	Emergency Engine DOM: 11/2012	180 kW	Deutz	TCD 6.1 L6	11360110
		241 hp			
LI13	Emergency Engine DOM: 11/2012	180 kW	Deutz	TCD 6.1 L6	11353814
		241 hp			

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-I-2. *[Title V OP Significant Revision (05/29/13); and Title V OP (03/28/2016)]*

Table III-I-2: PTE (tons per year) – LINQ Complex – High Roller

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
LI01	8,760 hr/yr	0.16	0.16	0.24	0.81	0.01	0.12	0.04
LI02	8,760 hr/yr	0.16	0.16	0.24	0.81	0.01	0.12	0.04
LI03	8,760 hr/yr	0.16	0.16	0.24	0.81	0.01	0.12	0.04
LI04	8,760 hr/yr	0.16	0.16	0.24	0.81	0.01	0.12	0.04
LI05	8,760 hr/yr	0.16	0.16	0.24	0.81	0.01	0.12	0.04
LI06	500 hr/yr	0.06	0.06	10.80	0.58	0.01	0.22	0.03
LI07	500 hr/yr	0.06	0.06	10.80	0.58	0.01	0.22	0.03
LI08	8,760 hr/yr	1.55	1.55	0.00	0.00	0.00	0.00	0.00
LI09	8,760 hr/yr	1.55	1.55	0.00	0.00	0.00	0.00	0.00
LI10	8,760 hr/yr	1.55	1.55	0.00	0.00	0.00	0.00	0.00
LI11	8,760 hr/yr	0.01	0.01	0.01	0.02	0.01	0.01	0.01
LI12	500 hr/yr	0.01	0.01	0.20	0.35	0.01	0.02	0.01
LI13	500 hr/yr	0.01	0.01	0.20	0.35	0.01	0.02	0.01

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of each of the diesel-fired emergency generators for testing and maintenance purposes to 100 hours per year. The permittee may operate each emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EUs: LI06, LI07, LI12, and LI13). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

Boilers/Water Heaters

a. The permittee shall combust only natural gas in all boilers/heaters. *[Title V OP (05/29/2013)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[Title V OP (05/29/2013)]*

c. The permittee shall operate and maintain the boilers (EUs: LI01 through LI05) with burners that have a manufacturer's maximum emission concentration of 9 ppm NO_x, corrected to 3% oxygen. *[Title V OP (05/29/2013)]*

d. The permittee shall operate and maintain the boilers (EUs: LI01 through LI05) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[Title V OP (05/29/2013)]*

Diesel Generators

e. The permittee shall operate and maintain all diesel generators in accordance with the manufacturer's O&M manual for emissions-related components. *[Title V OP (05/29/2013)]*

f. The permittee shall operate each of the diesel engines with turbochargers and aftercoolers (EUs: LI06, LI07, LI12, and LI13). *[Title V OP (05/29/2013)]*

g. The permittee shall ensure that the diesel engines are in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EUs: LI06, LI07, LI12, and LI13): *[40 CFR Part 60.4206]*

   i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

   ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

h. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. No chromium-containing compounds shall be used for water treatment. *[Title V OP (05/29/2013)]*

i. The permittee shall operate each of the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.005% (EUs: LI08 through LI10). *[Title V OP (05/29/2013)]*

j. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm. *[Title V OP (12/19/2019)]*

Other

k. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall perform a burner efficiency test once each calendar year (EUs: LI01 through LI05). *[AQR 12.5.2.6(d)]*

b. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: LI01 through LI05). *[AQR 12.5.2.6(d)]*

c. The permittee shall not have to perform a burner efficiency test if the actual hours of operation are 0. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: LI01 through LI05). *[AQR 12.5.2.6(d)]*

d. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: LI01 through LI05). *[AQR 12.5.2.6(d)]*

Diesel Generators

e. The permittee shall monitor operating hours for each applicable diesel engine utilizing nonresettable hour meters when operated for testing, maintenance, or during emergencies. (EUs: LI06, LI07, LI12, and LI13). *[AQR 12.5.2.6(d)]*

Visible Emissions

f. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

g. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

h. 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. *[AQR 12.5.2.6(d)]*

i. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

    i. 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

    ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

a. 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.

b. 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.

c. 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.

j. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

k. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS (EUs: LI08 through LI10). *[AQR 12.5.2.6(d)]*

6. Testing

No performance testing requirements have been identified. *[AQR 12.5.2.8(a)]*

7. Recordkeeping

a. The permittee shall maintain records on site that include, at minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this permit;

iv. Records of burner efficiency testing, as specified in this permit; and

v. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Date and duration of operation of generators for emergency use, including documentation justifying use during the emergency (EUs: LI06, LI07, LI12, and LI13); and

ii. Date and duration of operation of emergency generators for testing, maintenance, and nonemergency use (EUs: LI06, LI07, LI12, and LI13).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

J. BATTISTA'S

All the emission units at Battista's are insignificant and are listed in the TSD.

1. Emission Limitations

a. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

K. FORUM MEETING CENTER

1. Emission Units

a. The stationary source activities at the Forum Meeting Center covered by this Part 70 OP consist of the emission units and associated appurtenances summarized in Table III-K-1. *[AQR 12.5.2.3 and Title V OP (12/19/2019)]*

Table III-K-1: Summary of EUs – Forum Meeting Center

EU	Description	Rating	Make	Model No.	Serial No.
FMC01	Boiler	6.00 MMBtu/hr	Lochinvar	FBN6001	1847112615299
FMC02	Boiler	6.00 MMBtu/hr	Lochinvar	FBN6001	1847112615300
FMC03	Boiler	6.00 MMBtu/hr	Lochinvar	FBN6001	1847112615301
FMC04	Boiler	6.00 MMBtu/hr	Lochinvar	FBN6001	1847112615298
FMC05	Emergency	1,000 kW	Cummins	DQFAD-A061Y200	B190508151

	Generator DOM: 1/21/2019	1,490 hp		QST30	37277632
FMC06	Cooling Tower, 2-Cell	2,400 gpm/cell	Evapco	USS224-4P20	18-849683
FMC07	Cooling Tower, 2-Cell	2,400 gpm/cell	Evapco	USS224-4P20	18-849684

2. Emission Limitations

a. The permittee shall limit the actual emissions from each emission unit to the PTE listed in Table III-K-2. *[Title V OP (12/19/2019)]*

Table III-K-2: PTE (tons per year) – Forum Meeting Center

EU	Condition[1]	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
FMC01	8,760 hr/yr	0.20	0.20	0.29	0.97	0.02	0.14	0.05
FMC02	8,760 hr/yr	0.20	0.20	0.29	0.97	0.02	0.14	0.05
FMC03	8,760 hr/yr	0.20	0.20	0.29	0.97	0.02	0.14	0.05
FMC04	8,760 hr/yr	0.20	0.20	0.29	0.97	0.02	0.14	0.05
FMC05	500 hr/yr	0.08	0.08	3.61	0.41	0.01	0.26	0.01
FMC06	8,760 hr/yr	0.25	0.25	0.00	0.00	0.00	0.00	0.00
FMC07	8,760 hr/yr	0.25	0.25	0.00	0.00	0.00	0.00	0.00

[1]The quantities in this column are not intended as enforceable permit limits unless stated otherwise in this permit.

b. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than six consecutive minutes. *[AQR 26.1]*

3. Production Limitations

a. The permittee shall limit the operation of the diesel-fired emergency generator for testing and maintenance purposes to 100 hours per year. The permittee may operate the emergency generator up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for the facility (EU: FMC05). *[40 CFR Part 60.4211(f)]*

4. Control Requirements

<u>Boilers/Water Heaters</u>

a. The permittee shall combust only natural gas in all boilers/heaters. *[Title V OP (12/19/2019)]*

b. The permittee shall operate and maintain all boilers/heaters in accordance with the manufacturer's O&M manual for emissions-related components and good combustion practices. *[Title V OP (12/19/2019)]*

c. The permittee shall operate and maintain the boilers (FMC01 through FMC04) with burners that have a manufacturer's maximum emission concentration of 9 ppm NO_x, corrected to 3% oxygen. *[Title V OP (12/19/2019)]*

d. The permittee shall operate and maintain the boilers (EUs: FMC01 through FMC04) with burners that have a manufacturer's maximum emission concentration of 50 ppm CO, corrected to 3% oxygen. *[Title V OP (12/19/2019)]*

Diesel Generator

e. The permittee shall operate and maintain the diesel generator in accordance with the manufacturer's O&M manual for emissions-related components. *[Title V OP (12/19/2019)]*

f. The permittee shall operate the diesel engine with a turbocharger and aftercooler (EU: FMC05). *[Title V OP (12/19/2019)]*

g. The permittee shall ensure that the diesel engine is in compliance with 40 CFR Part 60, Subpart IIII, by meeting of all of the following (EU: FMC05): *[40 CFR Part 60.4206]*

   i. operation of the engine according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer; and

   ii. installation and configuration of the engine according to the manufacturer's specifications.

Cooling Towers

h. The permittee shall operate and maintain all cooling towers in accordance with the manufacturer's O&M manual for emissions-related components. No chromium-containing compounds shall be used for water treatment. *[Title V OP (12/19/2019)]*

i. The permittee shall operate each of the cooling towers with drift eliminators that have a manufacturer's maximum drift rate of 0.001% (EUs: FMC06 and FMC07). *[Title V OP (12/19/2019)]*

j. The permittee shall limit the TDS content of each cooling tower's circulation water to 5,000 ppm. *[Title V OP (12/19/2019)]*

Other

k. The permittee shall not cause, suffer, or allow any source to discharge air contaminants (or other materials) in quantities that will cause a nuisance, including excessive odors. *[AQR 40 & AQR 43]*

5. Monitoring

Boilers/Water Heaters

a. The permittee shall perform a burner efficiency once each calendar year (EUs: FMC01 through FMC04). *[AQR 12.5.2.6(d)]*

b. The permittee shall conduct burner efficiency tests in accordance with the manufacturer's O&M manual and good combustion practices. Alternative methods may be used upon Control Officer approval (EUs: FMC01 through FMC04). *[AQR 12.5.2.6(d)]*

c. The permittee shall not have to perform a burner efficiency test if the actual hours of operation are 0. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: FMC01 through FMC04). *[AQR 12.5.2.6(d)]*

d. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: FMC01 through FMC04). *[AQR 12.5.2.6(d)]*

Diesel Generator

e. The permittee shall monitor operating hours for the diesel engine utilizing a nonresettable hour meter when operated for testing, maintenance, or during emergencies. (EU: FMC05). *[AQR 12.5.2.6(d)]*

Visible Emissions

f. The responsible official shall sign and adhere to the *Visible Emissions Check Guidebook* and keep a copy of the signed guide on-site at all times. *[AQR 12.5.2.6(d)]*

g. The permittee shall conduct a visual emissions check at least quarterly on each diesel-fired emergency generator while in operation. *[AQR 12.5.2.6(d)]*

h. 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. *[AQR 12.5.2.6(d)]*

i. If a plume appears to exceed the opacity standard, the permittee shall do one of the following: *[AQR 12.5.2.6(d)]*

   i. 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

   ii. Call a certified VEE reader to perform an EPA Method 9 evaluation.

      a. 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.

      b. 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.

c. 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.

j. Any scenario of visible emissions noncompliance can and may lead to enforcement action. *[AQR 12.5.2.6(d)]*

Cooling Towers

k. The permittee shall monitor the TDS in the cooling tower circulation water monthly. The permittee may use a conductivity meter or an equivalent method approved in advance by the Control Officer to determine TDS (EUs: FMC06 and FMC07). *[AQR 12.5.2.6(d)]*

6. Testing

No performance testing requirements have been identified. *[AQR 12.5.2.8(a)]*

7. Recordkeeping

a. The permittee shall maintain records on site that include, at a minimum, the following: *[AQR 12.5.2.6(d)]*

i. Dates and times when visible emissions checks and observations are made, and the corrective steps taken to bring opacity into compliance;

ii. Monthly TDS content of cooling tower circulation water;

iii. Log book of all inspections, maintenance, and repairs, as specified in this permit;

iv. Records of burner efficiency testing, as specified in this permit; and

v. Records of location changes for nonroad engines, if applicable.

b. The permittee shall maintain records on site and report the following semiannually: *[AQR 12.5.2.6(d)]*

i. Date and duration of operation of the generator for emergency use, including documentation justifying use during the emergency (EU: FMC05); and

ii. Date and duration of operation of the emergency generator for testing, maintenance, and nonemergency use (EU: FMC05).

c. The permittee shall include, for all inspections, logs, visible emission checks, and testing required under monitoring, recordkeeping, and reporting sections, at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*

IV. MITIGATION

The source has no federal offset requirements. *[AQR 12.7]*

V. NONROAD ENGINES

Pursuant to 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 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.

VI. OTHER REQUIREMENTS

1. 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 (CFC) or hydrochlorofluorocarbon (HCFC) compound as a working fluid, unless such fluid has been approved for sale in such use by the Administrator. The permittee shall keep record of all paperwork relevant to the applicable requirements of 40 CFR Part 82 on site. *[40 CFR Part 82]*

2. Caesars shall complete the development and implementation of its Environmental Management Portal (EMP) to assure Caesars future compliance with the requirements of this Operating Permit. The EMP shall be utilized for: *[Hearing Officer's Order (03/28/2019)]*

    a. Monitoring and recording periodic inspections;

    b. Training personnel on regulatory requirements;

    c. Tracking of permitted EUs, regulatory requirements and deadlines, testing deadlines, and permit expiration dates; and

    d. Notifying personnel of upcoming regulatory requirements, including but not limited to testing and reporting deadlines and recordkeeping requirements.

3. The EMP must be in use at all times for recordkeeping, tracking, and notification purposes. *[Hearing Officer's Order (03/28/2019)]*

4. Caesars shall have adopted written procedures for the use of the EMP application and shall commence annual training of all appropriate staff from each of the Facilities. Caesars will maintain records of the attendees, topics addressed, and dates of training. *[Hearing Officer's Order (03/28/2019)]*

VII. PERMIT SHIELD

1. Compliance with the terms contained in this permit shall be deemed compliance with the following applicable requirements in effect on the date of permit issuance:

Table VII-1: Applicable Requirements Related to Permit Shield

Applicable Regulation	Title
40 CFR Part 60, Subpart Dc	Standards of Performance for New Stationary Sources (NSPS) – Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60, Subpart IIII	Standards of Performance for New Stationary Sources (NSPS) – Stationary Compression Ignition (CI) Internal Combustion Engines (ICE)
40 CFR Part 63, Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines
40 CFR Part 63, Subpart CCCCCC	National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities

VIII. ATTACHMENTS

A. APPLICABLE REGULATIONS

1. Nevada Revised Statutes, Chapter 445B.
2. Applicable AQR sections, as listed in Table VIII-A-1.

Table VIII-A-1: Requirements Specifically Identified As Applicable—Local

Citation	Title
AQR Section 0	Definitions
AQR Section 4	Control Officer
AQR Section 12.0	General application requirements for construction of new and modified sources of air pollution
AQR Section 12.2	Permit Requirements for Major Sources in Attainment Areas
AQR Section 12.3	Permit Requirements for Major Sources in Nonattainment Areas
AQR Section 12.4	Authority to Construct Application and Permit Requirements for Part 70 Sources
AQR Section 12.5	Part 70 Operating Permit Requirements
AQR Section 12.13	Posting of Permit
AQR Section 13.2(b)(82) Subpart ZZZZ	NESHAP – Stationary Reciprocating Internal Combustion Engines
AQR Section 13.2.(b)(106) Subpart CCCCCC	NESHAP – Gasoline Dispensing Facilities

Citation	Title
AQR Section 14.1(b)1, Subpart A	NSPS – General Provisions
AQR Section 14.1(b)(5)	NSPS – Standards of Performance for Small Industrial – Commercial – Institutional Steam Generating Units (Subpart Dc)
AQR Section 14.1(b)(80)	NSPS – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (Subpart IIII)
AQR Section 18	Permit and Technical Service Fees
AQR Section 25	Affirmative Defense for Excess Emissions Due to Malfunctions, Startup, and Shutdown
AQR Section 26.1	Emissions of Visible Air Contaminants
AQR Section 28	Fuel Burning Equipment
AQR Section 40	Prohibition of Nuisance Conditions
AQR Section 41.1	Fugitive Dust
AQR Section 42	Open Burning
AQR Section 43	Odors in the Ambient Air
AQR Section 70.4	Emergency Procedures
AQR Section 80	Circumvention

3. Clean Air Act, as amended (authority: 42 U.S.C. § 7401, et seq.)
4. Applicable 40 CFR subsections, as listed in Table VIII-A-2.

Table VIII-A-2. Requirements Specifically Identified As Applicable—Federal

Citation	Title
40 CFR Part 52.21	Prevention of Significant Deterioration (PSD)
40 CFR Part 52.1470	SIP Rules
40 CFR Part 60, Subpart A	Standards of Performance for New Stationary Sources – General Provisions
40 CFR Part 60, Subpart Dc	Standards of Performance for New Stationary Sources – Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60	Appendix A, Method 9 or equivalent, (Opacity)
40 CFR Part 60, Subpart IIII	Standards of Performance for New Stationary Sources – Stationary Compression Ignition (CI) Internal Combustion Engines (ICE)
43 CFR Part 63, Subpart ZZZZ	NESHAP for Stationary Reciprocating Internal Combustion Engines
40 CFR Part 63, Subpart CCCCCC	NESHAP for Gasoline Dispensing Facilities
40 CFR Part 70	Federally Mandated Operating Permits
40 CFR Part 82	Protection of Stratospheric Ozone

Appendix B

RACT Analysis – Hurst and Burnham Boilers

Emission Units CP01, CP02, CP03, CP04 and CP05

APPENDIX B

RACT Analysis

Hurst and Burnham Boilers, Emission Units CP01, CP02, CP03, CP04 and CP05

Appendix B
Table of Contents

Attachments

1.0 General

This appendix summarizes the Reasonably Available Control Technology (RACT) Analysis performed for the Hurst and Burnham boilers, Emission Units (EUs) CP01 - CP05, located at Caesars Entertainment, Inc. (Caesars), Caesars Palace. The basic steps for this analysis are as follows:

- 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

Controls for oxides of nitrogen (NO_X) are evaluated in this appendix.

2.0 NO_X RACT Assessment

2.1 Equipment Description and Limitations

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 @ 3% O_2 (1.24 lb/hr) for EUs CP01 and CP02 and 30 ppm @ 3% O_2 (1.23 lb/hr) for EUs CP03, CP04 and CP05. All five emissions units are similar (3-pass, fire-tube type and rated at 800 bhp). The only difference between the emission units is the manufacturer and maximum heat input rating of the burners, however, the difference in maximum heat input ratings between the Hurst and Burnham boilers is small. For these reasons, this evaluation is being performed for all five emission units concurrently.

2.2 Baseline Emissions

As noted in Section 3 of the report, baseline emissions can be set equivalent to actual emissions if actual emissions for the three previous consecutive years are 70% or less of the source's or individual emission unit's potential emissions. Caesars meets this criterion on both a facility-wide basis and individual emissions unit basis. Table 1 below summarizes the baseline NO_X emissions for each emission unit.

Table 1 - Baseline Emissions

Emission Unit	NO_X Emissions[1] (tons)
CP01	2.23
CP02	2.74
CP03	2.35
CP04	1.08
CP05	2.49

Notes: [1] Maximum annual emissions for 2019 - 2021.

2.3 Identification and Technical Feasibility of NO_X Control Options

2.3.1. Identification of Available Controls

A review of the most recent (5 years) determinations contained in the U.S. EPA RACT/BACT/LAER Clearinghouse was conducted to identify any recent RACT determinations for boilers of the same or comparable size. The database did not contain any RACT determinations for this time period. 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 2.

Table 2 – 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
Ultra-Low NOx 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

The technical feasibility of each control option will next be evaluated.

2.3.2. Flue Gas Recirculation (FGR)

FGR involves the recirculation of a portion of the flue gas to the burners. It reduces NO_X emissions by two mechanisms. First, the recirculated gas acts as a dilutant to reduce combustion temperatures, thus suppressing the thermal NO_X mechanism. Second, FGR lowers the oxygen concentration in the primary flame zone. The portion recycled is up to 25% to 30% and it can be implemented on most modern design types. It may not be feasible to retrofit this technology on all existing boiler types or in places with spacing limitations. 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 ultra-low NO_X burner.

2.3.3. Ultra-Low NO_X Burner

Low NO_X burners reduce NO_X by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame, which suppresses thermal NO_X formation. The two most common types of low NO_X burners being applied to natural gas boilers are staged air burners and staged fuel burners, or a combination thereof. The existing Riello burners associated with all five boilers are low NO_x design already and cannot be modified to increase NO_x reduction to the level of an ultra-low burner capability so it would be necessary to replace each burner with an ultra-low NO_X burner. This is technically feasible and would be capable of reducing the NO_X concentration in the boiler exhaust to 9 ppm @ 3% O_2. Emissions of CO would necessarily increase, however.

2.3.4. Selective Catalytic Reduction (SCR)

SCR involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst. The catalyst allows the ammonia to reduce NO_X levels at lower exhaust temperatures than selective non-catalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400-1600°F, SCR can be utilized where exhaust gases are between 500° F and 1200° F, depending on the catalyst used. SCR can result in NO_X reductions up to 75%. Since all of the boilers reviewed in this analysis generate exhaust temperatures of less than 400° F, an SCR system is not a technically feasible option for this application.

2.3.5. Selective Non-Catalytic Reduction (SNCR)

SNCR involves the injection of a NO_X reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1400-1600°F. The ammonia or urea breaks down the NO_X in the exhaust gases into water and atmospheric nitrogen. SNCR reduces NO_X up to 50%. As was the case with SCR control, the boiler exhaust temperatures are far too low to implement SNCR as a viable control technology. The 400 ° F boiler exhaust makes an SNCR system not technically feasible for this application.

2.3.6. Technological Feasibility Summary

Table 3 summarizes the technological feasibility evaluations of the identified control options.

Table 3 – NO_X Control Technology Methods for EU CP01 - CP05

Control Equipment	Technically Feasible?	Uncontrolled NO_X Emissions (tons/yr)	NO_X Controlled Emission Rate (tons/yr)	NO_X removed (tons/yr)
FGR	No	n/a	n/a	n/a
Ultra-Low NO_x Burner	Yes	1.08 - 2.74	0.32 - 0.82	0.76 - 1.92
SCR	No	n/a	n/a	n/a
SNCR	No	n/a	n/a	n/a

Based on the information presented in Table 3, Caesars will evaluate the cost of an ultra-low NO_X burner rated at 9 ppm.

2.4 Cost of NO_X Control Options

For each technically feasible method of control, a total annualized equipment cost and an annual operating cost has been calculated. The calculation of the capital cost recovery factor used to estimate the annualized equipment cost assumes an interest rate of 6% and equipment life of 10 years. The individual cost calculations for each EU are included in Attachment B-1. The capital cost is based on an actual quote from an equipment vendor, a copy of which is included with Attachment B-1. The calculated costs are summarized in Table 4.

Table 4 – Cost of NO_X Control Options for EUs CP01 - CP05

Method of Control	Annualized Cost ($/yr)	Estimated NO_X Removal (tons/yr)	Cost Effectiveness ($/ton removed)
Ultra-Low NO_X Burner (CP01)	$32,337	1.56	$20,715
Ultra-Low NO_X Burner (CP02)	$32,337	1.92	$16,860
Ultra-Low NO_X Burner (CP03)	$32,337	1.65	$19,657
Ultra-Low NO_X Burner (CP04)	$32,337	0.76	$42,773
Ultra-Low NO_X Burner (CP05)	$32,337	1.74	$18,552

2.5 Environmental, Energy & Economic Considerations

2.5.1. 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 two for each boiler retrofitted with an ultra-low NO_X burner.

2.5.2. 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.

2.5.3. Economic Impacts

The economic impacts analysis is based on the cost effectiveness of each technology in terms of the cost per ton of removed pollutant as evaluated in Section 2.4. A maximum cost effectiveness threshold for NO_X RACT has not been established by DAQ. In 1994, the U.S. EPA recommended a maximum of $1,300 per ton to represent RACT at that time. Based on the increase in the Chemical Engineering Plant Cost Index (CEPCI) between then and now, this equates to approximately $3,000 per ton for the present. The U.S. EPA, in its approval of certain State Implementation Plan revisions for Pennsylvania (85 FR 65706) noted that Pennsylvania's proposed maximum of $2,800 per ton was low compared to other states but approved it. Maximum thresholds for other jurisdictions were presented in the notice as follows:

- Wisconsin, $2,500 per ton NO_X
- Illinois, $2,500—$3,000 per ton NO_X

- Maryland, \$3,500—\$5,000 per ton NO_X
- Ohio, \$5,000 per ton NO_X
- New York, \$5,000—\$5,500 per ton NO_X

For the purpose of this analysis, even if the maximum value of \$5,500 from above is deemed appropriate in Clark County, the cost of control for each individual boiler significantly exceeds this value. Table 4 presents the cost effectiveness of the viable control option upgrades. They exceed the most stringent RACT thresholds several times over.

3.0 NO_X RACT Determination

After eliminating technically infeasible options and evaluating the remaining technologies for environmental, energy, and economic impacts, it is evident that emission units CP01-CP05 can be considered to comply with RACT with existing emission limitations, monitoring, testing and recordkeeping. Performance tests indicate the current emission limits are achieved.

ATTACHMENT B-1

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	CP01
Emission Unit Description	Hurst Boiler
Control Technology	Ultra-Low NO_X Burner
Baseline Emission Rate[1] (tons/year)	2.23
Emission Reduction[2] (%)	70%
Controlled Emissions (tons/year)	0.67

Annualized Capital Costs

Initial Capital Investment[3]	$235,000
Direct & Indirect Costs[4]	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$32,337

Annual Operating Costs

No additional annual operating cost identified

Total Annualized Cost	$32,337

Cost Effectiveness

Emissions Reduction (tons/year)	1.56
Cost Effectiveness of NO_X Reduction ($/ton)	$20,715

Notes:

[1] Maximum actual emissions for 2019 - 2021.

[2] NO_X emissions reduced from 29 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

Cost Effectiveness Calculation

Emission Unit/Control Technology	
Emission Unit	CP02
Emission Unit Description	Hurst Boiler
Control Technology	Ultra-Low NO_X Burner
Baseline Emission Rate[1] (tons/year)	2.74
Emission Reduction[2] (%)	70%
Controlled Emissions (tons/year)	0.82
Annualized Capital Costs	
Initial Capital Investment[3]	$235,000
Direct & Indirect Costs[4]	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$32,337
Annual Operating Costs	
No additional annual operating cost identified	
Total Annualized Cost	$32,337
Cost Effectiveness	
Emissions Reduction (tons/year)	1.92
Cost Effectiveness of NO_X Reduction ($/ton)	$16,860

Notes:

[1] Maximum actual emissions for 2019 - 2021.

[2] NO_X emissions reduced from 29 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	CP03
Emission Unit Description	Burnham Boiler
Control Technology	Ultra-Low NO_X Burner
Baseline Emission Rate[1] (tons/year)	2.35
Emission Reduction[2] (%)	70%
Controlled Emissions (tons/year)	0.71

Annualized Capital Costs

Initial Capital Investment[3]	$235,000
Direct & Indirect Costs[4]	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$32,337

Annual Operating Costs

No additional annual operating cost identified

Total Annualized Cost	$32,337

Cost Effectiveness

Emissions Reduction (tons/year)	1.65
Cost Effectiveness of NO_X Reduction ($/ton)	$19,657

Notes:

[1] Maximum actual emissions for 2019 - 2021.

[2] NO_X emissions reduced from 29 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	CP04
Emission Unit Description	Burnham Boiler
Control Technology	Ultra-Low NO_X Burner
Baseline Emission Rate[1] (tons/year)	1.08
Emission Reduction[2] (%)	70%
Controlled Emissions (tons/year)	0.32

Annualized Capital Costs

Initial Capital Investment[3]	$235,000
Direct & Indirect Costs[4]	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$32,337

Annual Operating Costs

No additional annual operating cost identified

Total Annualized Cost	$32,337

Cost Effectiveness

Emissions Reduction (tons/year)	0.76
Cost Effectiveness of NO_X Reduction ($/ton)	$42,773

Notes:

[1] Maximum actual emissions for 2019 - 2021.

[2] NO_X emissions reduced from 29 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	CP05
Emission Unit Description	Burnham Boiler
Control Technology	Ultra-Low NO_X Burner
Baseline Emission Rate[1] (tons/year)	2.49
Emission Reduction[2] (%)	70%
Controlled Emissions (tons/year)	0.75

Annualized Capital Costs

Initial Capital Investment[3]	$235,000
Direct & Indirect Costs[4]	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$32,337

Annual Operating Costs

No additional annual operating cost identified

Total Annualized Cost	$32,337

Cost Effectiveness

Emissions Reduction (tons/year)	1.74
Cost Effectiveness of NO_X Reduction ($/ton)	$18,552

Notes:

[1] Maximum actual emissions for 2019 - 2021.

[2] NO_X emissions reduced from 29 ppm to 9 ppm.

[3] Cost based on vendor estimate includes installation and startup.

[4] Performance testing.

Company:	Broadbent	Date	Estimate No
Attention:	Russ Harms	9/13/2022	221614
Phone:			
Fax:			

Pyro Combustion & Controls, Inc, is pleased to offer, for your consideration the following:

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* Install new refractory ring
* Mount burner to boiler
* Wire to existing controls
* Start-up and check safety controls for proper operation

Sales Tax - Clark County

Lead Time:

Our price, including labor, materials, applicable taxes and freight................ $234,863.00

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.

Joe Harris

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 joseph@pyrocombustion.com

Quote Valid for 30 Days

Acceptance: ______________________________ Date: ________________

Purchase Order # __________________________

BURNER SCOPE

Date: 09/12/2022

To: PYRO COMBUSTION AND CONTROLS

From: KEVIN STEPP
ENERGY PRODUCTS

Burner Information:

Burner: NVC13-G-30 9-12 PPM
Mode: MOD ODP   Approval: NFPA
Other: CSD-1
Gas Rate: 33600   Oil Rate:
Fuel Type: NAT GAS
Supply Voltage: 460/3/60

Boiler Information:

HURST AND BURNHAM BOILERS
Model: S4-G-400-150 3P-800
Type: SCOTCH-MARINE BOILER
Gas Pressure: Min: - Max: 5.00 (PSI)
Furnace Press: 1.93
Job Name: CAESARS K-PAK

We are pleased to quote the following equipment:

Equipment

QTY	DESCRIPTION
1	40.00 HP HIGH EFFICIENCY 3 PH BLOWER MOTOR
1	LMV52.440B1 FLAME SAFEGUARD AND PARALLEL POSITIONING CONTROL W/AZL UV
1	ALARM BUZZER
1	GAS PILOT WITH 6KV IGNITION TRANSFORMER
1	PREPURGE: PROVEN OPEN DAMPER PREPURGE SEQUENCE
1	MAIN GAS STRAINER
1	PILOT GAS STRAINER
1	AUXILIARY PILOT SOLENOID VALVE
1	PILOT N. O. VENT VALVE
1	LOCKING SHUTOFF COCK FOR PILOT N.O.V.V. AND MAIN N.O.V.V.
1	PREMIX SURFACE STABILIZED COMBUSTION HEAD
1	BLACK CONDUIT STD
1	Gas Train: SDC30-MOD-AXA-H
1	THREE GAS PRESSURE GAUGES
1	3.00" LUBRICATED LEAK TEST SHUTOFF
1	LGP-G 1-20 IN. LOW GAS PRESSURE SWITCH
1	SKP15.011U1 MOTORIZED VALVE BODY W/ PROOF OF CLOSURE
1	3.00" VGD40.08U DUAL VALVE BODY MAIN GAS SHUTOFF
1	1.25" NORMALLY OPEN VENT VALVE
1	HGP-G 2-20 IN. MANUAL RESET HIGH GAS PRESSURE SWITCH
1	3.00" MAIN GAS BALL VALVE SHUTOFF

Additional Equipment

QTY	TYPE	ID	DESCRIPTION
1	A	11.006	CSD-1 CODE GAS ADDERS 3.00 INCH GAS TRAIN

1	E	3.190	24 X 34 CONTROL PANEL
1	E	5.110	500VA STEPDOWN 208/230/460 PRIMARY 120 SECONDARY W/PRIMARY AND SECONDARY FUSES
1	E	7.300	AUTO RESET ALARM SILENCING SYSTEM
3	E	8.300	RED INDICATOR LIGHT 120V. - LW, FF, PFF
1	E	9.010	3PDT RELAY --- SPECIFY RELAY FUNCTION --- - CONTACT FOR BREAK GLASS STATION
3	E	9.010	3PDT RELAY --- SPECIFY RELAY FUNCTION --- - LW, FF, PFF SOUND ALARM CONDITIONS
2	E	10.404	CSD-1 ELECTRICAL TERMINALS FOR EMERGENCY DISCONNECT BY OTHERS
1	E	15.281	3 POLE 100 AMP FUSE BLOCK TOUCH SAFE 25 HP 208 50 HP 480 - SINGLE POINT
1	E	15.288	FUSES 3 POLE 100 AMP 25 HP AT 208 - 40 HP 480V FAST ACT REQUIRED FOR VFD
1	E	16.000	HOUR RUNNING METER 635G,99,999.9 HOURS
-2	G	3.460	3" ADDITIONAL BALL VALVE
2	G	3.485	3" ADDITIONAL BALL VALVE, CSD-1 COCKS
2	G	19.110	1/4" BALL VALVE LEAK TEST/GAUGE COCK
1	M	3.610	40 HP HIGH EFF. BLOWER MOTOR WITH TEFC ILO STD
1	P	94.220	LMV OPT. SENSORS 4-20 mA PRESS. 0-200 PSI - 502685
1	V	50.026	YASKAWA-VF DRIVES 40 HP 480 V GA80U4023ABM(60 amps) MOUNTING BRACKET
1	V	60.005	3 CONTACTOR BYPASS (5), 577556, 576150 x 2, 140720 460/3/60 40 HP OR LESS

Pricing summary for quote: 090822-055MJS

Estimated Weight: 3200

Lead Time: 16 TO 20 WKS

1 ALL PRICES QUOTED ARE IN USD FOB PARSONS, KANSAS UNLESS OTHERWISE STATED.

2 ALL PRICES QUOTED ARE IN USD EX-WORKS PARSONS, KANSAS UNLESS OTHERWISE STATED.

3 ALL BOILER CONTROLS AND TRIM ARE TO BE SUPPLIED BY OTHERS.

4 ANY ITEMS WHICH ARE REQUIRED BUT ARE NOT SPECIFICALLY LISTED ARE NOT INCLUDED IN THE QUOTED PRICE AND ARE ASSUMED TO BE SUPPLIED BY OTHERS.

5 CLERICAL ERRORS OR OMISSIONS ARE SUBJECT TO CORRECTION

6 CURRENT LEAD TIME ESTIMATES ARE BASED ON ENGINEERING AND PRODUCTION LEAD TIMES. THIS LEAD TIME DOES NOT TAKE INOT ACCOUNT ANY SUPPLIER/DELIVERY ISSUES OUTSIDE OF POWER FLAME CONTROL. IF WE FIND AN ISSUE WITH THIS INITIAL LEAD TIME ESTIMATE WE WILL INFORM YOU IN A TIMELY MANNER. A NEW ESTIMATED DELIVERY DATE WILL BE PROVIDED ALONG WITH ANY KNOWN ALTERNATE PARTS TO MITIGATE EXTENDED LEAD TIMES. ALTERNATE PARTS MAY OR MAY NOT INCLUDE A COST ADDER.

7 POWER FLAME WARRANTY IS 15 MONTHS PAST THE DATE OF DELIVERY FOR PARTS ONLY.
POWER FLAME TAKES EXCEPTION TO ANY BLANKET REFERENCE OF STATE AND OR LOCAL CODE THAT IS UNKNOWN TO POWER FLAME AND SUBJECT TO CHANGE

8 ALL PRICING VALID FOR 30 DAYS

9 NO OTHER OPTIONS REQUESTED.

10 FREIGHT IS NOT INCLUDED IN THIS PRICE

11 MILESTONE PAYMENT TERMS ARE:
30% DUE AT RELEASE TO MANUFACTURING
30% DUE PRIOR TO SHIPMENT
40% DUE 30 DAYS AFTER SHIPMENT

POWER FLAME INCORPORATED
GENERAL TERMS AND CONDITIONS
FOR EQUIPMENT AND ANCILLARY SERVICES

1. GENERAL: Seller requires that its dealers pass this agreement on to the end user. As used herein, "Equipment" is the equipment and/or parts identified in this Agreement as expressly agreed to be provided by Seller to Purchaser. As used herein, the "Services", if any, are the services identified in this Agreement as expressly agreed to be provided by Seller to Purchaser. As used herein, the "Software", if any, is the software identified in this Agreement as expressly agreed to be licensed by Seller to Purchaser. These General Terms and Conditions of Sale (the "Terms"), Seller's quote, Purchaser's Purchase Order and Seller's Order Acknowledgement are collectively referred to in the Terms as the "Agreement". The Agreement sets forth the entire, exclusive and complete agreement of Seller and Purchaser with respect to the sale and purchase of the Equipment, the performance of the Services and the license of the Software and supersedes any prior or contemporaneous written or oral agreement, understanding and communications and any course of dealing, usage of trade or course of performance. This Agreement prevails over any of Purchaser's terms and conditions of purchase or purchase order, regardless of whether or when Purchaser submitted such terms and conditions or purchase order. Fulfillment of Purchaser's order does not constitute acceptance of any of Purchaser's terms and conditions and does not serve to modify or amend these terms and conditions. No waiver or modification of this Agreement shall be effective unless in writing and signed by both Seller and Purchaser. Quotes are subject to change without notice. Prices quoted shall be firm for orders scheduled by Seller to be delivered within sixty (60) days after the quotation date; otherwise, Seller reserves the right to apply prices in effect at the time of delivery.

2. PERFORMANCE CONDITIONS: The performance of the Equipment covered in this Agreement cannot be exactly predicted for every operating condition. In consequence, any predicted performance data submitted is intended to show probable operating results which may be closely approximated, but which cannot be guaranteed.

3. ENGINEERING: Seller and Purchaser acknowledge and contemplate that any engineering services for which Seller is responsible pursuant to this Agreement will be performed by engineers employed by Seller only to the extent allowed by applicable laws and regulations. Otherwise, such engineering services will be provided by qualified, licensed engineers selected and retained by Seller at Seller's expense. Except as otherwise provided herein, Seller and Purchaser acknowledge and contemplate that upon acceptance of this Agreement by Seller, Seller's engineering department or a qualified, licensed engineer selected and retained by Seller at Seller's expense will perform whatever engineering analysis and design is necessary to fulfill its obligations under this Agreement, and will prepare whatever plant layouts, drawings, and design specifications are necessary in Seller's discretion to facilitate the performance of the Equipment in accordance with this Agreement. Seller and Purchaser further acknowledge and contemplate that this engineering process may result in modifications or changes which may include, but are not limited to: modifications in conveyor lengths, sizes, speeds, angles, or positions; changes in motor sizes; changes in Equipment or plant configuration; and modifications or parts lists. No such modifications or changes shall constitute a breach of contract by Seller.

4. DRAWINGS: Seller will furnish Purchaser with necessary drawings and instruction for Purchaser's erection or installation of the Equipment. Seller will not be held responsible for design and/or installation of footings and/or other items necessary for installing the Equipment unless otherwise stated herein.

5. DIFFERING SITE CONDITIONS: If, in the performance of this Agreement, subsurface or latent conditions at the site are found to be materially different from those indicated by geotechnical reports provided by Purchaser, or unknown conditions of an unusual nature are disclosed differing materially from those ordinarily encountered by Seller, then such conditions may result in adjustments to the Price, anticipated dates for delivery/shipment, and other contractual obligations. No such adjustments shall constitute a breach of contract by Seller.

6. CONFIDENTIALITY: All non-public, confidential or proprietary information of Seller, including but not limited to specifications, samples, patterns, designs, plans, drawings, documents, data, business operations, purchaser lists, pricing, discounts or rebates, disclosed by Seller to Purchaser, whether disclosed orally or disclosed or accessed in written, electronic or other form or media, and whether or not marked, designated or otherwise identified as "confidential" in connection with this Agreement shall be treated by Purchaser as confidential and may not be disclosed to any third party or copied by Purchaser unless authorized in advance by Seller in writing. Upon Seller's request, Purchaser shall return all documents and other materials received from Seller. Seller shall be entitled to seek injunctive relief for any violation of this Paragraph 6. This Paragraph 6 does not apply to information that is: (a) in the public domain; (b) Purchaser can show was known to Purchaser at the time of disclosure; or (c) Purchaser can show was rightfully obtained by Purchaser on a non-confidential basis from a third party. Purchaser's confidentiality, non-disclosure and non-use obligations herein shall remain in force for the maximum term permitted by applicable law.

7. WARRANTY:

a. Seller warrants that upon shipment from Seller's site and continuing for a period of fifteen (15) months from shipment from Seller's site (the "Equipment Warranty Period"), so long as shipment occurs within sixty (60) days of Seller's Ready to Ship Notification to Purchaser, that the Seller manufactured Equipment will be free of defects in material and workmanship, provided any operation of the Equipment by Purchaser has been in accordance with generally approved practice as instructed by Seller service personnel or set forth in Seller service instructions, if any, and provided that Purchaser notifies Seller in writing as soon as such defect becomes apparent, but in all events during the Equipment Warranty Period. Notwithstanding the foregoing, the Equipment Warranty Period for burner blast tubes (Firing Heads), and mesh head elements is five (5) years from shipment from Seller's site; provided that the warranty on mesh head elements is prorated at 20% / year. Seller shall repair, or at its option replace EXW point of shipment, any defective Equipment or parts covered by the warranty. If the Purchaser is entitled to a claim under this warranty, Purchaser shall, as a condition precedent to securing warranty performance, return the Equipment to Seller's plant, 2001 South 21st Street, Parsons, Kansas, transportation prepaid. Notwithstanding the foregoing, where repair or replacement is deemed by Seller to be commercially impractical, Seller may choose to refund the Price upon return of the Equipment. The right to have defective Equipment repaired or replaced shall constitute the Purchaser's sole and exclusive remedy for breach of this limited Equipment warranty. Labor for defective Equipment repair will be paid by Purchaser under a formula determined by Seller. For helical coils found in Seller's HCS heaters, the Equipment Warranty Period for the helical coils is three (3) years. For helical coils found in Seller's HC heaters, the Equipment Warranty Period for the helical coils is five (5) years. Equipment which is repaired or replaced shall carry a warranty equal to the unexpired portion of the Equipment Warranty Period.

b. Seller makes no warranties or guarantees with respect to Equipment not manufactured by Seller, including but not limited to diesel engines, motors, motor starters, pumps, mixers, mills, scales, speed reducers, and other assemblies, valves, pressure regulators, solenoids, electronic drives, pressure differential switches, temperature sensing switches, flame scanners, gauge boards, modulating actuators, electronic displays, pressure transmitters, radar sensors, other electronic controls and instrumentation and other parts and accessories. Liners, castings, furnace refractories, and refractory materials are subject to wide variations of destructive service, are also not covered by the Equipment warranty and are a maintenance responsibility of Purchaser from the beginning of operation. Seller will pass through to Purchaser any warranties and limitations provided by the original manufacturer of parts used in the Equipment manufactured by Seller, but Seller does not provide any warranty as to such items.

c. Seller warrants that the Services performed hereunder shall be free from defects in workmanship for a period of ninety (90) days from the date of performance (the "Service Warranty Period"). Seller undertakes at its cost to reperform defective Services covered by the warranty, provided that Purchaser notifies Seller in writing as soon as such defect becomes apparent, but in all events during the Service Warranty Period. The right to have defective Services reperformed shall constitute the Purchaser's sole and exclusive remedy for breach of this limited Service warranty. Services which are reperformed shall carry a warranty equal to the unexpired portion of the Service Warranty Period.

d. No warranty shall apply to Equipment which has been repaired or altered by others so as, in Seller's judgment, to adversely affect the same or which shall have been subject to negligence, accident, abuse or improper care, installation, maintenance, clogged or storage or other than normal use or service, during or after shipment. No warranty shall apply to any used Equipment or for ordinary wear and tear, or ordinary corrosion or erosion, or clogged or damaged filters. No warranty shall apply to any Equipment adversely affected by being used with any machinery, part or accessory not manufactured or authorized by Seller. No warranty shall apply to consumables or parts having a life expectancy shorter than the Equipment Warranty Period.

e. Seller does not warrant or represent that any Equipment furnished by it meets any federal, state or local safety, environmental or electrical regulations. Seller is wholly discharged from all liability under this warranty in the event that Purchaser fails to pay for the Equipment or Services in accordance with the applicable purchase terms. This Equipment warranty extends only to the first end-user and is not transferable. This warranty may not be modified except pursuant to a written agreement signed by Seller.

f. THE EXPRESS WARRANTIES AND WARRANTY REMEDIES PROVIDED IN THIS PARAGRAPH 7 ARE THE SOLE AND EXCLUSIVE WARRANTIES AND WARRANTY REMEDIES PROVIDED BY SELLER TO PURCHASER AND ARE PROVIDED IN LIEU OF ALL OTHER WARRANTIES, WHETHER EXPRESS OR IMPLIED (EXCEPT WARRANTY OF TITLE), INCLUDING, BUT NOT LIMITED TO, ANY IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE AND ANY IMPLIED WARRANTY FROM COURSE OF DEALING OR USAGE OF TRADE, ALL OF WHICH ARE HEREBY EXPRESSLY WAIVED AND DISCLAIMED.

8. LIMITATION OF LIABILITY: NOTWITHSTANDING ANYTHING ELSE TO THE CONTRARY CONTAINED IN THIS AGREEMENT, THE PARTIES AGREE THAT IN NO EVENT OR CIRCUMSTANCE IS SELLER LIABLE TO PURCHASER FOR SPECIAL, INDIRECT, INCIDENTAL, PUNITIVE OR CONSEQUENTIAL DAMAGES, COSTS OR LOSSES OF ANY NATURE WHATSOEVER, INCLUDING BUT NOT LIMITED TO LOST PROFITS OR REVENUE, LOSS OF PRODUCTION, LOSS OF USE OR LOSS OF CONTRACTS, COSTS FOR RAW MATERIAL, ENERGY, UTILITY, LABOR OR CAPITAL OR FOR ANY OTHER INDIRECT LOSS; OR FOR CLAIMS RAISED BY PURCHASER'S CUSTOMERS; AND WHETHER BASED ON BREACH OF CONTRACT OR WARRANTY, TERMINATION, NEGLIGENCE, TORT, STRICT LIABLITY, INDEMNITY AT LAW OR IN EQUITY OR OTHERWISE. IN NO EVENT SHALL SELLER'S AGGREGATE LIABILITY ARISING OUT OF OR RELATED TO THIS AGREEMENT, WHETHER ARISING OUT OF OR RELATED TO BREACH OF CONTRACT, TORT (INCLUDING NEGLIGENCE) OR OTHERWISE, EXCEED THE TOTAL OF THE AMOUNTS PAID TO SELLER FOR THE EQUIPMENT SOLD HEREUNDER.

9. INSURANCE: From the date Seller notifies Purchaser that the Equipment is ready to ship, until the date the Equipment is paid for in full, Purchaser shall provide and maintain insurance in an amount no less than the total value of the Equipment delivered hereunder which insurance provides coverage against customary casualties and risks, including fire and explosion, and shall also provide coverage against liability for accidents or injuries to the public or to employees, in the names of Seller and Purchaser, as their interest may appear, and in amounts satisfactory to Seller. If Purchaser fails to provide such insurance, it then becomes Purchaser's responsibility to notify Seller so that Seller may provide the same, and the cost thereof shall be added to the Price. All loss resulting from failure to affect such insurance shall be assumed by Purchaser.

10. SECURITY INTEREST; COST OF RECORDING: Purchaser hereby conveys and grants to Seller a purchase money security interest in the Equipment to secure payment by Purchaser of all amounts due hereunder including the Price and such other debts, obligations and liabilities of Purchaser to Seller which may now exist or hereafter arise, whether absolute or contingent, or primary or secondary, together with all extensions or renewals for the foregoing and all expenses, legal or otherwise (including court costs and reasonable attorney's fees) incurred by Seller in collecting or endeavoring to collect any or all of the foregoing, in protecting any collateral and in enforcing the Agreement. The Equipment shall remain personal property in all respects notwithstanding the manner of annexation of any of the Equipment to realty. Purchaser agrees to execute any instrument or document considered necessary by Seller to perfect its security interest in the Equipment, including, but not limited to, financing statements, chattel mortgages, deeds of trust, deeds to secure debt, mortgages or other security instruments. Until default hereunder, Purchaser may have possession of the Equipment and use the same in any lawful manner not inconsistent with this Proposal or with any policy of insurance thereon. Purchaser will pay the costs and taxes due for recording and filing any Financing, Continuation or Termination Statements with respect to Seller's security interest in the Equipment or in connection with any of the other security documents referred to above.

11. EQUIPMENT NOT TO BE REMOVED: As long as the security interest in the Equipment is retained by Seller, the Equipment shall not be removed from the erection site and Purchaser shall not permit, voluntarily or involuntarily, the Equipment or any part of it to be sold, transferred, encumbered, attached, seized or removed in any manner whatsoever.

12. DEFAULT: Upon default by Purchaser in the payment of the Price or any portion thereof when due or in the payment of all or any portion of any other indebtedness secured under this Agreement when due or in the performance of any other term or provision hereof, all unpaid amounts due Seller shall thereupon be immediately due and payable and Seller shall have the rights and remedies contained herein and the rights and remedies of a secured party under the Uniform Commercial Code of the State of Tennessee or under the laws of any other jurisdiction as a court of competent jurisdiction shall determine to be applicable. In the event of Purchaser's default, the following provisions shall apply: (a) Purchaser shall, upon request of Seller, disassemble the Equipment and make it available to Seller at a place designated by Seller; (b) Seller may enter Purchaser's premises where any part of the Equipment is located, and take possession of and remove all or any portion of the Equipment for purposes of disposition pursuant hereto; (c) Purchaser agrees that sales for cash or on credit to a wholesaler, retailer, or user or property of the type subject to this Agreement or at public auction or private sale are all commercially reasonable; (d) Seller shall give Purchaser notice of the time and place of any sale of any of the Equipment or of the time after which any private sale or any other intended disposition thereof is to be made by notice, postage prepaid and addressed to Purchaser at the latest address of Purchaser appearing on the records of Seller at least seven (7) days before the time of the sale or other disposition, which provisions for notice Purchaser and Seller agree are reasonable; (e) any proceeds of any disposition of any of the Equipment may be first applied by Seller to the payment of expenses in connection with exercising its rights and remedies hereunder, including reasonable attorney's fees and legal expenses, and any balance of such proceeds may be applied as Seller may elect in its sole discretion; (f) if the sale or other disposition of the Equipment fails to satisfy in full obligations of Purchaser secured by this Agreement, and the reasonable expenses of retaking, holding, preparing for sale, selling and the like, including reasonable attorney's fees and legal expenses incurred by Seller in connection with this Agreement or the obligation it secures, Purchaser shall be liable for any deficiency.

13. PERMITS AND APPROVAL OF PLANS: Purchaser assumes all responsibility for securing any necessary governmental approvals of the plans and specifications and any permits required for the installation and operation of the Equipment, all at Purchaser's expense.

14. PERMIT CONTINGENCY: If the purchase of Equipment under this Agreement is contingent on Purchaser's receipt of one or more permits or other governmental approvals, then the Price set forth in this Agreement will not be binding on Seller. Once all contingencies have been fulfilled or are waived, the Price will be determined by Seller taking into account any increase in Seller's cost of purchased components and/or raw materials, among other factors.

15. COMPLIANCE WITH APPLICABLE LAWS: Purchaser assumes all responsibility for complying with all federal, state and local statutes, laws, codes, regulations and ordinances in connection with the installation and operation of the Equipment and any other activity related thereto, including, without limitation, all federal, state and local environmental laws and regulations relating to pollution and protection of the environment and the Occupational Safety and Health Act and all rules and regulations promulgated thereunder.

16. PATENTS: In the event that any of the Equipment specified in this Agreement is based upon designs of or furnished by Purchaser, Purchaser shall indemnify Seller for any loss or expense incurred by it by reason of any claim for infringement of patents.

17. SHIPMENT:

a. If Purchaser is in default of any of its obligations under this Agreement, Seller may, at its election, withhold any further performance of its obligations and duties under this Agreement until such time as such default has been cured by Purchaser, in which event the anticipated date of shipment as set forth herein shall be adjusted accordingly. Seller shall not be liable or responsible for, nor shall the Price be reduced by any amount because of any matters beyond the control of Seller which delay or postpone the anticipated date set forth above for the shipment of the Equipment, such matters including, but not limited to, warlike acts, civil disorder, governmental restriction, acts of God, prior sale, acceptance of United States governmental contracts, strike, lockout, accidents, freight embargo, fire, flood, inability of Seller to obtain necessary materials, supplies, labor or transportation, pandemic, or any unforeseen water, soil or rock conditions.

b. A detailed shipping list will accompany the bill of lading and Purchaser agrees to check the Equipment as it is unloaded and any claim for shortage against Seller will be made in writing within twenty-four (24) hours of time of unloading, to be followed by an affidavit (if required) from the person in charge of the unloading. Claims for loss or damage in transit will be made on the carrier by Purchaser.

c. Except to the extent otherwise provided herein, Purchaser has full responsibility for erection and/or installation of the Equipment.

18. LATE CHARGES AND ATTORNEY'S FEES: Purchaser agrees that in the event any amount payable by Purchaser to Seller remains unpaid for more than 30 days, a service charge of 1.5% per month (18% per annum) or any portion thereof (or the highest rate of interest allowed by law, whichever is less) shall accrue on such unpaid amount beginning on the thirty-first (31st) day after such date payment is due. If the indebtedness, including late charges, arising out of this or any other transaction between Seller and Purchaser is placed in the hands of an attorney for collection, or is collected by and through an attorney, Purchaser will pay all costs of collection, including without limitation, court costs and reasonable attorney's fees.

19. POSTPONED DELIVERY (INCLUDING SHIPPING DELAY): If, through no fault of Seller, delivery or shipment is delayed or postponed (including deferral of shipment requested by Purchaser), Purchaser shall pay to Seller any additional costs, including plant Equipment storage, handling, and insurance, incurred by Seller arising from such delay, deferral, or postponement. Such a delay, postponement or deferral is considered "offer to ship" or "shipment" for all purposes, including invoicing, payment and transfer of title. Therefore, the balance remaining unpaid on the Price shall become due and payable immediately. Purchaser shall bear the risk of loss of or damage to the Equipment during storage and thereafter. If, as a result of the delay, postponement or deferral, the Equipment requires repainting, all costs associated with repainting shall be paid by the Purchaser. Should Purchaser delay/postpone/defer shipment, Purchaser and Seller will complete the attached "Postponed Delivery/Shipping Delay/Deferral Notice".

20. EQUIPMENT CERTIFICATION: Once certification and fabrication has been completed on control houses and power houses, if state certification specifications change or unit(s) are to be shipped to a location other than that for which the certification was acquired, the cost of any recertification and/or modifications required to be done on the Equipment shall be paid by Purchaser.

21. LIMITATION OF PROPOSAL: The Price and terms quoted in this Sales Proposal are subject to formal acceptance (i.e. signature on this Sales

Proposal) without change by Purchaser within a period 30 days from the date hereof, except that Seller shall have the right to withdraw its Sales Proposal at any time before formal acceptance by Purchaser.

22. EXECUTION OF CONTRACT: This Sales Proposal is merely the solicitation of an order and is not an offer from Seller to Purchaser (even though executed on behalf of Seller under "RESPECTFULLY SUBMITTED,") and does not obligate Seller in any manner whatsoever until this Agreement is both executed below on behalf of Purchaser as an order made to Seller as well as executed below on behalf of Seller as an acceptance of such order from Purchaser, at which time this Agreement shall become a binding contract between Seller and Purchaser. Once this Agreement has become a binding contract, it cannot be suspended or cancelled without the prior written consent of Seller, which may be withheld in the sole discretion of Seller. In no event will consent to suspension or cancellation be given without full reimbursement by Purchaser of all Seller's expenses, damages and losses arising from such cancellation or suspension and incurred through the date of cancellation or suspension, plus reasonable overhead and profit allocation on such amounts.

23. SEVERABILITY: If any provision of this Agreement is found to be legally invalid or unenforceable: (i) the validity and enforceability of the remainder of this Agreement shall not be affected, (ii) such provision shall be deemed modified to the minimum extent necessary to make such provision consistent with applicable law, and (iii) such provision shall be valid, enforceable and enforced in its modified form.

24. ASSIGNMENT: Purchaser shall not assign any of its rights or delegate any of its obligations under this Agreement without the prior written consent of Seller. Any purported assignment or delegation in violation of this Paragraph 24 is null and void. No assignment or delegation relieves Purchaser of any of its obligations under this Agreement.

25. LAW CONTROLLING: This Agreement and all questions regarding the performance of the parties hereunder shall be controlled by the laws of the State of Tennessee (without regard to conflicts of law). The parties agree that the United Nations Convention on Contracts for the International Sale of Goods does not apply to this Agreement, or the transactions contemplated thereby.

26. DISPUTE RESOLUTION: Any dispute or claim arising out of or relating to this Agreement, or the breach, termination or invalidity thereof, and any related tort, statutory and equitable claims (each a "Dispute"), which the parties are not able to settle amicably within 3 months from the first written request for such settlement, shall be brought exclusively in a state or federal court in the State of Tennessee, County of Hamilton. The parties hereby waive any right to challenge such choice of jurisdiction or venue or to seek transfer to another jurisdiction. THE PARTIES FURTHER KNOWINGLY AND VOLUNTARILY WAIVE ANY RIGHT TO A JURY TRIAL OF THE DISPUTE.

27. TAXES: Prices quoted herein do not include any Federal, State or Municipal Taxes. If under existing or future law passed by the United States, any state or any municipality, Seller, in its opinion, is required to pay or collect a tax, impost or charge upon the manufacture, sale, use or assembly of the material described herein, the Price shall be increased by the amount of such tax, impost or charge. The amount of such increase is to be paid to Seller upon demand. If Purchaser holds resale tax permits and the material described herein is for resale, such information shall be shown by Purchaser.

28. BACK-CHARGES AND ALLOWANCES: Seller shall not be called upon to make any allowance for material, labor, repairs or alterations made for its account unless authorized by Seller in writing.

29. INSPECTION AND ACCEPTANCE PERIOD: Purchaser agrees to inspect the Equipment immediately after delivery to the site, but in no event later than five (5) calendar days after such delivery (the "Acceptance Period"). Any defect discovered during the Acceptance period is subject to the procedures and remedies set forth in Paragraph 7 (Warranty).

30. RESPONSIBILITY OF PURCHASER FOR OPERATION OF EQUIPMENT: The operation of the Equipment at all times shall be the sole and exclusive responsibility of Purchaser or any end user. Any Services by Seller's representatives shall be given solely in a consulting or advisory capacity and shall not release Purchaser or any end user in any manner whatsoever from its responsibility for operating the Equipment.

31. INDEMNIFICATION: Purchaser agrees to indemnify and hold harmless Seller, its affiliates and their respective employees from and against any and all liabilities, damages, obligations and claims (including, without limitation, court costs and reasonable attorney's fees) arising from or with respect to the operation of the Equipment. Without limiting the generality of the preceding sentence, the parties acknowledge and agree that if a claim initially was brought against Seller for defective manufacture, design or the like and was finally determined by a court of competent jurisdiction or otherwise settled (such settlement being with Purchaser's consent) on a basis relating to the negligent operation or use of the Equipment, Seller will be entitled to indemnification pursuant to the provisions of the preceding sentence.

32. TITLE AND RISK OF LOSS: Title to the Equipment shall pass to Purchaser upon shipment or offer to ship should Purchaser delay shipment. The risk of loss or damage to the Equipment shall pass to Byer upon delivery of the Equipment (EXW point of shipment Seller site, Incoterms 2020), unless transferred earlier in accordance with Paragraph 19 (Postponed Delivery (Including Shipping Delay)).

33. NOTICES: Each party shall deliver all notices and other communications under this Agreement (each, a "Notice") in writing and addressed to the other party at the addresses set forth on the first page of this Sales Proposal. Each party shall deliver all Notices by personal delivery or through deposit in the mail, certified or registered (in each case, return receipt requested, postage prepaid) or through a nationally recognized overnight courier (with all fees prepaid). If Notice should be given immediately or promptly, then in addition to furnishing a copy of the Notice in the manner aforesaid, a copy shall be sent via e-mail (with confirmation of transmission). A Notice is effective only (a) upon receipt by the receiving party and (b) if the party giving the Notice has complied with the requirements of this Section 33, unless the receiving party has waived its requirements in writing. A copy of all notices to Seller shall be sent to: Power Flame, 1725 Shepherd Road, Chattanooga, TN 37421, Attn: Legal Counsel.

34. WEIGHTS: Shipping weights or dimensions wherever shown in price lists, catalogs and as show in proposals or quotations, are approximate and are not guaranteed.

35. DESIGN CHANGES: Seller reserves the right to make changes in design from time to time as are deemed desirable without incurring the obligation to furnish them for Equipment previously sold or shipped.

36. PAINTING: Before shipment, Seller will apply one coat of standard paint to all structural and plate work, and two coats to paving machines.

37. SAFETY DEVICES: The Equipment is provided with only those safety devices identified herein. It is the responsibility of Buyer to furnish other appropriate safety devices which are desired by Buyer and/or required by OSHA or other laws and regulations.

38. ELECTRICAL EQUIPMENT AND WIRING: Seller cannot assume responsibility that any weather-resistant cords, plugs or receptacles included with its power and/or control panels will be acceptable under the applicable electrical code. Buyer is responsible for any disconnect switches or other devices required in addition to the main disconnect switch in the power panel. Scale, probe or moisture meter cables or wires are not to be installed underground, and each is to be kept isolated from all other power and/or signal wires.

39. DISCONTINUANCE, IMPROVEMENT AND DESIGN CHANGES. Seller may discontinue the manufacture of any Equipment or make changes or improvements at any time in the specifications, construction or design of any Equipment without incurring any obligation to Buyer. Equipment so changed or improved will be accepted by Buyer in fulfillment of existing orders.

Appendix C

RACT Analysis – Emergency Generators

Emission Units HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CR07, CP13, CP14, CP15, CP16, CP17, CP28, CP29, PA17, PA18, IP08, IP09, PH10, PH11, PH12, PH13, LI06 and LI07

APPENDIX C

RACT Analysis

Emergency Generators, Emission Units HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CR07, CP13, CP14, CP15, CP16, CP17, CP28, CP29, PA17, PA18, IP08, IP09, PH10, PH11, PH12, PH13, LI06 and LI07

Appendix C
Table of Contents

Attachments

1.0 General

This appendix summarizes the Reasonably Available Control Technology (RACT) Analysis performed for the emergency generators, Emission Units (EU) HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CR07, CP13, CP14, CP15, CP16, CP17, CP28, CP29, PA17, PA18, IP08, IP09, PH10, PH11, PH12, PH13, LI06 and LI07 located at various properties associated with various Caesars Entertainment, Inc. properties. The basic steps for this analysis are as follows:

- 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

Controls for oxides of nitrogen (NO_X) are evaluated in this appendix.

2.0 NO_X RACT Assessment

2.1 Equipment Description and Limitations

EUs HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CR07, CP13, CP14, CP15, CP16, CP17, CP28, CP29, PA17, PA18, IP08, IP09, PH10, PH11, PH12, PH13, LI06 and LI07 have ratings varying from 600 kW to 2,100 kW and are all powered by compression ignition engines utilizing diesel as the fuel supply. They are all limited to 100 hours of operation per year for testing and maintenance purposes and up to 50 hours per year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. All of the engines are turbo-charged and aftercooled.

Due to the large number of generators requiring a RACT analysis for this source, individual emission units were grouped according to the power rating of the engine (hp). This is a reasonable approach since the engine horsepower ratings for each engine will largely determine the type and size of control device possible.

2.2 Baseline Emissions

As noted in Section 3 of the report, baseline emissions can be set equivalent to actual emissions if actual emissions for the three previous consecutive years are 70% or less of the source's or individual emission unit's potential emissions. Caesars meets this criterion on both a facility-wide basis and individual emissions unit basis.

Table 1 summarizes the baseline NO_X emissions for each emission unit.

Table 1 – Baseline Emissions for the Emergency Generators

Emission Unit	Engine Rating (hp)	Generator Rating (kW)	NO_X Emissions[1] (tons/year)
HA14, IP08, IP09	890	600	0.25
FL09, FL10	1109	750	0.28
HA18	1180	800	0.34
HA13	1232	800	0.21
CP16	1818	1250	0.67
BA04, BA05, BA11, BA12	1340	1000	0.26
CP15	2520	1750	0.78
PH10, PH11, PH12	2550	1750	0.30
PH13	2561	1750	0.13
PA17, PA18	2816	2000	0.45
CP13, CP14, CP17	2876	2000	1.04
CR07, CP28, CP29, LI06, LI07	3634	2000	0.56

Notes: [1] Maximum annual emissions for 2019 - 2021 for each group.

2.3 Identification and Technical Feasibility of NO_X Control Options

2.3.1. Identification of Available Controls

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 RACT determinations for generators of the same or comparable size. The database did not contain any RACT determinations for this time period. In addition, various U.S. EPA control technology reports were reviewed and the current contractor responsible for servicing the Caesars' emergency generators was consulted to identify potential controls. Based on the information obtained, the proposed NO_X control technology for the emergency generators is summarized in Table 2. It should be noted that all Caesars generators are equipped with turbochargers and aftercoolers which are considered the baseline control technology options for these emission units.

Table 2 – Available NO_X Control Technology Methods for the Emergency Generators

Control Equipment	NO_X Reduction Potential (%)	Range of Application	Commercial Availability/ R&D Status
Selective Catalytic Reduction (SCR)	90	Limited range of application	Commercially available

The technical feasibility of this control option will next be evaluated.

2.3.2. Selective Catalytic Reduction (SCR)

SCR involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst. The catalyst allows the ammonia to reduce NO_X levels at lower exhaust temperatures than selective non-catalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400-1600°F, SCR can be utilized where exhaust gases are between 500° F and 1200° F, depending on the catalyst used. SCR can result in NO_X reductions up to 90%. SCR systems are technically feasible for retrofit on existing generators.

2.3.3. Technological Feasibility Summary

Table 3 summarizes the technological feasibility evaluations of the identified control option.

Table 3 – NO_X Control Technology Methods for the Emergency Generators

Control Equipment	Technically Feasible?	Uncontrolled NO_X Emissions (tons/year)	NO_X Controlled Emission Rate (tons/year)	NO_X removed (tons/year)
SCR	Yes	0.25 - 1.04	0.01 - 0.10	0.12 - 0.94

Based on the information presented in Table 3, Caesars will evaluate the cost of installing SCR systems with a control efficiency of 90%.

2.4 Cost of NO_X Control Options

For the technically feasible method of control alternative, a total annualized equipment cost and an annual operating cost has been calculated. The calculation of the capital cost recovery factor used to estimate the annualized equipment cost assumes an interest rate of 6% and equipment life of 10 years. The individual cost calculations for each group of emissions units based on the size of the SRC system required are included in Attachment B-2. The capital cost for each generator is based on the actual quote from an equipment vendor. A copy of the quote obtained is included with Attachment B-2. The calculated costs are summarized in Table 4.

Table 4 – Cost of NO_X Control Options for the Emergency Generators

EU	Method of Control	Annualized Cost ($/year)	Estimated NO_X Removal (tons/year)	Cost Effectiveness ($/ton removed)
HA14, IP08, IP09	SCR	$25,938	0.23	$115,282
HA13, HA18, FL09, FL10, BA04, BA05, BA11, BA12	SCR	$27,385	0.31	$89,494
CP15, CP16	SCR	$27,862	0.70	$39,690
PH13	SCR	$27,627	0.12	$236,127
CR07, PH10, PH11, PH12	SCR	$29,668	0.27	$109,880
CP13, CP14, CP17,CP28, CP29, PA17, PA18, LI06, LI07	SCR	$32,224	0.94	$34,427

2.5 Environmental, Energy & Economic Considerations

2.5.1. Environmental Impacts

As shown in Table 4, there is only a minimal potential reduction in NO_X emissions associated with the installation of an SCR system.

2.5.2. Energy Impacts

It is anticipated that only minimal adverse energy impacts would be associated with an SCR system.

2.5.3. Economic Impacts

The economic impacts analysis is based on the cost effectiveness of each technology in terms of the cost per ton of removed pollutant as evaluated in Section 2.4. A maximum cost effectiveness threshold for NO_X RACT has not been established by DAQ. In 1994, the U.S. EPA recommended a maximum of $1,300 per ton to represent RACT at that time. Based on the increase in the Chemical Engineering Plant Cost Index (CEPCI) between then and now, this equates to approximately $3,000 per ton for the present. The U.S. EPA, in its approval of certain State Implementation Plan revisions for Pennsylvania (85 FR 65706) noted that Pennsylvania's proposed maximum of $2,800 per ton was low compared to other states but approved it. Maximum thresholds for other jurisdictions were presented in the notice as follows:

- Wisconsin, $2,500 per ton NO_X
- Illinois, $2,500—$3,000 per ton NO_X
- Maryland, $3,500—$5,000 per ton NO_X
- Ohio, $5,000 per ton NO_X
- New York, $5,000—$5,500 per ton NO_X

For the purpose of this analysis, even if the maximum value of $5,500 from above is deemed appropriate in Clark County, the cost of control for each individual boiler significantly exceeds this value. Table 4 presents the cost effectiveness of the viable control option upgrades. The costs exceed the most stringent RACT thresholds several times over.

3.0 NO_X RACT Determination

After eliminating the technically feasible control option and evaluating this control technology for environmental, energy, and economic impacts, it is evident that emission units HA13, HA14, HA18, FL09, FL10, BA04, BA05, BA11, BA12, CR07, CP13, CP14, CP15, CP16, CP17, CP28, CP29, PA17, PA18, IP08, IP09, PH10, PH11, PH12, PH13, LI06 and LI07 can be considered to comply with RACT with existing emission limitations (turbochargers and aftercoolers), monitoring, testing and recordkeeping. Caesars shall operate and maintain all diesel generators in accordance with the manufacturer's O&M manual for emission-related components.

ATTACHMENT C-1

Caesars Entertainment, Inc. **Attachment C-1** **Source ID 257**

Cost Effectiveness Calculation

SRC6X4-16

Emission Unit/Control Technology

Emission Unit	HA14, IP08, IP09
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	0.25
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.03

Annualized Capital Costs

Initial Capital Investment[3]	\$119,571
Direct & Indirect Costs[4]	\$15,340
Total Capital Investment	\$134,910
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	\$18,330

Annual Operating Costs

Urea	\$595
Catalyst[5]	\$1,013
Maintenance[6]	\$6,000

Total Annualized Cost	\$25,938

Cost Effectiveness

Emissions Reduction (tons/year)	0.23
Cost Effectiveness of NO_X Reduction (\$/ton)	\$115,282

Notes:

[1] Maximum actual emissions for 2019 - 2021 for group.

[2] Vendor specification.

[3] Cost based on vendor estimate.

[4] Installation, startup and performance testing.

[5] One replacement averaged over 10 years.

[6] Estimate.

Attachment C-1
Cost Effectiveness Calculation
SRC6X6-18

Emission Unit/Control Technology

Emission Unit	HA13, HA18, FL09, FL10, BA04, BA05, BA11, BA12
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	0.34
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.03

Annualized Capital Costs

Initial Capital Investment[3]	$125,615
Direct & Indirect Costs[4]	$15,340
Total Capital Investment	$140,955
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$19,151

Annual Operating Costs

Urea	$714
Catalyst[5]	$1,520
Maintenance[6]	$6,000

Total Annualized Cost	$27,385

Cost Effectiveness

Emissions Reduction (tons/year)	0.31
Cost Effectiveness of NO_X Reduction ($/ton)	$89,494

Notes:

[1] Maximum actual emissions for 2019 - 2021 for group.

[2] Vendor specification.

[3] Cost based on vendor estimate.

[4] Installation, startup and performance testing.

[5] One replacement averaged over 10 years.

[6] Estimate.

Attachment C-1

Cost Effectiveness Calculation

SRC6X6-20

Emission Unit/Control Technology	
Emission Unit	CP15, CP16
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	0.78
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.08
Annualized Capital Costs	
Initial Capital Investment[3]	$126,500
Direct & Indirect Costs[4]	$15,340
Total Capital Investment	$141,840
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$19,271
Annual Operating Costs	
Urea	$1,071
Catalyst[5]	$1,520
Maintenance[6]	$6,000
Total Annualized Cost	$27,862
Cost Effectiveness	
Emissions Reduction (tons/year)	0.70
Cost Effectiveness of NO_X Reduction ($/ton)	$39,690

Notes:

[1] Maximum actual emissions for 2019 - 2021 for group.

[2] Vendor specification.

[3] Cost based on vendor estimate.

[4] Installation, startup and performance testing.

[5] One replacement averaged over 10 years.

[6] Estimate.

Attachment C-1
Cost Effectiveness Calculation
SRC6X6-22

Emission Unit/Control Technology

Emission Unit	PH13
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	0.13
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.01

Annualized Capital Costs

Initial Capital Investment[3]	$128,269
Direct & Indirect Costs[4]	$15,340
Total Capital Investment	$143,609
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$19,512

Annual Operating Costs

Urea	$595
Catalyst[5]	$1,520
Maintenance[6]	$6,000
Total Annualized Cost	$27,627

Cost Effectiveness

Emissions Reduction (tons/year)	0.12
Cost Effectiveness of NO_X Reduction ($/ton)	$236,127

Notes:

[1] Maximum actual emissions for 2019 - 2021 for group.

[2] Vendor specification.

[3] Cost based on vendor estimate.

[4] Installation, startup and performance testing.

[5] One replacement averaged over 10 years.

[6] Estimate.

Caesars Entertainment, Inc. **Attachment C-1** **Source ID 257**

Cost Effectiveness Calculation

SRC8X6-22

Emission Unit/Control Technology

Emission Unit	CR07, PH10, PH11, PH12
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	0.30
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.03

Annualized Capital Costs

Initial Capital Investment[3]	$133,429
Direct & Indirect Costs[4]	$15,340
Total Capital Investment	$148,769
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$20,213

Annual Operating Costs

Urea	$1,428
Catalyst[5]	$2,027
Maintenance[6]	$6,000
Total Annualized Cost	$29,668

Cost Effectiveness

Emissions Reduction (tons/year)	0.27
Cost Effectiveness of NO_X Reduction ($/ton)	$109,880

Notes:

[1] Maximum actual emissions for 2019 - 2021 for group.

[2] Vendor specification.

[3] Cost based on vendor estimate.

[4] Installation, startup and performance testing.

[5] One replacement averaged over 10 years.

[6] Estimate.

Caesars Entertainment, Inc. **Attachment C-1** Source ID 257

Cost Effectiveness Calculation

SRC8X8-24

Emission Unit/Control Technology

Emission Unit	CP13, CP14, CP17,CP28, CP29, PA17, PA18, LI06, LI07
Emission Unit Description	Emergency Generator
Control Technology	SCR
Baseline Emission Rate[1] (tons/year)	1.04
Emission Reduction[2] (%)	90%
Controlled Emissions (tons/year)	0.10

Annualized Capital Costs

Initial Capital Investment[3]	$145,519
Direct & Indirect Costs[4]	$15,340
Total Capital Investment	$160,859
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$21,856

Annual Operating Costs

Urea	$1,666
Catalyst[5]	$2,702
Maintenance[6]	$6,000
Total Annualized Cost	$32,224

Cost Effectiveness

Emissions Reduction (tons/year)	0.94
Cost Effectiveness of NO_X Reduction ($/ton)	$34,427

Notes:

1 Maximum actual emissions for 2019 - 2021 for group.

2 Vendor specification.

3 Cost based on vendor estimate.

4 Installation, startup and performance testing.

5 One replacement averaged over 10 years.

6 Estimate.

Design Parameters

The following conditions were used to design the emergency standby SCR systems.

Table 1. Full Load Design Parameters per SCR

Tag No.	Engine	Engine HP	Gas Rate (Lb/hr)	Gas Temp (ºF)	Fuel	SCR Model	32.5% Urea
HA13	Detroit Diesel	1,232	13,500	920	ULSD	SCR6x6-18	<6 GPH
HA14, IP08, IP09	Caterpillar	890	9,500	920	ULSD	SCR6x4-16	<5 GPH
HA18	Caterpillar	1,180	13,500	920	ULSD	SCR6x6-18	<6 GPH
FL09, FL10	Caterpillar	1,109	13,500	920	ULSD	SCR6x6-18	<6 GPH
BA05, BA05, BA11, BA12	Detroit Diesel	1,340	13,500	920	ULSD	SCR6x6-18	<6 GPH
CR07	Caterpillar	2,206	16,800	930	ULSD	SCR8x6-22	<12 GPH
CP28, CP29, LI06, LI07	Caterpillar	2,937	22,400	930	ULSD	SCR8x8-24	<14 GPH
CP13, CP14, CP17	Caterpillar	2,876	22,000	930	ULSD	SCR8x8-24	<14 GPH
CP15	Caterpillar	2,520	17,400	930	ULSD	SCR8x6-22	<12 GPH
CP16	Caterpillar	1,818	15,300	920	ULSD	SCR6x6-20	<9 GPH
PA17, PA18	Cummins	2,816	22,000	930	ULSD	SCR8x8-24	<14 GPH
PH10, PH11, PH12	Detroit Diesel	2,550	17,400	930	ULSD	SCR8x6-22	<12 GPH
PH13	Detroit Diesel	2,560	17,400	930	ULSD	SCR6x6-22	<5 GPH

Table 2. Full Load Emissions Data per SCR

Exhaust Component	Catalyst Inlet	Catalyst Outlet	Required Reduction
NOx	10.89 g/hp-hr	1.08 g/hp-hr	90% minimum
NOx	5.08 g/hp-hr	0.50 g/hp-hr	90% minimum
NOx	5.23 g/hp-hr	0.52 g/hp-hr	90% minimum
NOx	4.53 g/hp-hr	0.45 g/hp-hr	90% minimum
NOx	5.39 g/hp-hr	0.53 g/hp-hr	90% minimum

Table 3. Full Load SCR System Data per SCR

Maximum Ammonia Slip	10 ppmvd @ 15% O2
Estimated 32.5% Urea Usage	Varies with engine NOx emissions – see above
Estimated System Pressure Loss (catalyst in new condition)	≤7.5"w.c.

NOTES:

Johnson Matthey has calculated the appropriate catalyst volume and necessary equipment to achieve the stated emission reductions based on the above Design Parameters. If the actual operating conditions are different from above conditions more catalyst and/or different equipment may be required for the system to achieve the required emission reductions. For this reason, all operating conditions must be closely reviewed and confirmed because different Parameters will void the warranty.

Emission reduction across catalyst is at steady state conditions, and with a maximum tolerance of + 3% deviation from the stated catalyst inlet emission value(s).

Equipment Description Per SCR System Per Engine

General Arrangement:

The proposed design is a horizontal configuration as shown on the referenced preliminary general arrangement drawings. Modifying the design to accommodate different specifications, configurations, etc. other than what is proposed will require a change to the price and/or shipment schedule.

Horizontal SCR Housing:

The SCR catalyst housing and catalyst tracks are fabricated from 400 series stainless steel. The housing is complete with a hinged catalyst access door, lifting lugs and misc. instrument connections. The floating catalyst tracks provide a labyrinth seal to prevent gas from by-passing the catalyst while minimizing the use for gaskets. Such gaskets tend to crack after thermal expansion and contraction cycles, and these cracks enable gas to by-pass the catalyst, which reduces the overall system performance.

Please refer to the following preliminary arrangement drawings for overall system dimensions SCR6x4

drawing number 202-C0031739 SCR6x6 drawing number 202-C0028769

SCR8x6 drawing number 202-CC0031740 SCR8x8 drawing number 202-C0028770

SCR10x8 drawing number 202-C0028771

Lot SCR Catalyst:

The SCR system will be provided with the catalyst type and volume that is needed to achieve the emission reductions which are listed above. Johnson Matthey designs and manufactures our own catalyst and has been doing so for decades. We integrate the proven performance of our catalyst into every SCR system that we provide. The catalyst is supplied in modules or blocks of sufficient size and weight to facilitate handling for loading the catalyst into the catalyst housing.

Horizontal Mixing Pipe:

The mixing pipe is optimized for the injection, atomization and mixing of the reductant into the engine exhaust gas. The pipe itself is fabricated from 300 series stainless steel and mixing duct internals are also fabricated from 300 series stainless steel. The pipe is supplied with internal mixers and all necessary fittings for the installation of the urea injection lance.

The dimensions of the mixing pipe vary with the SCR system size as indicated below.

SCR6x4-16 = 16″ diameter x 8′ long SCR6x6-18 = 18″ diameter x 8′ long

SCR6x6-20 = 20″ diameter x 8′ long SCR6x6-22 = 22″ diameter x 8′ long

SCR8x6-22 = 22″ diameter x 8′ long SCR8x8-24 = 24″ diameter x 8′ long

Urea Injection Control System:

This system will utilize an automatic urea injection system based on measurements from NOx sensors which are included with the SCR system. Requires Purchaser provided 4-20mA engine load signal and engine run signal.

The primary components of the urea injection control system are:

Control Panel – Painted carbon steel enclosure containing a touch screen Allen Bradley PLC with HMI and Modbus IP communication, on-off switch, on-off status indicator lights. Touch screen can be used for system commissioning and setup. System includes remote access capability for off-site monitoring. The control panel is mounted to the dosing panel that is described below. Both panels are designed for indoor installations. Please refer to the attached drawing for approximate overall dimensions of the panel.

Urea Dosing Panel – Attached to the control panel that is described above and contains the positive displacement urea metering pump (requires flooded suction), system purge valve, air regulator, air pressure switch, check valves, overpressure regulator, 3-way injection valve and leak detector.

Urea Injection Lance - Specially designed 2-phase 300 series stainless steel lance/nozzle assembly with high temperature protection.

Exhaust Gas Temperature Transmitter - To allow urea system to start injecting at temperatures greater than 575°F.

Available panel options include a stainless steel panel in lieu of painted carbon steel, a data logger, a modem for remote screen viewing, a heater and an air conditioner.

Instruction Manuals:

- Included are an electronic General Arrangement Approval Drawing, plus P&ID and the control/dosing panel general arrangement drawings and wiring schematic. Also included is an electronic Operation and Maintenance Manual for the SCR system.

Onsite Services:

Two (2) Technicians to install and test SCR over the course of Three (3) Days per Unit. Commissioning and Operation Inspection to include One (1) Four (4) hour load bank test using portable resistive load bank, to be completed during normal business hours, Monday thru Friday (excluding holidays). Additional trips or hours onsite, due to construction or other delays beyond our control, will be billed at extra cost at prevailing rate.

BASE PRICING:

SCR 8X8 - 24	Qty. 9	$1,309,673.00
SCR 8X6 - 22	Qty. 5	$667,147.00
SCR 6X6 - 22	Qty. 1	$128,269.00
SCR 6X6 - 20	Qty. 1	$126,500.00
SCR 6X6 - 18	Qty. 8	$1,004,923.00
SCR 6X4 - 16	Qty. 3	$358,712.00
Onsite Services	Qty. 27	$333,174.00

TOTAL ……………………………………………………………………………….. $3,928,398.00

W.W. Williams RESERVES THE RIGHT TO CORRECT ERRORS OR OMISSIONS.

Price DOES NOT include the following:
Any Applicable Local, State, or Federal Taxes

Lead Times: Estimated delivery of this product is approximately **32 - 34 Weeks** from date of submittal approval and/or release for manufacturing. Please note that this is an estimate, and actual ship date could vary. In no event will we be responsible for any delay damages, liquidated damages, or any other late fees or penalties. If a specific ship date is required for this project, we must be notified in writing prior to date of order and we will accept or reject the order depending on all factors involved. We will not accept back charges or penalties unless we have agreed in writing to do so.

Terms:
Payment Schedule: **Net 30** based on the following invoice schedule:
- 10% Invoiced upon receipt of Purchase Order
- 50% Invoiced upon receipt of Release for Manufacturing
- 30% Invoiced upon Delivery of Equipment
- 10% Invoiced upon completion of Start-Up

With Approved Credit, Otherwise C.O.D. - A 1 ½% (18% APR) Finance Charge Will Be Applied to All Accounts Past Due. 90% OF JOB TOTAL MUST BE PAID *BEFORE* START-UP IS PERFORMED.
Terms and Conditions include those on the last page of this document.

Acceptable methods of payment include cash, check, ACH, wire, or debit card.

If you are a new customers, or need to update terms, to help expedite your order please fill out our Credit App available at credit@wwwilliams.com.

Thank you for the opportunity to provide this quote and support all of your power generation requirements.

Best regards,

Jordan Lockett

Power Generation Sales
The W.W. Williams Company, LLC

ELECTION TO PURCHASE OR LEASE (CHOOSE ONE):

☐ PURCHASE - If a purchase order is written, we will also require that you sign and date this proposal in the following space provided. Please include this signed proposal with your purchase order. We will not order any equipment until you have submitted a credit application to W. W. Williams and it has been approved by W. W. Williams.

DATE: _______________ ACCEPTED FIRM NAME: ________________________ BY: ________________________________

TERMS AND CONDITIONS

These Terms and Conditions apply to all sales transactions with The W.W. Williams Company, LLC, including quotations, purchase orders, service orders, sales orders, or similar documents:

1. **Terms Exclusive.** These Terms and Conditions and the applicable quotation, purchase order, service order, sales order or similar document constitute the complete, exclusive and final agreement (collectively, the "Agreement") of the buyer ("Buyer") and The W.W. Williams Company, LLC ("Williams"). All other additional or conflicting terms or conditions which may now or in the future appear on Buyer's acknowledgment, purchase order, or other similar document are expressly objected to by Williams without future notification and shall be null and void. These Terms and Conditions may only be modified, superseded or altered in writing signed by both parties. Buyer's acceptance of any performance by Williams shall be taken as Buyer's acceptance of these Terms and Conditions.

2. **Prices.** Prices are subject to change or withdrawal without notice. Unless otherwise stated in the Agreement, prices may be adjusted to and invoiced at Williams's price list in effect at the time of the shipment of goods or furnishing of the services. Unless otherwise stated in the Agreement, prices are exclusive of applicable taxes, excises, duties, quotation fees or other governmental impositions which Williams may be required to pay or collect on behalf of Buyer.

3. **Payment Terms; Security Interest.** Extensions of credit by Williams are subject to credit approval by Williams in its sole discretion, which may be modified or revoked by Williams at any time. Unless otherwise stated in the Agreement, payment shall be due and payable in full and without setoff within 15 days following delivery of the goods or completion of the services. Any payment not made when due shall be subject to a carrying charge of one and one-half percent (1 ½%) per month on the unpaid balance until paid in full. Buyer expressly grants to Williams a security interest in any goods, or a mechanic's or garage keeper's lien, as applicable, in respect of any services, to secure payment of the purchase price therefore and any other amounts or charges owed by Buyer to Williams. Buyer authorizes Williams (but Williams is not obligated) to file a financing statement or take such action as Williams deems advisable to evidence and perfect its security interest.

4. **Delivery; Force Majeure.** Unless otherwise stated in the Agreement, delivery of the goods, and services, if any, shall be F.O.B. point of shipment. Any delivery date specified is approximate only. Acceptance of shipment by a common carrier shall constitute tender of delivery. Upon tender of delivery, risk of loss shall pass to Buyer. Title shall pass to Buyer when the full price has been paid. Partial shipments may be made and payments therefore shall become due in accordance with the terms hereof as shipments are made and invoices rendered. If Williams is not able to meet the delivery date specified by reason of any force majeure event beyond Williams's control, including (but not limited to) war, governmental requests, restrictions or regulations, fire, flood, casualty, accident, or other acts of God, disease or illness, including but not limited to epidemic, pandemic, or quarantine, national or state declared emergency, strikes or other difficulties with employees, supplier delays, delay or inability to obtain goods, labor, equipment, material and service through Williams's usual sources, failure, refusal or delay of any carrier to transport materials, or any other similar event, Williams shall not be liable therefor and may, in its discretion without prior notice to Buyer, postpone the delivery date(s) under this Agreement for a time which is reasonable under all the circumstances. Acceptance of the goods or services shall constitute a waiver of all claims for damages.

5. **Standard Limited Warranty; Limitations of Liability.** The Williams Standard Limited Warranty and the limitations of liability contained therein, attached as Exhibit A hereto, shall apply to the purchase and sale of goods and services under this Agreement.

6. **Indemnification.** Buyer shall indemnify, defend, and hold harmless Williams, its directors, officers, employees and their respective affiliates against any claim, demand, complaint, liability, loss, cost, damage and/or expense (including attorneys' fees, costs and expenses of litigation and settlements) incurred by Williams arising out of or as a result of this Agreement, except to the extent caused by the negligence of Williams.

7. **Claims.** Unless otherwise stated in the Agreement, claims respecting the condition of goods, compliance with specifications, or any other matter affecting goods shipped or services provided to Buyer, must be made promptly and in no event later than twenty (20) days after receipt of the goods by Buyer or the furnishing of the services by Williams. Failure of Buyer to make a claim within such 20-day period shall be deemed an unqualified acceptance of the goods or services by Buyer. Buyer shall set aside, protect, and hold such goods (without charge to Williams) without further processing until Williams has an opportunity to inspect and advise of the disposition, if any, to be made of such goods. In no event shall any goods be returned, reworked, or scrapped by Buyer without the express written authorization of Williams.

8. **<u>Default and Williams's Remedies.</u>** If Buyer fails to make timely payment on any sale of goods or services from Williams to Buyer, Williams, in addition to any other remedies available to it, may at its option, (a) defer further shipment or services until such payments are made and satisfactory credit arrangements are reestablished or (b) cancel the balance of any order, and Buyer shall not have any cause of action or be entitled to any offset, counterclaim, or recoupment against Williams by reason of such action. In the event of Buyer's default, Williams may exercise any and all remedies set forth in this Agreement, any other agreement between the parties, and applicable law, all of which rights and remedies are cumulative.

9. **<u>Collection Costs and Attorney Fees.</u>** Buyer agrees to pay all of Williams's costs and expenses incurred in collecting payments due from Buyer (including without limitation reasonable attorney fees and costs and expenses of any collection agency).

10. **<u>Return Policy</u>**. Returns must be accompanied by this invoice and in the original, unopened box or packaging. A 15% restocking charge will be applied to all returned items. No returns on electrical items. No returns on special order items. No returns after 30 days from invoice date.

11. **<u>Technical Assistance.</u>** Unless otherwise stated in the Agreement: (a) any technical advice provided by Williams with respect to the use of goods or services furnished to Buyer shall be provided as a courtesy without charge and without warranty; (b) Williams assumes no obligation and disclaims all liability for any such advice or for any results occurring as a result of the application of such advice; and (c) Buyer shall have sole responsibility for selection and specification of the goods and services appropriate for the end use of such goods or services.

12. **<u>Miscellaneous</u>**. This Agreement will be governed by the laws of the State of Ohio. The exclusive venue for any dispute related to this Agreement shall be the federal and state courts located in Columbus, Ohio. If any of the provisions hereof shall be held invalid, illegal or unenforceable, the validity, legality and enforceability of the remaining provisions shall in no way be affected or impaired thereby. The individual rights and remedies of Williams reserved herein shall be cumulative and additional to any other or further remedies provided in law or equity. Waiver by Williams of performance or inaction with respect to Buyer's breach of any provision hereof, or failure of Williams to enforce any provision hereof which may establish a defense or limitation of liability, shall not be deemed a waiver of future compliance therewith or a course of performance modifying such provision, and such provision shall remain in full force and effect as written.

13. **<u>Entire Agreement.</u>** This Agreement, including without limitation the Terms and Conditions and any other document incorporated herein by reference, constitutes the sole and entire agreement between Buyer and Williams with respect to any order or sale of goods or furnishing of services to Buyer, superseding completely any prior or contemporaneous oral or written communications.

EXHIBIT A

The W.W. Williams Company, LLC

Standard Limited Warranty

Limited warranty for parts and equipment:

The sole warranty provided for any part or equipment sold by The W.W. Williams Company, LLC ("Williams") is to assign the warranty offered by the manufacturer or supplier to the Buyer. WILLIAMS MAKES NO REPRESENTATION OR WARRANTY TO THE EFFECTIVENESS OR EXTENT OF SUCH MANUFACTURER OR SUPPLIER WARRANTY. WILLIAMS EXPRESSLY DISCLAIMS ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, and does not assume or authorize any other person to assume for it any liability in connection with the sale.

Limited warranty for services:

Williams warrants its workmanship for a period of ninety (90) days from the date the services are performed (the "Warranty Period"). This warranty covers defects in Williams's workmanship that are discovered during the Warranty Period. Buyer's sole remedy, and Williams's only liability, for Williams's breach of its service warranty shall be, at Williams's option, (i) reperforming the defective services; or (ii) refunding the purchase price paid for the defective services. WILLIAMS EXPRESSLY DISCLAIMS ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, and does not assume or authorize any other person to assume for it any liability in connection with the sale.

Limitations of Liability:

IN NO EVENT SHALL WILLIAMS BE LIABLE FOR ANY PUNITIVE, INDIRECT, INCIDENTAL, CONSEQUENTIAL, SPECIAL OR UNKNOWN DAMAGES, INCLUDING BUT NOT LIMITED TO, LOSS OF PROPERTY OR EQUIPMENT, LOSS OF DATA, LOSS OF USE, LOSS OF TIME, LOSS OF REVENUE, LOSS OF PROFIT, OR LOSS OF INCOME, WHETHER THE DAMAGES BE IN CONTRACT OR TORT.

WILLIAMS'S TOTAL LIABILITY FOR ANY PARTS, EQUIPMENT, OR SERVICES SOLD SHALL NOT EXCEED THE AMOUNT PAID TO WILLIAMS FOR SUCH PARTS, EQUIPMENT, OR SERVICES CAUSING THE LIABILITY.

Appendix 4

Switch RACT Analysis

REASONABLY AVAILIBLE CONTROL TECHNOLOGY REVIEW

Switch / Las Vegas, NV

Prepared By:

TRINITY CONSULTANTS
9190 Double Diamond Parkway Suite 126
Reno, NV 89521
(775) 242-3200

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Project 220506.0015

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1. EXECUTIVE SUMMARY

Switch, Ltd. (Switch) has been encouraged 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 operated at Switch's West Campus in Las Vegas, Nevada (the Facility). DAQ issued a revised Part 70 Operating Permit No. 16304 on September 12, 2022 for the Facility (the Permit).

DAQ requested that a RACT analysis be submitted by October 3, 2022 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 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 marginal to moderate nonattainment for ozone.[1] The new classification would require HA 212 to achieve attainment by August 3, 2024, and require DAQ 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 use of control technology that is reasonably available considering technological and economical feasibility.[3]

The Facility is currently a major source of NO_x (i.e., site-wide NO_x PTE is greater than 100 tpy). The Facility does not include any emission units at the Facility with PTE greater than five tpy of NO_x. However, per guidance from DAQ, Switch is proactively submitting this RACT analysis for the Facility.[4] The site-wide PTE is presented in Table 1-1 of this report.[5]

Table 1-1. Site-Wide PTE including Unconstructed Emission Units (tpy)

Pollutant	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP	GHG
Source Total	6.98	2.69	246.18	32.58	1.30	3.71	1.30	24,048.43

Per the August 1, 2022 DAQ RACT Stakeholder meeting, DAQ is requesting that the following information be submitted, 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:

[1] 87 FR 43764.

[2] Per the August 1, 2022 Clark County DAQ 2015 Ozone NAAQ - Reasonably Available Control Technology (RACT) Requirements Presentation.

[3] Ibid.

[4] Email from Ted Lendis (DAQ) to Sean Keane (Trinity) on September 14, 2022.

[5] Site-wide PTE per the Permit.

- Information sources relied on to identify available control options
- Evaluation of technical feasibility
- Proposed RACT emission limitation or averaging approach
- Proposed testing, monitoring, and recordkeeping and reporting meeting periodic or CAM monitoring requirements.

Trinity has reviewed the technical feasibility of control methods with Switch for the diesel-fired emergency engines and fire pumps engines at the Facility and determined that complying with the applicable 40 CFR Part 60 Subpart IIII requirements, including emissions standards, for stationary compression ignition (CI) internal combustion emergency engines constitutes RACT for the diesel-fired emergency engines. Additionally, Facility's diesel-fired emergency engines currently comply with relevant RACT prohibitory rules of other air agencies. Therefore, there are no proposed changes to the emission limitations and testing, monitoring, and recordkeeping requirements contained in the Permit for the diesel-fired emergency engines. 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. Trinity undertook an evaluation on Switch's behalf, and believes the current level of NO_x emissions from the emergency engine is considered RACT and no additional control technology is technically or economically feasible.

2.1 Technically Feasible Options

Trinity has evaluated RACT, on behalf of Switch, for all applicable diesel-fired emergency engines 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 preparing the RACT analysis for the diesel-fired emergency engines.

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 diesel-fired emergency engines and fire pump engines of various makes and models. Therefore, the diesel-fired emergency engines either are classified as Large Internal Combustion Engines (> 500 hp) or Small Internal Combustion Engines (< 500 hp) for purposes of the RBLC. Please refer to Table 1-1 to Table 1-6 of the Permit for a complete description of each diesel-fired emergency engine at the Facility.

2.1.2 Identification of Potential Control Technologies

Available NO_x 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.

On behalf of Switch, Trinity has performed searches of the RBLC in September 2022 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 Switch. 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)
- Small Internal Combustion Engines (< 500 hp)
  - Fuel Oil (ASTM #1,2, includes kerosene, aviation, diesel fuel) (RBLC Code 17.210)

The following control technologies are technologically feasible based on the RBLC database search results.

- EPA Tier Certification
- Use of good combustion practices (GCP)

The RBLC search results are available in Appendix A.

2.1.2.2 EPA Tier Certification

Emergency engines are certified to comply with EPA Tier Emission Standards as outlined in 40 CFR Part 60 Subpart IIII for stationary CI internal combustion emergency engine or stationary fire pump engines, per the maximum engine power and model year.

2.1.2.3 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.

2.1.2.4 Technical Feasibility Determination – Diesel-Fired Emergency Engines

The diesel-fired emergency engines are assumed to use GCP as they meet manufacturer specifications and comply with the applicable 40 CFR Part 60 Subpart IIII requirements, including emissions standards per the maximum engine power and model year, for stationary CI internal combustion emergency engines. The use of GCP is technically feasible and use of an EPA Tier certified engine has been demonstrated in practice for those emergency engines subject to 40 CFR Part 60 Subpart IIII requirements (i.e., the 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 numbers of hours per year, the costs of emission control are not warranted when compared to the emission reductions that would be achieved." 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.[6]

[6] 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).

Furthermore, Trinity has reviewed the current RACT requirements for emergency engines in other agency jurisdictions, on behalf of Switch. 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). [7] 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).[8] Trinity completed an assessment on behalf of Switch, and 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.

2.1.3 Selection of NO_x RACT for the Diesel-Fired Emergency Engines

As discussed in Section 2.1.2.4, the diesel-fired emergency engines use GCP as they meet manufacturer specifications and 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 and compliance with applicable 40 CFR Part 60 Subpart IIII requirements, such as emission standards, is technically feasible and is selected as meeting RACT for all of the diesel-fired emergency engines.

Switch intends to maintain the current emission limits for NO_x as contained in the Permit for each of the affected diesel emergency engines. Switch will utilize the existing Permit conditions to monitor compliance with the NO_x emission limits contained in the Permit.

[7] SJVAPCD Rule 4702, Amended August 19, 2021. https://www.valleyair.org/rules/currntrules/r4702.pdf

[8] 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

APPENDIX A: SUMMARY OF RBLC

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
AK-0076	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT01	1382	211111	8/20/2012	Combustion of Diesel by ICEs	17.11	ULSD	1750	kW	NO_x	10102		6.4	G/KW-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Remote Incinerator Generator Engine	21.4	Ultra Low Sulfur Diesel	102	hp	NO_x	10102		3	LB/TON	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Emergency Camp Generators	17.11	Ultra Low Sulfur Diesel	2695	hp	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Airstrip Generator Engine	17.21	Ultra Low Sulfur Diesel	490	hp	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Agitator Generator Engine	17.21	Ultra Low Sulfur Diesel	98	hp	NO_x	10102		5.6	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Incinerator Generator Engine	17.21	Ultra Low Sulfur Diesel	102	hp	NO_x	10102-44-0		4.9	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Fine Water Pumps	17.11	Ultra Low Sulfur Diesel	610	hp	NO_x	10102		3	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	1382	211111	1/23/2015	Bulk Tank Generator Engines	17.11	Ultra Low Sulfur Diesel	891	hp	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0084	DONLIN GOLD PROJECT	AQ0934CPT01	1041	212221	6/30/2017	Black Start and Emergency Internal Combustion Engines	17.11	Diesel	1500	kWe	NO_x	10102	Good Combustion Practices	8	G/KW-HR	BACT-PSD
AK-0084	DONLIN GOLD PROJECT	AQ0934CPT01	1041	212221	6/30/2017	Fire Pump Diesel Internal Combustion Engines	17.21	Diesel	252	hp	NO_x	10102	Good Combustion Practices	3.7	G/KW-HR	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
AK-0085	GAS TREATMENT PLANT	AQ1524CPT01	4922	486210	8/13/2020	One (1) Black Start Generator Engine	17.11	ULSD	186.6	gph	NO_x	10102	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	8/13/2020	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	17.21	ULSD	19.4	gph	NO_x	10102	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	7/7/2022	Diesel Fire Pump Engine	17.11	Diesel	27.9	Gal/hr	NO_x	10102	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII	3.6	G/HP-HR	BACT-PSD
AK-0088	LIQUEFACTION PLANT	AQ1539CPT01	4922	488999	7/7/2022	Auxiliary Air Compressor Engine	17.21	Diesel	14.6	Gal/hr	NO_x	10102	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII	0.45	G/HP-HR	BACT-PSD
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	413-0033-X014 - X020	3312	331111	7/22/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL	800	HP	NO_x	10102		0.015	LB/HP-H	BACT-PSD
*AL-0318	TALLADEGA SAWMILL	309-0075	2421	321113	12/18/2017	250 Hp Emergency CI, Diesel-fired RICE	17.11	Diesel	0		NO_x	10102		0		N/A
AL-0328	PLANT BARRY	503-1001	4911	221112	11/9/2020	Diesel Emergency Engines	17.11	Diesel	0		NO_x	10102		3	GR/BHP-HR	BACT-PSD
AR-0161	SUN BIO MATERIAL COMPANY	2384-AOP-R0	2611	322110	9/23/2019	Emergency Engines	17.11	Diesel	0		NO_x	10102	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	6/9/2019	Emergency Engines	17.11	Diesel	0		NO_x	10102	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	4.86	G/KW-HR	BACT-PSD
CA-1219	CITY OF SAN DIEGO PUD (PUMP STATION 1)	2012--APP-002009	4952	221320	7/9/2012	IC engine	17.11	diesel	2722	bhp	NO_x	10102	Tier 2 certified engine and 50 hr/yr for M&T	4	G/B-HP-H	OTHER CASE-BY-CASE
DC-0009	BLUE PLAINS ADVANCED WASTEWATER TREATEMENT PLANT	6372-A1	4952	221320	3/15/2012	Diesel Emergency Generator	17.11	Ultra-low Sulfur Diesel	2682	hp	NO_x	10102		31.87	LB/HR	LAER
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Main Propulsion Engines - Development Driller 1	17.11	Diesel	0		NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, and additional enhanced work practice standards including an engine performance management system, positive crankcase ventilation, turbocharger with aftercooler, and high pressure fuel injection with aftercooler.	12.1	G/KW-H	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Main Propulsion Engines - C.R. Luigs	17.11	Diesel	5875	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, and additional enhanced work practice standards including an engine performance management system, positive crankcase ventilation, turbocharger with aftercooler, and high pressure fuel injection with aftercooler.	18.1	G/KW-H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Wireline Unit Engines - C.R. Luigs	17.21	diesel	300	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, turbocharger with aftercooler, high pressure fuel injection with aftercooler	8.92	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Fast Rescue Craft Diesel Engine - Development Driller 1	17.21	Diesel	142	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, and turbocharger	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Life Boat Diesel Engines - Development Driller 1	17.21	Diesel	110	hp	NO_x	10102-44-0	Use of good combustion practices based on the current manufacturerâ's specifications for these engines and use of low sulfur diesel fuel	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Port and Stb Fwd and Aft Crane Diesel Engines - C.R. Luigs	17.21	diesel	305	HP	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	82.83	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Fast Rescue Craft Diesel Engine - C.R. Luigs	17.11	diesel	142	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines and use of low sulfur diesel fuel	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Seismic Operations Diesel Engines - Development Driller 1	17.21	Diesel	415	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, and turbocharger	3.54	TONS	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Life Boat Diesel Engines - C.R. Luigs	17.21	diesel	39	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Emergency Generator Diesel Engine - Development Driller 1	17.11	Diesel	2229	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	1.6	T/12MO ROLLING TOTAL	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Cementing and Nitrogen Pump Diesel Engines - Development Driller 1	17.21	Diesel	0		NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel injection with aftercooler	9.5	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Wireline Unit Diesel Engines - Development Driller 1	17.21	Diesel	0		NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, turbocharger with aftercooler, high pressure fuel injection with aftercooler	8.92	TONS	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Black Start Air Compressor - C.R. Luigs	17.21	diesel	6	hp	NO_x	10102-44-0	Use of good combustion practices based on the current manufacturerâ's specifications for the engine and the use of low sulfur diesel fuel	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Emergency Generator Diesel Engine - C.R. Luigs	17.11	diesel	2064	hp	NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	1.49	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	1381	211111	5/30/2012	Cementing and Nitrogen Pump Diesel Engines - C.R. Luigs	17.21	diesel	0		NO_x	10102	Use of good combustion practices based on the current manufacturerâ's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel injection with aftercooler	8.69	T/12MO ROLLING TOTAL	BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Main Propulsion Generator Diesel Engines	17.11	Diesel	9910	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	12.7	G/KW-H	BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Diesel Powered Forklift Engine	17.21	Diesel	30	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Wireline Diesel Engines	17.21	Diesel	0		NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0		BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Water Blasting Diesel Engine	17.21	Diesel	208	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Well Evaluation Diesel Engine	17.21	Diesel	140	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Fast Rescue Craft Diesel Engine	17.21	Diesel	230	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Escape Capsule Diesel Engine	17.21	Diesel	39	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Emergency Diesel Engine	17.11	Diesel	3300	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	1381	211111	9/16/2014	Remotely Operated Vehicle Emergency Generator	17.21	Diesel	427	hp	NO_x	10102	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0		BACT-PSD
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	1381	213111	5/15/2012	Main Propulsion Generators	17.21	Diesel	4425	hp	NO_x	10102	Use of engine with turbo charger with after cooler, an enhanced work practice power management, NOx emissions maintenance system, and good combustion and maintenance practices based on the current manufacturerâ's specifications for each engine	26	G/KW-H	BACT-PSD
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	1381	213111	5/15/2012	Drill Floor and Crew Quarters Electrical Generators	17.11	Diesel	6789	hp	NO_x	10102	Use of engine with turbo charger with after cooler, an enhanced work practice power management, NOx emissions maintenance system, and good combustion and maintenance practices based on the current manufacturerâ's specifications for each engine.	26	G/KW-H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	1381	213111	5/15/2012	Emergency Electrical Generator	17.11	Diesel	1100	hp	NO_x	10102	Use of good combustion and maintenance practices based on the current manufacturerâ's specifications for this engine.	0.22	TONS	BACT-PSD
FL-0350	ANADARKO PETROLEUM, INC DIAMOND BLACKHAWK DRILLING PROJECT	OCS-EPA-R4019	1381	213111	12/31/2014	Main Propulsion Generator Engines	17.11	Diesel	0		NO_x	10102	Use of good combustion practices based on the most recent manufacturerâ's specifications issued for these engines at the time that the engines are operating under this permit	0		BACT-PSD
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1010524-001-AC	4911	221112	7/27/2018	1,500 kW Emergency Diesel Generator	17.11	ULSD	14.82	MMBtu/hour	NO_x	10102	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	7/27/2018	Emergency Fire Pump Engine (347 HP)	17.21	ULSD	8700	gal/year	NO_x	10102	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	6/7/2021	1,500 kW Emergency Diesel Generator	17.11	ULSD	14.82	MMBtu/hour	NO_x	10102		6.4	G/KW-HOUR	BACT-PSD
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1010524-003-AC (PSD-FL-444A)	4911	221112	6/7/2021	Emergency Fire Pump Engine (347 HP)	17.21	ULSD	2.46	MMBtu/hour	NO_x	10102		4	G/KW-HOUR	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	12-219	2873	325311	10/26/2012	Emergency Generator	17.11	diesel fuel	142	GAL/H	NO_x	10102	good combustion practices	6	G/KW-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	12-219	2873	325311	10/26/2012	Fire Pump	17.21	diesel fuel	14	GAL/H	NO_x	10102	good combustion practices	3.75	G/KW-H	BACT-PSD
IL-0114	CRONUS CHEMICALS, LLC	13060007	2873	325311	9/5/2014	Emergency Generator	17.11	distillate fuel oil	3755	HP	NO_x	10102	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.67	G/KW-H	BACT-PSD
IL-0114	CRONUS CHEMICALS, LLC	13060007	2873	325311	9/5/2014	Firewater Pump Engine	17.21	distillate fuel oil	373	hp	NO_x	10102	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	3.5	G/KW-H	BACT-PSD
IL-0129	CPV THREE RIVERS ENERGY CENTER	16060032	4911	221112	7/30/2018	Emergency Engines	17.11	Ultra-low sulfur diesel	0		NO_x	10102		0		LAER
IL-0129	CPV THREE RIVERS ENERGY CENTER	16060032	4911	221112	7/30/2018	Firewater Pump Engine	17.21	Ultra-low sulfur diesel	0		NO_x	10102		0		LAER
IL-0130	JACKSON ENERGY CENTER	17040013	4911	221112	12/31/2018	Firewater Pump Engine	17.21	Ultra-Low Sulfur Diesel	420	horsepower	NO_x	10102		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	NO_x	10102		6.4	G/KW-HR	LAER
*IL-0133	LINCOLN LAND ENERGY CENTER	18040008	4911	221112	7/29/2022	Emergency Engines	17.11	Ultra-Low Sulfur Diesel	1250	kW	NO_x	10102		6.4	GRAMS	BACT-PSD
*IL-0133	LINCOLN LAND ENERGY CENTER	18040008	4911	221112	7/29/2022	Fire Water Pump Engine	17.21	Ultra-Low Sulfur Diesel	320	horsepower	NO_x	10102		4	GRAMS	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	4911	221112	12/3/2012	TWO (2) FIREWATER PUMP DIESEL ENGINES	17.21	DIESEL	371	BHP, EACH	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	3	G/HP-H	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	4911	221112	12/3/2012	TWO (2) EMERGENCY DIESEL GENERATORS	17.11	DIESEL	1006	HP EACH	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	4911	221112	12/3/2012	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	2012	HP	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	BACT-PSD
IN-0166	INDIANA GASIFICATION, LLC	T147-30464-00060	4925	221210	6/27/2012	TWO (2) EMERGENCY GENERATORS	17.11	DIESEL	1341	HORSEPOWER, EACH	NO_x	10102	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION	0		BACT-PSD
IN-0166	INDIANA GASIFICATION, LLC	T147-30464-00060	4925	221210	6/27/2012	THREE (3) FIREWATER PUMP ENGINES	17.11	DIESEL	575	HORSEPOWER, EACH	NO_x	10102	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION	0		BACT-PSD
IN-0173	MIDWEST FERTILIZER CORPORATION	129-33576-00059	2873	325311	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	NO. 2, DIESEL	3600	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/BHP-H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
IN-0173	MIDWEST FERTILIZER CORPORATION	129-33576-00059	2873	325311	6/4/2014	RAW WATER PUMP	17.21	DIESEL, NO. 2	500	HP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.83	G/BHP-H	BACT-PSD
IN-0179	OHIO VALLEY RESOURCES, LLC	147-32322-00062	2873	325311	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	17.11	NO. 2 FUEL OIL	4690	B-HP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	BACT-PSD
IN-0179	OHIO VALLEY RESOURCES, LLC	147-32322-00062	2873	325311	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	17.21	NO. 2 FUEL OIL	481	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.86	G/B-HP-H	BACT-PSD
IN-0180	MIDWEST FERTILIZER CORPORATION	129-33576-00059	2873	325311	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	NO. 2, DIESEL	3600	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	BACT-PSD
IN-0180	MIDWEST FERTILIZER CORPORATION	129-33576-00059	2873	325311	6/4/2014	RAW WATER PUMP	17.21	DIESEL, NO. 2	500	HP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.83	G/B-HP-H	BACT-PSD
IN-0185	MAG PELLET LLC	181-33965-00054	1011	212210	4/24/2014	DIESEL FIRE PUMP	17.11	DIESEL	300	HP	NO_x	10102		3	G/HP-H	BACT-PSD
IN-0263	MIDWEST FERTILIZER COMPANY LLC	129-36943-00059	2873	325311	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	17.11	DISTILLATE OIL	3600	HP EACH	NO_x	10102	GOOD COMBUSTION PRACTICES	4.42	G/HP-H EACH	BACT-PSD
IN-0317	RIVERVIEW ENERGY CORPORATION	T147-39554-00065	2911	324110	6/11/2019	Emergency generator EU-6006	17.11	Diesel	2800	HP	NO_x	10102	Tier II diesel engine	6.4	G/KWH	BACT-PSD
IN-0317	RIVERVIEW ENERGY CORPORATION	T147-39554-00065	2911	324110	6/11/2019	Emergency fire pump EU-6008	17.11	Diesel	750	HP	NO_x	10102	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	5/6/2022	emergency generator EU 014a	17.11	distillate oil	3600	HP	NO_x	10102		4.42	G/HP-HR	BACT-PSD
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	C-10656	4911	221112	3/18/2013	Caterpillar C18DITA Diesel Engine Generator	17.11	No. 2 Distillate Fuel Oil	900	BHP	NO_x	10102	utilize efficient combustion/design technology	14	LB/HR	BACT-PSD
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	C-10656	4911	221112	3/18/2013	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	17.21	No. 2 Fuel Oil	182	BHP	NO_x	10102	utilize efficient combustion/design technology	2	LB/HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 10-02 - North Water System Emergency Generator	17.11	Diesel	2922	HP	NO_x	10102	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	7/23/2020	EP 10-03 - South Water System Emergency Generator	17.11	Diesel	2922	HP	NO_x	10102	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	7/23/2020	EP 10-04 - Emergency Fire Water Pump	17.11	Diesel	920	HP	NO_x	10102	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	7/23/2020	EP 11-01 - Melt Shop Emergency Generator	17.21	Diesel	260	HP	NO_x	10102	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	7/23/2020	EP 11-02 - Reheat Furnace Emergency Generator	17.21	Diesel	190	HP	NO_x	10102	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	7/23/2020	EP 10-07 - Air Separation Plant Emergency Generator	17.11	Diesel	700	HP	NO_x	10102	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	7/23/2020	EP 10-01 - Caster Emergency Generator	17.11	Diesel	2922	HP	NO_x	10102	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	7/23/2020	EP 11-03 - Rolling Mill Emergency Generator	17.21	Diesel	440	HP	NO_x	10102	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.98	G/HP-HR	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	3312	331111	7/23/2020	EP 11-04 - IT Emergency Generator	17.21	Diesel	190	HP	NO_x	10102	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	7/23/2020	EP 11-05 - Radio Tower Emergency Generator	17.21	Diesel	61	HP	NO_x	10102	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	4/19/2021	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	17.11	Diesel	2922	HP	NO_x	10102	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	4/19/2021	Tunnel Furnace Emergency Generator (EP 08-06)	17.11	Diesel	2937	HP	NO_x	10102	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	4/19/2021	Caster B Emergency Generator (EP 08-07)	17.11	Diesel	2937	HP	NO_x	10102	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	4/19/2021	Air Separation Unit Emergency Generator (EP 08-08)	17.11	Diesel	700	HP	NO_x	10102	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	4/19/2021	Cold Mill Complex Emergency Generator (EP 09-05)	17.21	Diesel	350	HP	NO_x	10102	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	1/22/2016	Emergency Generators No. 1 & No. 2	17.11	Diesel	1341	HP	NO_x	10102	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-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	PSD-LA-779	2821	325211	5/23/2014	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	17.11	Diesel	2682	HP	NO_x	10102	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturerâ's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	27.37	LB/HR	BACT-PSD
LA-0305	LAKE CHARLES METHANOL FACILITY	PSD-LA-803(M1)	2869	325199	6/30/2016	Diesel Engines (Emergency)	17.11	Diesel	4023	hp	NO_x	10102	Complying with 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0307	MAGNOLIA LNG FACILITY	PSD-LA-792	4922	221210	3/21/2016	Diesel Engines	17.11	Diesel	0		NO_x	10102	good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0308	MORGAN CITY POWER PLANT	PSD-LA-767	4911	221112	9/26/2013	2000 KW Diesel Fired Emergency Generator Engine	17.11	Diesel	20.4	MMBTU/hr	NO_x	10102	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	33.07	LB/H	BACT-PSD
LA-0308	MORGAN CITY POWER PLANT	PSD-LA-767	4911	221112	9/26/2013	380 HP Diesel Fired Pump Engine	17.21	Diesel	2.3	MMBTU/hr	NO_x	10102	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	2.92	LB/H	BACT-PSD
LA-0309	BENTELER STEEL TUBE FACILITY	PSD-LA-774(M1)	3312	331111	6/4/2015	Firewater Pump Engines	17.21	Diesel	288	hp (each)	NO_x	10102	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	6/4/2015	Emergency Generator Engines	17.11	Diesel	2922	hp (each)	NO_x	10102	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	6/30/2017	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	17.11	Diesel	650	horsepower	NO_x	10102	Compliance with NSPS Subpart IIII	6.6	LB/HR	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
*LA-0312	ST. JAMES METHANOL PLANT	PSD-LA-780(M-1)	2869	325998	6/30/2017	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	17.11	Diesel	1474	horsepower	NO_x	10102	Compliance with NSPS Subpart IIII	19.23	LB/HR	BACT-PSD
LA-0313	ST. CHARLES POWER STATION	PSD-LA-804	4911	221112	8/31/2016	SCPS Emergency Diesel Generator 1	17.11	Diesel	2584	HP	NO_x	10102	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	8/31/2016	SCPS Emergency Diesel Firewater Pump 1	17.21	Diesel	282	HP	NO_x	10102	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-0315	G2G PLANT	PSD-LA-781	2869	325110	5/23/2014	Emergency Diesel Generator 1	17.11	Diesel	5364	HP	NO_x	10102	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	2869	325110	5/23/2014	Emergency Diesel Generator 2	17.11	Diesel	5364	HP	NO_x	10102	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	2869	325110	5/23/2014	Fire Pump Diesel Engine 1	17.11	Diesel	751	HP	NO_x	10102	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	2869	325110	5/23/2014	Fire Pump Diesel Engine 2	17.11	Diesel	751	HP	NO_x	10102	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	BACT-PSD
LA-0316	CAMERON LNG FACILITY	PSD-LA-766(M3)	4922	221210	2/17/2017	firewater pump engines (8 units)	17.21	diesel	460	hp	NO_x	10102-44-0	Complying with 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0316	CAMERON LNG FACILITY	PSD-LA-766(M3)	4922	221210	2/17/2017	emergency generator engines (6 units)	17.11	diesel	3353	hp	NO_x	10102	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		NO_x	10102	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)	NO_x	10102	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	1/9/2017	Fire Water Diesel Pump No. 3 Engine	17.11	Diesel Fuel	600	hp	NO_x	10102	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	1/9/2017	Fire Water Diesel Pump No. 4 Engine	17.11	Diesel Fuel	600	hp	NO_x	10102	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	1/9/2017	Standby Generator No. 9 Engine	17.21	Diesel Fuel	400	hp	NO_x	10102	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0331	CALCASIEU PASS LNG PROJECT	PDS-LA-805	4925	221210	9/21/2018	Firewater Pumps	17.11	Diesel Fuel	634	kW	NO_x	10102	Good Combustion and Operating Practices.	3.1	G/HP-H	BACT-PSD
LA-0331	CALCASIEU PASS LNG PROJECT	PDS-LA-805	4925	221210	9/21/2018	Large Emergency Engines (>50kW)	17.11	Diesel Fuel	5364	HP	NO_x	10102	Good Combustion and Operating Practices	5.6	G/KW-H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
LA-0364	FG LA COMPLEX	PSD-LA-812	2869	325110	1/6/2020	Emergency Generator Diesel Engines	17.11	Diesel Fuel	550	hp	NO_x	10102	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	1/6/2020	Emergency Fire Water Pumps	17.11	Diesel Fuel	550	hp	NO_x	10102	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-0379	SHINTECH PLAQUEMINES PLANT 1	PSD-LA-709(M-4)	2821	325211	5/4/2021	PVC Emergency Combustion Equipment A	17.21	Diesel	450	hp	NO_x	10102	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	5/4/2021	PVC Emergency Combustion Equipment 2A and 2B	17.21	Diesel	300	hp	NO_x	10102	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	4/25/2019	Emergency Engines (EQT0014 - EQT0017)	17.11	Diesel	0		NO_x	10102	Comply with standards of 40 CFR 60 Subpart IIII	0		BACT-PSD
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	PSD-LA-838	4925	486210	9/3/2020	Emergency Engines (EQT0011 - EQT0016)	17.11	Diesel	0		NO_x	10102	Comply with 40 CFR 60 Subpart IIII	0		BACT-PSD
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	NE-12-022	4911	221112	1/30/2014	Emergency Engine/Generator	17.11	ULSD	7.4	MMBTU/H	NO_x	10102		4.8	GM/BHP-H	LAER
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	NE-12-022	4911	221112	1/30/2014	Fire Pump Engine	17.21	ULSD	2.7	MMBTU/H	NO_x	10102		3	GM/BHP-H	LAER
MA-0043	MIT CENTRAL UTILITY PLANT	NE-15-018	8221	611310	6/21/2017	Cold Start Engine	17.11	ULSD	19.04	MMBTU/HR	NO_x	10102		35.09	LB/HR	OTHER CASE-BY-CASE
MD-0042	WILDCAT POINT GENERATION FACILITY	CPCN CASE NO. 9327	4911	221119	4/8/2014	EMERGENCY GENERATOR 1	17.11	ULTRA LOW SULFU DIESEL	2250	KW	NO_x	10102	LIMITED OPERATING HOURS, USE OF ULTRA- LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.8	G/HP-H	LAER
MD-0042	WILDCAT POINT GENERATION FACILITY	CPCN CASE NO. 9327	4911	221119	4/8/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRA LOW SULFUR DIESEL	477	HP	NO_x	10102	LIMITED OPERATING HOURS, USE OF ULTRA- LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	3	G/HP-H	LAER
MD-0043	PERRYMAN GENERATING STATION	PSC CASE NO. 9136	4911	221119	7/1/2014	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	1300	HP	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	4.8	G/HP-H	LAER
MD-0043	PERRYMAN GENERATING STATION	PSC CASE NO. 9136	4911	221119	7/1/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRAL LOW SULFUR DIESEL	350	HP	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	3	G/HP-H	LAER
MD-0044	COVE POINT LNG TERMINAL	PSC CASE NO. 9318	4911	221119	6/9/2014	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	1550	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.8	G/HP-H	LAER
MD-0044	COVE POINT LNG TERMINAL	PSC CASE NO. 9318	4911	221119	6/9/2014	5 EMERGENCY FIRE WATER PUMP ENGINES	17.21	ULTRA LOW SULFUR DIESEL	350	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	3	G/HP-H	LAER

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
MI-0394	WARREN TECHNICAL CENTER	160-11	3711	336211	2/29/2012	Four (4) Emergency Generators	17.11	Diesel	2280	KW	NO_x	10102	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	6.93	G/KW-H	BACT-PSD
MI-0394	WARREN TECHNICAL CENTER	160-11	3711	336211	2/29/2012	Nine (9) DRUPS Emergency Generators	17.11	Diesel	3010	KW	NO_x	10102	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.98	G/KW-H	BACT-PSD
MI-0395	WARREN TECHNICAL CENTER	160-11A	3711	336211	7/13/2012	Nine (9) DRUPS Emergency Generators	17.11	Diesel	3010	KW	NO_x	10102	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.98	G/KW-H	BACT-PSD
MI-0395	WARREN TECHNICAL CENTER	160-11A	3711	336211	7/13/2012	Four (4) Emergency Generators	17.11	Diesel	2500	KW	NO_x	10102	No add-on control, but ignition 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-0406	RENAISSANCE POWER LLC	51-13	4911	221112	11/1/2013	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	17.11	Diesel	1000	kW	NO_x	10102	Good combustion practices	4.8	G/B-HP-H	BACT-PSD
MI-0418	WARREN TECHNICAL CENTER	160-11B	3711	336211	1/14/2015	FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines)	17.11	Diesel	3490	KW	NO_x	10102	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	1/14/2015	Four (4) emergency engines in FG-BACKUPGENS	17.11	Diesel	2710	KW	NO_x	10102	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	8/26/2016	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	17.11	Diesel	500	H/YR	NO_x	10102	Certified engines, limited operating hours.	22.6	LB/H	BACT-PSD
MI-0421	GRAYLING PARTICLEBOARD	59-16	2493	321219	8/26/2016	Dieself fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	500	H/YR	NO_x	10102	Certified engines, limited operating hours.	3.53	LB/H	BACT-PSD
MI-0423	INDECK NILES, LLC	75-16	4911	221112	1/4/2017	EUEMENGINE (Diesel fuel emergency engine)	17.11	Diesel Fuel	22.68	MMBTU/H	NO_x	10102	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	BACT-PSD
MI-0423	INDECK NILES, LLC	75-16	4911	221112	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump)	17.21	Diesel	1.66	MMBTU/H	NO_x	10102	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	G/BHP-H	BACT-PSD
MI-0425	GRAYLING PARTICLEBOARD	59-16A	2493	321219	5/9/2017	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	17.11	Diesel	500	H/YR	NO_x	10102	Certified engines, limited operating hours.	21.2	LB/H	BACT-PSD
MI-0425	GRAYLING PARTICLEBOARD	59-16A	2493	321219	5/9/2017	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	17.11	Diesel	500	H/YR	NO_x	10102	Certified engines, limited operating hours	4.4	LB/H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
MI-0425	GRAYLING PARTICLEBOARD	59-16A	2493	321219	5/9/2017	EUFIREPUMP in FGRICE (Diesel fire pump engine)	17.11	Diesel	500	H/YR	NO_x	10102	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	6/29/2018	EUFPENGINE (South Plant): Fire pump engine	17.21	Diesel	300	HP	NO_x	10102	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	6/29/2018	EUEMENGINE (North Plant): Emergency Engine	17.11	Diesel	1341	HP	NO_x	10102	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	6/29/2018	EUFPENGINE (North Plant): Fire pump engine	17.21	Diesel	300	HP	NO_x	10102	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	6/29/2018	EUEMENGINE (South Plant): Emergency Engine	17.11	Diesel	1341	HP	NO_x	10102	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	3/22/2018	EUENGINE01 through EUENGINE08	17.11	Diesel	3633	BHP	NO_x	10102	Good combustion practices.	6.4	G/KW-H	BACT-PSD
MI-0434	FLAT ROCK ASSEMBLY PLANT	122-17	8741	561110	3/22/2018	EUFIREPUMPENGS (2 emergency fire pump engines)	17.21	Diesel	250	BHP	NO_x	10102	Good combustion practices.	3	G/B-HP-H	BACT-PSD
MI-0434	FLAT ROCK ASSEMBLY PLANT	122-17	8741	561110	3/22/2018	EULIFESAFETYENG - One diesel-fueled emergency engine/generator	17.21	Diesel	500	KW	NO_x	10102	Good combustion practices.	4	G/KW-H	BACT-PSD
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	19-18	4911	221112	7/16/2018	EUEMENGINE: Emergency engine	17.11	Diesel	2	MW	NO_x	10102	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	7/16/2018	EUFPENGINE: Fire pump engine	17.21	Diesel	399	BHP	NO_x	10102	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	NO_x	10102	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	NO_x	10102	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	8/21/2019	FGEMENGINE	17.11	Diesel	1100	KW	NO_x	10102		5.3	G/HP-H	BACT-PSD
*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	NO_x	10102	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	NO_x	10102	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	NO_x	10102	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	NO_x	10102	Certified Engines, Limited Operating Hours	4.4	LB/H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
MI-0448	GRAYLING PARTICLEBOARD	59-16E	2493	321219	12/18/2020	Diesel fire pump engine (EUFIREPUMP in FGRICE)	17.11	Diesel	500	h/yr	NO_x	10102	Certified Engines, Limited Operating Hours	3.53	LB/H	BACT-PSD
NJ-0079	WOODBRIDGE ENERGY CENTER	18940 - BOP110003	4911	221112	7/25/2012	Emergency Generator	17.11	Ultra Low Sulfur distillate Diesel	100	H/YR	NO_x	10102	Use of ULSD diesel oil	21.16	LB/H	LAER
NJ-0080	HESS NEWARK ENERGY CENTER	08857/BOP110001	4911	221112	11/1/2012	Emergency Generator	17.11	ULSD	200	H/YR	NO_x	10102	use of ultra low sulfur diesel (ULSD) a clean fuel	18.53	LB/H	LAER
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	18068/BOP150001	4911	221112	3/10/2016	Diesel Fired Emergency Generator	17.11	ULSD	44	H/YR	NO_x	10102	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	3/10/2016	Emergency Diesel Fire Pump	17.21	ULSD	100	H/YR	NO_x	10102	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	2/3/2016	Black start generator	17.11	ultra low sulfur diesel	3000	KW	NO_x	10102	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
NY-0103	CRICKET VALLEY ENERGY CENTER	3-1326-00275/00009	4911	221112	2/3/2016	Emergency fire pump	17.21	ultra low sulfur diesel	460	hp	NO_x	10102	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.6	G/BHP-H	LAER
OH-0352	OREGON CLEAN ENERGY CENTER	P0110840	4931	221112	6/18/2013	Emergency fire pump engine	17.21	diesel	300	HP	NO_x	10102	Purchased certified to the standards in NSPS Subpart IIII	1.7	LB/H	BACT-PSD
OH-0352	OREGON CLEAN ENERGY CENTER	P0110840	4931	221112	6/18/2013	Emergency generator	17.11	diesel	2250	KW	NO_x	10102	Purchased certified to the standards in NSPS Subpart IIII	27.8	LB/H	BACT-PSD
OH-0360	CARROLL COUNTY ENERGY	P0113762	4911	221112	11/5/2013	Emergency generator (P003)	17.11	diesel	1112	KW	NO_x	10102	Purchased certified to the standards in NSPS Subpart IIII	13.74	LB/H	BACT-PSD
OH-0360	CARROLL COUNTY ENERGY	P0113762	4911	221112	11/5/2013	Emergency fire pump engine (P004)	17.21	diesel	400	HP	NO_x	10102	Purchased certified to the standards in NSPS Subpart IIII	2.3	LB/H	BACT-PSD
OH-0363	NTE OHIO, LLC	P0116610	4911	221112	11/5/2014	Emergency generator (P002)	17.11	Diesel fuel	1100	KW	NO_x	10102	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	29.01	LB/H	BACT-PSD
OH-0363	NTE OHIO, LLC	P0116610	4911	221112	11/5/2014	Emergency Fire Pump Engine (P003)	17.21	Diesel fuel	260	HP	NO_x	10102	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	1.72	LB/H	BACT-PSD
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	P0117655	4911	221112	8/25/2015	Emergency fire pump engine (P004)	17.21	Diesel fuel	140	HP	NO_x	10102	State-of-the-art combustion design	0.81	LB/H	BACT-PSD
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	P0117655	4911	221112	8/25/2015	Emergency generator (P003)	17.11	Diesel fuel	2346	HP	NO_x	10102	State-of-the-art combustion design	21.6	LB/H	BACT-PSD
OH-0367	SOUTH FIELD ENERGY LLC	P0119495	4911	221112	9/23/2016	Emergency fire pump engine (P004)	17.21	Diesel fuel	311	HP	NO_x	10102	State-of-the-art combustion design	1.79	LB/H	BACT-PSD
OH-0367	SOUTH FIELD ENERGY LLC	P0119495	4911	221112	9/23/2016	Emergency generator (P003)	17.11	Diesel fuel	2947	HP	NO_x	10102	State-of-the-art combustion design	27.18	LB/H	BACT-PSD
OH-0368	PALLAS NITROGEN LLC	P0118959	2873	325311	4/19/2017	Emergency Fire Pump Diesel Engine (P008)	17.21	Diesel fuel	460	HP	NO_x	10102	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

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
OH-0368	PALLAS NITROGEN LLC	P0118959	2873	325311	4/19/2017	Emergency Generator (P009)	17.11	Diesel fuel	5000	HP	NO_x	10102	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	9/7/2017	Emergency generator (P003)	17.11	Diesel fuel	1529	HP	NO_x	10102	State-of-the-art combustion design	16.07	LB/H	BACT-PSD
OH-0370	TRUMBULL ENERGY CENTER	P0122331	4911	221112	9/7/2017	Emergency fire pump engine (P004)	17.21	Diesel fuel	300	HP	NO_x	10102	State-of-the-art combustion design	1.97	LB/H	BACT-PSD
OH-0372	OREGON ENERGY CENTER	P0121049	4911	221112	9/27/2017	Emergency generator (P003)	17.11	Diesel fuel	1529	HP	NO_x	10102	State-of-the-art combustion design	16.1	LB/H	BACT-PSD
OH-0372	OREGON ENERGY CENTER	P0121049	4911	221112	9/27/2017	Emergency fire pump engine (P004)	17.21	Diesel fuel	300	HP	NO_x	10102	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	NO_x	10102	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	BACT-PSD
OH-0374	GUERNSEY POWER STATION LLC	P0122594	4911	221112	10/23/2017	Emergency Fire Pump (P006)	17.21	Diesel fuel	410	HP	NO_x	10102	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	BACT-PSD
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	P0122829	4911	221112	11/7/2017	Emergency Diesel Generator Engine (P001)	17.11	Diesel fuel	2206	HP	NO_x	10102	Good combustion design	24.71	LB/H	BACT-PSD
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	P0122829	4911	221112	11/7/2017	Emergency Diesel Fire Pump Engine (P002)	17.11	Diesel fuel	700	HP	NO_x	10102	Good combustion design	4.97	LB/H	BACT-PSD
OH-0376	IRONUNITS LLC - TOLEDO HBI	P0123395	3312	331111	2/9/2018	Emergency diesel-fueled fire pump (P006)	17.21	Diesel fuel	250	HP	NO_x	10102	Comply with NSPS 40 CFR 60 Subpart IIII	1.6	LB/H	BACT-PSD
OH-0376	IRONUNITS LLC - TOLEDO HBI	P0123395	3312	331111	2/9/2018	Emergency diesel-fired generator (P007)	17.11	Diesel fuel	2682	HP	NO_x	10102	Comply with NSPS 40 CFR 60 Subpart IIII	28.2	LB/H	BACT-PSD
OH-0377	HARRISON POWER	P0122266	4911	221112	4/19/2018	Emergency Diesel Generator (P003)	17.11	Diesel fuel	1860	HP	NO_x	10102	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	4/19/2018	Emergency Fire Pump (P004)	17.21	Diesel fuel	320	HP	NO_x	10102	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	NO_x	10102	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	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	NO_x	10102	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	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	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	NO_x	10102	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	BACT-PSD
OH-0379	PETMIN USA INCORPORATED	P0125024	3312	331111	2/6/2019	Black Start Generator (P007)	17.21	Diesel fuel	158	HP	NO_x	10102	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	2/6/2019	Emergency Generators (P005 and P006)	17.11	Diesel fuel	3131	HP	NO_x	10102	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	7/17/2020	Diesel-fired emergency fire pumps (2) (P009 and P010)	17.11	Diesel fuel	3131	HP	NO_x	10102	Tier IV NSPS standards certified by engine manufacturer.	0		BACT-PSD
OK-0145	BROKEN BOW OSB MILL	2003-099-C(M-3)PSD	2493	321219	6/25/2012	Emerg Diesel Gen, Fire Pump, Rail Steam Gen, Air Makeup Units	17.11	Diesel	0		NO_x	10102		0		BACT-PSD
OK-0154	MOORELAND GENERATING STA	2008-302-C(M-1)PSD	4911	221112	7/2/2013	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	17.11	DIESEL	1341	HP	NO_x	10102	COMBUSTION CONTROL	0.011	LB/HP-HR	BACT-PSD
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	08Â·00045A	491	221112	10/10/2012	Emergency Generator	17.11	Diesel	0		NO_x	10102		4.93	G/B-HP-H	OTHER CASE-BY-CASE
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	08Â·00045A	491	221112	10/10/2012	Fire Pump	17.21	Diesel	0		NO_x	10102		2.6	G/B-HP-H	OTHER CASE-BY-CASE
*PA-0282	JOHNSON MATTHEY INC/CATALYTIC SYSTEMS DIV	15-0027K	3714	336399	6/1/2012	ENGINE TEST CELLS (6)	19.9	GASOLINE/DIESEL	27	GAL/H	NO_x	10102		11	T/YR	OTHER CASE-BY-CASE
*PA-0282	JOHNSON MATTHEY INC/CATALYTIC SYSTEMS DIV	15-0027K	3714	336399	6/1/2012	650-KW BACKUP DIESEL GENERATOR	17.11	Diesel / #2 Oil	45.8	GAL/H	NO_x	10102		6.9	G/HP-H	OTHER CASE-BY-CASE
PA-0291	HICKORY RUN ENERGY STATION	37-337A	4911	221112	4/23/2013	EMERGENCY FIREWATER PUMP	17.21	ULTRA LOW SULFUR DISTILLATE	3.25	MMBTU/H	NO_x	10102		1.86	LB/H	OTHER CASE-BY-CASE
PA-0291	HICKORY RUN ENERGY STATION	37-337A	4911	221112	4/23/2013	EMERGENCY GENERATOR	17.11	Ultra Low sulfur Distillate	7.8	MMBTU/H	NO_x	10102		9.89	LB/H	OTHER CASE-BY-CASE
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	NO_x	10102		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		NO_x	10102		5.45	GM/HP-HR	LAER
PA-0310	CPV FAIRVIEW ENERGY CENTER	11-00536A	4911	221112	9/2/2016	Emergency Generator Engines	17.11	ULSD	0		NO_x	10102		4.8	G/BHP-HR	LAER
PA-0310	CPV FAIRVIEW ENERGY CENTER	11-00536A	4911	221112	9/2/2016	Emergency Fire Pump Engine	17.21	ULSD	0		NO_x	10102		3	G/BHP-HR	LAER
PA-0311	MOXIE FREEDOM GENERATION PLANT	40-00129A	4911	221112	9/1/2015	Fire Pump Engine	17.11	diesel	0		NO_x	10102		3	G/HP-HR	LAER
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	R2-PSD 1	4953	221119	4/10/2014	Emergency Diesel Fire Pump	17.21	ULSD Fuel Oil #2	0		NO_x	10102		2.85	G/B-HP-H	BACT-PSD
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	R2-PSD 1	4953	221119	4/10/2014	Emergency Diesel Generator	17.11	ULSD Fuel oil # 2	0		NO_x	10102		2.85	G/B-HP-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	3295	327992	2/8/2012	EMERGENCY ENGINE 1 THRU 8	17.21	DIESEL	29	HP	NO_x	10102	PURCHASE OF CERTIFIED ENGINE.	7.5	GR/KW-H	BACT-PSD

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	3295	327992	2/8/2012	FIRE PUMP	17.21	DIESEL	500	HP	NO_x	10102	PURCHASE OF CERTIFIED ENGINE BASED ON NSPS, SUBPART IIII.	4	GR/KW-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	3295	327992	2/8/2012	EMERGENCY GENERATORS 1 THRU 8	17.11	DIESEL	757	HP	NO_x	10102	ENGINES MUST BE CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	4	GR/KW-H	BACT-PSD
TX-0671	PROJECT JUMBO	108446/PSDTX1352	2821	325211	12/1/2014	Engines	17.11	ultra low sulfur diesel fuel	0		NO_x	10102	Each emergency generator's emission factor is based on EPA's Tier 2 standards at 40CFR89.112 for NOx	5.43	G/KW-H	BACT-PSD
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	118239, N200	2813	325311	4/1/2015	Emergency Diesel Generator	17.11	Diesel	1500	hp	NO_x	10102	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	2/6/2020	Emergency generator	17.11	DIESEL	0		NO_x	10102	Tier 4 exhaust emission standards specified in 40 CFR Â§ 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	2/19/2020	Emergency Firewater Engine	17.11	Ultra-low sulfur diesel	0		NO_x	10102	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	4/23/2020	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	17.11	Ultra-low Sulfur Diesel	0		NO_x	10102	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	9/9/2020	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	0		NO_x	10102	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0		BACT-PSD
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	160299, PSDTX1576, GHGPSDTX200	2869	325998	9/16/2020	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	0		NO_x	10102	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		NO_x	10102	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0		BACT-PSD
VA-0325	GREENSVILLE POWER STATION	52525	4911	221112	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	17.11	DIESEL FUEL	0		NO_x	10102	Good Combustion Practices/Maintenance	6.4	G/KW	N/A
VA-0325	GREENSVILLE POWER STATION	52525	4911	221112	6/17/2016	DIESEL-FIRED WATER PUMP 376 bph (1)	17.21	DIESEL FUEL	0		NO_x	10102	Good Combustion Practices/Maintenance	0		N/A
VA-0328	C4GT, LLC	52588	4911	221112	4/26/2018	Emergency Diesel GEN	17.11	Ultra Low Sulfur Diesel	500	H/YR	NO_x	10102	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	4/26/2018	Emergency Fire Water Pump	17.21	Ultra Low Sulfur Diesel	500	HR/YR	NO_x	10102	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	6/24/2019	Emergency Diesel Generator - 300 kW	17.11	Ultra Low Sulfur Diesel	500	H/YR	NO_x	10102	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

Table 1. NO_x RBLC Data for Diesel Generators

RBLCID	Facility Name	Permit No.	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
VA-0332	CHICKAHOMINY POWER LLC	52610-1	4911	221112	6/24/2019	Emegency Fire Water Pump	17.21	Ultra Low Sulfur Diesel	500	HR/YR	NO_x	10102	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	4/24/2018	Diesel-Fired Emergency Generators	17.11	Diesel Fuel	0		NO_x	10102	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	4/24/2018	P42 -Diesel Fired Emergency Generator	17.11	Diesel Fuel	0		NO_x	10102	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	9/1/2020	Emergency Diesel Fire Pump (P06)	17.21	Diesel	282	HP	NO_x	10102	Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturerâ's recommendations.	3	G/HP-H	BACT-PSD
WI-0300	NEMADJI TRAIL ENERGY CENTER	18-MMC-168	4911	221121	9/1/2020	Emergency Diesel Generator (P07)	17.11	Diesel	1490	HP	NO_x	10102	Operation limited to 500 hours/year and operate and maintain according to the manufacturerâ's recommendations.	4.8	G/HP-H	BACT-PSD
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	R14-0030	4911	221112	11/21/2014	Emergency Generator	17.11	Diesel	2015.7	HP	NO_x	10102		0		BACT-PSD
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	R14-0030	4911	221112	11/21/2014	Fire Pump Engine	17.21	Diesel	251	HP	NO_x	10102		0		BACT-PSD
WV-0027	INWOOD	R14-0015M	3296	327993	9/15/2017	Emergency Generator - ESDG14	17.11	ULSD	900	bhp	NO_x	10102	Engine Design	4.77	G/HP-HR	BACT-PSD
*WV-0033	MAIDSVILLE	R14-0038	4911	221112	1/5/2022	Emergency Generator	17.11	ULSD	2100	hp	NO_x	10102	Combustion Control (retarded timing and/or lean burn)	24.6	LB/HR	BACT-PSD
*WV-0033	MAIDSVILLE	R14-0038	4911	221112	1/5/2022	Fire Water Pump	17.11	ULSD	240	bhp	NO_x	10102	Combustion control (retarded timing and/or lean burn)	1.59	LB/HR	BACT-PSD
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	CT-12636	491	221112	8/28/2012	Diesel Emergency Generator (EP15)	17.11	Ultra Low Sulfur Diesel	839	hp	NO_x	10102	EPA Tier 2 rated	0		BACT-PSD
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	CT-12636	491	221112	8/28/2012	Diesel Fire Pump Engine (EP16)	17.21	Ultra Low Sulfur Diesel	327	hp	NO_x	10102	EPA Tier 3 rated	0		BACT-PSD

Appendix 4a

Switch Part 70 Technical Support Document (TSD)

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
TECHNICAL SUPPORT DOCUMENT
(STATEMENT of BASIS)

APPLICATION FOR:
Renewal of Part 70 Operating Permit

SUBMITTED BY:
Trinity Consultants, Inc.
7919 Folsom Blvd., Suite 320
Sacramento, CA 95826

FOR:
Switch, Ltd.
Source ID: 16304

LOCATION:
7135 S. Decatur Blvd.
Las Vegas, Nevada 89118

SIC code 7375, "Information Retrieval Services"
NAICS code 517919, "All Other Telecommunications"

July 1, 2021

EXECUTIVE SUMMARY

Switch, Ltd. (Switch) owns and operates six separate and adjacent advanced technology ecosystem communications facilities, referred to as NAP 7, NAP 8, NAP 9, NAP 10, NAP 11, and NAP 12 and is located at 7135 S. Decatur Blvd., Las Vegas, Nevada. The source is under SIC code 7375, "Information Retrieval Services," and NAICS code 517919, "All Other Telecommunications." The source is in Hydrographic Area (HA) 212 (Las Vegas Valley). HA 212 is currently designated as attainment for all pollutants except ozone. HA 212 was designated a marginal nonattainment area for ozone on August 3, 2018 for the 2015 NAAQS. The designation has not imposed any new requirements at this time. HA 212 is also subject to a maintenance plan for the CO and PM_{10} NAAQS.

Switch is permitted as a Part 70 major source of NO_X, a synthetic minor source of CO, and a minor source for all other regulated pollutants. Switch is a source of greenhouse gases (GHG).

The following table summarizes the source potential to emit for each regulated air pollutant from all emission units addressed by this Part 70 Operating Permit:

Source PTE (tons per year)

	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP	GHG[1]
Source PTE	**6.61**	**2.54**	**241.90**	**31.98**	**1.22**	**3.59**	**1.22**	**23,618.83**
Major Source Thresholds (Title V)	100	100	100	100	100	100	10/25[1]	-
Major Stationary Source Thresholds (PSD)	250	250	-	250	250	-	10/25[1]	-
Major Stationary Source Threshold (Nonattainment)	-	-	100	-	-	100	-	-

[1]GHG expressed as CO_2.

Clark County Department of Environment and Sustainability (DES) has delegated authority to implement the requirement of the Part 70 operating permit program (Part 70 OP). Based on information submitted by the applicant and a technical review performed by DAQ staff, DAQ issued an initial Part 70 OP on February 26, 2016, and minor revisions on March 6, 2017, November 27, 2017, June 18, 2018, December 20, 2018, and June 24, 2019. Since that time, Switch applied for renewal of its Part 70 OP on August 11, 2020, and for revisions on May 1, 2020, July 13, 2020, and November 30, 2020. Supplemental information was submitted on February 8, 2021. The Authority to Construct Permit (ATC) that was issued on June 27, 2014 was administratively revised on June 26, 2019, to remove an expiration date of the permit that was included in error, as ATC permits do not expire.

Based on information submitted by the applicant and a technical review performed by DAQ staff, DAQ proposes the issuance of a Part 70 OP to Switch.

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I. ACRONYMS AND ABBREVIATIONS

DAQ	Division of Air Quality
DES	Clark County Department of Environment and Sustainability
AQR	Clark County Air Quality Regulations
AST	aboveground storage tank
ATC	Authority to Construct
CFR	United States Code of Federal Regulations
CO	carbon monoxide
EF	emission factor
EPA	United States Environmental Protection Agency
EU	emission unit
HAP	hazardous air pollutant
HC	hydrocarbon
HP	horse power
IC	internal combustion
kW	kilowatt
MMBtu	millions of British thermal units
NAICS	North American Industry Classification System
NMHC	non-methane hydrocarbon
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	operations & maintenance
ORVR	onboard refueling vapor recovery
$PM_{2.5}$	particulate matter less than 2.5 microns
PM_{10}	particulate matter less than 10 microns
ppm	parts per Million
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RACT	reasonably available control technology
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SO_2	sulfur dioxide
TSD	Technical Support Document
UST	underground storage tank
VAEL	voluntarily accepted emission limitation
VOC	volatile organic compound

II. SOURCE INFORMATION

A. General

Permittee	Switch, Ltd.
Mailing Address	PO Box 400850, Las Vegas, Nevada 89140
Responsible Official	Brandie Koehler, Vice President of Data Center Operations
Source Location	7135 S. Decatur Blvd., Las Vegas, Nevada 89118
Hydrographic Areas	212
SIC Code	7375 – Information Retrieval Services
NAICS Code	517919 – All Other Telecommunications

B. Description of Process

Switch, Ltd. owns and operates six separate and adjacent advanced technology ecosystem communications facilities, referred to as NAP 7, NAP 8, NAP 9, NAP 10, NAP 11, and NAP 12. The source consists of diesel-powered emergency generators, fire pumps, and cooling towers. It is categorized under SIC code 7375, "Information Retrieval Services," and NAICS code 517919, "All Other Telecommunications." The source meets or exceeds the major stationary source threshold for NO_x emissions (NA NSR), is a synthetic minor source of CO, and is a minor source for PM_{10}, $PM_{2.5}$, SO_2, and VOC.

Switch is subject to 40 CFR Part 60, Subpart IIII, and 40 CFR Part 63, Subpart ZZZZ. The engines subject to 40 CFR Part 60, Subpart IIII, satisfy the requirements of 40 CFR Part 63, Subpart ZZZZ, through compliance with 40 CFR Part 60, Subpart IIII.

C. Permitting Action

In the renewal application submitted on August 11, 2020, Switch requested to update the Responsible Official (RO), add the 23 emission units listed in Table II-C-1 to the Operating Permit (OP) from Authority to Construct (ATC) Permits, and increase the TDS for the cooling towers.

In a revision application submitted on May 1, 2020, Switch requested to incorporate 18 emissions units (EUs: F03, F07, F11, J07 through J15, K03, K05 through K07, K09, and K10) which was repeated in the renewal application and to update the date of manufacture for six generators (EUs: J01 through J06) from 2015 to 2018.

In a revision application submitted on July 13, 2020, Switch requested to increase the TDS content of the cooling tower recirculation water from 2,100 ppm to 5,000 ppm. This request was repeated in the renewal application. The increase in TDS concentration for the installed cooling towers is considered a separate project from the original installations and this change was not reasonably foreseeable at the time the ATC applications were submitted. Therefore the increase in emissions resulting from the TDS increase is assessed separately and since the resulting emissions are less than the minor NSR significance thresholds, no controls analysis is required.

In a revision application submitted on November 30, 2020, Switch requested that a cooling tower (EU: D16) be incorporated into the OP with an increased TDS of 5,000 ppm.

In a letter submitted on February 8, 2021, Switch proposed to modify the conditions of the Part 70 OP to allow the use of emergency engines during nonemergency events. DAQ agrees with this change. The use of the engines during nonemergency situations will be included in the 104 hours per calendar year total operation of the units and the 50 hours per calendar year limit of 40 CFR Part 60, Subpart IIII, and 40 CFR Part 63, Subpart ZZZZ.

In reviewing the draft documents, Switch requested the removal of two ATC-Only generators (EUs: A30 and A31) stating that Switch has no plans to construct these units.

During this action, Air Quality has added standard nonroad engine language as Section III-B of the Part 70 OP and has updated the visible emission check language per Air Quality policy.

Table II-C-1: ATC Units Incorporated into the Title V Operating Permit During This Action

EU	EU Description	Make	Model	Serial	DATE DAQ Notified	Delivery Date	Start Up Date
F03	Cooling Tower	Evapco	ESWA 216-460	18-836259	6/18/2019	3/14/2019	5/14/2019
K05	Cooling Tower	Evapco	ESWA 216-460-C	19-871147	8/12/2019	8/8/2019	10/8/2019
K06	Cooling Tower	Evapco	ESWA 216-460-C	19-871155	8/12/2019	8/8/2019	10/8/2019
F07	Cooling Tower	Evapco	ESWA 216-460-C	19-873232	9/5/2019	9/4/2019	11/4/2019
J08	Engine	Detroit Diesel	MTU16V4000 DS2250	95030501820	10/4/2019	10/02/2019	12/02/2019
J10	Engine	Detroit Diesel	MTU16V4000 DS2250	95030501822	10/4/2019	10/02/2019	12/02/2019
J12	Engine	Detroit Diesel	MTU16V4000 DS2250	95030501821	10/4/2019	10/02/2019	12/02/2019
F11	Cooling Tower	EVAPCO	ESWA 216-460	19-872198	10/10/2019	10/10/2019	12/10/2019
K09	Cooling Tower	EVAPCO	ESWA-216-460	19-871162	10/25/2019	10/24/2019	1/30/2020
K10	Cooling Tower	EVAPCO	ESWA-216-460	19-871158	10/25/2019	10/24/2019	1/30/2020
K03	Cooling Tower	EVAPCO	ESWA-216-460-C	19-872170	11/14/2019	11/13/2019	1/13/2020
K07	Cooling Tower	EVAPCO	ESWA-216-460-C	19-872176	11/22/2019	11/22/2019	1/23/2020
J07	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501900 5482000210	2/11/2020	2/6/2020	3/6/2020
J09	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501901 5482000209	2/11/2020	2/6/2020	3/6/2020
J11	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501908 5482000208	2/11/2020	2/6/2020	3/6/2020
J13	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501909 5482000212	4/16/2020	4/10/2020	6/1/2020

EU	EU Description	Make	Model	Serial	DATE DAQ Notified	Delivery Date	Start Up Date
J14	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501910 5482000211	4/16/200	4/10/2020	6/1/2020
J15	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G83	95030501911 5482000207	4/16/2020	4/13/2020	6/1/2020
J16	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G24S	95030501979 5482000244	5/14/2020	5/12/2020	6/1/2020
J17	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G24S	95030501981 5482000246	5/14/2020	5/12/2020	6/1/2020
J18	Generator	Marathon Electric Detroit Diesel	MTU 16V4000 DS2250 16V4000G24S	95030501980 5482000245	5/14/2020	5/12/2020	6/1/2020
F12	Cooling Tower	Evapco	ESWA 216-460	20P101332	6/8/2020	5/27/2020	6/10/2020
K11	Cooling Tower	Evapco	ESWA-216-460	20P103709	11/30/2020	11/18/2020	12/15/2020
D16	Cooling Tower	Evapco	ESWA-216-460	20P104320	11/30/2020	11/19/2020	12/15/2020

III. EMISSION UNITS AND PTE

A. Emission Units

Table III-A-1: Summary of Emissions Units NAP 7

EU	Rating	Description	Make	Model	Serial
A02	2,300 kW	Generator, Emergency	Detroit Diesel	2250 DSEC	2185979
	3,353 hp	Diesel Engine, DOM: 2007			
A03	2,320 kW	Generator, Emergency	Detroit Diesel	744RSL5163	WA-6006372-1219
	3,353 hp	Diesel Engine, DOM: 2007			
A04	2,300 kW	Generator, Emergency	Detroit Diesel	2250 DSEC	2185985
	3,353 hp	Diesel Engine, DOM: 2007			
A05	2,300 kW	Generator, Emergency	Detroit Diesel	2250 DSEC	2183861
	3,353 hp	Diesel Engine, DOM: 2007			
A06	2,300 kW	Generator, Emergency	Detroit Diesel	2250 DSEC	2183870
	3,353 hp	Diesel Engine, DOM: 2007			
A07	2,250 kW	Generator, Emergency	Detroit Diesel	2250RXC6DT2	176196-1-2-0608
	3,353 hp	Diesel Engine, DOM: 2008			
A08	2,250 kW	Generator, Emergency	Detroit Diesel	2250RXC6DT2	175966-1-2-0608
	3,353 hp	Diesel Engine, DOM: 2008			

EU	Rating	Description	Make	Model	Serial
A09	2,250 kW	Generator, Emergency	Detroit Diesel	2250RXC6DT2	175966-1-3-0608
	3,353 hp	Diesel Engine, DOM: 2008			
A10	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	330055-1-2-0311
	3,353 hp	Diesel Engine, DOM: 2010			
A11	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	330055-1-3-0311
	3,353 hp	Diesel Engine, DOM: 2010			
A12	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	330055-1-1-0311
	3,353 hp	Diesel Engine, DOM: 2010			
A13	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	333726-1-1-0811
	3,353 hp	Diesel Engine, DOM: 2011			
A14	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	333726-2-2-0811
	3,353 hp	Diesel Engine, DOM: 2011			
A15	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	333726-2-1-0811
	3,353 hp	Diesel Engine, DOM: 2011			
A16	2,250 kW	Generator, Emergency	Marathon Electric	2250RXC6DT2	334657-1-1-0811
	3,353 hp	Diesel Engine, DOM: 2011			
A17	2,250 kW	Generator, Emergency	Marathon Electric	2250RXC6DT2	341530-1-1-0112
	3,353 hp	Diesel Engine, DOM: 2011			
A18	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	341565-1-3-0212
	3,353 hp	Diesel Engine, DOM: 2011			
A19	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369767-1-1-0214
	3,353 hp	Diesel Engine, DOM: 2014			
A20	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	341565-1-1-0212
	3,353 hp	Diesel Engine, DOM: 2011			
A21	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	346646-1-1-0512
	3,353 hp	Diesel Engine, DOM: 2011			
A22	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348117-1-3-0812
	3,353 hp	Diesel Engine, DOM: 2011			
A23	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348117-1-1-1112
	3,353 hp	Diesel Engine, DOM: 2012			
A24	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	356251-1-4-0213
	3,353 hp	Diesel Engine, DOM: 2013			
A25	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	346646-1-2-0512
	3,353 hp	Diesel Engine, DOM: 2011			
A26	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348117-1-2-0812
	3,353 hp	Diesel Engine, DOM: 2011			
A27	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	36251-1-1-0213
	3,353 hp	Diesel Engine, DOM: 2013			

EU	Rating	Description	Make	Model	Serial
A28	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	356251-1-2-0213
	3,353 hp	Diesel Engine, DOM: 2013			
A29	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	356251-1-3-0213
	3,353 hp	Diesel Engine, DOM: 2013			
A32	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369338-1-3-0114
	3,353 hp	Diesel Engine, DOM: 2014			
A33	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369338-1-1-0114
	3,353 hp	Diesel Engine, DOM: 2014			
A34	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369338-1-2-0114
	3,353 hp	Diesel Engine, DOM: 2014			
B01	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	7-324424
B02	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	7-324425
B03	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	7-324426
B04	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	7-324359
B05	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	7-324360
B07	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	10-386399
B08	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	10-386400
B09	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	10-386401
B10	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-411470
B11	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-411468
B12	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-411469
B13	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-452969
B14	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-452982
B15	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	11-452987
B16	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	12-468991
B17	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	12-468982
B18	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	12-468985
B19	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	12-468996
B20	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	13-523739
B21	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	13-658453
B23	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	14-719109

Table III-A-2: Summary of Emissions Units NAP 8

EU	Rating	Description	Make	Model	Serial
C01	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348116-1-1-0712
	3,353 hp	Diesel Engine, DOM: 2011			
C02	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348116-1-2-0712
	3,353 hp	Diesel Engine, DOM: 2011			

EU	Rating	Description	Make	Model	Serial
C03	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	348116-1-3-0712
	3,353 hp	Diesel Engine, DOM: 2011			
C04	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	360838-1-3-0713
	3,353 hp	Diesel Engine, DOM: 2013			
C05	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	360838-1-1-0713
	3,353 hp	Diesel Engine, DOM: 2013			
C06	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	360838-1-2-0713
	3,353 hp	Diesel Engine, DOM: 2013			
C07	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	365276-1-1-1013
	3,353 hp	Diesel Engine, DOM: 2013			
C08	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	365276-1-2-1013
	3,353 hp	Diesel Engine, DOM: 2013			
C09	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	365276-1-3-1013
	3,353 hp	Diesel Engine, DOM: 2013			
C10	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369877-1-1-0514
	3,353 hp	Diesel Engine, DOM: 2014			
C11	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369877-1-3-0614
	3,353 hp	Diesel Engine, DOM: 2014			
C12	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369877-1-2-0614
	3,353 hp	Diesel Engine, DOM: 2014			
C13	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	370421-1-1-0514
	3,353 hp	Diesel Engine, DOM: 2014			
C14	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	370421-1-2-0514
	3,353 hp	Diesel Engine, DOM: 2014			
C15	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	370421-1-3-0514
	3,353 hp	Diesel Engine, DOM: 2014			
C16	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	341565-1-2-0212
	3,353 hp	Diesel Engine, DOM: 2011			
C17	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369767-1-3-0214
	3,353 hp	Diesel Engine, DOM: 2014			
C18	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	369767-1-2-0214
	3,353 hp	Diesel Engine, DOM: 2015			
C19	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500170
	3,353 hp	Diesel Engine, DOM: 2015			
C20	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500168
	3,353 hp	Diesel Engine, DOM: 2015			
C21	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500169
	3,353 hp	Diesel Engine, DOM: 2015			

EU	Rating	Description	Make	Model	Serial
C22	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500326
	3,353 hp	Diesel Engine, DOM: 2015			
C23	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500327
	3,353 hp	Diesel Engine, DOM: 2015			
C24	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500325
	3,353 hp	Diesel Engine, DOM: 2015			
C25	1,500 gpm	Fire Pump	Patterson	8x6 MI	FP-CO114338
	110 hp	Diesel Engine, DOM: 2012	John Deere	4045HFC28	PE4045L219637
C26	200 kW	Generator, Emergency	MTU	MTU 6R0120 DS200	95130500694
	331 hp	Diesel Engine, DOM: 2006+			
D01	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	12-485179
D02	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	12-485182
D03	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	13-544070
D04	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	13-544060
D05	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	14-673905
D06	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	14-686651
D07	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	13-655349
D08	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	13-655348
D10	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	14-686661
D11	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	14-686648
D12	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460C	14-686653
D13	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	17-820571
D14	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	15-767529
D16	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	20P104320

Table III-A-3: Summary of Emissions Units NAP 9

EU	Rating	Description	Make	Model	Serial
G01	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500461
	3,353 hp	Diesel Engine, DOM: 2016			
G02	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500157
	3,353 hp	Diesel Engine, DOM: 2015			

EU	Rating	Description	Make	Model	Serial
G03	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500463
	3,353 hp	Diesel Engine, DOM: 2016			
G04	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500158
	3,353 hp	Diesel Engine, DOM: 2015			
G05	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500494
	3,353 hp	Diesel Engine, DOM: 2016			
G06	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500159
	3,353 hp	Diesel Engine, DOM: 2015			
G07	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500628
	3,353 hp	Diesel Engine, DOM: 2017			
G08	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500331
	3,353 hp	Diesel Engine, DOM: 2015			
G09	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500631
	3,353 hp	Diesel Engine, DOM: 2017			
G10	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500330
	3,353 hp	Diesel Engine, DOM: 2015			
G11	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500634
	3,353 hp	Diesel Engine, DOM: 2017			
G12	2,250 kW	Generator, Emergency	Marathon Electric	16V4000DS2250	95030500332
	3,353 hp	Diesel Engine, DOM: 2015			
G13	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500256
	3,353 hp	Diesel Engine, DOM: 2015			
G14	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500483
	3,353 hp	Diesel Engine, DOM: 2016			
G15	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500255
	3,353 hp	Diesel Engine, DOM: 2015			
G16	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500484
	3,353 hp	Diesel Engine, DOM: 2016			
G17	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500249
	3,353 hp	Diesel Engine, DOM: 2015			
G18	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500485
	3,353 hp	Diesel Engine, DOM: 2016			
G19	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500557
	3,353 hp	Diesel Engine, DOM: 2016			
G20	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500626
	3,353 hp	Diesel Engine, DOM: 2017			

EU	Rating	Description	Make	Model	Serial
G21	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500555
	3,353 hp	Diesel Engine, DOM: 2016			
G22	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500624
	3,353 hp	Diesel Engine, DOM: 2017			
G23	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500625
	3,353 hp	Diesel Engine, DOM: 2017			
G24	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500698
	3,353 hp	Diesel Engine, DOM: 2017			
H01	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	14-715086
H02	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	14715088
H03	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	15770216
H04	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	17-804846
H06	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	16-795374
H07	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	15-758292
H08	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	15-758298
H09	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	15766408
H10	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	15766416
H11	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	16-795365
H12	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	17-818677
H13	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	16782903
H14	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	16782926
H15	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	16801280
H16	1,250 gpm	Cooling Tower	Evapco	ESWB1246018	17804855
H17	800 gpm	Cooling Tower	Evapco	ESWA-102-45J-Z-C	17-822513
H18	800 gpm	Cooling Tower	Evapco	ESWA-102-45J-Z-C	17-822512

Table III-A-4: Summary of Emissions Units NAP 10

EU	Rating	Description	Make	Model	Serial
E01	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500632
	3,353 hp	Diesel Engine, DOM: 2017			
E02	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500493
	3,353 hp	Diesel Engine, DOM: 2016			
E03	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500627
	3,353 hp	Diesel Engine, DOM: 2017			

EU	Rating	Description	Make	Model	Serial
E04	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500462
	3,353 hp	Diesel Engine, DOM: 2016			
E05	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500633
	3,353 hp	Diesel Engine, DOM: 2017			
E06	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500492
	3,353 hp	Diesel Engine, DOM: 2016			
E07	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500703
	3,353 hp	Diesel Engine, DOM: 2017			
E08	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500701
	3,353 hp	Diesel Engine, DOM: 2017			
E09	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500700
	3,353 hp	Diesel Engine, DOM: 2017			
E10	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500702
	3,353 hp	Diesel Engine, DOM: 2017			
E11	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500766
	3,353 hp	Diesel Engine, DOM: 2017			
E12	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500699
	3,353 hp	Diesel Engine, DOM: 2017			
E13	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501092
	3,353 hp	Diesel Engine, DOM: 2018			
E14	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501091
	3,353 hp	Diesel Engine, DOM: 2018			
E15	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501098
	3,353 hp	Diesel Engine, DOM: 2018			
E16	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501065
	3,353 hp	Diesel Engine, DOM: 2018			
E17	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501068
	3,353 hp	Diesel Engine, DOM: 2018			
E18	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501064
	3,353 hp	Diesel Engine, DOM: 2018			
E19	1,500 gpm	Fire Pump	Clarke	8x6 MI	FP-CO133769
	125 hp	Diesel Engine, DOM: 2014	John Deere	4045HFC28	PE4045L266693

EU	Rating	Description	Make	Model	Serial
E20	1,500 gpm	Fire Pump	Clarke	8x6 MI	FP-CO152216
	125 hp	Diesel Engine, DOM: 2016	John Deere	4045HFC28	PE4045N0000 49
F01	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	16-799616
F02	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	16-798860
F03	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	18-836259
F05	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	16-804570
F06	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	16-804573
F07	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	19-873232
F09	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	17-831176
F10	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	17-831179
F11	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	19-872198
F12	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	20P101332

Table III-A-5: Summary of Emissions Units NAP 11

EU	Rating	Description	Make	Model	Serial
J01	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500919
	3,353 hp	Diesel Engine, DOM: 2018			
J02	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500920
	3,353 hp	Diesel Engine, DOM: 2018			
J03	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500921
	3,353 hp	Diesel Engine, DOM: 2018			
J04	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500926
	3,353 hp	Diesel Engine, DOM: 2018			
J05	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500925
	3,353 hp	Diesel Engine, DOM: 2018			
J06	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500927
	3,353 hp	Diesel Engine, DOM: 2018			
J07	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501900
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000210
J08	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501820
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel		5482000191
J09	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501901
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000209
J10	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501822
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel		5482000192

EU	Rating	Description	Make	Model	Serial
J11	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501908
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000208
J12	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501821
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel		5482000190
J13	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501909
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000212
J14	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501910
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000211
J15	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501911
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G83	5482000207
J16	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501979
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G24S	5482000244
J17	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501981
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G24S	5482000246
J18	2,250 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030501980
	3,353 hp	Diesel Engine, DOM: 2019	Detroit Diesel	16V4000G24S	5482000245
J19	1,500 gpm	Fire Pump	Patterson	8x6 MI	FP-C0168036-01
	125 hp	Diesel Engine, DOM: 2018	John Deere	6068HFC48	PE6068N007610
K01	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	17-833057
K02	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	17-833082
K03	1,250 gpm	Cooling Tower	Evapco	ESWA-216-460-C	19-872170
K05	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460-C	19-871147
K06	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460-C	19-871155
K07	1,250 gpm	Cooling Tower	Evapco	ESWA-216-460-C	19-872176
K09	1,250 gpm	Cooling Tower	Evapco	ESWA-216-460	19-871162
K10	1,250 gpm	Cooling Tower	Evapco	ESWA-216-460	19-871158
K11	1,250 gpm	Cooling Tower	Evapco	ESWA-216-460	20P103709

Table III-A-6: Summary of Emissions Units NAP 12

EU	Rating	Description	Make	Model	Serial
L01	2,045 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500548
	3,353 hp	Diesel Engine, DOM: 2016			
L02	2,045 kW	Generator, Emergency	Marathon Electric	MTU16V4000DS2250	95030500549
	3,353 hp	Diesel Engine, DOM: 2016			

Table III-A-7: Summary of ATC-Only Emissions Units

EU	Rating	Description	Make	Model	Serial
NAP 7					
B24	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
NAP 8					
D09	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
D15	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
NAP 9					
H05	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
NAP 10					
F04	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
F08	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
NAP 11					
K04	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
K08	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
K12	1,250 gpm	Cooling Tower	Evapco	ESWA 216-460	TBD
NAP 12					
L03	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	TBD
	3,353 hp	Diesel Engine, DOM: 2015	MTU Detroit Diesel	16V4000G83	TBD
L04	2,250 kW	Generator, Emergency	Marathon Electric	2250LXC6DT2	TBD
	3,353 hp	Diesel Engine, DOM: 2015	MTU Detroit Diesel	16V4000G83	TBD

B. Potential to Emit and Status Determination Emissions

Table III-B-1: Individual Emissions Unit PTE (tons per year)

EU Type	Identical EUs Group[1]	Hours per Year	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
3,353 hp Diesel engine (117 units)	A02-A29, A32-A34, C01-C24, E01-E18, G01-G24, J01-J18, L01, L02	104 each	0.02	0.02	2.06	0.27	0.01	0.03	0.01
1,250 gpm Cooling tower (69 units)	B01-B05, B07-B21, B23, D01-D08, D10-D14, D16, F01-F03, F05-F07, F09-F12, H01-H04, H06-H16, K01-K03, K05-K07, K09-K11	8,760 each	0.06	0.002	0	0	0	0	0
800 gal/min Cooling Tower (2 units)	H17, H18	8,760 each	0.04	0.0002	0	0	0	0	0
125 hp Diesel engine (3 units)	E19, E20, J19	500 each	0.01	0.01	0.19	0.09	0.01	0.01	0.01

EU Type	Identical EUs Group[1]	Hours per Year	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
110 hp Diesel engine (1 unit)	C25	500	0.01	0.01	0.17	0.07	0.01	0.01	0.01
331 hp Diesel engine (1 unit)	C26	104	0.01	0.01	0.14	0.05	0.01	0.04	0.01

[1] Each EU group consists of identical EUs with identical PTE.

Table III-B-2: ATC-Only Individual Emissions Unit PTE (tons per year)

EU Type	Identical EUs Group[1]	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
3,353 hp Diesel engine (4 units)	L03, L04	0.02	0.02	2.06	0.27	0.01	0.03	0.01
1,250 gpm Cooling tower (9 units)	B24, D09, D15, F04, F08, H05, K04, K08, K12	0.03	0.0009	0	0	0	0	0

Table III-B-3: Source PTE Summary (tons per any consecutive 12-month period)

Location	EUs	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
NAP 7	31 emergency generators	0.62	0.62	63.86	8.37	0.31	0.93	0.31
	21 cooling towers	1.26	0.04	0.00	0.00	0.00	0.00	0.00
NAP 8	24 emergency generators	0.48	0.48	49.44	6.48	0.24	0.72	0.24
	14 cooling towers	0.84	0.03	0.00	0.00	0.00	0.00	0.00
	1 emergency generator (331 hp)	0.01	0.01	0.14	0.05	0.01	0.04	0.01
	1 fire pump	0.01	0.01	0.17	0.07	0.01	0.01	0.01
NAP 9	24 emergency generators	0.48	0.48	49.44	6.48	0.24	0.72	0.24
	15 cooling towers	0.90	0.03	0.00	0.00	0.00	0.00	0.00
	2 small cooling towers[1]	0.08	0.01	0.00	0.00	0.00	0.00	0.00
NAP 10	18 emergency generators	0.36	0.36	37.08	4.86	0.18	0.54	0.18
	10 cooling towers	0.60	0.02	0.00	0.00	0.00	0.00	0.00
	2 fire pumps	0.02	0.02	0.38	0.18	0.02	0.02	0.02
NAP 11	18 emergency generators	0.36	0.36	37.08	4.86	0.18	0.54	0.18
	9 cooling towers	0.54	0.02	0.00	0.00	0.00	0.00	0.00
	1 fire pump	0.01	0.01	0.19	0.09	0.01	0.01	0.01
NAP 12	2 emergency generators	0.04	0.04	4.12	0.54	0.02	0.06	0.02
Totals		**6.61**	**2.54**	**241.90**	**31.98**	**1.22**	**3.59**	**1.22**

[1] Small cooling towers are the 800 gpm units.

Refer to the attachments section of this document for the PTE of the ATC-only emission units.

To calculate the SDE, the emergency generators' operational limit of 104 hours per year each is increased to 500 hours per year each in accordance with DES policy. As the cooling towers are unlimited and the fire pumps' PTE is based on 500 hours per year each, there is no difference in PTE and SDE for these units.

Table III-B-4: Source SDE Summary (tons per year)

Location	EUs	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
NAP 7	31 emergency generators	2.79	2.79	306.59	40.30	0.31	5.27	0.93
	21 cooling towers	1.26	0.04	0.00	0.00	0.00	0.00	0.00
NAP 8	24 emergency generators	2.16	2.16	237.36	31.20	0.24	4.08	0.72
	14 cooling towers	0.84	0.03	0.00	0.00	0.00	0.00	0.00
	1 emergency generator (331 hp)	0.01	0.01	0.14	0.05	0.01	0.04	0.01
	1 fire pump	0.01	0.01	0.17	0.07	0.01	0.01	0.01
NAP 9	24 emergency generators	2.16	2.16	237.36	31.20	0.24	4.08	0.72
	15 cooling towers	0.90	0.03	0.00	0.00	0.00	0.00	0.00
	2 small cooling towers	0.08	0.01	0.00	0.00	0.00	0.00	0.00
NAP 10	18 emergency generators	1.62	1.62	178.02	23.40	0.18	3.06	0.54
	10 cooling towers	0.60	0.02	0.00	0.00	0.00	0.00	0.00
	2 fire pumps	0.02	0.02	0.38	0.18	0.02	0.02	0.02
NAP 11	18 emergency generators	1.62	1.62	178.02	23.4	0.18	3.06	0.54
	9 cooling towers	0.54	0.02	0.00	0.00	0.00	0.00	0.00
	1 fire pump	0.01	0.01	0.19	0.09	0.01	0.01	0.01
NAP 12	2 emergency generators	0.18	0.18	19.78	2.60	0.02	0.34	0.06
Totals		**14.80**	**10.73**	**1,158.01**	**152.49**	**1.22**	**19.97**	**3.56**
Major Source Thresholds		**100**	**100**	**100**	**100**	**100**	**100**	**10/25[1]**

[1] Ten tons for any one HAP or 25 tons for combination of all HAPs.

Switch is a major source of NO_x. With a CO SDE greater than the major source threshold and a CO PTE less than the major source threshold, as a result of the emergency generator operating hour limitation, Switch is considered a synthetic minor of CO emissions. The hour limit is a voluntary limitation.

C. Emissions Increase

Table III-C-1 shows the increase in emissions from the previous Title V OP. The increase is due from incorporation of the emission units listed in Table II-C-1 that were initially permitted in an ATC and the increase in TDS of the cooling tower recirculation water. The ATC units underwent a controls analysis during that those action and are not subject to a controls analysis in this action. The emissions increases due to the TDS increase are below the Minor NSR Significant Levels, therefore, no controls analysis is required in this permitting action.

Table III-C-1: Emissions Increase (tons per year)

EUs	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
Current PTE	6.61	2.54	241.90	31.98	1.22	3.59	1.22
Previous PTE (06/24/19)	3.90	2.20	217.18	28.74	1.10	3.23	1.10
Emissions Increase	**2.71**	**0.20**	**24.72**	**3.24**	**0.12**	**0.36**	**0.12**
Emissions Increase due to TDS Increase	**2.11**	**0.08**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
AQR 12.5 Minor NSR Significant Levels	**7.5**	**5.0**	**20**	**50**	**20**	**20**	**--**

D. Operational Limitations

Typically, DES allows unlimited operation of emergency generators for emergency use and calculates the PTE based on 500 hours per year usage. The source took a voluntary emission limitation for each emergency generator to avoid becoming a major PSD source of NO_X. Switch uses 2.2 MW emergency generators and is confident they can reasonably limit the cap on hours of operation on the emergency generators and each emergency generator's operation shall be limited to 104 hours per calendar year, including emergencies. This hour limit is also used for the PTE calculation. This accommodates a worst-case emergency use of 55 hours per year and hours for testing and maintenance in accordance with the manufacturer's specifications. Switch has continuously complied with this limit.

The first 59 generators had an operational limit of 155 hours per year. This limit was established to not exceed the NAAQS for NO_2.

Switch has not requested an operational limit for the cooling towers. The fire pumps are limited to 100 hours for testing and maintenance per 40 CFR Part 60, Subpart IIII.

E. Monitoring

The new emission units in this renewal did not trigger additional monitoring requirements, as similar units are present in the permit with sufficient monitoring requirements. The units added to the Title V OP were added to the existing conditions as applicable.

Switch is required to monitor opacity, hours of operation of each generator and fire pump, and the TDS of the cooling towers.

F. Testing

The new emission units did not trigger addition performance testing.

As deemed necessary and upon written request from the Control Officer, Switch may be required to conduct performance testing on any emergency generator or fire pump engine to demonstrate compliance with the emission limits in 40 CFR Part 60, Subpart IIII.

IV. REGULATORY REVIEW

A. Local Regulatory Requirements

DAQ has determined that the following public laws, statutes, and associated regulations are applicable:

1. CAAA (authority: 42 U.S.C. § 7401, et seq.);

2. Title 40 of the CFR, including 40 CFR Part 70 and others;

3. Chapter 445 of the NRS, Sections 401 through 601;

4. Portions of the AQR included in the state implementation plan (SIP) for Clark County, Nevada. SIP requirements are federally enforceable. All requirements from ATC permits issued by DAQ are federally enforceable because these permits were issued pursuant to SIP-included sections of the AQR; and

5. Portions of the AQR not included in the SIP. These locally applicable requirements are locally enforceable only.

B. Federally Applicable Regulations

40 CFR Part 60 (NSPS), Subpart A—General Provisions

40 CFR Part 60.7: Notification and recordkeeping.

Discussion: This regulation requires notification to DES of modifications, opacity testing, and records of malfunctions of process equipment, and performance test data. These requirements are found in the Part 70 OP in Section III. DAQ requires records to be maintained for five years, a more stringent requirement than the two years required by 40 CFR Part 60.7.

40 CFR Part 60.8: Performance tests.

Discussion: Notice of intent to test, the applicable test methods, and acceptable test method operating conditions are outlined in this regulation. DES also reserves the right to require more frequent testing.

40 CFR Part 60.11: Compliance with standards and maintenance requirements.

Discussion: Switch is subject to one NSPS standard: Subpart IIII – Standards for Performance for Stationary Compression Ignition Internal Combustion Engines. Compliance requirements for this standard is discussed in corresponding sections.

40 CFR Part 60.12: Circumvention.

Discussion: This prohibition is addressed in the Part 70 OP. There is also a local rule, AQR 80.1.

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

40 CFR Part 60.4200: Applicability determination.

Discussion: The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) with a displacement less than 30 liters per cylinder where the model year is 2007 or later, for engines that are not fire pumps, and July 1, 2006, for ICE certified by National Fire Protection Association as fire pump engines. Switch operates emission units that are subject to this subpart.

40 CFR Part 60.4202: Emission standards for owners and operators.

Discussion: The operator of the stationary CI ICE must provide the manufacturer certification of the emission standards specified in this subpart. These requirements are addressed in the Part 70 OP. By meeting the manufacturer's certified emissions, the emission units are in compliance with the emission standards of this subpart.

40 CFR Parts 60.4206 and 60.4211: Compliance requirements.

Discussion: The operator of the stationary CI ICE must operate and maintain CI ICE that achieve the emission standards according to the manufacturer's written instructions and procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine. These requirements are addressed in the Part 70 OP.

40 CFR Part 60.4214: Reporting and recordkeeping requirements.

Discussion: The operator of the CI ICE shall keep records that include: engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement; emission control equipment; and fuel used. If the stationary CI internal combustion is a certified engine, the owner or operator shall keep documentation from the manufacturer that the engine is certified to meet the emission standards. These requirements are addressed in the Part 70 OP.

40 CFR Part 63, Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

40 CFR Part 63.6585: Applicability determination.

Discussion: The provisions of this subpart are applicable to owners and operators of stationary RICE at major or area sources of HAP. Numeric emission standards are not applied to these emergency engines, however, operational limitations, management practices and record keeping are required. The engines meet the requirements of 40 CFR Part 63, Subpart ZZZZ, by complying with 40 CFR Part 60, Subpart IIII.

40 CFR Part 63, Subpart Q—National Emissions Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers

40 CFR Part 63.400: Applicability.

Discussion: This subpart does not apply to the cooling towers at Switch, as chromium-based water treatment chemical are not used in these units and Switch is not a major source of HAP.

40 CFR Part 64—Compliance Assurance Monitoring

40 CFR Part 64.2: Applicability.

Discussion: CAM does not apply to any emission unit at Switch as no emission unit is subject to an emission limitation or standard, has an uncontrolled PTE greater than a major source threshold, and uses that control device to achieve compliance with the emission standard.

40 CFR Part 72—Acid Rain Permits Regulation

40 CFR Part 72.6: Applicability.

Discussion: There is no emissions unit at this source that meets the definition of affected unit under this rule, therefore, 40 CFR Part 72 does not apply to this source.

40 CFR 75—Continuous Emission Monitoring

Discussion: This source is not subject to the Acid Rain limitations of 40 CFR Part 72, therefore, the source is not subject to the monitoring requirements of this regulation.

C. Permit Shield

Switch did not request a permit shield with this permitting action.

V. CONTROL TECHNOLOGY

Switch is not proposing to construct any new emission units in this permitting action. The emission units incorporated from an ATC will maintain controls required in the ATC.

The emergency generators were required to have RACT for NOx. The generators from this ATC are Tier 2 Certified ICE, use good combustion practices, and have limited hours for testing, maintenance, and operation during emergencies. Each diesel engine is equipped with a turbocharger and with a separate circuit air cooler. The diesel engines will be maintained in accordance with manufacturer's specifications and will use only low sulfur diesel fuel. DAQ agreed that these control equipment and practices met RACT requirements for these diesel engines.

No controls analysis were required for the fire pumps or cooling towers when originally permitted.

Additionally, the source meets the emission standards of 40 CFR Part 60, Subpart IIII, listed in Attachment 3 of this document.

VI. COMPLIANCE

A. Compliance Certification

Recordkeeping requirements are to be kept for all limitations specified in the permit.

1. Requirements for reporting

a. 12.5.2.8: Requirements for compliance certification:

i. Regardless of the date of issuance of this Part 70 OP, the schedule for the submittal of reports to DAQ shall be that in Table VI-A-1.

Table VI-A-1. Reporting Schedule

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 Emission Inventory Report	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
Report of Malfunctions, Startup, Shutdowns, or Deviations with Excess Emission	As required	Within 72 hours of the notification
Deviation Report without Excess Emissions	As required	Along with semiannual reports[1]
Excess Emissions that Pose a Potential Imminent and Substantial Danger	As required	Within 12 hours of the permittee learns of the event
Performance Testing Protocol	As required	No less than 45 days, but no more than 90 days, before the anticipated test date[1]
Performance Testing	As required	Within 60 days of end of test[1]

[1]If the due date falls on a Saturday, Sunday, or federal or Nevada holiday, the submittal is due on the next regularly scheduled business day.

ii. A statement of methods used for determining compliance, including a description of monitoring, recordkeeping, and reporting requirements and test methods.

iii. A schedule for submission of compliance certifications during the permit term.

iv. A statement indicating the source's compliance status with any applicable enhanced monitoring and compliance certification requirements of the Act.

B. Compliance Summary

Table VI-B-1: Applicable Regulations

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 0	Definitions	Applicable – Switch will comply with all applicable definitions as they apply.	Switch will meet all applicable test methods should new definitions apply.	Switch complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 4	Control Officer	Applicable – The Control Officer or his representative may enter into Switch property, with or without prior notice, at any reasonable time for purpose of establishing compliance.	Switch will allow Control Officer to enter Station property as required.	Switch complies with applicable requirements.
AQR Section 5	Interference with Control Officer	Applicable – Switch shall not hinder, obstruct, delay, resist, or interfere with the Control Officer.	Switch will allow Control Officer to operate as needed.	Switch complies with applicable requirements.
AQR Section 8	Persons Liable for Penalties	Applicable – Switch and employees will be individually and collectively liable to any penalty or punishment from DES.	Switch will adhere to the rules stipulated in applicable AQR.	Switch complies with applicable requirements.
AQR Section 9	Civil Penalties	Applicable – The rule stipulates penalties for AQR violations.	Switch will adhere to the rules stipulated in applicable AQR.	Switch complies with applicable requirements.
AQR Section 12.0	Applicability, General Requirements and Transition	Applicable – Switch as a whole is not subject to these requirements. Rule outlines source applicability, requirements for a source to obtain a permit and transition for sources that received a permit prior to rulemaking.	Switch applied for and received ATC permits for Air Quality prior to commercial operation. Switch will comply with the requirements of the ATCs.	Switch complies with applicable requirements.
AQR Section 12.4	ATC application and Permit Requirements for Part 70 Sources	Applicable – Switch applied for an ATC from Air Quality.	Switch applied for, and received, ATC permits from Air Quality. Switch shall comply with the requirements for ATCs.	Switch complies with applicable requirements.
AQR Section 12.5	Part 70 Operating Permit Requirements	Applicable – Switch as a whole is applicable. Renewal applications are due 6 to 18 months prior to expiration. Revision applications will be submitted with 12 months of commencing operation of a new emission unit.	Switch complies with the requirements for Title V permits outlined in this AQR and with the current ATC.	Switch complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 12.9	Annual Emissions Inventory	Applicable – Switch shall complete and submit an annual emissions inventory.	Annual emission inventories shall be submitted by March 31 each year.	Switch complies with applicable requirements.
AQR Section 12.10	Continuous Monitoring Requirements	Not Applicable.	Not Applicable.	Not Applicable.
AQR Section 13.2(b)(1) Subpart A	MACT – General Provisions	Applicable – Switch emits hazardous air pollutants.	Switch complies with the applicable requirements of 40 CFR Part 61 and Part 63.	Switch complies with applicable requirements.
AQR Section 13.2(b)(82) Subpart ZZZZ	National Emission Standard for Hazardous Air Pollutants – Stationary Reciprocating Internal Combustion Engines	Applicable – as of May 3, 2013, for the affected units in this permit.	Applicable compliance, monitoring, recordkeeping, and reporting requirements.	Switch complies with applicable requirements.
AQR Section 14.1(b)(1) Subpart A	NSPS – General Provisions	Applicable – Switch is an affected source under the regulations. AQR Section 14 is locally enforceable; however, the NSPS standards they reference are federally enforceable.	Applicable monitoring, recordkeeping and reporting requirements.	Switch complies with applicable requirements.
AQR Section 14.1(b)(80) Subpart IIII	NSPS – Standards of Performance for Stationary Reciprocating Internal Combustion Engines	Applicable – Switch is subject to this regulation.	Switch has met the required certification for these engines.	Switch complies with applicable requirements.
AQR Section 18	Permit and Technical Service Fees	Applicable – Switch will be required to pay all required/applicable permit and technical service fees.	Switch is required to pay all required/applicable permit and technical service fees.	Switch complies with applicable requirements.
AQR Section 21	Acid Rain Permits	Not Applicable.	Not Applicable.	Not Applicable.
AQR Section 22	Acid Rain Continuous Emission Monitoring	Not Applicable.	Not Applicable.	Not Applicable.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 25	Upset/Breakdown, Malfunctions	Applicable – Any upset, breakdown, emergency condition, or malfunction which causes emissions of regulated air pollutants in excess of any permit limits shall be reported to Control Officer. Section 25.1 is locally and federally enforceable.	Any upset, breakdown, emergency condition, or malfunction in which emissions exceed any permit limit shall be reported to the Control Officer within twenty (24) hours of the time that the permittee learns of the event.	Switch complies with applicable requirements.
AQR Section 26	Emissions of Visible Air Contaminants	Applicable – Opacity for the Switch emission units must not exceed 20 percent for more than 6 consecutive minutes.	Compliance determined by EPA Method 9, as required.	Switch complies with applicable requirements.
AQR Section 40	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 cause a nuisance. Section 40 is locally enforceable only.	Switch air contaminant emissions are controlled by pollution control devices or good combustion in order not to cause a nuisance.	Switch complies with applicable requirements.
AQR Section 41	Fugitive Dust	Applicable – Switch shall take necessary actions to abate fugitive dust from becoming airborne.	Switch utilizes appropriate best practices to not allow airborne fugitive dust.	Switch complies with applicable requirements.
AQR Section 42	Open Burning	Applicable – In the event Switch burns combustible material in any open areas, such burning activity will have been approved by Control Officer in advance. Section 42 is a locally enforceable rule only.	Switch will contact the Air Quality and obtain approval in advance for applicable burning activities as identified in the rule.	Switch complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
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 a period of an hour, if the odor causes a nuisance, and if the detection of odors is separated by at least fifteen minutes. Section 43 is a locally enforceable rule only.	Switch will not operate its source in a manner which will cause odors.	Switch complies with applicable requirements.
AQR Section 70.4	Emergency Procedures	Applicable – Switch submitted an emergency standby plan for reducing or eliminating air pollutant emissions in the Section 12.5 Operating Permit Application.	Switch submitted an emergency standby plan and received the Section 12.5 Operating Permit.	Switch complies with applicable requirements.
AQR Section 80	Circumvention	Applicable – Switch shall not conceal emissions in any way.	Switch will disclose all emissions as required by state and federal regulations.	Switch complies with applicable requirements.
NRS Chapter 445B	Nevada Revised Statutes, Air pollution	Applicable – Switch shall comply with applicable regulations.	Switch complies with applicable regulations.	Switch complies with applicable requirements.
40 CFR Part 52.1470	State Implementation Plan Rules	Applicable – Switch is subject to the Nevada SIP.	Switch shall continue to comply with the federally enforceable monitoring, testing, recordkeeping, and reporting requirements stipulated in the SIP.	Switch complies with applicable requirements.
40 CFR Part 60 Subpart A	Standards of Performance for New Stationary Sources – General provisions	Applicable – Switch is an affected facility. Therefore, Subpart A provisions are applicable.	Switch shall continue to adhere to applicable monitoring, testing, recordkeeping, and reporting regulations.	Switch complies with applicable requirements.
40 CFR Part 60 Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	Applicable – Switch is subject to this regulation.	Switch shall continue to adhere to applicable monitoring, testing, recordkeeping, and reporting regulations.	NAFB complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
40 CFR Part 63 Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	Applicable – The continuous-duty generators/water pump is subject to this subpart.	Switch shall continue to adhere to the applicable emission limitations, operating and maintenance requirements, recordkeeping, reporting, and general provisions.	Switch complies with applicable requirements.
40 CFR Part 70	Federally Mandated Operating Permits	Applicable – The regulations provide for the establishment of State air quality permitting systems consistent with the requirements of Title V of the Clean Air Act.	Switch complies with this regulation by maintaining an updated Title V federal operating permit.	Switch complies with applicable requirements.
40 CFR Part 72	Acid Rain Permit Regulations	Not Applicable.	Not Applicable.	Not Applicable.
40 CFR Part 73	Acid Rain Sulfur Dioxide Allowance System	Not Applicable.	Not Applicable.	Not Applicable.
40 CFR Part 75	Acid Rain Continuous Emission Monitoring	Not Applicable.	Not Applicable.	Not Applicable.

C. Summary of Monitoring for Compliance

Table VI-C-1: Compliance Monitoring

EU	Regulation (40 CFR)	Regulatory Standard	Permit Limit	Is Permit Limit Equal or More Stringent?	Averaging Period Comparison			Streamlining Statement
					Standard	Permit Limit	Is Permit Limit Equal or More Stringent?	
A02-A29, A32-A34, C01-C24, C26, E01-E18, G01-G24, J01-J18, L01, L02	60.4205(b) and 60.4211 (IIII)	Various limits for NOx, CO, PM, and VOC pollutants based on model year and engine power rating		Yes	Compliance demonstrated by keeping records of engine manufacturer's certified emissions data		Yes	The permit requirements and federal standards are identical
C25, E19, E20, J19	60.4205(c) and 60.4211 (IIII)	Various limits for NOx, CO, PM, and VOC pollutants based on model year and engine power rating		Yes	Compliance demonstrated by keeping records of engine manufacturer's certified emissions data		Yes	The permit requirements and federal standards are identical

VII. EMISSION REDUCTION CREDITS (OFFSETS)

The permittee is not required to obtain offsets in this permitting action.

VIII. ADMINISTRATIVE REQUIREMENTS

AQR Section 12.5 requires that Air Quality identify the original authority for each term or condition in the Part 70 OP. Such reference of origin or citation is denoted by [italic text in brackets] after each Part 70 OP condition.

Air Quality proposes to issue the Part 70 OP conditions on the following basis:

Legal:

On December 5, 2001, in 66 FR 30097, EPA fully approved the Title V Operating Permit Program submitted by DES for the purpose of complying with the Title V requirements of the 1990 CAAA and implementing 40 CFR Part 70.

Factual:

Switch has supplied all the necessary information for Air Quality to draft Part 70 OP conditions, encompassing all applicable requirements and corresponding compliance.

Conclusion:

DES has determined that Switch will continue to determine compliance through the use of performance testing, semiannual reporting, and daily and monthly recordkeeping coupled with annual certifications of compliance. Air Quality proceeds with the decision that a Part 70 OP should be issued as drafted to Switch for a period not to exceed five years.

IX. INCREMENT

Switch Ltd is a major source in Hydrographic Area 212 (the Las Vegas Valley). Permitted emission units include 120 generators, 80 cooling towers and four fire pumps. Since minor source baseline dates for NO_x (October 21, 1988) and SO_2 (June 29, 1979) have been triggered, Prevention of Significant Deterioration (PSD) increment analysis is required.

DAQ modeled the source using AERMOD to track the increment consumption. Average annual actual emissions (2018-2019) were used for the generators in the NO_X modeling. Stack data submitted by the applicant were supplemented with information available for similar emission units. Five years (2011 to 2015) of meteorological data from the McCarran Station were used in the model. U.S. Geological Survey National Elevation Dataset terrain data were used to calculate elevations. Table IX-1 shows the location of the maximum impact and the potential PSD increment consumed by the source at that location. The impacts are below the PSD increment limits.

Table IX-1: PSD Increment Consumption

Pollutant	Averaging Period	PSD Increment Consumption by the Source (μg/m^3)	Location of Maximum Impact	
			UTM X (m)	UTM Y (m)
SO_2	3-hour	10.97[1]	660847	3991932
SO_2	24-hour	6.29[1]	660847	3991932
SO_2	Annual	3.17	660848	3991932
NO_X	Annual	5.79	660848	3991932

[1] Highest Second High Concentration

X. PUBLIC NOTICE

This permitting action is a renewal and therefore is subject to public notice per AQR 12.5.2.17.

XI. PERMIT SHIELD

None has been identified in this permitting action.

XII. ACID RAIN REQUIREMENTS

This source is not subject to the acid rain requirements.

XIII. ATTACHMENTS

Attachment 1 – ATC-only Units

ATC-Only Emission Units PTE Summary (tons per any consecutive 12-month period)

Location	EUs	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
NAP 7	1 cooling tower (EU: B24)	0.03	0.01	0.00	0.00	0.00	0.00	0.00
NAP 8	2 cooling towers (EUs: D09 and D15)	0.06	0.01	0.00	0.00	0.00	0.00	0.00
NAP 9	1 cooling tower (EU: H05)	0.03	0.01	0.00	0.00	0.00	0.00	0.00
NAP 10	2 cooling towers (EUs: F04 and F08)	0.06	0.01	0.00	0.00	0.00	0.00	0.00
NAP 11	2 cooling towers (EUs: K04, K08, and K12)	0.09	0.01	0.00	0.00	0.00	0.00	0.00
NAP 12	2 emergency generators (EU: L03 and L04)	0.04	0.04	4.12	0.54	0.02	0.06	0.02
	Totals	**0.31**	**0.09**	**4.12**	**0.54**	**0.02**	**0.06**	**0.02**

Attachment 2 – Source PTE Including ATC-Only Emission Units

Emission Units PTE Summary (tons per any consecutive 12-month period)

PTE	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
Title V OP PTE	6.61	2.54	241.90	31.98	1.22	3.59	1.22
ATC-Only Emission Unit PTE	**0.31**	**0.09**	**4.12**	**0.54**	**0.02**	**0.06**	**0.02**
Totals	**6.92**	**2.63**	**246.02**	**32.52**	**1.24**	**3.65**	**1.24**

Attachment 3 – 40 CFR Part 60, Subpart IIII, Emission Standards

40 CFR Part 60, Subpart IIII, Emission Standards (g/kW-hr)

EU	HC	NO_X	NMHC + NO_X	CO	PM
A02 through A12, C26	1.3	9.2		11.4	0.54
A13 through A29, A32 through A34, C01 through C24, E01 through E18, G01 through G24, J01 through J18, L01, L02			6.4	3.5	0.2
C25, E19, E20, J19			10.5	5.0	0.80

Attachment 4 – Emission Unit EF and PTE Tables

						Emission Factor (lb/hp-hr)	Control Efficiency	Potential Emissions		
EU#	A02-A29, A32-A34, C01-C24, E01-E18, G01-G24, J01-J18, L01, L02		**Horsepower:**	3,353						
Make:	Detroit Diesel		**Hours/Day:**					**lb/hr**	**lb/day**	**ton/yr**
Model:	16V4000		**Hours/Year**	104	**PM10**	1.07E-04	0.00%	0.36	0.00	0.02
S/N:					**NOx**	1.18E-02	0.00%	39.57	0.00	2.06
					CO	1.55E-03	0.00%	5.20	0.00	0.27
Manufacturer Guarantees					**SO_2**	1.21E-05	0.00%	0.04	0.00	0.01
PM10	0.000107	lb/hp-hr			**VOC**	1.97E-04	0.00%	0.66	0.00	0.03
NOx	0.0118	lb/hp-hr			**HAP**	3.05E-05	0.00%	0.10	0.00	0.01
CO	0.00155	lb/hp-hr								
SO_2		lb/hp-hr								
VOC	0.000197	lb/hp-hr								
Engine Type:	Diesel				Diesel Fuel Sulfur Content is 15 ppm (0.0015%)					

						Emission Factor (lb/hp-hr)	Control Efficiency	Potential Emissions		
EU#	A02-A29, A32-A34, C01-C24, E01-E18, G01-G24, J01-J18, L01, L02		**Horsepower:**	3,353						
Make:			**Hours/Day:**					**lb/hr**	**lb/day**	**ton/yr**
Model:			**Hours/Year**	500	**PM10**	1.07E-04	0.00%	0.36	0.00	0.09
S/N:					**NOx**	1.18E-02	0.00%	39.57	0.00	9.89
					CO	1.55E-03	0.00%	5.20	0.00	1.30
Manufacturer Guarantees					**SO_2**	1.21E-05	0.00%	0.04	0.00	0.01
PM10	0.000107	lb/hp-hr			**VOC**	1.97E-04	0.00%	0.66	0.00	0.17
NOx	0.0118	lb/hp-hr			**HAP**	3.05E-05	0.00%	0.10	0.00	0.03
CO	0.00155	lb/hp-hr								
SO_2		lb/hr								
VOC	0.000197	lb/hp-hr								
Engine Type:	Diesel				Diesel Fuel Sulfur Content is 15 ppm (0.0015%)					

					Emission Factor (lb/hp-hr)	Control Efficiency	Potential Emissions lb/hr	Potential Emissions ton/yr
EU#	C25	**Horsepower:**	110					
Make:	Clarke John Deere	**Hours/Day:**						
Model:	JU4H-UFAD5G	**Hours/Year**	500	**PM10**	4.11E-04	0.00%	0.05	0.01
S/N:				**NOx**	6.08E-03	0.00%	0.67	0.17
				CO	2.47E-03	0.00%	0.27	0.07
Manufacturer Guarantees				**SO_2**	1.21E-05	0.00%	0.01	0.01
PM10	0.25	g/kW-hr		**VOC**	1.64E-04	0.00%	0.02	0.01
NOx	3.7	g/kW-hr		**HAP**	4.52E-05	0.00%	0.01	0.01
CO	1.5	g/kW-hr						
SO_2	0.0000121	lb/hp-hr						
VOC	0.1	g/kW-hr						
Engine Type:	Diesel			Diesel Fuel Sulfur Content is 15 ppm (0.0015%)				

					Emission Factor (lb/hp-hr)	Control Efficiency	Potential Emissions lb/hr	Potential Emissions ton/yr
EU#	E19, E20, J19	**Horsepower:**	125					
Make:	Clarke John Deere	**Hours/Day:**						
Model:	JU4H-UFADP0	**Hours/Year**	500	**PM10**	2.79E-04	0.00%	0.03	0.01
S/N:				**NOx**	6.08E-03	0.00%	0.76	0.19
				CO	2.79E-03	0.00%	0.35	0.09
Manufacturer Guarantees				**SO_2**	1.21E-05	0.00%	0.01	0.01
PM10	0.17	g/kW-hr		**VOC**	3.29E-04	0.00%	0.04	0.01
NOx	3.7	g/kW-hr		**HAP**	4.52E-05	0.00%	0.01	0.01
CO	1.7	g/kW-hr						
SO_2	0.0000121	lb/hp-hr						
VOC	0.2	g/kW-hr						
Engine Type:	Diesel			Diesel Fuel Sulfur Content is 15 ppm (0.0015%)				

EU	Description	Model No.	Drift Loss % (1)	Flow Rate (gal/min)	TDS (mg/l)	Hours of Operation hr/day	Hours of Operation hr/yr	PM10 Emissions lb/hr	PM10 Emissions ton/yr	PM2.5 Emissions lb/hr	PM2.5 Emissions ton/yr
B01-B05, B07-B21, B23, D01-D08, D10-D14, D16, F01-F03, F05-F07, F09-F12, H01-H04, H06-H16, K01-K03, K05-K07, K09-K11	Evapco Cooling Tower	ESWA 216-460	0.001%	1250	5000	24	8760	0.01	0.06	0.000464	0.002036

EU	Description	Model No.	Drift Loss % (1)	Flow Rate (gal/min)	TDS (mg/l)	Hours of Operation hr/day	Hours of Operation hr/yr	PM10 Emissions lb/hr	PM10 Emissions ton/yr	PM2.5 Emissions lb/hr	PM2.5 Emissions ton/yr
H17, H18	Evapco Cooling Tower	ESWA-102-45J-Z-C	0.001%	800	5000	24	8760	0.01	0.04	4.2E-05	0.0002

Appendix 5

MGMRI RACT Analysis

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REASONABLY AVAILABLE CONTROL TECHNOLOGY REVIEW

MGM RESORTS INTERNATIONAL

MGM Resorts International / Las Vegas, NV
Source ID # 00825

Prepared By:

TRINITY CONSULTANTS
9190 Double Diamond Parkway
Suite 126
Reno, NV 89521
(775) 242-3200

September 2022
Project 222901.0027

Trinity Consultants

TABLE OF CONTENTS

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. DAQ issued MGMRI a renewed Part 70 Operating Permit on May 19, 2022 (the Permit) which includes requirements for the following hotels, hereby referred to as "MGMRI Hotels": MGM Grand, New York-New York, Park MGM, The Signature at MGM Grand, Mandalay Bay, The Four Seasons, Luxor, Excalibur, Bellagio, CityCenter, and T-Mobile Arena.

DAQ requested that a RACT analysis be submitted by October 3, 2022, 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 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 marginal to moderate nonattainment for ozone.[1] The new classification would require HA 212 to achieve attainment by August 3, 2024, and require DAQ 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]

The MGMRI Hotels are currently a major source of NO_x (i.e., site-wide NO_x PTE is greater than 100 tpy), therefore this analysis considers any emission units at the MGMRI Hotels with PTE greater than five tpy of NO_x. Various natural gas-fired boilers and diesel-fired engines driving emergency generators have potential emissions greater than five tpy of NO_x and 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]

Table 1-1. Site-Wide PTE (tpy)

Pollutant	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP	GHG
Source Total	87.88	87.88	757.05	367.41	4.98	73.41	21.79	567,540.77

Per the August 1, 2022, DAQ RACT Stakeholder meeting, DAQ is requesting that various information 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

[1] 87 FR 43764.

[2] Per the August 1, 2022, Clark County DAQ 2015 Ozone NAAQ - Reasonably Available Control Technology (RACT) Requirements Presentation.

[3] Ibid.

[4] Site-wide PTE per the Permit.

  - 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 natural gas-fired boilers and diesel-fired emergency engines 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 TM01 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.

MGMRI determined that the current low NO_x burners with GCP constitute RACT for the affected natural gas-fired boilers. Therefore, there are no proposed changes to the emission limitations and testing, monitoring, and recordkeeping requirements contained in the Permit for the applicable boilers or diesel-fired emergency engines. 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 natural gas-fired boilers 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 natural gas-fired boilers and diesel-fired emergency engines 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 two natural gas-fired boilers with a rating of 32.66 MMBtu/hr and 47 diesel-fired emergency engines with ratings approximately between 1,100 and 3,700 horsepower (hp). Therefore, the boilers are classified as Commercial/Institutional-Sized Boilers/Furnaces (< 100 MMBtu/hr) and the engines as Large Internal Combustion Engines (> 500 hp) for purposes of the RBLC. Please refer to Appendix B for a complete description of each applicable diesel-fired emergency engine and boiler at the Facility.

2.1.2 Identification of Potential Control Technologies

Available NO_x 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 September 2022 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:

- Commercial/Institutional-Sized Boilers/Furnaces (< 100 MMBtu/hr)
  - Natural Gas (includes propane and liquefied petroleum gas) (RBLC Code 13.310)
- Large Internal Combustion Engines (> 500 hp)
  - Fuel Oil (ASTM #1,2, includes kerosene, aviation, diesel fuel) (RBLC Code 17.110)

The following control technologies are technologically feasible based on the RBLC database search results.

- For natural gas-fired boilers,
  - Use of GCP
  - Low NO_x burners and Flue Gas Recirculation (FGR)
  - Ultra-low NO_x burners (ULNB) and FGR
  - Selective Catalytic Reduction (SCR)
- For diesel-fired emergency engines,
  - Use of GCP
  - EPA Tier Certification

The RBLC search results are available in Appendix A.

2.1.2.2 Technical Feasible Options for Natural Gas Boilers

2.1.2.2.1 Low/Ultra Low NO_x Burners and Flue Gas Recirculation

NO_x is primarily formed through the thermal oxidation of nitrogen and oxygen in the boiler exhaust stream. The FGR system reduces NO_x emissions by recirculating gas that acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NO_x formation. Since recirculating gas acts as a diluent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. An FGR system is normally used in combination with specially designed low NO_x burners. Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame that suppresses thermal NO_x formation. When low NO_x burners and FGR are used in combination, these techniques can reduce NO_x emissions by 60 to 90 percent. In some cases, the addition of NO_x control systems such as low NO_x burners and FGR may also reduce combustion efficiency, resulting in higher CO emissions relative to uncontrolled boilers.[5] ULNB use similar methods to low NO_x burners but can achieve a higher NO_x reduction than low NO_x burners. ULNB can emit as low as 10 parts per million (ppm) of NO_x in some cases.[6]

2.1.2.2.2 Selective Catalytic Reduction

The SCR process chemically reduces the NO_x molecule into molecular nitrogen and water vapor. A nitrogen-based reagent, typically ammonia or urea, is injected into the exhaust stream of a combustion unit. The exhaust gases mix with the nitrogen reagent and pass over a catalyst. The reagent reacts selectively with

[5] AP-42 Chapter 1.4, Natural Gas Combustion https://www.epa.gov/sites/default/files/2020-09/documents/1.4_natural_gas_combustion.pdf

[6] U.S. Department of Energy, Guide to Low-Emission Boiler and Combustion Equipment Selection. ORNL/TM-2002/19. https://www.energy.gov/sites/prod/files/2014/05/f15/guide_low_emission.pdf

the NO_x within a specific temperature range (480°F to 800°F with 700°F to 750°F being optimal) and in the presence of the catalyst and oxygen. SCR is typically cost-effective only on larger industrial boilers (>50 MMBtu/hr for natural gas-fired boilers). SCR can achieve control efficiencies in the range of 70% to 90%.[7] [8]

2.1.2.2.3 Good Combustion Practices

The use of GCP at the facility includes operating boilers 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 boiler operators from an efficiency and reliability perspective.

2.1.2.3 Technically Feasible Options for Diesel Emergency Engines

2.1.2.3.1 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.

2.1.2.3.2 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.

2.1.2.4 Technical Feasibility Determination – Natural Gas-Fired Boilers

The four potential controls for the natural gas-fired boilers are listed below:

- GCP (Assumed baseline)
- Low NO_x Burners and FGR
- ULNB and FGR
- SCR

The applicable boilers at the MGMRI Hotels are rated at 32.66 MMBtu/hr (EUs: MG13 and MG14) and are currently equipped with a low NO_x burner to minimize NO_x emissions to <40 ppm at 3% O_2 per Condition III-A-5(c) of the Permit. Therefore, it is assumed that GCP will be implemented for the boilers regardless of other emission controls (or lack thereof). Low NO_x burners and GCP with firing of pipeline-quality natural gas will be used as the baseline emissions scenario for the boiler NO_x RACT analysis.

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[7] EPA Air Pollution Control Technology Fact Sheet EPA-452/F-03-032 https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

[8] EPA Air Pollution Control Cost Manual Section 4, Chapter 2 – Selective Catalytic Reduction (updated on 06/12/2019) Table 2.1b. https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

The exhaust temperature for smaller boilers (<100 MMBtu/hr) is typically less than the optimal temperature range of 700°F to 750°F. Additionally, publications from EPA[9,10] detail that SCR applications on natural gas burning industrial-commercial boilers are typically only applied to boilers above 100 MMBtu/hr. Therefore, SCR is considered not technically feasible for MG13 and MG14 because the operating temperature and boiler size are not in alignment with optimal SCR operation.

2.1.2.5 Rank Remaining Boiler Control Technologies by Control Effectiveness

The baseline emissions scenario is low NO_x burners and GCP with the firing of pipeline-quality natural gas. This section evaluates additional controls for their reduction effectiveness, as detailed in Table 2-1 below.

Table 2-1. Emission Reduction Calculations

Control Technology	NO_x Emission Factor (lb/MMScf)[1]	NO_x Control Efficiency	Annual Emissions (tpy) [2]	Emissions Reduction (tpy)
Baseline	49.76	-	1.66	-
Low NO_x burner with FGR	32.00	35.69%	1.06	0.59
ULNB with FGR	12.44	75.00%	0.41	1.24

1. Baseline emission factor for low NO_x burners and GCP with firing of pipeline-quality natural gas per the permit limit of 40 ppm NO_x at 3% O_2. Low NO_x burner with FGR emission factor is per AP-42 Chapter 1.4 Table 1.4-1. ULNB with FGR emission factor is per the U.S. Department of Energy, Guide to Low-Emission Boiler and Combustion Equipment Selection (ULNB capable of achieving <10 ppm NO_x in some cases).
2. Annual emissions are calculated by multiplying the 2019 to 2021 average actual fuel rate of 66.6 MMscf/yr, for each EU MG13 and MG14 as they are identical units, by the NOx emission factor for each control technology. The average actual fuel rate is less than 70% of the permitted fuel rate of 280.5 MMscf/yr (32.66 MMBtu/hr / 1020 btu/scf * 8760 hr/yr) and, per DAQ guidance, can be used in this analysis (versus potential fuel rate). Also note that the fuel usage for each of the individual three years (2019, 2020, and 2021) is less than 70% of the permitted fuel rate for each boiler (EUs MG13 and MG14).

2.1.2.6 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., TM01) 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 numbers of hours per year, the costs

[9] EPA Air Pollution Control Cost Manual Section 4, Chapter 2 – Selective Catalytic Reduction (updated on 06/12/2019) Table 2.1b. https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

[10] EPA Air Pollution Control Technology Fact Sheet: SCR (EPA-452/F-03-032). https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

of emission control are not warranted when compared to the emission reductions that would be achieved."[11] 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, MGM 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).[12] 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 NOx emissions from engines. Per Subsection (i) of that Rule, emergency engines are not subject to the emission standards of the Rule (and associated requirements).[13] MGM 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.

2.2 Economic Analysis Summary

The most effective remaining control for natural gas boilers is ULNB with FGR. Economic feasibility is principally based on the tons per year of the pollutant removed and the annualized cost of the control, expressed in dollars per tons of pollutant ($/ton).

MGMRI reviewed publicly available data for the material cost of the addition of FGR to a low NO_x burner and for ULNB burners with FGR; the economic analysis for these control options is shown in Table 2-2 below.

Table 2-2. NO_x RACT Economic Feasibility Analysis

Control Technology	Total Emissions Reduction (tpy)	Total Capital Investment of Control ($USD) [1, 2]	Total Annual Equipment Cost ($USD) [3]	Total Annual Operating Cost ($USD) [4]	Total Cost per Ton ($USD/Ton) [5]
Baseline	-	-	-	-	-
Low NO_x burner with FGR	0.59	77,200.00	13,587.20	39,520.61	89,869.40

[11] 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).

[12] SJVAPCD Rule 4702, Amended August 19, 2021. https://www.valleyair.org/rules/currntrules/r4702.pdf

[13] 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

Control Technology	Total Emissions Reduction (tpy)	Total Capital Investment of Control ($USD) [1, 2]	Total Annual Equipment Cost ($USD) [3]	Total Annual Operating Cost ($USD) [4]	Total Cost per Ton ($USD/Ton) [5]
ULNB with FGR	1.24	126,200.00	22,211.20	39,520.61	49,707.34

1. The total installed capital equipment costs are from the Bay Area Air Quality Management District (BAAQMD) Example Cost-Effectiveness Calculations for NOx Controls for FGR and ULNB. It was assumed that the low NO_x burner costs are equivalent to the costs of a ULNB. Since the BAAQMD example includes the installation of an SCR only a third of the labor and engineering costs, included in the BAAQMD cost estimates, were included in these costs estimates. [14]
2. It is assumed that the new FGR fan will be 40 hp and the existing FD fan will increase from 25 to 40 HP. The increased size of the FD fan is associated with the increased mass flow from flue gas recirculation.
3. Annualized equipment costs are determined using the simplified formula Cost Effectiveness Determination for BACT below:
   Annualized Equipment Cost = $ Capital Investment [CRF (0.136) + Tax (0.01) + Ins. (0.01) + G&A (0.02)]
   Capital Recovery Factor (CRF) of 0.136 is per Table A.2 of the EPA Chapter 2 Cost Estimation: Concepts and Methodology, for 6% interest over 10 years[15]
4. The units can operate 8,760 hours per year, and this was used to determine the annual operating costs.
5. The total cost per ton is determined as the total emissions reduction divided by the sum of the total annual equipment cost and the annual operating costs.

2.2.1 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. EU TM01 is 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., EU TM01).

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.

2.2.2 Selection of NO_x RACT for the Natural Gas-Fired Boilers

The result of the economic analysis (Section 2.2) shows that low NO_x burners with FGR has significantly higher costs on a $/ton then ULNB with FGR, while both are not economically feasible. The cost per ton calculated for either control option significantly exceeds cost effectiveness thresholds defined by other agencies, such as SJVAPCD.[16] ULNB being a significantly more costly capital investment (mainly due to the costs of installing the ULNB and FGR system) and has additional considerations for increased CO emissions.

[14] BAAQMD Example Cost-Effectiveness Calculations for NO_x Controls for FGR and ULNB https://www.baaqmd.gov/~/media/files/engineering/bact-tbact-workshop/appendix/cost-effectiveness-calculations-nox.pdf

[15] EPA Chapter 2 Cost Estimation: Concepts and Methodology, November 2017 https://www.epa.gov/sites/default/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[16] For example, SJVAPCD NO_x cost effectiveness threshold of $32,900 $/ton per SJVAPCD Policy 1305, https://www.valleyair.org/policies_per/Policies/APR%201305.pdf.

As such, MGMRI concludes that the current low NO_x burners and GCP with firing of pipeline-quality natural gas is considered RACT for MG13 and MG14.

MGMRI intends to maintain the current emission limits for NO_x as contained in the Permit for each of the MG13 and MG14. MGMRI will utilize the existing Permit conditions to monitor compliance with the NO_x emission limits contained in the Permit.

APPENDIX A: SUMMARY OF RBLC

Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
AK-0076	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT01	AK	1382	211111	8/20/2012	COMBUSTION OF DIESEL BY ICES	17.11	ULSD	1,750	KW	NO_x	10102		6.4	G/KW-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	REMOTE INCINERATOR GENERATOR ENGINE	21.4	ULTRA-LOW SULFUR DIESEL	102	HP	NO_x	10102		3	LB/TON	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	EMERGENCY CAMP GENERATORS	17.11	ULTRA-LOW SULFUR DIESEL	2,695	HP	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	AIRSTRIP GENERATOR ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	490	HP	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	AGITATOR GENERATOR ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	98	HP	NO_x	10102		5.6	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	INCINERATOR GENERATOR ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	102	HP	NO_x	10102-44-0		4.9	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	FINE WATER PUMPS	17.11	ULTRA-LOW SULFUR DIESEL	610	HP	NO_x	10102		3	GRAMS/HP-H	BACT-PSD
AK-0082	POINT THOMSON PRODUCTION FACILITY	AQ1201CPT03	AK	1382	211111	1/23/2015	BULK TANK GENERATOR ENGINES	17.11	ULTRA-LOW SULFUR DIESEL	891	HP	NO_x	10102		4.8	GRAMS/HP-H	BACT-PSD
AK-0084	DONLIN GOLD PROJECT	AQ0934CPT01	AK	1041	212221	6/30/2017	BLACK START AND EMERGENCY INTERNAL COMBUSTION ENGINES	17.11	DIESEL	1,500	KW	NO_x	10102	GOOD COMBUSTION PRACTICES	8	G/KW-HR	BACT-PSD
AK-0084	DONLIN GOLD PROJECT	AQ0934CPT01	AK	1041	212221	6/30/2017	FIRE PUMP DIESEL INTERNAL COMBUSTION ENGINES	17.21	DIESEL	252	HP	NO_x	10102	GOOD COMBUSTION PRACTICES	3.7	G/KW-HR	BACT-PSD
AK-0085	GAS TREATMENT PLANT	AQ1524CPT01	AK	4922	486210	8/13/2020	ONE (1) BLACK START GENERATOR ENGINE	17.11	ULSD	186.60	GPH	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMIT OPERATION TO 500 HOURS PER YEAR.	3.3	G/HP-HR	BACT-PSD
AK-0085	GAS TREATMENT PLANT	AQ1524CPT01	AK	4922	486210	8/13/2020	THREE (3) FIREWATER PUMP ENGINES AND TWO (2) EMERGENCY DIESEL GENERATORS	17.21	ULSD	19.4	GPH	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMIT OPERATION TO 500 HOURS PER YEAR PER ENGINE	3.6	G/HP-HR	BACT-PSD
AK-0088	LIQUEFACTION PLANT	AQ1539CPT01	AK	4922	488999	7/7/2022	DIESEL FIRE PUMP ENGINE	17.11	DIESEL	27.9	GAL/HR	NO_x	10102	GOOD COMBUSTION PRACTICES; LIMITED OPERATION; 40 CFR 60 SUBPART IIII	3.6	G/HP-HR	BACT-PSD
AK-0088	LIQUEFACTION PLANT	AQ1539CPT01	AK	4922	488999	7/7/2022	AUXILIARY AIR COMPRESSOR ENGINE	17.21	DIESEL	14.6	GAL/HR	NO_x	10102	GOOD COMBUSTION PRACTICES; LIMITED OPERATION; 40 CFR 60 SUBPART IIII	0.45	G/HP-HR	BACT-PSD
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	413-0033-X014 - X020	AL	3312	331111	7/22/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL	800	HP	NO_x	10102		0.015	LB/HP-H	BACT-PSD
*AL-0318	TALLADEGA SAWMILL	309-0075	AL	2421	321113	12/18/2017	250 HP EMERGENCY CI, DIESEL-FIRED RICE	17.11	DIESEL	0		NO_x	10102		0		N/A
AL-0328	PLANT BARRY	503-1001	AL	4911	221112	11/9/2020	DIESEL EMERGENCY ENGINES	17.11	DIESEL	0		NO_x	10102		3	GR/BHP-HR	BACT-PSD
AR-0161	SUN BIO MATERIAL COMPANY	2384-AOP-R0	AR	2611	322110	9/23/2019	EMERGENCY ENGINES	17.11	DIESEL	0		NO_x	10102	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	AR	3312	331111	6/9/2019	EMERGENCY ENGINES	17.11	DIESEL	0		NO_x	10102	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	4.86	G/KW-HR	BACT-PSD
CA-1219	CITY OF SAN DIEGO PUD (PUMP STATION 1)	2012--APP-002009	CA	4952	221320	7/9/2012	IC ENGINE	17.11	DIESEL	2,722	BHP	NO_x	10102	TIER 2 CERTIFIED ENGINE AND 50 HR/YR FOR M&T	4	G/B-HP-H	OTHER CASE-BY-CASE

* Represents draft entries into the RBLC which may not be complete.

Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
DC-0009	BLUE PLAINS ADVANCED WASTEWATER TREATEMENT PLANT	6372-A1	DC	4952	221320	3/15/2012	DIESEL EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	2,682	HP	NO_x	10102		31.87	LB/HR	LAER
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	MAIN PROPULSION ENGINES DEVELOPMENT DRILLER 1	17.11	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, AND ADDITIONAL ENHANCED WORK PRACTICE STANDARDS INCLUDING AN ENGINE PERFORMANCE MANAGEMENT SYSTEM, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER WITH AFTERCOOLER, AND HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER.	12.1	G/KW-H	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	MAIN PROPULSION ENGINES C.R. LUIGS	17.11	DIESEL	5,875	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, AND ADDITIONAL ENHANCED WORK PRACTICE STANDARDS INCLUDING AN ENGINE PERFORMANCE MANAGEMENT SYSTEM, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER WITH AFTERCOOLER, AND HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER.	18.1	G/KW-H	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	WIRELINE UNIT ENGINES - C.R. LUIGS	17.21	DIESEL	300	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, TURBOCHARGER WITH AFTERCOOLER, HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	8.92	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	FAST RESCUE CRAFT DIESEL ENGINE - DEVELOPMENT DRILLER 1	17.21	DIESEL	142	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, AND TURBOCHARGER	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	LIFE BOAT DIESEL ENGINES - DEVELOPMENT DRILLER 1	17.21	DIESEL	110	HP	NO_x	10102-44-0	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES AND USE OF LOW SULFUR DIESEL FUEL	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	PORT AND STB FWD AND AFT CRANE DIESEL ENGINES - C.R. LUIGS	17.21	DIESEL	305	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER WITH AFTERCOOLER, HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	82.83	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	FAST RESCUE CRAFT DIESEL ENGINE - C.R. LUIGS	17.11	DIESEL	142	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES AND USE OF LOW SULFUR DIESEL FUEL	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	SEISMIC OPERATIONS DIESEL ENGINES - DEVELOPMENT DRILLER 1	17.21	DIESEL	415	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, AND TURBOCHARGER	3.54	TONS	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	LIFE BOAT DIESEL ENGINES - C.R. LUIGS	17.21	DIESEL	39	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL	0		BACT-PSD

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Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	EMERGENCY GENERATOR DIESEL ENGINE - DEVELOPMENT DRILLER 1	17.11	DIESEL	2,229	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER WITH AFTERCOOLER, HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	1.6	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	CEMENTING AND NITROGEN PUMP DIESEL ENGINES - DEVELOPMENT DRILLER 1	17.21	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER, AND HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	9.5	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	WIRELINE UNIT DIESEL ENGINES - DEVELOPMENT DRILLER 1	17.21	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, TURBOCHARGER WITH AFTERCOOLER, HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	8.92	TONS	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	BLACK START AIR COMPRESSOR - C.R. LUIGS	17.21	DIESEL	6	HP	NO_x	10102-44-0	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THE ENGINE AND THE USE OF LOW SULFUR DIESEL FUEL	0		BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	EMERGENCY GENERATOR DIESEL ENGINE - C.R. LUIGS	17.11	DIESEL	2,064	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER WITH AFTERCOOLER, HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	1.49	T/12MO ROLLING TOTAL	BACT-PSD
FL-0338	SAKE PROSPECT DRILLING PROJECT	OCS-EPA-R4008	FL	1381	211111	5/30/2012	CEMENTING AND NITROGEN PUMP DIESEL ENGINES - C.R. LUIGS	17.21	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THESE ENGINES, USE OF LOW SULFUR DIESEL FUEL, POSITIVE CRANKCASE VENTILATION, TURBOCHARGER, AND HIGH PRESSURE FUEL INJECTION WITH AFTERCOOLER	8.69	T/12MO ROLLING TOTAL	BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	MAIN PROPULSION GENERATOR DIESEL ENGINES	17.11	DIESEL	9,910	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINES AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	12.7	G/KW-H	BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	DIESEL POWERED FORKLIFT ENGINE	17.21	DIESEL	30	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	WIRELINE DIESEL ENGINES	17.21	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	WATER BLASTING DIESEL ENGINE	17.21	DIESEL	208	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	0		BACT-PSD

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RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	WELL EVALUATION DIESEL ENGINE	17.21	DIESEL	140	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	FAST RESCUE CRAFT DIESEL ENGINE	17.21	DIESEL	230	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	ESCAPE CAPSULE DIESEL ENGINE	17.21	DIESEL	39	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	EMERGENCY DIESEL ENGINE	17.11	DIESEL	3,300	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINES AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	0		BACT-PSD
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	OCS-EPA-R4015	FL	1381	211111	9/16/2014	REMOTELY OPERATED VEHICLE EMERGENCY GENERATOR	17.21	DIESEL	427	HP	NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR ENGINES AND WITH TURBOCHARGER, AFTERCOOLER, AND HIGH INJECTION PRESSURE	0		BACT-PSD
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	FL	1381	213111	5/15/2012	MAIN PROPULSION GENERATORS	17.21	DIESEL	4,425	HP	NO_x	10102	USE OF ENGINE WITH TURBO CHARGER WITH AFTER COOLER, AN ENHANCED WORK PRACTICE POWER MANAGEMENT, NOX EMISSIONS MAINTENANCE SYSTEM, AND GOOD COMBUSTION AND MAINTENANCE PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR EACH ENGINE	26	G/KW-H	BACT-PSD
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	FL	1381	213111	5/15/2012	DRILL FLOOR AND CREW QUARTERS ELECTRICAL GENERATORS	17.11	DIESEL	6,789	HP	NO_x	10102	USE OF ENGINE WITH TURBO CHARGER WITH AFTER COOLER, AN ENHANCED WORK PRACTICE POWER MANAGEMENT, NOX EMISSIONS MAINTENANCE SYSTEM, AND GOOD COMBUSTION AND MAINTENANCE PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR EACH ENGINE.	26	G/KW-H	BACT-PSD
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	OCS-EPA-R4009	FL	1381	213111	5/15/2012	EMERGENCY ELECTRICAL GENERATOR	17.11	DIESEL	1,100	HP	NO_x	10102	USE OF GOOD COMBUSTION AND MAINTENANCE PRACTICES BASED ON THE CURRENT MANUFACTURER'S SPECIFICATIONS FOR THIS ENGINE.	0.22	TONS	BACT-PSD
FL-0350	ANADARKO PETROLEUM, INC DIAMOND BLACKHAWK DRILLING PROJECT	OCS-EPA-R4019	FL	1381	213111	12/31/2014	MAIN PROPULSION GENERATOR ENGINES	17.11	DIESEL	0		NO_x	10102	USE OF GOOD COMBUSTION PRACTICES BASED ON THE MOST RECENT MANUFACTURER'S SPECIFICATIONS ISSUED FOR THESE ENGINES AT THE TIME THAT THE ENGINES ARE OPERATING UNDER THIS PERMIT	0		BACT-PSD
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1010524-001-AC	FL	4911	221112	7/27/2018	1,500 KW EMERGENCY DIESEL GENERATOR	17.11	ULSD	14.82	MMBTU/HR	NO_x	10102	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	FL	4911	221112	7/27/2018	EMERGENCY FIRE PUMP ENGINE (347 HP)	17.21	ULSD	8,700	GAL/YR	NO_x	10102	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)	FL	4911	221112	6/7/2021	1,500 KW EMERGENCY DIESEL GENERATOR	17.11	ULSD	14.82	MMBTU/HR	NO_x	10102		6.4	G/KW-HOUR	BACT-PSD

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Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1010524-003-AC (PSD-FL-444A)	FL	4911	221112	6/7/2021	EMERGENCY FIRE PUMP ENGINE (347 HP)	17.21	ULSD	2.46	MMBTU/HR	NO_x	10102		4	G/KW-HOUR	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	12-219	IA	2873	325311	10/26/2012	EMERGENCY GENERATOR	17.11	DIESEL	142	GAL/HR	NO_x	10102	GOOD COMBUSTION PRACTICES	6	G/KW-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	12-219	IA	2873	325311	10/26/2012	FIRE PUMP	17.21	DIESEL	14	GAL/HR	NO_x	10102	GOOD COMBUSTION PRACTICES	3.75	G/KW-H	BACT-PSD
IL-0114	CRONUS CHEMICALS, LLC	13060007	IL	2873	325311	9/5/2014	EMERGENCY GENERATOR	17.11	DISTILLATE OIL	3,755	HP	NO_x	10102	TIER IV STANDARDS FOR NON-ROAD ENGINES AT 40 CFR 1039.102, TABLE 7.	0.67	G/KW-H	BACT-PSD
IL-0114	CRONUS CHEMICALS, LLC	13060007	IL	2873	325311	9/5/2014	FIRE WATER PUMP ENGINE	17.21	DISTILLATE OIL	373	HP	NO_x	10102	TIER IV STANDARDS FOR NON-ROAD ENGINES AT 40 CFR 1039.102, TABLE 7.	3.5	G/KW-H	BACT-PSD
IL-0129	CPV THREE RIVERS ENERGY CENTER	16060032	IL	4911	221112	7/30/2018	EMERGENCY ENGINES	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102		0		LAER
IL-0129	CPV THREE RIVERS ENERGY CENTER	16060032	IL	4911	221112	7/30/2018	FIRE WATER PUMP ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102		0		LAER
IL-0130	JACKSON ENERGY CENTER	17040013	IL	4911	221112	12/31/2018	FIRE WATER PUMP ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	420	HP	NO_x	10102		4	G/KW-HR	LAER
IL-0130	JACKSON ENERGY CENTER	17040013	IL	4911	221112	12/31/2018	EMERGENCY ENGINE	17.11	ULTRA-LOW SULFUR DIESEL	1,500	KW	NO_x	10102		6.4	G/KW-HR	LAER
*IL-0133	LINCOLN LAND ENERGY CENTER	18040008	IL	4911	221112	7/29/2022	EMERGENCY ENGINES	17.11	ULTRA-LOW SULFUR DIESEL	1,250	KW	NO_x	10102		6.4	GRAMS	BACT-PSD
*IL-0133	LINCOLN LAND ENERGY CENTER	18040008	IL	4911	221112	7/29/2022	FIRE WATER PUMP ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	320	HP	NO_x	10102		4	GRAMS	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	IN	4911	221112	12/3/2012	TWO (2) FIRE WATER PUMP DIESEL ENGINES	17.21	DIESEL	371	BHP, EACH	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	3	G/HP-H	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	IN	4911	221112	12/3/2012	TWO (2) EMERGENCY DIESEL GENERATORS	17.11	DIESEL	1,006	HP EACH	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	IN	4911	221112	12/3/2012	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	2,012	HP	NO_x	10102	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	BACT-PSD
IN-0166	INDIANA GASIFICATION, LLC	T147-30464-00060	IN	4925	221210	6/27/2012	TWO (2) EMERGENCY GENERATORS	17.11	DIESEL	1,341	HP EACH	NO_x	10102	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON- EMERGENCY OPERATION	0		BACT-PSD
IN-0166	INDIANA GASIFICATION, LLC	T147-30464-00060	IN	4925	221210	6/27/2012	THREE (3) FIRE WATER PUMP ENGINES	17.11	DIESEL	575	HP EACH	NO_x	10102	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON- EMERGENCY OPERATION	0		BACT-PSD
IN-0173	MIDWEST FERTILIZER CORPORATION	129-33576-00059	IN	2873	325311	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL	3,600	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/BHP-H	BACT-PSD
IN-0173	MIDWEST FERTILIZER CORPORATION	129-33576-00059	IN	2873	325311	6/4/2014	RAW WATER PUMP	17.21	DIESEL	500	HP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.83	G/BHP-H	BACT-PSD
IN-0179	OHIO VALLEY RESOURCES, LLC	147-32322-00062	IN	2873	325311	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	17.11	NO. 2 FUEL OIL	4,690	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	BACT-PSD
IN-0179	OHIO VALLEY RESOURCES, LLC	147-32322-00062	IN	2873	325311	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	17.21	NO. 2 FUEL OIL	481	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.86	G/B-HP-H	BACT-PSD
IN-0180	MIDWEST FERTILIZER CORPORATION	129-33576-00059	IN	2873	325311	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL	3,600	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	BACT-PSD
IN-0180	MIDWEST FERTILIZER CORPORATION	129-33576-00059	IN	2873	325311	6/4/2014	RAW WATER PUMP	17.21	DIESEL	500	HP	NO_x	10102	GOOD COMBUSTION PRACTICES	2.83	G/B-HP-H	BACT-PSD
IN-0185	MAG PELLET LLC	181-33965-00054	IN	1011	212210	4/24/2014	DIESEL FIRE PUMP	17.11	DIESEL	300	HP	NO_x	10102		3	G/HP-H	BACT-PSD

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IN-0263	MIDWEST FERTILIZER COMPANY LLC	129-36943-00059	IN	2873	325311	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	17.11	DISTILLATE OIL	3,600	HP EACH	NO_x	10102	GOOD COMBUSTION PRACTICES	4.42	G/HP-H EACH	BACT-PSD
IN-0317	RIVERVIEW ENERGY CORPORATION	T147-39554-00065	IN	2911	324110	6/11/2019	EMERGENCY GENERATOR EU 6006	17.11	DIESEL	2,800	HP	NO_x	10102	TIER II DIESEL ENGINE	6.4	G/KWH	BACT-PSD
IN-0317	RIVERVIEW ENERGY CORPORATION	T147-39554-00065	IN	2911	324110	6/11/2019	EMERGENCY FIRE PUMP EU 6008	17.11	DIESEL	750	HP	NO_x	10102	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	IN	2873	325311	5/6/2022	EMERGENCY GENERATOR EU 014A	17.11	DISTILLATE OIL	3,600	HP	NO_x	10102		4.42	G/HP-HR	BACT-PSD
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	C-10656	KS	4911	221112	3/18/2013	CATERPILLAR C18DITA DIESEL ENGINE GENERATOR	17.11	DISTILLATE OIL	900	BHP	NO_x	10102	UTILIZE EFFICIENT COMBUSTION/DESIGN TECHNOLOGY	14	LB/HR	BACT-PSD
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	C-10656	KS	4911	221112	3/18/2013	CUMMINS 6BTA 5.9F-1 DIESEL ENGINE FIRE PUMP	17.21	NO. 2 FUEL OIL	182	BHP	NO_x	10102	UTILIZE EFFICIENT COMBUSTION/DESIGN TECHNOLOGY	2	LB/HR	BACT-PSD
KY-0110	NUCOR STEEL BRANDENBURG	V-20-001	KY	3312	331111	7/23/2020	EP 10-02 - NORTH WATER SYSTEM EMERGENCY GENERATOR	17.11	DIESEL	2,922	HP	NO_x	10102	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	KY	3312	331111	7/23/2020	EP 10-03 - SOUTH WATER SYSTEM EMERGENCY GENERATOR	17.11	DIESEL	2,922	HP	NO_x	10102	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	KY	3312	331111	7/23/2020	EP 10-04 - EMERGENCY FIRE WATER PUMP	17.11	DIESEL	920	HP	NO_x	10102	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	KY	3312	331111	7/23/2020	EP 11-01 - MELT SHOP EMERGENCY GENERATOR	17.21	DIESEL	260	HP	NO_x	10102	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	KY	3312	331111	7/23/2020	EP 11-02 - REHEAT FURNACE EMERGENCY GENERATOR	17.21	DIESEL	190	HP	NO_x	10102	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	KY	3312	331111	7/23/2020	EP 10-07 - AIR SEPARATION PLANT EMERGENCY GENERATOR	17.11	DIESEL	700	HP	NO_x	10102	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	KY	3312	331111	7/23/2020	EP 10-01 - CASTER EMERGENCY GENERATOR	17.11	DIESEL	2,922	HP	NO_x	10102	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	KY	3312	331111	7/23/2020	EP 11-03 - ROLLING MILL EMERGENCY GENERATOR	17.21	DIESEL	440	HP	NO_x	10102	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	KY	3312	331111	7/23/2020	EP 11-04 - IT EMERGENCY GENERATOR	17.21	DIESEL	190	HP	NO_x	10102	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	KY	3312	331111	7/23/2020	EP 11-05 - RADIO TOWER EMERGENCY GENERATOR	17.21	DIESEL	61	HP	NO_x	10102	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	KY	3316	331111	4/19/2021	NEW PUMP HOUSE (XB13) EMERGENCY GENERATOR #1 (EP 08-05)	17.11	DIESEL	2,922	HP	NO_x	10102	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	TUNNEL FURNACE EMERGENCY GENERATOR (EP 08-06)	17.11	DIESEL	2,937	HP	NO_x	10102	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	CASTER B EMERGENCY GENERATOR (EP 08-07)	17.11	DIESEL	2,937	HP	NO_x	10102	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	AIR SEPARATION UNIT EMERGENCY GENERATOR (EP 08-08)	17.11	DIESEL	700	HP	NO_x	10102	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN	0		BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	COLD MILL COMPLEX EMERGENCY GENERATOR (EP 09-05)	17.21	DIESEL	350	HP	NO_x	10102	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN	0		BACT-PSD

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LA-0292	HOLBROOK COMPRESSOR STATION	PSD-LA-769(M-1)	LA	4922	486210	1/22/2016	EMERGENCY GENERATORS NO. 1 &; NO. 2	17.11	DIESEL	1,341	HP	NO_x	10102	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-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	PSD-LA-779	LA	2821	325211	5/23/2014	EMERGENCY DIESEL GENERATORS (EQTS 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, &; 1202)	17.11	DIESEL	2,682	HP	NO_x	10102	COMPLIANCE WITH 40 CFR 60 SUBPART IIII; OPERATING THE ENGINE IN ACCORDANCE WITH THE ENGINE MANUFACTURER'S INSTRUCTIONS AND/OR WRITTEN PROCEDURES (CONSISTENT WITH SAFE OPERATION) DESIGNED TO MAXIMIZE COMBUSTION EFFICIENCY AND MINIMIZE FUEL USAGE.	27.37	LB/HR	BACT-PSD
LA-0305	LAKE CHARLES METHANOL FACILITY	PSD-LA-803(M1)	LA	2869	325199	6/30/2016	DIESEL ENGINES (EMERGENCY)	17.11	DIESEL	4,023	HP	NO_x	10102	COMPLYING WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0307	MAGNOLIA LNG FACILITY	PSD-LA-792	LA	4922	221210	3/21/2016	DIESEL ENGINES	17.11	DIESEL	0		NO_x	10102	GOOD COMBUSTION PRACTICES, USE ULTRA LOW SULFUR DIESEL, AND COMPLY WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0308	MORGAN CITY POWER PLANT	PSD-LA-767	LA	4911	221112	9/26/2013	2000 KW DIESEL FIRED EMERGENCY GENERATOR ENGINE	17.11	DIESEL	20.4	MMBTU/HR	NO_x	10102	GOOD COMBUSTION AND MAINTENANCE PRACTICES, AND COMPLIANCE WITH NSPS 40 CFR 60 SUBPART IIII	33.07	LB/H	BACT-PSD
LA-0308	MORGAN CITY POWER PLANT	PSD-LA-767	LA	4911	221112	9/26/2013	380 HP DIESEL FIRED PUMP ENGINE	17.21	DIESEL	2.3	MMBTU/HR	NO_x	10102	GOOD COMBUSTION AND MAINTENANCE PRACTICES, AND COMPLIANCE WITH NSPS 40 CFR 60 SUBPART IIII	2.92	LB/H	BACT-PSD
LA-0309	BENTELER STEEL TUBE FACILITY	PSD-LA-774(M1)	LA	3312	331111	6/4/2015	FIRE WATER PUMP ENGINES	17.21	DIESEL	288	HP EACH	NO_x	10102	COMPLYING WITH 40 CFR 60 SUBPART IIII	3	G/BHP-HR	BACT-PSD
LA-0309	BENTELER STEEL TUBE FACILITY	PSD-LA-774(M1)	LA	3312	331111	6/4/2015	EMERGENCY GENERATOR ENGINES	17.11	DIESEL	2,922	HP EACH	NO_x	10102	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)	LA	2869	325998	6/30/2017	DFP1-13 - DIESEL FIRE PUMP ENGINE (EQT0013)	17.11	DIESEL	650	HP	NO_x	10102	COMPLIANCE WITH NSPS SUBPART IIII	6.6	LB/HR	BACT-PSD
*LA-0312	ST. JAMES METHANOL PLANT	PSD-LA-780(M-1)	LA	2869	325998	6/30/2017	DEG1-13 - DIESEL FIRED EMERGENCY GENERATOR ENGINE (EQT0012)	17.11	DIESEL	1,474	HP	NO_x	10102	COMPLIANCE WITH NSPS SUBPART IIII	19.23	LB/HR	BACT-PSD
LA-0313	ST. CHARLES POWER STATION	PSD-LA-804	LA	4911	221112	8/31/2016	SCPS EMERGENCY DIESEL GENERATOR 1	17.11	DIESEL	2,584	HP	NO_x	10102	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	LA	4911	221112	8/31/2016	SCPS EMERGENCY DIESEL FIREWATER PUMP 1	17.21	DIESEL	282	HP	NO_x	10102	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-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	EMERGENCY DIESEL GENERATOR 1	17.11	DIESEL	5,364	HP	NO_x	10102	COMPLIANCE WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	52.58	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	EMERGENCY DIESEL GENERATOR 2	17.11	DIESEL	5,364	HP	NO_x	10102	COMPLIANCE WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	52.58	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	FIRE PUMP DIESEL ENGINE 1	17.11	DIESEL	751	HP	NO_x	10102	COMPLIANCE WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	4.6	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	FIRE PUMP DIESEL ENGINE 2	17.11	DIESEL	751	HP	NO_x	10102	COMPLIANCE WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	4.6	LB/H	BACT-PSD
LA-0316	CAMERON LNG FACILITY	PSD-LA-766(M3)	LA	4922	221210	2/17/2017	FIRE WATER PUMP ENGINES (8 UNITS)	17.21	DIESEL	460	HP	NO_x	10102-44-0	COMPLYING WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0316	CAMERON LNG FACILITY	PSD-LA-766(M3)	LA	4922	221210	2/17/2017	EMERGENCY GENERATOR ENGINES (6 UNITS)	17.11	DIESEL	3,353	HP	NO_x	10102	COMPLYING WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0317	METHANEX - GEISMAR METHANOL PLANT	PSD-LA-761(M4)	LA	2869	325199	12/22/2016	EMERGENCY GENERATOR ENGINES (4 UNITS)	17.11	DIESEL	0		NO_x	10102	COMPLYING WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	0		BACT-PSD

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LA-0317	METHANEX - GEISMAR METHANOL PLANT	PSD-LA-761(M4)	LA	2869	325199	12/22/2016	FIRE WATER PUMP ENGINES (4 UNITS)	17.11	DIESEL	896	HP EACH	NO_x	10102	COMPLYING WITH 40 CFR 60 SUBPART IIII AND 40 CFR 63 SUBPART ZZZZ	0		BACT-PSD
LA-0323	MONSANTO LULING PLANT	PSD-LA-890	LA	2879	325320	1/9/2017	FIRE WATER DIESEL PUMP NO. 3 ENGINE	17.11	DIESEL	600	HP	NO_x	10102	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	LA	2879	325320	1/9/2017	FIRE WATER DIESEL PUMP NO. 4 ENGINE	17.11	DIESEL	600	HP	NO_x	10102	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	LA	2879	325320	1/9/2017	STANDBY GENERATOR NO. 9 ENGINE	17.21	DIESEL	400	HP	NO_x	10102	PROPER OPERATION AND LIMITS ON HOURS OF OPERATION FOR EMERGENCY ENGINES AND COMPLIANCE WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0331	CALCASIEU PASS LNG PROJECT	PDS-LA-805	LA	4925	221210	9/21/2018	FIRE WATER PUMPS	17.11	DIESEL	634	KW	NO_x	10102	GOOD COMBUSTION AND OPERATING PRACTICES.	3.1	G/HP-H	BACT-PSD
LA-0331	CALCASIEU PASS LNG PROJECT	PDS-LA-805	LA	4925	221210	9/21/2018	LARGE EMERGENCY ENGINES (50KW)	17.11	DIESEL	5,364	HP	NO_x	10102	GOOD COMBUSTION AND OPERATING PRACTICES	5.6	G/KW-H	BACT-PSD
LA-0364	FG LA COMPLEX	PSD-LA-812	LA	2869	325110	1/6/2020	EMERGENCY GENERATOR DIESEL ENGINES	17.11	DIESEL	550	HP	NO_x	10102	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	LA	2869	325110	1/6/2020	EMERGENCY FIRE WATER PUMPS	17.11	DIESEL	550	HP	NO_x	10102	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-0379	SHINTECH PLAQUEMINES PLANT 1	PSD-LA-709(M-4)	LA	2821	325211	5/4/2021	PVC EMERGENCY COMBUSTION EQUIPMENT A	17.21	DIESEL	450	HP	NO_x	10102	GOOD COMBUSTION PRACTICES/GASEOUS FUEL BURNING.	6.9	G/HP-HR	BACT-PSD
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PSD-LA-709(M-4)	LA	2821	325211	5/4/2021	PVC EMERGENCY COMBUSTION EQUIPMENT 2A AND 2B	17.21	DIESEL	300	HP	NO_x	10102	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)	LA	2869	325199	4/25/2019	EMERGENCY ENGINES (EQT0014 - EQT0017)	17.11	DIESEL	0		NO_x	10102	COMPLY WITH STANDARDS OF 40 CFR 60 SUBPART IIII	0		BACT-PSD
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	PSD-LA-838	LA	4925	486210	9/3/2020	EMERGENCY ENGINES (EQT0011 - EQT0016)	17.11	DIESEL	0		NO_x	10102	COMPLY WITH 40 CFR 60 SUBPART IIII	0		BACT-PSD
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	NE-12-022	MA	4911	221112	1/30/2014	EMERGENCY ENGINE/GENERATOR	17.11	ULSD	7.4	MMBTU/HR	NO_x	10102		4.8	GM/BHP-H	LAER
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	NE-12-022	MA	4911	221112	1/30/2014	FIRE PUMP ENGINE	17.21	ULSD	2.7	MMBTU/HR	NO_x	10102		3	GM/BHP-H	LAER
MA-0043	MIT CENTRAL UTILITY PLANT	NE-15-018	MA	8221	611310	6/21/2017	COLD START ENGINE	17.11	ULSD	19.04	MMBTU/HR	NO_x	10102		35.09	LB/HR	OTHER CASE-BY-CASE
MD-0042	WILDCAT POINT GENERATION FACILITY	CPCN CASE NO. 9327	MD	4911	221119	4/8/2014	EMERGENCY GENERATOR 1	17.11	ULTRA-LOW SULFUR DIESEL	2,250	KW	NO_x	10102	LIMITED OPERATING HOURS, USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.8	G/HP-H	LAER

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MD-0042	WILDCAT POINT GENERATION FACILITY	CPCN CASE NO. 9327	MD	4911	221119	4/8/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRA-LOW SULFUR DIESEL	477	HP	NO_x	10102	LIMITED OPERATING HOURS, USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	3	G/HP-H	LAER
MD-0043	PERRYMAN GENERATING STATION	PSC CASE NO. 9136	MD	4911	221119	7/1/2014	EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	1,300	HP	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	4.8	G/HP-H	LAER
MD-0043	PERRYMAN GENERATING STATION	PSC CASE NO. 9136	MD	4911	221119	7/1/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	17.21	ULTRA-LOW SULFUR DIESEL	350	HP	NO_x	10102	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	3	G/HP-H	LAER
MD-0044	COVE POINT LNG TERMINAL	PSC CASE NO. 9318	MD	4911	221119	6/9/2014	EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	1,550	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.8	G/HP-H	LAER
MD-0044	COVE POINT LNG TERMINAL	PSC CASE NO. 9318	MD	4911	221119	6/9/2014	5 EMERGENCY FIRE WATER PUMP ENGINES	17.21	ULTRA-LOW SULFUR DIESEL	350	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	3	G/HP-H	LAER
MI-0394	WARREN TECHNICAL CENTER	160-11	MI	3711	336211	2/29/2012	FOUR (4) EMERGENCY GENERATORS	17.11	DIESEL	2,280	KW	NO_x	10102	NO ADD-ON CONTROLS, BUT IGNITION TIMING RETARDATION (ITR) IS GOOD DESIGN. ENGINES ARE TUNED FOR LOW-NOX OPERATION VERSUS LOW CO OPERATION.	6.93	G/KW-H	BACT-PSD
MI-0394	WARREN TECHNICAL CENTER	160-11	MI	3711	336211	2/29/2012	NINE (9) DRUPS EMERGENCY GENERATORS	17.11	DIESEL	3,010	KW	NO_x	10102	NO ADD-ON CONTROLS, BUT IGNITION TIMING RETARDATION (ITR) IS GOOD DESIGN. ENGINES ARE TUNED FOR LOW-NOX OPERATION VERSUS LOW CO OPERATION.	5.98	G/KW-H	BACT-PSD
MI-0395	WARREN TECHNICAL CENTER	160-11A	MI	3711	336211	7/13/2012	NINE (9) DRUPS EMERGENCY GENERATORS	17.11	DIESEL	3,010	KW	NO_x	10102	NO ADD-ON CONTROLS, BUT IGNITION TIMING RETARDATION (ITR) IS GOOD DESIGN. ENGINES ARE TUNED FOR LOW-NOX OPERATION VERSUS LOW CO OPERATION.	5.98	G/KW-H	BACT-PSD
MI-0395	WARREN TECHNICAL CENTER	160-11A	MI	3711	336211	7/13/2012	FOUR (4) EMERGENCY GENERATORS	17.11	DIESEL	2,500	KW	NO_x	10102	NO ADD-ON CONTROL, BUT IGNITION 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-0406	RENAISSANCE POWER LLC	51-13	MI	4911	221112	11/1/2013	FG-EMGEN7-8; TWO (2) 1,000KW DIESEL-FUELED EMERGENCY RECIPROCATING INTERNAL COMBUSTION ENGINES	17.11	DIESEL	1,000	KW	NO_x	10102	GOOD COMBUSTION PRACTICES	4.8	G/B-HP-H	BACT-PSD
MI-0418	WARREN TECHNICAL CENTER	160-11B	MI	3711	336211	1/14/2015	FG-BACK UP GENS (NINE (9) DRUPS EMERGENCY ENGINES)	17.11	DIESEL	3,490	KW	NO_x	10102	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	MI	3711	336211	1/14/2015	FOUR (4) EMERGENCY ENGINES IN FG- BACK UP GENS	17.11	DIESEL	2,710	KW	NO_x	10102	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	MI	2493	321219	8/26/2016	EMERGENCY DIESEL GENERATOR ENGINE (EU EMRG RICE IN FG RICE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS.	22.6	LB/H	BACT-PSD
MI-0421	GRAYLING PARTICLEBOARD	59-16	MI	2493	321219	8/26/2016	DIESEL FIRE PUMP ENGINE (EU FIRE PUMP IN FG RICE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS.	3.53	LB/H	BACT-PSD
MI-0423	INDECK NILES, LLC	75-16	MI	4911	221112	1/4/2017	EU EM ENGINE (DIESEL FUEL EMERGENCY ENGINE)	17.11	DIESEL	22.68	MMBTU/HR	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS IIII REQUIREMENTS.	6.4	G/KW-H	BACT-PSD
MI-0423	INDECK NILES, LLC	75-16	MI	4911	221112	1/4/2017	EU FP ENGINE (EMERGENCY ENGINE--DIESEL FIRE PUMP)	17.21	DIESEL	1.66	MMBTU/HR	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS SUBPART IIII REQUIREMENTS.	3	G/BHP-H	BACT-PSD
MI-0425	GRAYLING PARTICLEBOARD	59-16A	MI	2493	321219	5/9/2017	EU EMRG RICE 1 IN FG RICE (EMERGENCY DIESEL GENERATOR ENGINE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS.	21.2	LB/H	BACT-PSD

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RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
MI-0425	GRAYLING PARTICLEBOARD	59-16A	MI	2493	321219	5/9/2017	EU EMRG RICE 2 IN FG RICE (EMERGENCY DIESEL GENERATOR ENGINE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS	4.4	LB/H	BACT-PSD
MI-0425	GRAYLING PARTICLEBOARD	59-16A	MI	2493	321219	5/9/2017	EU FIRE PUMP IN FGRICE (DIESEL FIRE PUMP ENGINE)	17.11	DIESEL	500	H/YR	NO_x	10102	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	MI	4911	221112	6/29/2018	EU FP ENGINE (SOUTH PLANT): FIRE PUMP ENGINE	17.21	DIESEL	300	HP	NO_x	10102	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	MI	4911	221112	6/29/2018	EU EM ENGINE (NORTH PLANT): EMERGENCY ENGINE	17.11	DIESEL	1,341	HP	NO_x	10102	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	MI	4911	221112	6/29/2018	EU FP ENGINE (NORTH PLANT): FIRE PUMP ENGINE	17.21	DIESEL	300	HP	NO_x	10102	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	MI	4911	221112	6/29/2018	EU EM ENGINE (SOUTH PLANT): EMERGENCY ENGINE	17.11	DIESEL	1,341	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS IIII REQUIREMENTS.	6.4	G/KW-H	BACT-PSD
MI-0434	FLAT ROCK ASSEMBLY PLANT	122-17	MI	8741	561110	3/22/2018	EU ENGINE 01 THROUGH EU ENGINE 08	17.11	DIESEL	3,633	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES.	6.4	G/KW-H	BACT-PSD
MI-0434	FLAT ROCK ASSEMBLY PLANT	122-17	MI	8741	561110	3/22/2018	EU FIRE PUMPINGS (2 EMERGENCY FIRE PUMP ENGINES)	17.21	DIESEL	250	BHP	NO_x	10102	GOOD COMBUSTION PRACTICES.	3	G/B-HP-H	BACT-PSD
MI-0434	FLAT ROCK ASSEMBLY PLANT	122-17	MI	8741	561110	3/22/2018	EU LIFE SAFETY ENG - ONE DIESEL-FUELED EMERGENCY ENGINE/GENERATOR	17.21	DIESEL	500	KW	NO_x	10102	GOOD COMBUSTION PRACTICES.	4	G/KW-H	BACT-PSD
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	19-18	MI	4911	221112	7/16/2018	EU EM ENGINE: EMERGENCY ENGINE	17.11	DIESEL	2	MW	NO_x	10102	STATE OF THE ART COMBUSTION DESIGN.	6.4	G/KW-H	BACT-PSD
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	19-18	MI	4911	221112	7/16/2018	EU FP ENGINE: FIRE PUMP ENGINE	17.21	DIESEL	399	BHP	NO_x	10102	STATE OF THE ART COMBUSTION DESIGN.	4	G/KW-H	BACT-PSD
MI-0441	LBWL–ERICKSON STATION	74-18	MI	4911	221112	12/21/2018	EU EMG D1–A 1500 HP DIESEL FUELED EMERGENCY ENGINE	17.11	DIESEL	1,500	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND WILL BE NSPS COMPLIANT.	6.4	G/KW-H	BACT-PSD
MI-0441	LBWL–ERICKSON STATION	74-18	MI	4911	221112	12/21/2018	EU EMG D2–A 6000 HP DIESEL FUEL FIRED EMERGENCY ENGINE	17.11	DIESEL	6,000	HP	NO_x	10102	GOOD COMBUSTION PRACTICES AND WILL BE NSPS COMPLIANT.	6.4	G/KW-H	BACT-PSD
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	210-18	MI	4911	221112	8/21/2019	FG EM ENGINE	17.11	DIESEL	1,100	KW	NO_x	10102		5.3	G/HP-H	BACT-PSD
*MI-0445	INDECK NILES, LLC	75-16B	MI	4911	221112	11/26/2019	EU FP ENGINE (EMERGENCY ENGINE-DIESEL FIRE PUMP	17.21	DIESEL	1.66	MMBTU/HR	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS SUBPART IIII REQUIREMENTS	3	G/BHP-H	BACT-PSD
*MI-0445	INDECK NILES, LLC	75-16B	MI	4911	221112	11/26/2019	EU EM ENGINE (DIESEL FUEL EMERGENCY ENGINE)	17.11	DIESEL	22.68	MMBTU/HR	NO_x	10102	GOOD COMBUSTION PRACTICES AND MEETING NSPS SUBPART IIII REQUIREMENTS	6.4	G/KW-H	BACT-PSD
MI-0448	GRAYLING PARTICLEBOARD	59-16E	MI	2493	321219	12/18/2020	EMERGENCY DIESEL GENERATOR ENGINE (EU EMRG RICE 1 IN FG RICE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS	21.2	LB/H	BACT-PSD
MI-0448	GRAYLING PARTICLEBOARD	59-16E	MI	2493	321219	12/18/2020	EMERGENCY DIESEL GENERATOR ENGINE (EU EMRG RICE 2 IN FGRICE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS	4.4	LB/H	BACT-PSD
MI-0448	GRAYLING PARTICLEBOARD	59-16E	MI	2493	321219	12/18/2020	DIESEL FIRE PUMP ENGINE (EU FIRE PUMP IN FG RICE)	17.11	DIESEL	500	H/YR	NO_x	10102	CERTIFIED ENGINES, LIMITED OPERATING HOURS	3.53	LB/H	BACT-PSD
NJ-0079	WOODBRIDGE ENERGY CENTER	18940 - BOP110003	NJ	4911	221112	7/25/2012	EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	100	H/YR	NO_x	10102	USE OF ULSD DIESEL OIL	21.16	LB/H	LAER
NJ-0080	HESS NEWARK ENERGY CENTER	08857/BOP110001	NJ	4911	221112	11/1/2012	EMERGENCY GENERATOR	17.11	ULSD	200	H/YR	NO_x	10102	USE OF ULTRA LOW SULFUR DIESEL (ULSD) A CLEAN FUEL	18.53	LB/H	LAER

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NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	18068/BOP150001	NJ	4911	221112	3/10/2016	DIESEL FIRED EMERGENCY GENERATOR	17.11	ULSD	44	H/YR	NO_x	10102	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	NJ	4911	221112	3/10/2016	EMERGENCY DIESEL FIRE PUMP	17.21	ULSD	100	H/YR	NO_x	10102	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	NY	4911	221112	2/3/2016	BLACK START GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	3,000	KW	NO_x	10102	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
NY-0103	CRICKET VALLEY ENERGY CENTER	3-1326-00275/00009	NY	4911	221112	2/3/2016	EMERGENCY FIRE PUMP	17.21	ULTRA-LOW SULFUR DIESEL	460	HP	NO_x	10102	COMPLIANCE DEMONSTRATED WITH VENDOR EMISSION CERTIFICATION AND ADHERENCE TO VENDOR-SPECIFIED MAINTENANCE RECOMMENDATIONS.	2.6	G/BHP-H	LAER
OH-0352	OREGON CLEAN ENERGY CENTER	P0110840	OH	4931	221112	6/18/2013	EMERGENCY FIRE PUMP ENGINE	17.21	DIESEL	300	HP	NO_x	10102	PURCHASED CERTIFIED TO THE STANDARDS IN NSPS SUBPART IIII	1.7	LB/H	BACT-PSD
OH-0352	OREGON CLEAN ENERGY CENTER	P0110840	OH	4931	221112	6/18/2013	EMERGENCY GENERATOR	17.11	DIESEL	2,250	KW	NO_x	10102	PURCHASED CERTIFIED TO THE STANDARDS IN NSPS SUBPART IIII	27.8	LB/H	BACT-PSD
OH-0360	CARROLL COUNTY ENERGY	P0113762	OH	4911	221112	11/5/2013	EMERGENCY GENERATOR (P003)	17.11	DIESEL	1,112	KW	NO_x	10102	PURCHASED CERTIFIED TO THE STANDARDS IN NSPS SUBPART IIII	13.74	LB/H	BACT-PSD
OH-0360	CARROLL COUNTY ENERGY	P0113762	OH	4911	221112	11/5/2013	EMERGENCY FIRE PUMP ENGINE (P004)	17.21	DIESEL	400	HP	NO_x	10102	PURCHASED CERTIFIED TO THE STANDARDS IN NSPS SUBPART IIII	2.3	LB/H	BACT-PSD
OH-0363	NTE OHIO, LLC	P0116610	OH	4911	221112	11/5/2014	EMERGENCY GENERATOR (P002)	17.11	DIESEL	1,100	KW	NO_x	10102	EMERGENCY OPERATION ONLY, < 500 HOURS/YEAR EACH FOR MAINTENANCE CHECKS AND READINESS TESTING DESIGNED TO MEET NSPS SUBPART IIII	29.01	LB/H	BACT-PSD
OH-0363	NTE OHIO, LLC	P0116610	OH	4911	221112	11/5/2014	EMERGENCY FIRE PUMP ENGINE (P003)	17.21	DIESEL	260	HP	NO_x	10102	EMERGENCY OPERATION ONLY, < 500 HOURS/YEAR EACH FOR MAINTENANCE CHECKS AND READINESS TESTING DESIGNED TO MEET NSPS SUBPART IIII	1.72	LB/H	BACT-PSD
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	P0117655	OH	4911	221112	8/25/2015	EMERGENCY FIRE PUMP ENGINE (P004)	17.21	DIESEL	140	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	0.81	LB/H	BACT-PSD
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	P0117655	OH	4911	221112	8/25/2015	EMERGENCY GENERATOR (P003)	17.11	DIESEL	2,346	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	21.6	LB/H	BACT-PSD
OH-0367	SOUTH FIELD ENERGY LLC	P0119495	OH	4911	221112	9/23/2016	EMERGENCY FIRE PUMP ENGINE (P004)	17.21	DIESEL	311	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	1.79	LB/H	BACT-PSD
OH-0367	SOUTH FIELD ENERGY LLC	P0119495	OH	4911	221112	9/23/2016	EMERGENCY GENERATOR (P003)	17.11	DIESEL	2,947	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	27.18	LB/H	BACT-PSD
OH-0368	PALLAS NITROGEN LLC	P0118959	OH	2873	325311	4/19/2017	EMERGENCY FIRE PUMP DIESEL ENGINE (P008)	17.21	DIESEL	460	HP	NO_x	10102	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	OH	2873	325311	4/19/2017	EMERGENCY GENERATOR (P009)	17.11	DIESEL	5,000	HP	NO_x	10102	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	OH	4911	221112	9/7/2017	EMERGENCY GENERATOR (P003)	17.11	DIESEL	1,529	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	16.07	LB/H	BACT-PSD
OH-0370	TRUMBULL ENERGY CENTER	P0122331	OH	4911	221112	9/7/2017	EMERGENCY FIRE PUMP ENGINE (P004)	17.21	DIESEL	300	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	1.97	LB/H	BACT-PSD

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OH-0372	OREGON ENERGY CENTER	P0121049	OH	4911	221112	9/27/2017	EMERGENCY GENERATOR (P003)	17.11	DIESEL	1,529	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	16.1	LB/H	BACT-PSD
OH-0372	OREGON ENERGY CENTER	P0121049	OH	4911	221112	9/27/2017	EMERGENCY FIRE PUMP ENGINE (P004)	17.21	DIESEL	300	HP	NO_x	10102	STATE-OF-THE-ART COMBUSTION DESIGN	1.97	LB/H	BACT-PSD
OH-0374	GUERNSEY POWER STATION LLC	P0122594	OH	4911	221112	10/23/2017	EMERGENCY GENERATORS (2 IDENTICAL, P004 AND P005)	17.11	DIESEL	2,206	HP	NO_x	10102	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	OH	4911	221112	10/23/2017	EMERGENCY FIRE PUMP (P006)	17.21	DIESEL	410	HP	NO_x	10102	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	OH	4911	221112	11/7/2017	EMERGENCY DIESEL GENERATOR ENGINE (P001)	17.11	DIESEL	2,206	HP	NO_x	10102	GOOD COMBUSTION DESIGN	24.71	LB/H	BACT-PSD
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	P0122829	OH	4911	221112	11/7/2017	EMERGENCY DIESEL FIRE PUMP ENGINE (P002)	17.11	DIESEL	700	HP	NO_x	10102	GOOD COMBUSTION DESIGN	4.97	LB/H	BACT-PSD
OH-0376	IRONUNITS LLC - TOLEDO HBI	P0123395	OH	3312	331111	2/9/2018	EMERGENCY DIESEL-FUELED FIRE PUMP (P006)	17.21	DIESEL	250	HP	NO_x	10102	COMPLY WITH NSPS 40 CFR 60 SUBPART IIII	1.6	LB/H	BACT-PSD
OH-0376	IRONUNITS LLC - TOLEDO HBI	P0123395	OH	3312	331111	2/9/2018	EMERGENCY DIESEL-FIRED GENERATOR (P007)	17.11	DIESEL	2,682	HP	NO_x	10102	COMPLY WITH NSPS 40 CFR 60 SUBPART IIII	28.2	LB/H	BACT-PSD
OH-0377	HARRISON POWER	P0122266	OH	4911	221112	4/19/2018	EMERGENCY DIESEL GENERATOR (P003)	17.11	DIESEL	1,860	HP	NO_x	10102	GOOD COMBUSTION PRACTICES (ULSD) AND COMPLIANCE WITH 40 CFR PART 60, SUBPART IIII	19.68	LB/H	BACT-PSD
OH-0377	HARRISON POWER	P0122266	OH	4911	221112	4/19/2018	EMERGENCY FIRE PUMP (P004)	17.21	DIESEL	320	HP	NO_x	10102	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	OH	2869	325110	12/21/2018	FIREWATER PUMPS (P005 AND P006)	17.21	DIESEL	402	HP	NO_x	10102	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	OH	2869	325110	12/21/2018	EMERGENCY DIESEL-FIRED GENERATOR ENGINE (P007)	17.11	DIESEL	3,353	HP	NO_x	10102	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
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	P0124972	OH	2869	325110	12/21/2018	1,000 KW EMERGENCY GENERATORS (P008 - P010)	17.11	DIESEL	1,341	HP	NO_x	10102	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	OH	3312	331111	2/6/2019	BLACK START GENERATOR (P007)	17.21	DIESEL	158	HP	NO_x	10102	TIER IV ENGINE TIER IV NSPS STANDARDS CERTIFIED BY ENGINE MANUFACTURER.	0.104	LB/H	BACT-PSD
OH-0379	PETMIN USA INCORPORATED	P0125024	OH	3312	331111	2/6/2019	EMERGENCY GENERATORS (P005 AND P006)	17.11	DIESEL	3,131	HP	NO_x	10102	TIER IV ENGINE TIER IV NSPS STANDARDS CERTIFIED BY ENGINE MANUFACTURER.	3.45	LB/H	BACT-PSD

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OH-0383	PETMIN USA INCORPORATED	P0127678	OH	3312	331111	7/17/2020	DIESEL-FIRED EMERGENCY FIRE PUMPS (2) (P009 AND P010)	17.11	DIESEL	3,131	HP	NO_x	10102	TIER IV NSPS STANDARDS CERTIFIED BY ENGINE MANUFACTURER.	0		BACT-PSD
OK-0145	BROKEN BOW OSB MILL	2003-099-C(M-3)PSD	OK	2493	321219	6/25/2012	EMERG DIESEL GEN, FIRE PUMP, RAIL STEAM GEN, AIR MAKEUP UNITS	17.11	DIESEL	0		NO_x	10102		0		BACT-PSD
OK-0154	MOORELAND GENERATING STA	2008-302-C (M-1) PSD	OK	4911	221112	7/2/2013	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	17.11	DIESEL	1,341	HP	NO_x	10102	COMBUSTION CONTROL	0.011	LB/HP-HR	BACT-PSD
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	08-00045A	PA	491	221112	10/10/2012	EMERGENCY GENERATOR	17.11	DIESEL	0		NO_x	10102		4.93	G/B-HP-H	OTHER CASE-BY-CASE
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	08-00045A	PA	491	221112	10/10/2012	FIRE PUMP	17.21	DIESEL	0		NO_x	10102		2.6	G/B-HP-H	OTHER CASE-BY-CASE
*PA-0282	JOHNSON MATTHEY INC/CATALYTIC SYSTEMS DIV	15-0027K	PA	3714	336399	6/1/2012	ENGINE TEST CELLS (6)	19.9	GASOLINE/DIESEL	27	GAL/HR	NO_x	10102		11	T/YR	OTHER CASE-BY-CASE
*PA-0282	JOHNSON MATTHEY INC/CATALYTIC SYSTEMS DIV	15-0027K	PA	3714	336399	6/1/2012	650-KW BACKUP DIESEL GENERATOR	17.11	DIESEL	45.8	GAL/HR	NO_x	10102		6.9	G/HP-H	OTHER CASE-BY-CASE
PA-0291	HICKORY RUN ENERGY STATION	37-337A	PA	4911	221112	4/23/2013	EMERGENCY FIREWATER PUMP	17.21	ULTRA LOW SULFUR DISTILLATE	3.25	MMBTU/HR	NO_x	10102		1.86	LB/H	OTHER CASE-BY-CASE
PA-0291	HICKORY RUN ENERGY STATION	37-337A	PA	4911	221112	4/23/2013	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DISTILLATE	7.8	MMBTU/HR	NO_x	10102		9.89	LB/H	OTHER CASE-BY-CASE
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	35-00069A	PA	4911	221112	12/23/2015	FIRE PUMP ENGINE	17.21	ULTRA-LOW SULFUR DIESEL	15	GAL/HR	NO_x	10102		3	GM/HP-HR	LAER
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	35-00069A	PA	4911	221112	12/23/2015	2000 KW EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102		5.45	GM/HP-HR	LAER
PA-0310	CPV FAIRVIEW ENERGY CENTER	11-00536A	PA	4911	221112	9/2/2016	EMERGENCY GENERATOR ENGINES	17.11	ULSD	0		NO_x	10102		4.8	G/BHP-HR	LAER
PA-0310	CPV FAIRVIEW ENERGY CENTER	11-00536A	PA	4911	221112	9/2/2016	EMERGENCY FIRE PUMP ENGINE	17.21	ULSD	0		NO_x	10102		3	G/BHP-HR	LAER
PA-0311	MOXIE FREEDOM GENERATION PLANT	40-00129A	PA	4911	221112	9/1/2015	FIRE PUMP ENGINE	17.11	DIESEL	0		NO_x	10102		3	G/HP-HR	LAER
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	R2-PSD 1	PR	4953	221119	4/10/2014	EMERGENCY DIESEL FIRE PUMP	17.21	ULSD FUEL OIL # 2	0		NO_x	10102		2.85	G/B-HP-H	BACT-PSD
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	R2-PSD 1	PR	4953	221119	4/10/2014	EMERGENCY DIESEL GENERATOR	17.11	ULSD FUEL OIL # 2	0		NO_x	10102		2.85	G/B-HP-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	SC	3295	327992	2/8/2012	EMERGENCY ENGINE 1 THRU 8	17.21	DIESEL	29	HP	NO_x	10102	PURCHASE OF CERTIFIED ENGINE.	7.5	GR/KW-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	SC	3295	327992	2/8/2012	FIRE PUMP	17.21	DIESEL	500	HP	NO_x	10102	PURCHASE OF CERTIFIED ENGINE BASED ON NSPS, SUBPART IIII.	4	GR/KW-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	SC	3295	327992	2/8/2012	EMERGENCY GENERATORS 1 THRU 8	17.11	DIESEL	757	HP	NO_x	10102	ENGINES MUST BE CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	4	GR/KW-H	BACT-PSD

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Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
TX-0671	PROJECT JUMBO	108446/PSDTX1352	TX	2821	325211	12/1/2014	ENGINES	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102	EACH EMERGENCY GENERATOR'S EMISSION FACTOR IS BASED ON EPA'S TIER 2 STANDARDS AT 40CFR89.112 FOR NOX	5.43	G/KW-H	BACT-PSD
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	118239, N200	TX	2813	325311	4/1/2015	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	1,500	HP	NO_x	10102	MINIMIZED HOURS OF OPERATIONS TIER II ENGINE	0.0218	G/HP HR	LAER
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	PSDTX1546 AND GHGPSDTX186	TX	2869	325110	2/6/2020	EMERGENCY GENERATOR	17.11	DIESEL	0		NO_x	10102	TIER 4 EXHAUST EMISSION STANDARDS SPECIFIED IN 40 CFR Â§ 1039.101, LIMITED TO 100 HOURS PER YEAR OF NON-EMERGENCY OPERATION	0		BACT-PSD
TX-0879	MOTIVA PORT ARTHUR TERMINAL	7238 AND PSDTX1548	TX	5171	424710	2/19/2020	EMERGENCY FIREWATER ENGINE	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102	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	TX	2821	325211	4/23/2020	EMERGENCY GENERATORS &; FIRE WATER PUMP ENGINES	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102	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	TX	2869	325199	9/9/2020	EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102	100 HOURS OPERATIONS, TIER 4 EXHAUST EMISSION STANDARDS SPECIFIED IN 40 CFR Â§ 1039.101	0		BACT-PSD
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	160299, PSDTX1576, GHGPSDTX200	TX	2869	325998	9/16/2020	EMERGENCY GENERATOR	17.11	ULTRA-LOW SULFUR DIESEL	0		NO_x	10102	LIMITED TO 100 HOURS PER YEAR OF NON-EMERGENCY OPERATION	0		BACT-PSD
TX-0933	NACERO PENWELL FACILITY	164137 PSDTX1594 GHGPSDTX207	TX	2869	325110	11/17/2021	EMERGENCY GENERATORS	17.11	ULTRA-LOW SULFUR DIESEL (NO MORE THAN 15)	0		NO_x	10102	LIMITED TO 100 HOURS PER YEAR OF NON-EMERGENCY OPERATION. EPA TIER 2 (40 CFR Â§ 1039.101) EXHAUST EMISSION STANDARDS	0		BACT-PSD
VA-0325	GREENSVILLE POWER STATION	52525	VA	4911	221112	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 KW (1)	17.11	DIESEL FUEL	0		NO_x	10102	GOOD COMBUSTION PRACTICES/MAINTENANCE	6.4	G/KW	N/A
VA-0325	GREENSVILLE POWER STATION	52525	VA	4911	221112	6/17/2016	DIESEL-FIRED WATER PUMP 376 BPH (1)	17.21	DIESEL FUEL	0		NO_x	10102	GOOD COMBUSTION PRACTICES/MAINTENANCE	0		N/A
VA-0328	C4GT, LLC	52588	VA	4911	221112	4/26/2018	EMERGENCY DIESEL GEN	17.11	ULTRA-LOW SULFUR DIESEL	500	H/YR	NO_x	10102	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	VA	4911	221112	4/26/2018	EMERGENCY FIRE WATER PUMP	17.21	ULTRA-LOW SULFUR DIESEL	500	HR/YR	NO_x	10102	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	VA	4911	221112	6/24/2019	EMERGENCY DIESEL GENERATOR - 300 KW	17.11	ULTRA-LOW SULFUR DIESEL	500	H/YR	NO_x	10102	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	VA	4911	221112	6/24/2019	EMEGENCY FIRE WATER PUMP	17.21	ULTRA-LOW SULFUR DIESEL	500	HR/YR	NO_x	10102	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	WI	4911	221112	4/24/2018	DIESEL-FIRED EMERGENCY GENERATORS	17.11	DIESEL	0		NO_x	10102	THE USE OF ULTRA-LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	5.36	G/KWH	BACT-PSD

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Table 1. NOx RBLC Data For Diesel Generators

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	18-JJW-022	WI	3679	334419	4/24/2018	P42 -DIESEL FIRED EMERGENCY GENERATOR	17.11	DIESEL	0		NO_x	10102	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	WI	4911	221121	9/1/2020	EMERGENCY DIESEL FIRE PUMP (P06)	17.21	DIESEL	282	HP	NO_x	10102	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	WI	4911	221121	9/1/2020	EMERGENCY DIESEL GENERATOR (P07)	17.11	DIESEL	1,490	HP	NO_x	10102	OPERATION LIMITED TO 500 HOURS/YEAR AND OPERATE AND MAINTAIN ACCORDING TO THE MANUFACTURER'S RECOMMENDATIONS.	4.8	G/HP-H	BACT-PSD
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	R14-0030	WV	4911	221112	11/21/2014	EMERGENCY GENERATOR	17.11	DIESEL	2,015.7	HP	NO_x	10102		0		BACT-PSD
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	R14-0030	WV	4911	221112	11/21/2014	FIRE PUMP ENGINE	17.21	DIESEL	251	HP	NO_x	10102		0		BACT-PSD
WV-0027	INWOOD	R14-0015M	WV	3296	327993	9/15/2017	EMERGENCY GENERATOR - ESDG14	17.11	ULSD	900	BHP	NO_x	10102	ENGINE DESIGN	4.77	G/HP-HR	BACT-PSD
•WV-0033	MAIDSVILLE	R14-0038	WV	4911	221112	1/5/2022	EMERGENCY GENERATOR	17.11	ULSD	2,100	HP	NO_x	10102	COMBUSTION CONTROL (RETARDED TIMING AND/OR LEAN BURN)	24.6	LB/HR	BACT-PSD
•WV-0033	MAIDSVILLE	R14-0038	WV	4911	221112	1/5/2022	FIRE WATER PUMP	17.11	ULSD	240	BHP	NO_x	10102	COMBUSTION CONTROL (RETARDED TIMING AND/OR LEAN BURN)	1.59	LB/HR	BACT-PSD
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	CT-12636	WY	491	221112	8/28/2012	DIESEL EMERGENCY GENERATOR (EP15)	17.11	ULTRA-LOW SULFUR DIESEL	839	HP	NO_x	10102	EPA TIER 2 RATED	0		BACT-PSD
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	CT-12636	WY	491	221112	8/28/2012	DIESEL FIRE PUMP ENGINE (EP16)	17.21	ULTRA-LOW SULFUR DIESEL	327	HP	NO_x	10102	EPA TIER 3 RATED	0		BACT-PSD

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Table 2. NOx RBLC Data for Boilers

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
AK-0083	KENAI NITROGEN OPERATIONS	AQ0083CPT06	AK	2873	325311	1/6/2015	THREE (3) PACKAGE BOILERS	12.31	NATURAL GAS	243	MMBTU/HR	NO_x	ULTRA LOW NOX BURNERS	0.01	LB/MMBTU	BACT-PSD
AK-0083	KENAI NITROGEN OPERATIONS	AQ0083CPT06	AK	2873	325311	1/6/2015	FIVE (5) WASTE HEAT BOILERS	13.31	NATURAL GAS	50	MMBTU/HR	NO_x	SELECTIVE CATALYTIC REDUCTION	7	PPMV	BACT-PSD
AL-0307	ALLOYS PLANT	701-0007-X121-X126	AL	3353	331315	10/9/2015	PACKAGE BOILER	13.31	NATURAL GAS	17.5	MMBTU/HR	NO_x	LOW NOX BURNER FLUE GAS RECIRCULATION GCP	30	PPMVD	BACT-PSD
AL-0307	ALLOYS PLANT	701-0007-X121-X126	AL	3353	331315	10/9/2015	2 CALP LINE BOILERS	13.31	NATURAL GAS	24.59	MMBTU/HR	NO_x	LOW NOX BURNER FLUE GAS RECIRCULATION (FGR) GOOD COMBUSTION PRACTICES (GCP)	30	PPMVD	BACT-PSD
AL-0328	PLANT BARRY	503-1001	AL	4911	221112	11/9/2020	90.5 MMBTU/HR AUX BOILER	13.31	NATURAL GAS	90.5	MMBTU/HR	NO_x		0.011	LB/MMBTU	BACT-PSD
AR-0140	BIG RIVER STEEL LLC	2305-AOP-R0	AR	3312	331111	9/18/2013	BOILER, VACUUM DEGASSER	13.29	NATURAL GAS	51.2	MMBTU/HR	NO_x	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE LOW NOX BURNERS	0.035	LB/MMBTU	BACT-PSD
AR-0140	BIG RIVER STEEL LLC	2305-AOP-R0	AR	3312	331111	9/18/2013	BOILER, PICKLE LINE	13.31	NATURAL GAS	67	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0140	BIG RIVER STEEL LLC	2305-AOP-R0	AR	3312	331111	9/18/2013	BOILERS SN-26 AND 27, GALVANIZING LINE	13.31	NATURAL GAS	24.5	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0155	BIG RIVER STEEL LLC	2035-AOP-R2	AR	3312	331111	11/7/2018	BOILER, VACUUM DEGASSER	13.29	NATURAL GAS	88.7	MMBTU/HR	NO_x	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE LOW NOX BURNERS	0.035	LB/MMBTU	BACT-PSD
AR-0155	BIG RIVER STEEL LLC	2035-AOP-R2	AR	3312	331111	11/7/2018	BOILER, PICKLE LINE	13.31	NATURAL GAS	53.7	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0155	BIG RIVER STEEL LLC	2035-AOP-R2	AR	3312	331111	11/7/2018	BOILER SN-26, GALVANIZING LINE	13.31	NATURAL GAS	53.7	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0159	BIG RIVER STEEL LLC	2305-AOP-R4	AR	3312	331111	4/5/2019	BOILER, PICKLE LINE	13.31	NATURAL GAS	0		NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0159	BIG RIVER STEEL LLC	2305-AOP-R4	AR	3312	331111	4/5/2019	BOILER, ANNEALING PICKLE LINE	13.31	NATURAL GAS	0		NO_x	LOW NOX BURNERS, COMBUSTION OF CLEAN FUEL, AND GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0159	BIG RIVER STEEL LLC	2305-AOP-R4	AR	3312	331111	4/5/2019	BOILERS SN-26 AND SN- 27, GALVANIZING LINE	13.31	NATURAL GAS	0		NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0167	LION OIL COMPANY	0868-AOP-R18	AR	2911	324110	12/1/2020	SN-803 - #4 PRE-FLASH COLUMN REBOILER	13.31	NATURAL GAS	40	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS AND GOOD COMBUSTION PRACTICE	1.9	LB/HR	BACT-PSD
AR-0167	LION OIL COMPANY	0868-AOP-R18	AR	2911	324110	12/1/2020	SN-805 - #4 PRE-FLASH REBOILER	13.31	NATURAL GAS	75	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS AND GOOD COMBUSTION PRACTICE	3.5	LB/HR	BACT-PSD

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AR-0167	LION OIL COMPANY	0868-AOP-R18	AR	2911	324110	12/1/2020	SN-810 - #9 HYDROTREATER FURNACE/REBOILER	13.31	NATURAL GAS	70	MMBTU/HR	NO_x		12.7	LB/HR	BACT-PSD
AR-0171	NUCOR STEEL ARKANSAS	1139-AOP-R24	AR	3312	331111	2/14/2019	SN-142 VACUUM DEGASSER BOILER	13.31	NATURAL GAS	50.4	MMBTU/HR	NO_x	LOW NOX BURNERS	0.035	LB/MMBTU	BACT-PSD
AR-0171	NUCOR STEEL ARKANSAS	1139-AOP-R24	AR	3312	331111	2/14/2019	SN-233 GALVANIZING LINE BOILERS	13.31	NATURAL GAS	15	MMBTU/HR EACH	NO_x	LOW NOX BURNERS	0.1	LB/MMBTU	BACT-PSD
AR-0172	NUCOR STEEL ARKANSAS	1139-AOP-R26	AR	3312	331111	9/1/2021	SN-202, 203, 204 PICKLE LINE BOILERS	13.31	NATURAL GAS	0		NO_x	LOW NOX BURNERS	0.035	LB/MMBTU	BACT-PSD
AR-0173	BIG RIVER STEEL LLC	2445-AOP-R0	AR	3462	331111	1/31/2022	PICKLE LINE BOILER	13.31	NATURAL GAS	53.7	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0173	BIG RIVER STEEL LLC	2445-AOP-R0	AR	3462	331111	1/31/2022	GALVANIZING LINE BOILERS #1 AND #2	13.31	NATURAL GAS	53.7	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
AR-0173	BIG RIVER STEEL LLC	2445-AOP-R0	AR	3462	331111	1/31/2022	PICKLE GALVANIZING LINE BOILER	13.31	NATURAL GAS	53.7	MMBTU/HR	NO_x	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU	BACT-PSD
CA-1189	PETROROCK-TUNNELL LEASE	ATC- 12949-01 (2)	CA	1311	211111	1/24/2012	BOILER	13.31	PROPANE, FIELD GAS, PUC NATURAL GAS	2	MMBTU/HR	NO_x	LOW NOX BURNER	20	PPMVD@3% O2	OTHER CASE-BY-CASE
CT-0159	CPV TOWANTIC, LLC	144-0025	CT	4911	221112	11/30/2015	AUX BOILER	13.31	NATURAL GAS	359.6	MMCF	NO_x	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	LAER
FL-0335	SUWANNEE MILL	1210468-001-AC(PSD FL-417)	FL	2421	321113	9/5/2012	FOUR(4) NATURAL GAS BOILERS - 46 MMBTU/HOUR	13.31	NATURAL GAS	46	MMBTU/HR	NO_x	LOW NOX BURNER AND FLUE GAS RECIRCULATION	0.036	LB/MMBTU	BACT-PSD
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	0930117-001-AC	FL	4911	221112	3/9/2016	AUXILIARY BOILER, 99.8 MMBTU/HR	13.31	NATURAL GAS	99.8	MMBTU/HR	NO_x	LOW-NOX BURNERS	0.05	LB/MMBTU	BACT-PSD
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1010524-001-AC	FL	4911	221112	7/27/2018	60 MMBTU/HOUR AUXILIARY BOILER	13.31	NATURAL GAS	60	MMBTU/HR	NO_x	LOW-NOX BURNERS	0.05	LB/MMBTU	BACT-PSD
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1010524-003-AC (PSD-FL-444A)	FL	4911	221112	6/7/2021	60 MMBTU/HOUR AUXILIARY BOILER	13.31	NATURAL GAS	60	MMBTU/HR	NO_x	LOW-NOX BURNERS	0.05	LB/MMBTU	BACT-PSD

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IA-0107	MARSHALLTOWN GENERATING STATION	13-A-499-P	IA	4911	221112	4/14/2014	AUXILIARY BOILER	13.31	NATURAL GAS	60.1	MMBTU/HR	NO_x		0.013	LB/MMBTU	BACT-PSD
IL-0129	CPV THREE RIVERS ENERGY CENTER	16060032	IL	4911	221112	7/30/2018	AUXILIARY BOILER	13.31	NATURAL GAS	96	MMBTU/HR	NO_x	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	LAER
IL-0130	JACKSON ENERGY CENTER	17040013	IL	4911	221112	12/31/2018	AUXILIARY BOILER	13.31	NATURAL GAS	96	MMBTU/HR	NO_x	ULTRA LOW-NOX BURNERS AND FLUE GAS RECIRCULATION AIR PREHEATER, AUTOMATED COMBUSTION MANAGEMENT SYSTEMS, AUTOMATED WATER BLOWDOWN, GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU	LAER
*IL-0133	LINCOLN LAND ENERGY CENTER	18040008	IL	4911	221112	7/29/2022	AUXILIARY BOILER	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	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/MM BTU	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	IN	4911	221112	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	LOW NOX BURNER WITH FLUE GAS RECIRCULATION	0.032	LB/MMBTU	BACT-PSD
IN-0263	MIDWEST FERTILIZER COMPANY LLC	129-36943-00059	IN	2873	325311	3/23/2017	NATURAL GAS AUXILIARY BOILERS (EU-012A, EU- 012B, EU-012C)	12.31	NATURAL GAS	218.6	MMBTU/HR	NO_x	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES	20.4	LB/MMCF EACH	BACT-PSD
IN-0324	MIDWEST FERTILIZER COMPANY LLC	129-44510-00059	IN	2873	325311	5/6/2022	NATURAL GAS-FIRED AUXILIARY BOILERS EU 012A AND EU 012B	12.31	NATURAL GAS	218.6	MMBTU/HR	NO_x	THE NATURAL GAS-FIRED AUXILIARY BOILERS SHALL COMBUST NATURAL GAS	20.4	LB/MMCF	BACT-PSD
KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	VACUUM DEGASSER BOILER (EP 20-13)	13.31	NATURAL GAS	50.4	MMBTU/HR	NO_x	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN. ALSO EQUIPPED WITH LOW- NOX BURNERS.	35	LB/MMSCF	BACT-PSD

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KY-0115	NUCOR STEEL GALLATIN, LLC	V-20-015	KY	3316	331111	4/19/2021	PICKLE LINE #2 BOILER #1 & #2 (EP 21-04 & EP 21-05)	13.31	NATURAL GAS	18	MMBTU/HR EACH	NO_x	THE PERMITTEE MUST DEVELOP A GOOD COMBUSTION AND OPERATING PRACTICES (GCOP) PLAN. EQUIPPED WITH LOW-NOX BURNERS.	50	LB/MMSCF	BACT-PSD
LA-0305	LAKE CHARLES METHANOL FACILITY	PSD-LA-803(M1)	LA	2869	325199	6/30/2016	AUXILIARY BOILERS AND SUPERHEATERS	11.31	NATURAL GAS	0		NO_x	SCR	0.015	LBS/MM BTU	BACT-PSD
LA-0307	MAGNOLIA LNG FACILITY	PSD-LA-792	LA	4922	221210	3/21/2016	AUXILIARY BOILERS	12.31	NATURAL GAS	171	MMBTU/HR	NO_x	LOW NOX BURNERS	0		BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	UTILITY BOILER 1	11.31	NATURAL GAS	656	MMBTU/HR	NO_x	SELECTIVE CATALYTIC REDUCTION (SCR)	3.94	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	UTILITY BOILER 2	11.31	NATURAL GAS	656	MMBTU/HR	NO_x	SELECTIVE CATALYTIC REDUCTION (SCR)	3.94	LB/H	BACT-PSD
*LA-0315	G2G PLANT	PSD-LA-781	LA	2869	325110	5/23/2014	UTILITY BOILER 3	11.31	NATURAL GAS	656	MMBTU/HR	NO_x	SELECTIVE CATALYTIC REDUCTION (SCR)	3.94	LB/H	BACT-PSD
LA-0364	FG LA COMPLEX	PSD-LA-812	LA	2869	325110	1/6/2020	BOILERS	11.31	NATURAL GAS	1,200	MMBTU/HR	NO_x	SCR AND LNB	0.01	LB/MMBTU	BACT-PSD
LA-0364	FG LA COMPLEX	PSD-LA-812	LA	2869	325110	1/6/2020	PR WASTE HEAT BOILER	13.31	NATURAL GAS	94	MMBTU/HR	NO_x	SCR AND LNB	14.41	LB/H	BACT-PSD
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	NE-12-022	MA	4911	221112	1/30/2014	AUXILIARY BOILER	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	ULTRA LOW NOX BURNERS	0.011	LB/MMBTU	LAER
MD-0041	CPV ST. CHARLES	PSC CASE NO. 9280	MD	4911	221119	4/23/2014	AUXILLARY BOILER	13.31	NATURAL GAS	93	MMBTU/HR	NO_x	EXCLUSIVE USE OF NATURAL GAS, ULTRA LOW-NOX BURNERS, AND FLUE GAS RECIRCULATION (FGR)	0.011	LB/MMBTU	LAER
MD-0042	WILDCAT POINT GENERATION FACILITY	CPCN CASE NO. 9327	MD	4911	221119	4/8/2014	AUXILLARY BOILER	13.31	NATURAL GAS	45	MMBTU/HR	NO_x	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU	LAER
MD-0045	MATTAWOMAN ENERGY CENTER	PSC CASE. NO. 9330	MD	4911	221119	11/13/2015	AUXILIARY BOILER	13.31	NATURAL GAS	42	MMBTU/HR	NO_x	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, ULTRA LOW- NOX BURNERS, AND GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU	BACT-PSD
MD-0046	KEYS ENERGY CENTER	PSC CASE NO. 9297	MD	4911	221119	10/31/2014	AUXILIARY BOILER	13.31	PIPELINE QUALITY NATURAL GAS	93	MMBTU/HR	NO_x	EFFICIENT BOILER DESIGN WITH ULTRA LOW NOX BURNER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, AND APPLICATION OF GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU	BACT-PSD

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MI-0406	RENAISSANCE POWER LLC	51-13	MI	4911	221112	11/1/2013	EU-HEATER SC: NATURAL GAS-FIRED FUEL HEATER USED FOR HEATING NATURAL GAS PRIOR TO COMBUSTION IN THE CTGS. MISC. BOILERS, FURNACES, AND HEATERS	19.6	NATURAL GAS	20	MMBTU/HR	NO_x	GOOD COMBUSTION PRACTICES	0.15	LB/MMBTU	BACT-PSD
MI-0406	RENAISSANCE POWER LLC	51-13	MI	4911	221112	11/1/2013	FG-AUX BOILER 1-2; TWO (2) NATURAL GAS-FIRED AUXILIARY BOILERS.	13.31	NATURAL GAS	40	MMBTU/HR	NO_x	GOOD COMBUSTION PRACTICES.	0.035	LB/MMBTU	BACT-PSD
MI-0410	THETFORD GENERATING STATION	191-12	MI	4911	221112	7/25/2013	FG AUX BOILERS: TWO AUXILIARY BOILERS < 100 MMBTU/H HEAT INPUT EACH	13.31	NATURAL GAS	100	MMBTU/HR HEAT INPUT EACH	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION.	0.05	LB/MMBTU	BACT-PSD
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	107-13	MI	4931	221112	12/4/2013	AUXILIARY BOILER B (EU AUX BOILERB)	13.31	NATURAL GAS	95	MMBTU/HR	NO_x	DRY LOW NOX BURNERS, FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.05	LB/MMBTU	BACT-PSD
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	107-13	MI	4931	221112	12/4/2013	AUXILIARY BOILER A (EU AUX BOILERA)	13.31	NATURAL GAS	55	MMBTU/HR	NO_x	LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.05	LB/MMBTU	BACT-PSD
MI-0420	DTE GAS COMPANY–MILFORD COMPRESSOR STATION	185-15	MI	4922	486210	6/3/2016	FG AUX BOILERS	13.31	NATURAL GAS	6	MMBTU/HR	NO_x	ULTRA LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES.	14	PPMVOL	BACT-PSD
MI-0423	INDECK NILES, LLC	75-16	MI	4911	221112	1/4/2017	EU AUX BOILER (AUXILIARY BOILER)	12.31	NATURAL GAS	182	MMBTU/HR	NO_x	LOW NOX BURNERS/FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.04	LB/MMBTU	BACT-PSD
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	107-13C	MI	4931	221112	12/5/2016	EU AUX BOILER (AUXILIARY BOILER)	13.31	NATURAL GAS	83.5	MMBTU/HR	NO_x	LOW NOX BURNERS/INTERNAL FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.05	LB/MMBTU	BACT-PSD

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MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	185-15A	MI	4922	486210	3/24/2017	FG AUX BOILERS (6 AUXILIARY BOILERS EU AUX BOIL 2A, EU AUX BOIL 3A, EU AUX BOIL 2B, EU AUX BOIL 3B, EU AUX BOIL 2C, EU AUX BOIL 3C)	13.31	NATURAL GAS	3	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES.	20	PPM AT 3% O2	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	MI	4911	221112	6/29/2018	EU AUX BOILER (NORTH PLANT): AUXILIARY BOILDER	13.31	NATURAL GAS	61.5	MMBTU/HR	NO_x	LOW NOX BURNERS/FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.04	LB/MMBTU	BACT-PSD
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	MI	4911	221112	6/29/2018	EU AUX BOILER (SOUTH PLANT): AUXILIARY BOILER	13.31	NATURAL GAS	61.5	MMBTU/HR	NO_x	LOW NOX BURNERS/FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.04	LB/MMBTU	BACT-PSD
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	19-18	MI	4911	221112	7/16/2018	EU AUX BOILER: AUXILIARY BOILER	13.31	NATURAL GAS	99.9	MMBTU/HR	NO_x	LOW NOX BURNERS/FLUE GAS RECIRCULATION.	0.036	LB/MMBTU	BACT-PSD
MI-0440	MICHIGAN STATE UNIVERSITY	139-18	MI	4911	611310	5/22/2019	EU STM BOILER	11.31	NATURAL GAS	300	MMBTU/HR	NO_x	LOW-NOX BURNERS AND INTERNAL FLUE GAS RECIRCULATION (FGR)	0.04	LB/MMBTU	BACT-PSD
MI-0441	LBWL–ERICKSON STATION	74-18	MI	4911	221112	12/21/2018	EU AUX BOILER–NATURAL GAS FIRED AUXILIARY BOILER RATED AT = 99MMBTU/H	13.31	NATURAL GAS	99	MMBTU/HR	NO_x	LOW NOX BURNERS (LNB) OR FLUE GAS RECIRCULATION ALONG WITH GOOD COMBUSTION PRACTICES.	30	PPM	BACT-PSD
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	210-18	MI	4911	221112	8/21/2019	FG AUX BOILER	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	GOOD COMBUSTION PRACTICES AND LOW NOX BURNERS.	0.036	LB/MMBTU	BACT-PSD
*MI-0445	INDECK NILES, LLC	75-16B	MI	4911	221112	11/26/2019	EU AUX BOILER	12.31	NATURAL GAS	182	MMBTU/HR	NO_x	LOW NOX BURNERS/FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES.	0.04	LB/MMBTU	BACT-PSD
MI-0447	LBWL–ERICKSON STATION	74-18A	MI	4911	221112	1/7/2021	EU AUX BOILER--NAT GAS FIRED AUXILIARY BOILER	13.31	NATURAL GAS	50	MMBTU/HR	NO_x	LOW NOX BURNERS (LNB) OR FLUE GAS RECIRCULATION (FGR) ALONG WITH GOOD COMBUSTION PRACTICES.	30	PPM	BACT-PSD
NJ-0079	WOODBRIDGE ENERGY CENTER	18940 - BOP110003	NJ	4911	221112	7/25/2012	COMMERCIAL/INSTITUTIONAL SIZE BOILERS LESS THAN 100 MMBTU/HR	13.31	NATURAL GAS	2,000	H/YR	NO_x	LOW NOX BURNERS	0.01	LB/MMBTU	LAER
NJ-0080	HESS NEWARK ENERGY CENTER	08857/BOP110001	NJ	4911	221112	11/1/2012	BOILER LESS THAN 100 MMBTU/HR	13.31	NATURAL GAS	51.9	MMCFT/YR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	0.01	LB/MMBTU	LAER

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NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	18068/BOP150001	NJ	4911	221112	3/10/2016	AUXILIARY BOILER FIRING NATURAL GAS	13.31	NATURAL GAS	687	MMCFT/YR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION (FGR)	0.8	LB/H	LAER
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	19149/PCP150001	NJ	4911	221112	7/19/2016	AUXILIARY BOILER	13.31	NATURAL GAS	4,000	H/YR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION (FGR) AND USE OF NATURAL GAS A CLEAN BURNING FUEL	0.975	LB/H	LAER
NY-0103	CRICKET VALLEY ENERGY CENTER	3-1326-00275/00009	NY	4911	221112	2/3/2016	AUXILIARY BOILER	13.31	NATURAL GAS	60	MMBTU/HR	NO_x	FLUE GAS RECIRCULATION WITH LOW NOX BURNERS	0.0085	LB/MMBTU	LAER
NY-0104	CPV VALLEY ENERGY CENTER	3-335600136/00001	NY	4911	221112	8/1/2013	AUXILIARY BOILER	13.31	NATURAL GAS	0		NO_x	FLUE GAS RECIRCULATION WITH LOW NOX BURNERS.	0.045	LB/MMBTU	LAER
OH-0350	REPUBLIC STEEL	P0109191	OH	3312	331111	7/18/2012	STEAM BOILER	13.31	NATURAL GAS	65	MMBTU/HR	NO_x		0.07	LB/MMBTU	N/A
OH-0352	OREGON CLEAN ENERGY CENTER	P0110840	OH	4931	221112	6/18/2013	AUXILLARY BOILER	13.31	NATURAL GAS	99	MMBTU/HR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	1.98	LB/H	BACT-PSD
OH-0360	CARROLL COUNTY ENERGY	P0113762	OH	4911	221112	11/5/2013	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	99	MMBTU/HR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	1.98	LB/H	BACT-PSD
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	P0117655	OH	4911	221112	8/25/2015	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	34	MMBTU/HR	NO_x	FLUE GAS RECIRCULATION (FGR) AND LOW NOX BURNER	0.68	LB/H	BACT-PSD
OH-0367	SOUTH FIELD ENERGY LLC	P0119495	OH	4911	221112	9/23/2016	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	99	MMBTU/HR	NO_x	FLUE GAS RECIRCULATION (FGR), LOW NOX BURNER, AND NATURAL GAS/ULTRA LOW SULFUR DIESEL	9.9	LB/H	BACT-PSD
OH-0368	PALLAS NITROGEN LLC	P0118959	OH	2873	325311	4/19/2017	PACKAGE BOILERS (2 IDENTICAL, B003 AND B004)	11.31	NATURAL GAS	265	MMBTU/HR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION (FGR)	3.3	LB/H	BACT-PSD
OH-0370	TRUMBULL ENERGY CENTER	P0122331	OH	4911	221112	9/7/2017	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	37.8	MMBTU/HR	NO_x	FLUE GAS RECIRCULATION (FGR), LOW NOX BURNER	0.76	LB/H	BACT-PSD
OH-0372	OREGON ENERGY CENTER	P0121049	OH	4911	221112	9/27/2017	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	37.8	MMBTU/HR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	0.76	LB/H	BACT-PSD
OH-0374	GUERNSEY POWER STATION LLC	P0122594	OH	4911	221112	10/23/2017	AUXILIARY BOILER (B001)	12.31	NATURAL GAS	185	MMBTU/HR	NO_x	LOW-NOX BURNERS AND FLUE GAS RECIRCULATION	3.7	LB/H	BACT-PSD
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	P0122829	OH	4911	221112	11/7/2017	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	26.8	MMBTU/HR	NO_x	FLUE GAS RECIRCULATION AND LOW NOX BURNER	0.29	LB/H	BACT-PSD
OH-0377	HARRISON POWER	P0122266	OH	4911	221112	4/19/2018	AUXILIARY BOILER (B001)	13.31	NATURAL GAS	44.55	MMBTU/HR	NO_x	GOOD COMBUSTION PRACTICES AND LOW NOX BURNER	1.56	LB/H	BACT-PSD

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OH-0377	HARRISON POWER	P0122266	OH	4911	221112	4/19/2018	AUXILIARY BOILER (B002)	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	GOOD COMBUSTION PRACTICES AND LOW NOX BURNER	2.19	LB/H	BACT-PSD
OH-0379	PETMIN USA INCORPORATED	P0125024	OH	3312	331111	2/6/2019	STARTUP BOILER (B001)	13.31	NATURAL GAS	15.17	MMBTU/HR	NO_x	LOW-NOX BURNERS, GOOD COMBUSTION PRACTICES AND THE USE OF NATURAL GAS	0.634	LB/H	BACT-PSD
OK-0148	BUFFALO CREEK PROCESSING PLANT	2012-1026-C PSD	OK	1321	211112	9/12/2012	COMMERCIAL/INSTITUTIONAL BOILERS (100 MMBTUH)	13.31	NATURAL GAS	11.04	MMBTU/HR	NO_x	LOW-NOX BURNERS	0.045	LB/MMBTU	BACT-PSD
OK-0156	NORTHSTAR AGRI IND ENID	2013-0109-C PSD	OK	2076	311223	7/31/2013	REFINERY BOILER	13.31	NATURAL GAS	5	MMBTU/HR	NO_x	GOOD COMBUSTION	0.0075	LB/MMBTU	N/A
OR-0050	TROUTDALE ENERGY CENTER, LLC	26-0235	OR	4911	221112	3/5/2014	AUXILIARY BOILER	13.31	NATURAL GAS	39.8	MMBTU/HR	NO_x	UTILIZE LOW-NOX BURNERS AND FGR.	0.035	LB/MMBTU	BACT-PSD
PA-0291	HICKORY RUN ENERGY STATION	37-337A	PA	4911	221112	4/23/2013	AUXILIARY BOILER	13.31	NATURAL GAS	40	MMBTU/HR	NO_x		0.011	LB/MMBTU	OTHER CASE-BY-CASE
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNE E	06-05150A	PA	4931	221112	12/17/2013	AUXILIARY BOILER	13.31	NATURAL GAS	40	MMBTU/HR	NO_x		1.01	T/YR	OTHER CASE-BY-CASE
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	67-05083D/F	PA	4911	221112	6/15/2015	AUXILARY BOILER	13.31	NATURAL GAS	62.04	MCF/HR	NO_x	GOOD COMBUSTION PRACTICES, ULTRA-LOW NOX BURNERS, FGR	0.0086	LB/MMBTU	LAER
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	35-00069A	PA	4911	221112	12/23/2015	AUXILLARY BOILER	13.31	NATURAL GAS	13.31	MMBTU/HR	NO_x	SCR AND ULTRA LOW NOX BURNERS, FIRED ONLY ON NATURAL GAS SUPPLIED BY A PUBLIC UTILITY.	0.006	LB/MMBTU	LAER
PA-0310	CPV FAIRVIEW ENERGY CENTER	11-00536A	PA	4911	221112	9/2/2016	AUXILARY BOILER	13.31	NATURAL GAS	92.4	MMBTU/HR	NO_x	ULTRA LOW NOX BURNERS, FGR, GOOD COMBUSTION PRACTICES	0.011	LB/MMBTU	LAER
PA-0311	MOXIE FREEDOM GENERATION PLANT	40-00129A	PA	4911	221112	9/1/2015	AUXILARY BOILER	13.31	NATURAL GAS	55.4	MMBTU/HR	NO_x		0.006	LB/MMBTU	LAER
*PA-0316	RENOVO ENERGY CENTER, LLC	18-00033A	PA	4911	221112	1/26/2018	AUXILIARY BOILER	13.31	NATURAL GAS	118,800	MMBTU/HR 12-MONTH PERIOD	NO_x	ULTRA-LOW NOX BURNERS AND FLUE GAS RE-CIRCULATION OPERATED IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATIONS AND GOOD OPERATING PRACTICES	0.011	LB	LAER
*PA-0319	RENAISSANCE ENERGY CENTER	30-00235A	PA	4911	221112	8/27/2018	NATURAL GAS FIRED AUXILIARY BOILER	13.31	NATURAL GAS	88	MMBTU/HR	NO_x	LO-NOX BURNERS, FLUE GAS RECIRCULATION, GOOD COMBUSTION PRACTICES, PROPER OPERATION AND MAINTAINANCE.	0.02	LB/MMBTU	LAER

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Table 2. NOx RBLC Data for Boilers

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	SC	3295	327992	2/8/2012	BOILERS	13.31	NATURAL GAS	5	MMBTU/HR	NO_x	GOOD DESIGN AND COMBUSTION PRACTICES, LOW NOX BURNERS, COMBUSTION OF NATURAL GAS/PROPANE.	0		BACT-PSD
SC-0149	KLAUSNER HOLDING USA, INC	1860-0128-CA	SC	2421	321113	1/3/2013	NATURAL GAS BOILER EU003	11.31	NATURAL GAS	46	MMBTU/HR	NO_x		0.036	LB/MMBTU	OTHER CASE-BY-CASE
SC-0149	KLAUSNER HOLDING USA, INC	1860-0128-CA	SC	2421	321113	1/3/2013	NATURAL GAS BOILER EU004	13.31	NATURAL GAS	46	MMBTU/HR	NO_x		0.036	LB/MMBTU	OTHER CASE-BY-CASE
SC-0149	KLAUSNER HOLDING USA, INC	1860-0128-CA	SC	2421	321113	1/3/2013	NATURAL GAS BOILER EU005	13.31	NATURAL GAS	46	MMBTU/HR	NO_x		0.036	LB/MMBTU	OTHER CASE-BY-CASE
SC-0149	KLAUSNER HOLDING USA, INC	1860-0128-CA	SC	2421	321113	1/3/2013	NATURAL GAS BOILER EU006	13.31	NATURAL GAS	46	MMBTU/HR	NO_x		0.036	LB/MMBTU	OTHER CASE-BY-CASE
TX-0656	GAS TO GASOLINE PLANT	PSDTX1340 AND 107764	TX	2911	325199	5/16/2014	BOILER	11.31	NATURAL GAS AND FUEL GAS	950	MMBTU/HR	NO_x	SCR	0.01	LB/MMBTU	BACT-PSD
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	108411 PSDTX1350	TX	4911	221112	4/29/2014	BOILER	13.31	NATURAL GAS	90	MMBTU/HR	NO_x	ULTRA LOW-NOX BURNERS, LIMITED USE	9	PPMVD	BACT-PSD
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	102731 PSDTX1294	TX	4911	221112	12/19/2014	BOILER	13.31	NATURAL GAS	80	MMBTU/HR	NO_x	LOW-NOX BURNERS	0.036	LB/MMBTU	BACT-PSD
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	117026, PSDTX1390, N194	TX	4911	221122	6/18/2015	COMMERCIAL/IN STITUTIONAL SIZE BOILERS (100 MMBTU) NATURAL GAS	13.31	NATURAL GAS	73.3	MMBTU/HR	NO_x		0.01	MMBTU/H	LAER
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOADTER MINAL (PBPTT)	118901, GHGPSDTX108 AND PSDTX1	TX	5171	424710	11/6/2015	COMMERCIAL/IN STITUTIONAL - SIZE BOILERS/FURNAC ES	13.31	NATURAL GAS	40	MMBTU/HR	NO_x	LOW NOX BURNERS	0.036	LB/MMBTU	BACT-PSD
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	118901, GHGPSDTX108 AND PSDTX1	TX	5171	424710	11/6/2015	COMMERCIAL/IN STITUTIONAL - SIZE BOILERS/FURNAC ES	13.31	NATURAL GAS	95.7	MMBTU/HR	NO_x	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	0.011	LB/MMBTU	BACT-PSD
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	118901, GHGPSDTX108 AND PSDTX1	TX	5171	424710	11/6/2015	COMMERCIAL/IN STITUTIONAL - SIZE BOILERS/FURNAC ES	13.31	NATURAL GAS	13.2	MMBTU/HR	NO_x		0.1	LB/MMBTU	BACT-PSD
TX-0888	ORANGE POLYETHYLENE PLANT	155952 PSDTX1556 GHGPSDTX192	TX	2821	325211	4/23/2020	BOILERS	11.31	NATURAL GAS, ETHANE, FUEL, OR VENT GAS	250	MMBTU/HR	NO_x	SCR	0.015	LB/MMBTU	BACT-PSD

* Represents draft entries into the RBLC which may not be complete.

Table 2. NOx RBLC Data for Boilers

RBLCID	Facility Name	Permit No.	Facility State	SIC	NAICS	Permit Issuance Date	Process	Process Type	Fuel	Throughput	Unit	Pollutant	Control Method	Emission Limit	Unit	Determination Basis
VA-0321	BRUNSWICK COUNTY POWER STATION	52404	VA	4911	221112	3/12/2013	AUXILIARY BOILER	13.31	NATURAL GAS	66.7	MMBTU/HR	NO_x	DRY LOW NOX BURNER.	9	PPMVD	BACT-PSD
WI-0283	AFE, INC. LCM PLANT	17-JJW-207	WI	3679	334419	4/24/2018	B01-B12, BOILERS	13.31	NATURAL GAS	28	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS, FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES	0.0105	LB/MMBTU	BACT-PSD
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	18-JJW-017	WI	4911	221112	4/24/2018	B13-B24 & B25-B36 NATURAL GAS-FIRED BOILERS	13.31	NATURAL GAS	28	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS, FLUE GAS RECIRCULATION, AND GOOD COMBUSTION PRACTICES.	0.0105	LB/MMBTU	BACT-PSD
WI-0300	NEMADJI TRAIL ENERGY CENTER	18-MMC-168	WI	4911	221121	9/1/2020	NATURAL GAS-FIRED AUXILIARY BOILER (B02)	13.31	NATURAL GAS	100	MMBTU/HR	NO_x	ULTRA-LOW NOX BURNERS, FLUE GAS RECIRCULATION, AND OPERATE AND MAINTAIN B02 ACCORDING TO THE MANUFACTURER'S RECOMMENDATIONS.	0.011	LB/MMBTU	BACT-PSD
WI-0306	WPL- RIVERSIDE ENERGY CENTER	19-POY-212	WI	4911	221112	2/28/2020	TEMPORARY BOILER (B98A)	13.31	NATURAL GAS	14.67	MMBTU/HR	NO_x	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	BACT-PSD
*WV-0029	HARRISON COUNTY POWER PLANT	R14-0036	WV	4911	221112	3/27/2018	AUXILIARY BOILER	13.31	NATURAL GAS	77.8	MMBTU/HR	NO_x	LNB, FGR, GOOD COMBUSTION PRACTICES	0.86	LB/HR	BACT-PSD
*WV-0032	BROOKE COUNTY POWER PLANT	R14-0035	WV	4911	221112	9/18/2018	AUXILIARY BOILER	13.31	NATURAL GAS / ETHANE	111.9	MMBTU/HR	NO_x	LNB, GOOD COMBUSTION PRACTICES	1.23	LB/HR	BACT-PSD
WY-0075	CHEYENNE PRAIRIE GENERATING STATION	MD-16173	WY	4911	221122	7/16/2014	AUXILIARY BOILER	13.31	NATURAL GAS	25.06	MMBTU/HR	NO_x	ULTRA LOW NOX BURNERS AND FLUE GAS RECIRCULATION	0.0175	LB/MMBTU	BACT-PSD

* Represents draft entries into the RBLC which may not be complete.

APPENDIX B: EMISSION UNITS SUBJECT TO RACT

Table B-1. List of EU's Subject to RACT

EU	Description	NO_x (tpy)	EU	Description	NO_x (tpy)
MG13	Cleaver Brooks Boiler, M/N: CBLE700-800-200, S/N: OL097510	6.95	LX025	Caterpillar Emergency Generator, M/N: 3512C, S/N: EGB00203	7.5
MG14	Cleaver Brooks Boiler, M/N: CBLE700-800-200, S/N: OL096895	6.95	EX007	Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02774	9.55
MG17	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02910	15.12	EX008	Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02784	9.55
MG18	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02931	15.12	EX009	Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02770	9.55
MG19	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02927	15.12	EX010	Caterpillar Emergency Generator, M/N: 3512, S/N: 24Z02753	9.55
MG20	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02913	15.12	BE80	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05330	15.12
MG21	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02929	15.12	BE81	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05335	15.12
MG22	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02932	15.12	BE82	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05333	15.12
MG23	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02916	15.12	BE83	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05332	15.12
MC019	Caterpillar Emergency Generator, M/N: 3512, S/N: 6WN00081	13.03	BE85	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05339	15.12
MC020	Caterpillar Emergency Generator, M/N: 3512, S/N: 6WN00082	13.03	BE86	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05338	15.12
TBA15	Caterpillar Diesel Emergency Generator, M/N: 3412CTA, S/N: 1EZ07104	7.08	BE87	Caterpillar Emergency Generator, M/N: 3416, S/N: 25Z05340	15.12
MB061	Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 25Z06027	13.01	BE88	Caterpillar Emergency Generator, M/N: 3416, S/N: 1LZ00545	15.12

EU	Description	NO_x (tpy)	EU	Description	NO_x (tpy)
MB062	Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 25Z02994	13.01	CC009	Caterpillar Emergency Generator, M/N: 3416, S/N: 1LZ00546	15.12
MB063	Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 25Z03002	13.01	CC010	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBK00196	9.35
MB066	Caterpillar Emergency Generator, M/N: 3516 DITA, S/N: 3NS00234	15.11	CC011	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBK00197	9.35
MB067	Cummins Emergency Generator, M/N: KTA50-G9, S/N: 33146939	13.32	CC012	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBK00198	9.35
MB093	Caterpillar Emergency Generator, M/N: 3512, S/N: 1GZ01339	13.03	CC013	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00378	10.47
LX009	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z03005	13.01	CC014	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00379	10.47
LX010	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02998	13.01	CC015	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00380	10.47
LX011	Caterpillar Emergency Generator, M/N: 3516TA, S/N: 25Z02999	13.01	TM01	Caterpillar Diesel Emergency Generator, M/N: 3516C, S/N: SBJ00382	10.47
LX024	Caterpillar Emergency Generator, M/N: 3512C, S/N: EGB00199	7.5	TBB15	Caterpillar Emergency Generator, M/N: 3516DITA, S/N: DD501118	10.83
NY27	Caterpillar Emergency Generator, M/N: 3512TA, S/N: 24Z06937	10.91	TBB15	Caterpillar Emergency Generator, M/N: 3516 BTA, S/N: GZR00237	15.12
NY28	Caterpillar Emergency Generator, M/N: 3512TA, S/N: 24Z06932	10.91	NY29	Caterpillar Emergency Generator, M/N: 3512TA, S/N: 24Z06931	10.91

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

Calnev Pipe Line, LLC
Las Vegas Terminal

5049 North Sloan Lane
Las Vegas, NV 89115

Part 70 Permit No. 13

October 2022

Prepared by:

Yorke
ENGINEERING, LLC
www.YorkeEngr.com

Office Locations:
Los Angeles, Orange County,
Riverside, Ventura, San Diego, Fresno, Merced,
Bakersfield, Berkeley, San Francisco

Tel: (949) 248-8490
Fax: (949) 248-8499

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.

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.

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.

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

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

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.

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

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

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.

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.

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**

Appendix 7

NV Energy RACT Analysis
(Clark Generating Station/Sun Peak Generating Station)

NVEnergy

RECEIVED CC DAQ
2022 OCT 3 PM1:59

October 3, 2022

Mr. Ted Lendis
Permitting Manager
Clark County Department of Environmental and Sustainability, Division of Air Quality
4701 W. Russel Road, Suite 200
Las Vegas, Nevada 89118

RE: RACT Analyses Submittal
Clark Generating Station (Source: 7) & Sun Peak Generating Station (Source: 423)

Dear Mr. Lendis:

NV Energy (NVE) hereby submits the RACT evaluations for its Clark Generating Station (Source 7) and Sun Peak Generating Station (Source 423) as requested by DAQ via email correspondence dated August 3, 2022. The report and its attachments detail the RACT evaluation for both facilities, comprising of a NOx RACT analysis for the Sun Peak Generating Station as well as NOx & VOC RACT analyses for the Clark Generating Station, as clarified in subsequent correspondence.

NVE anticipates further communication from DAQ on this topic in the near future. If you require additional information or have any questions, please contact Sean Spitzer at (702) 402-5132, or via email at sean.spitzer@nvenergy.com.

I certify that, based on the information and belief formed after reasonable inquiry, the statements and information in this document are true, accurate, and complete.

Sincerely,

Mathew Johns
Vice President, Environmental Services and Land Management
NV Energy
Alternate Responsible Official

Reasonably Available Control Technology (RACT) Review – NOx and VOC Emissions

Clark and Sun Peak Generating Stations

Prepared for:

NV Energy
6226 W Sahara Ave
Las Vegas, NV 89146

Prepared by:

AECOM Technical Services, Inc.
250 Apollo Drive
Chelmsford, MA 01824

October 2022

1.0 Overview

On August 3, 2018 the Environmental Protection Agency (EPA) classified 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 moderate non-attainment area for this pollutant.

The proposed 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, these requirements include preparation and submittal to the EPA of State Implementation Plan (SIP) revisions that include provisions to address the adoption of Reasonably Available Control Technology (RACT) for each major source of nitrogen oxide (NOx) or volatile organic compounds (VOC) emissions within the non-attainment area (i.e., sources that emit 100 tons/yr (tpy) or more of NOx or VOC). Based on the facilities potential to emit, the DAQ has determined that NV Energy's Edward W. Clark Generating Station (CGS) and Sun Peak Generating Station (SPGS) meet this 100 tpy emissions threshold and are thus subject to the requirement to evaluate RACT.

The DAQ is using a phased approach towards collecting information to inform its SIP revision that initially exempts any emission units at major sources that have potential emission rates that are less than or equal to 5 tpy from needing RACT consideration.

The SPGS is a major source of NOx emissions but is not a major source for VOC emissions. As described further below, the emission units at the SPGS whose PTE exceeds the 5 tpy RACT consideration threshold consist of three natural gas-fired General Electric Frame 7EA combustion turbines that operate in simple cycle mode. Accordingly, these three units (Units 3 – 5) are subject to RACT for NOx only. Furthermore, although these units are permitted to fire diesel fuel, the NOx RACT analysis for these units only contemplates their natural gas-fired operation, as diesel fuel was not used in any of the units during the baseline years and is not expected to be used in the future.

The CGS is a major source of both NOx and VOC emissions, and the emission units at the CGS with potential emissions above the DAQ's 5 tpy RACT threshold consist of seventeen natural gas-fired combustion turbine-based generating units. Four of these units (Units 5 – 8) are Westinghouse Model 501B6 combustion turbines operating in combined cycle mode that were installed in the 1980's, while one unit (Unit 4) is a General Electric Frame 7B (MS-7000) combustion turbine operating in simple cycle mode that was installed in 1973. The remaining emission units (Units 11 – 22) consist of twelve pairs of Pratt and Whitney FT8 combustion turbines installed in 2008 that operate in simple cycle mode. Thus, all seventeen combustion turbines at the CGS are subject to RACT for NOx and VOC emissions.

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.

[1] 44 Federal Register 53672, September 17, 1979

The DAQ has requested 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 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 two NV Energy power plants.

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 CGS and SPGS.

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 in order 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 show in Table 3-1.

Table 3-1: Actual Output Data by Unit, 2017 – 2021 (MWhr/yr)

	Potential Output	Actual Output				
		2017	2018	2019	2020	2021
Clark Generating Station						
Unit 4	525,600	4,350	3,250	2,015	10,943	17,707
Unit 5	744,600	72,227	88,783	66,925	87,402	117,764
Unit 6	744,600	86,463	91,634	84,984	77,873	117,951
Unit 7	744,600	80,284	82,879	68,327	129,027	126,882
Unit 8	744,600	79,151	89,259	76,214	83,564	96,725
Unit 11	202,650	21,416	33,513	16,589	18,404	28,387
Unit 12	202,650	34,688	32,454	28,157	30,653	22,883
Unit 13	202,650	28,128	23,589	21,095	18,990	10,765
Unit 14	202,650	43,764	33,120	19,131	25,996	17,941
Unit 15	202,650	31,858	34,273	16,704	22,698	33,541
Unit 16	202,650	36,170	29,384	20,436	18,298	21,002
Unit 17	202,650	26,994	30,284	21,051	27,078	20,173
Unit 18	202,650	38,072	27,171	17,473	16,674	25,388
Unit 19	202,650	23,974	22,509	17,456	26,737	27,515
Unit 20	202,650	29,111	36,092	22,813	25,045	17,247
Unit 21	202,650	25,809	29,854	17,456	10,366	21,328
Unit 22	202,650	24,342	20,216	11,536	17,533	26,109
Sun Peak Generating Station						
Unit 3	370,110	8,564	12,260	19,099	51,180	28,192
Unit 4	370,110	6,373	8,603	14,128	34,258	25,928
Unit 5	370,110	5,083	11,273	21,097	33,306	19,502

As a consequence of each unit's low actual output level, annual NOx and VOC emissions from each unit over the past five years have also been low. Table 3-2 summarizes the actual annual NOx emission rates from the units at the CGS and the SPGS over the past five years, and Table 3-3 summarizes the annual actual VOC emission rates from the units at the CGS over the past five years.

Table 3-2: Actual NOx Emissions by Unit, 2017 – 2021 (tons/yr)

	2017	2018	2019	2020	2021
Clark Generating Station					
Unit 4	8.70	11.32	5.41	27.74	47.56
Unit 5	10.20	13.40	10.00	11.90	14.26
Unit 6	10.40	10.80	9.80	9.29	12.25
Unit 7	7.90	10.10	9.30	13.33	15.27
Unit 8	11.20	12.20	10.70	11.16	12.83
Unit 11	2.95	4.19	2.31	2.49	3.24
Unit 12	4.68	3.38	3.21	3.48	2.60
Unit 13	3.24	2.45	2.60	2.39	1.24
Unit 14	5.33	3.41	2.12	2.78	2.27
Unit 15	3.39	3.27	1.69	2.47	3.60
Unit 16	3.70	2.80	2.01	2.53	2.34
Unit 17	3.22	3.21	2.19	3.10	2.12
Unit 18	4.25	2.61	1.90	1.78	2.85
Unit 19	3.13	2.71	2.16	3.32	2.96
Unit 20	4.19	3.80	2.66	2.66	1.90
Unit 21	3.08	3.13	2.17	1.21	2.26
Unit 22	3.25	2.44	1.49	2.10	2.68
Sun Peak Generating Station					
Unit 3	6.73	9.98	15.81	41.56	22.81
Unit 4	5.10	6.94	11.69	27.64	20.96
Unit 5	4.04	8.94	16.98	26.40	15.45

Table 3-3: Actual CGS VOC Emissions by Unit, 2017 – 2021 (tons/yr)

	2017	2018	2019	2020	2021
Unit 4	0.52	0.62	0.29	1.51	2.59
Unit 5	2.29	2.95	2.11	2.68	4.85
Unit 6	2.53	2.78	2.43	2.20	4.90
Unit 7	1.83	2.69	2.03	3.81	5.32
Unit 8	2.44	2.89	2.27	2.49	4.27
Unit 11	0.26	0.42	0.19	0.21	0.52
Unit 12	0.44	0.40	0.32	0.35	0.42
Unit 13	0.34	0.29	0.24	0.21	0.20
Unit 14	0.54	0.41	0.22	0.30	0.34
Unit 15	0.39	0.42	0.19	0.26	0.59
Unit 16	0.44	0.36	0.23	0.21	0.38
Unit 17	0.33	0.37	0.24	0.31	0.37
Unit 18	0.47	0.34	0.20	0.20	0.48
Unit 19	0.30	0.28	0.20	0.31	0.50
Unit 20	0.36	0.44	0.26	0.29	0.32
Unit 21	0.32	0.37	0.20	0.12	0.39
Unit 22	0.30	0.25	0.13	0.20	0.47

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 combustion turbine assets at the CGS and SPGS. Table 3-4 compares the average of the forecasted annual output levels for each unit over the course of the next ten years (i.e., 2023 – 2032) 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 is less than their actual annual average output over the past five years.

Table 3-4: 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)
Clark Generating Station	Unit 4	14,325	1,445
	Unit 9[1]	218,099	209,302
	Unit 10[2]	200,495	190,997
	Unit 11	27,465	15,980
	Unit 12	33,571	14,820
	Unit 13	25,859	16,209
	Unit 14	38,442	14,221
	Unit 15	33,065	13,439
	Unit 16	32,777	13,638
	Unit 17	28,639	13,277
	Unit 18	32,621	12,137
	Unit 19	27,126	11,574
	Unit 20	32,602	11,325
	Unit 21	27,832	11,000
	Unit 22	22,279	10,073
Sun Peak Generating Station	Unit 3	39,686	4,797
	Unit 4	30,093	5,313
	Unit 5	27,201	5,983
Notes: 1 – CGS combined cycle Unit 9 is made up of combustion turbine Unit Nos. 7 and 8 2 – CGS combined cycle Unit 10 is made up of combustion turbine Unit Nos. 5 and 6			

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 3-5.

Table 3-5: Projected Future Actual Emission Rates by Unit

		NOx Emissions (ton/yr)	VOC Emissions (ton/yr)
Clark Generating Station	Unit 4	37.65	2.05
	Unit 5	13.08	3.77
	Unit 6	10.77	3.55
	Unit 7	14.30	4.57
	Unit 8	12.00	3.38
	Unit 11	3.57	0.37
	Unit 12	4.03	0.42
	Unit 13	2.85	0.32
	Unit 14	4.37	0.48
	Unit 15	3.33	0.43
	Unit 16	3.25	0.40
	Unit 17	3.22	0.35
	Unit 18	3.43	0.41
	Unit 19	3.14	0.41
	Unit 20	4.00	0.40
	Unit 21	3.11	0.35
	Unit 22	2.85	0.34
Sun Peak Generating Station	Unit 3	32.19	*
	Unit 4	24.30	*
	Unit 5	21.69	*
* - The SPGS units are not subject to RACT for VOC			

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., CN, 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 three simple-cycle combustion turbine units at the SPGS (Units 3, 4, and 5) are equipped with water injection to control NOx emissions and are required to meet a NOx emission limit of 42 ppmv @ 15% O2. Each unit is limited to an operating schedule of 12 hours per day.

At the CGS, the simple-cycle Unit 4 is not equipped with NOx controls; the unit is subject to an annual potential-to-emit limit of 1,732.6 tons NOx/yr but is not subject to short-term limits, either on an exhaust concentration basis (i.e., ppmv) or mass basis (pounds per hour). The combined-cycle units (Units 5, 6, 7, and 8) are equipped with Ultra Low NOx Burners (ULNB), a type of DLN combustors; collectively these four units are subject to an annual NOx limit of 360 tons/yr and each unit is subject to short-term limit NOx limits of 5 ppm @ 15% O2, expressed on a one-hour average, and 19.11 pounds per hour. The simple-cycle Units 11 – 22 are equipped with selective catalytic reduction (SCR) systems and each unit is subject to an annual NOx limit of 30.96 tons/yr and short-term limits of 5 ppm @ 15% O2 (one hour average) and 11.01 lb/hr. Units 11 – 22 are also each subject to an annual operating limit of 3,500 hours per year.

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. For SCR to be technically feasible on simple-cycle units, which typically have exhaust gas temperatures that are higher than the normal range of SCR catalyst effectiveness, either special high-temperature catalyst formulations must be employed, or the turbine exhaust must be cooled prior to introducing it into the SCR reactor. The most common mechanism used to cool simple cycle turbine exhaust gas is to mix it with a sufficient quantity of ambient air.

SCR catalyst materials lose activity over time, necessitating catalyst cleaning or replacement. In base-loaded natural gas-fired applications, expected SCR catalyst life is within the range of 32,000 to 80,000 operating hours.[3] Catalyst life is lower in simple cycle 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.

[3] EPA Air Pollution Control Cost Manual, Section 4 Chapter 2 "Selective Catalytic Reduction" (June 2019)

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. 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**

Searches of EPA's RBLC were carried out to identify listings containing NOx BACT or RACT determinations for large natural gas-fired combined-cycle and simple-cycled units permitted since 2012. The results of these RBLC searches are summarized in Appendix A, Tables A-1 and A-2.

Among the combined-cycle unit listings in the RBLC that met these criteria there are 150 listings that identify the NOx emission control alternative. The following provides a breakdown of these listings for the emission control alternatives employed:

- 142 list the use of SCR (either alone or in conjunction other alternatives),
- 101 list the use of DLN combustors,
- 4 list water or steam injection,
- 6 list natural gas or clean fuels, and
- 10 list good combustion practices.

Consequently, the use of SCR, DLN, and water or steam injection are technically feasible alternatives for control of NOx emissions from natural gas-fired combined cycle units.

Among the simple-cycle unit listings, there are 56 listings in which the NOx emission control alternative that is employed is described. The breakdown in emission control alternatives used by these simple cycle units is as follows:

- 13 list the use of SCR,
- 42 list the use of DLN combustors,
- 9 list water or steam injection,
- 10 list natural gas or clean fuels, and
- 10 list good combustion practices.

Thus, for simple-cycle units, SCR, DLN combustors, and water or steam injection are all considered a technically feasible alternatives for control of NOx emissions.

The top-level control of NOx emissions for natural gas-fired combined-cycle units is the use of DLN combustors to minimize NOx formation in conjunction with the use of SCR, followed by the use of DLN or water injection alone. Good combustion practices would represent the lowest level of NOx control for this source type. The RBLC limits for combined-cycle units using SCR and DLN range from 2 to 15 ppmvd @15% O_2. The limits for combined-cycle units using DLN alone range from 5 to 41 ppmv @15% O_2. The emission limit for the only combined-cycle unit listed as using water or

[4] 42 Fed. Reg. 53,782, 53,785 (Oct. 3, 1977).

steam injection alone (without SCR or DLN combustors) is 25 ppmvd @ 15% O_2. Accordingly, 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

For natural gas-fired simple-cycle units, the top level of NOx emissions control is similarly the use of SCR in combination with DLN combustors. The RBLC limits for simple-cycle units employing these technologies together range from 2 – 5 ppmvd @ 15% O_2. The limits for units utilizing DLN alone range from 9 to 30 ppmvd @ 15% O_2. The emission limit for the two simple-cycle units listed as using water or steam injection alone is 25 ppmvd @ 15% O_2. Thus, the hierarchy of NOx emission controls for natural gas-fired simple-cycle units is the same as for natural gas-fired combined-cycle units.

As described previously in Section 1.4.2, the combined-cycle units at CGS (Units 5 – 8) are already equipped with DLN combustors. Thus, the only more stringent NOx control alternative for these units would be to retrofit them with SCR.

Of the simple cycle units at CGS, Unit 4 is not currently equipped with NOx controls, so NOx control alternatives for this unit include both SCR and DLN combustors. As described further below, however, the original equipment manufacturer (GE) has never implemented a DLN retrofit on this type of combustion turbine (i.e., the Frame 7B model). The other simple-cycle units (Units 11 – 22) are already equipped with SCR and therefore retrofitting these units with DLN combustors would be the only available alternative to the existing controls. The simple-cycle units at SPGS utilize water injection to control NOx, so both SCR and DLN combustors are available control alternatives for these units.

4.5 Step 4 – NOx Control Effectiveness Evaluation

Economic Impacts

Installation of either SCR or DLN combustors on the existing combustion turbine units at the CGS and SPGS would entail significant capital and annual costs. Estimates of the cost impacts for these units is provided in the following paragraphs and tables with detailed cost calculations summarized in Appendix B[5]. SCR capital costs are based on recent budgetary estimates for SCR for the various turbine configurations provided by an SCR vendor. The capital cost to install DLN combustors are from a budgetary estimate provided by GE specific to each combustion turbine type.

Table 4-1 summarizes the economic impact of retrofitting SCR and/or DLN combustors (if available) on the simple-cycle GE Frame 7B CGS Unit 4. As noted above, GE has stated that they have never retrofit DLN combustors on the Frame 7B series combustion turbines; they indicated that installing this technology on this unit would constitute a custom retrofit situation that would require a feasibility study be carried out to confirm that the retrofit was technically feasible. Although EPA has previously stated that sources are not expected to experience trials or research to learn how to apply a particular emission control alternative on a source[6], for the purpose of this RACT assessment NV Energy assumes that retrofitting the unit with DLN combustors is a technically feasible

[5] Appendix B contains cost calculations for CGS Units 4 – 9 and SPGS Units 3 – 5. Detailed cost calculations were not carried out for CGS Units 11 – 22 as these units are already equipped with emission controls that are representative of RACT

[6] EPA OAQPS New Source Review Workshop Manual, Section IV. B (1990).

alternative for CGS Unit 4. The total installed cost estimate for retrofitting DLN combustors onto this unit was provided by GE; equipment and direct installation costs for SCR were provided by a vendor of this equipment.

Annualized costs 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 for SCR the cost of ammonia. Ammonia costs are estimated using the current unit cost for this material used in CGS Units 11 – 22 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. Described further below, implementation of SCR would have a negative impact on the electrical output capacity of the unit, and thus annual costs for this alternative also include capacity replacement and lost power charges. Annualized DLN costs, however, do not include higher fuel usage due to the change in the unit's heat rate that would likely occur with the use of DLN combustors.

As described in Section 4.2, CGS Units 5 – 8 are already equipped with DLN combustors and are subject to NOx emission limit of 5 ppmv @15% O2. Based on the RBLC search results, this permit limit is within the range of limits that have been concluded to be representative of BACT for combined-cycle units that are equipped with SCR. While it may be technically feasible to retrofit these units with SCR to further reduce their emission levels, this alternative would result in minimal reduction in NOx emissions due to the low annual utilization rate of these units and their already-low emission limit. The capital cost to install SCR on each of these units would be expected to be nearly the same as the cost to retrofit this alternative on to the similarly sized CGS Unit 4. Given their lower baseline emissions rate, however, the use of SCR on these units would be expected to be even less cost effective than it would be on CGS Unit 4.

Table 4-1: Estimated Economic Impact of Alternative NOx Controls: CGS Unit 4

	SCR & DLN Combustors	SCR	DLN Combustors
Baseline Emissions Level (ton/yr)	37.65		
Achievable Emissions Level (ton/yr)	0.6	1.3	7.8
Annual Emissions Reduction (tons/yr)	37.02	36.39	29.77
Total Installed Capital Cost	$40,262,200	$21,262,200	$19,000,000
Annualized Capital Cost	$3,841,000	$2,028,400	$1,812,600
Annual O&M Cost	$400,300	$325,000	$95,000
Total Annual Cost	$4,241,300	$2,353,400	$1,907,600
Cost Effectiveness ($/ton removed)	$114,578	$64,672	$64,069

The estimated economic impacts of retrofitting SCR or DLN combustors on the simple cycle SPGS Units 3 – 5 are shown on Tables 4-2 through 4-4. Capital costs are based on estimated equipment and direct installation costs for these size units provided by an equipment vendor. Annualized costs for this alternative were estimated in the same fashion that the corresponding annualized costs were estimated for CGS Unit 4, (described above), including an estimated 20-year equipment life for the emission control equipment. Considering that the SCR equipment vendors contact stated that the lowest NOx emission level found in the RBLC search (2 ppmv @ 15% O2) could be achieved on these units using SCR alone, any further reduction in emissions that might potentially be achieved by retrofitting SCR in combination with DLN on these units was not considered to be feasible. Thus, for these units the available NOx control alternatives consist of retrofitting the units either with SCR or DLN combustors.

Table 4-2: Estimated Economic Impact of Alternative NOx Controls: SPGS Unit 3

	SCR	DLN Combustors
Baseline Emissions Level (ton/yr)	32.19	
Achievable Emissions Level (ton/yr)	1.75	7.85
Annual Emissions Reduction (tons/yr)	30.44	24.33
Total Installed Capital Cost	$26,151,300	$14,208,900
Annualized Capital Cost	$2,494,800	$1,355,500
Annual O&M Cost	$359,700	$906,300
Total Annual Cost	$2,854,500	$2,261,800
Cost Effectiveness ($/ton removed)	$93,779	$92,978

Table 4-3: Estimated Economic Impact of Alternative NOx Controls: SPGS Unit 4

	SCR	DLN Combustors
Baseline Emissions Level (ton/yr)	24.30	
Achievable Emissions Level (ton/yr)	1.34	6.04
Annual Emissions Reduction (tons/yr)	22.96	18.26
Total Installed Capital Cost	$26,151,300	$14,208,900
Annualized Capital Cost	$2,494,800	$1,355,500
Annual O&M Cost	$350,800	$823,700
Total Annual Cost	$2,845,600	$2,179,200
Cost Effectiveness ($/ton removed)	$123,944	$119,316

Table 4-4: Estimated Economic Impact of Alternative NOx Controls: SPGS Unit 5

	SCR	DLN Combustors
Baseline Emissions Level (ton/yr)	21.69	
Achievable Emissions Level (ton/yr)	1.18	5.33
Annual Emissions Reduction (tons/yr)	20.51	16.36
Total Installed Capital Cost	$26,151,300	$14,208,900
Annualized Capital Cost	$2,494,800	$1,355,500
Annual O&M Cost	$347,900	$796,500
Total Annual Cost	$2,842,700	$2,122,000
Cost Effectiveness ($/ton removed)	$138,633	$131,553

Energy impacts

There are adverse energy impacts associated with the use of either SCR or DLN combustors to reduce NOx emissions. With SCR, the required catalyst grid reduces the electrical generating capacity of a combustion turbine system because the catalyst grid causes backpressure within the turbine and reduces its efficiency. Similarly, DLN combustors have lower combustion efficiency than conventional combustors, which adversely affect the fuel efficiency of these units. In addition to these power generation efficiency losses, NV Energy would need to purchase additional generating capacity elsewhere to maintain the total system generating capacity that would be lost by equipping these combustion turbines with either SCR or DLN combustors. These energy cost impacts are included in the estimated O&M costs for each control option shown in Tables 4-1 to 4-4. For the CGS Unit 4 and the SPGS Units 3 - 5, replacing the existing combustors with DLN combustors would also incur an energy penalty; for the combustors on SPGS Units 3 – 5 that employ water injection, the power loss would be due to the loss of the power augmentation that accompanies the use of water injection for NOx control. Based on information from GE, the energy penalty for CGS Unit 4 would be up to 4% of the rated output capacity; the penalty for SPGS Units 3 – 5 would be up to 9% of their output capacity.

Environmental Impacts

The use of SCR requires that a reducing agent (ammonia) be injected into the turbine exhaust to react with NOx. This 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. In addition, the use of an SCR can increase the formation of sulfuric acid emissions by oxidizing a portion of the turbine's SO_2 emissions to SO_3 which subsequently reacts with water vapor to form sulfuric acid. Also, the catalyst must periodically be regenerated and must be disposed of or recycled at the end of its useful life.

There are no adverse environmental impacts, however, associated with DLN combustors.

4.6 Step 5 - Evaluation of RACT for NOx Control

Available NOx control alternatives for the existing simple-cycle and combined-cycle combustion turbines at CGS and SPGS consist of retrofitting the units SCR systems or DLN combustors. However, considering the low rates that these units have historically and are projected to operate in the future, only modest reductions in NOx emissions from these units would be realized by implementing these alternatives. In each instance, installing SCR systems or DLN combustions would entail substantial capital and annual operating expenses, and therefore the cost effectiveness of these alternatives on each combustion turbine unit is estimated to be extremely unreasonable.

Clark Generating Station Unit 4: Retrofitting this simple-cycle unit with both DLN combustors and SCR is projected to result in an annual reduction in NOx emissions of 37.02 tons/yr at an estimated annualized cost of over $4.2 million per year. This alternative is thus concluded to be unrepresentative of RACT on the basis of adverse economic impact due to an estimated cost effectiveness of over $115,000 per ton removed. Retrofitting the unit with just SCR is projected to result in an annual reduction in NOx emissions of 36.39 tons/yr at an estimated annualized cost of over $2.3 million per year. Similarly, with an estimated cost effectiveness of over $64,000 per ton removed, this alternative is concluded to be unrepresentative of RACT on the basis of adverse economic impact. Finally, retrofitting this unit with DLN combustors may not be technically feasible with this unit; even if it were feasible, the estimated cost effectiveness of this alternative (with an estimated annual reduction of NOx emissions of only 7.8 tons/yr and an estimated annualized cost impact of over $1.9 million per year) would also be over $64,000 per ton removed and therefore unrepresentative of RACT on the basis of cost. Therefore NV Energy concludes that RACT for NOx for this unit is the current emission level (1,732.6 tpy) with the current combustion turbine configuration. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

Clark Generating Station Units 5 – 8: These combined-cycle units are all equipped with DLN combustors and subject to an emissions limit of 5 ppmv @ 15% O2, one-hour average. Although retrofitting them with SCR would be technically feasible, the high capital and annualized operating expense of this alternative is unjustifiable considering the relatively limited schedule under which they have operated and are projected to operate in the future. Therefore, NV Energy concludes that RACT for NOx from these units is their current emission level. The units are equipped with CEMS for NOx, which is proposed as the NOx RACT compliance monitoring method for these units. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

Clark Generating Station Units 11 – 22: These simple-cycle units are all equipped with SCR and subject to an emissions limit of 5 ppmv @15% O2, one-hour average. The units are limited to an annual operating schedule of 3,500 hours per year, but have in the recent past have operated at around 20% of this level. NV Energy concludes that NOx RACT for these units is their current emissions level. The units are equipped with CEMS for NOx, which is proposed as the NOx RACT compliance monitoring method for these units. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

Sun Peak Generating Station Units 3 – 5: The Sun Peak simple-cycle units utilize water injection to control NOx emissions to a limit of 42 ppmv @15% O2, three-hour average. The units are limited to an operating schedule of 12 hours per day and are typically only operated for a few hours per day. Retrofitting them with SCR is technically feasible but not cost effective given their limited projected operating schedule. Annualized operating costs for each unit are estimated at over $2.8 million per year with cost effectiveness levels for each unit estimated between $93,700 and $138,600 per ton of NOx removed. Similarly, retrofitting these units with DLN combustors would be technically feasible but cost ineffective; the estimated annualized cost of this alternative on these units is $2.1 million per year and cost effectiveness levels for the three units range from $92,900 to $131,500 per ton of NOx removed. Therefore, NV Energy concludes that the current means of NOx control on these units is representative of RACT. The units are equipped with CEMS for NOx, which is proposed as the NOx RACT compliance monitoring method for these units. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

5.0 RACT for Volatile Organic Compound (VOC) Emissions

5.1 Formation

VOC emissions are generated in combustion turbines due to the incomplete conversion of carbon-containing compounds to CO_2 and water during fuel combustion. VOC emission rates are principally influenced by equipment operating conditions. Higher VOC emissions may be the result of lower than optimal combustion temperature, insufficient combustor residence time, and lower operating loads.

5.2 Step 1 - Available VOC Control Alternatives

Available control technologies to reduce VOC emissions from combined cycle units include oxidation catalyst and combustion controls/good combustion practices.

Oxidation Catalyst

An oxidation catalyst is a post-combustion technology that removes VOC from the exhaust gas stream after it is formed in the combustion turbine. In the presence of a catalyst, VOC will react with oxygen present in the turbine exhaust, converting it to carbon dioxide. The activation energy required for the oxidation reactions to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of particulate matter and sulfuric acid mist.

VOC catalytic oxidation systems operate in a relatively narrow temperature range. At lower temperatures, VOC conversion efficiency falls off rapidly. At higher temperatures, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, in combined-cycle combustion turbines the oxidation catalyst is placed within the HRSG at a location that is selected to ensure that the proper operating temperature is maintained, considering the temperature variations that are expected to occur across the unit's operating load range. Simple-cycle combustion turbines employing oxidation catalyst systems typically are equipped with the means to reduce the temperature of the turbine exhaust prior to introducing it into the catalytic reactor.

Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation to minimize VOC emissions.

No supplementary reactant is used in conjunction with an oxidation catalyst. The performance of an oxidation catalyst system is dependent on the specific VOC constituents present in the turbine exhaust.

Good Combustion Practices

As noted above, VOCs are formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of VOC is limited by designing and operating the combustion system to maximize oxidation of the fuel carbon to CO_2. Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time within the turbine combustor will minimize the formation of VOCs.

5.3 Step 2 - Technical Feasibility Assessment and Ranking of VOC Control Alternatives

Searches of EPA's RBLC were performed to identify large natural gas-fired combined-cycle and simple-cycle units permitted since 2012 with BACT or RACT determinations for VOC. The results of these RBLC searches are summarized in Appendix A, Tables A-3 and A-4.

The search among the combined-cycle unit listings found 128 listings that identify the VOC emission control alternative. The breakdown of these listings by emission control alternatives employed is as follows:

- 112 list the use of oxidation catalyst,
- 79 list good combustion practices, and.
- 19 list natural gas or clean fuels.

For the listings of simple-cycle units, the search identified 39 listings that identify the VOC emission control alternative. The breakdown of emission control alternatives identified in these listings is as follows:

- 15 list the use of oxidation catalyst,
- 31 list good combustion practices, and.
- 11 list natural gas or clean fuels.

Thus, oxidation catalyst and combustor design or good combustion practices are considered technically feasible alternatives for control of VOC emissions from natural gas-fired combined-cycle and simple-cycle combustion turbines. The hierarchy of VOC emission controls for natural gas-fired combustion turbines, including both combined-cycle and simple-cycle units, is as follows:

- Oxidation catalyst, either alone or in combination with good combustion practices, and
- Good combustion practices alone.

5.4 Step 4 – VOC Control Effectiveness Evaluation

Available VOC control alternatives for the existing simple-cycle Unit 4 and combined-cycle Units 5 – 8 combustion turbines at CGS consist of either oxidation catalyst systems or good combustion practices.

The existing simple-cycle Units 11 – 22 are already equipped with oxidation catalyst systems, and NV Energy concludes that the existing controls, emission limits, and monitoring method on these units are representative of RACT for VOC.

Considering the low rates that Units 4 – 8 are projected to operate in the future, very small reductions in VOC emissions from these units would be realized by retrofitting them with oxidation catalyst systems. As described further below, the cost effectiveness of oxidation catalyst systems on these units is estimated to be extremely unreasonable.

Economic Impacts

As with SCR, the retrofit of oxidation catalyst systems on the existing combustion turbine units at the CGS would entail significant capital and annual costs. Cost impact estimates for these units, based on budgetary estimates received from an equipment vendor, are provided in the following paragraphs and tables. The estimated emission control effectiveness of this alternative on these units is 80%.

Table 5-1 summarizes the economic impact of retrofitting an oxidation catalyst system on the simple-cycle CGS Unit 4, and on the combined-cycle Units 5 - 8. As with the economic analysis of NOx control alternatives presented in Section 4, annualized costs for each unit include capital recovery (based on a 20-year equipment life and an annual return on capital of 7.14%), annual maintenance costs, catalyst replacement costs, and lost power and capacity replacement charges due to the additional pressure drop imposed by the oxidation catalyst grid.

Table 5-1: Estimated Economic Impact of Retrofitting Oxidation Catalyst Systems: CGS Units 5 - 8

	CGS Unit 4	CGS Unit 5	CGS Unit 6	CGS Unit 7	CGS Unit 8
Baseline Emissions Level (ton/yr)	2.05	3.77	3.55	4.57	3.38
Achievable Emissions Level (ton/yr)	0.41	0.75	0.71	0.91	0.68
Annual Emissions Reduction (tons/yr)	1.64	3.02	2.84	3.65	2.70
Total Installed Capital Cost	$4,366,600	$5,030,300	$5,030,300	$5,030,300	$5,030,300
Annualized Capital Cost	$416,600	$479,900	$479,900	$479,900	$479,900
Annual O&M Cost	$200,800	$262,600	$259,900	$281,700	$261,600
Total Annual Cost	$617,400	$742,500	$739,800	$761,600	$741,500
Cost Effectiveness ($/ton removed)	$376,082	$246,514	$260,493	$208,543	$274,223

Energy Impacts

As with SCR, the required oxidation catalyst grid reduces the combustion turbine system generating capacity due to increased turbine backpressure and reduced efficiency. If these VOC control systems were installed, NV Energy would need to purchase additional generating capacity elsewhere to make up the lost system generating capacity. These energy cost impacts are included in the estimated O&M costs of this control option shown in Table 5-1.

Environmental Impacts

The use of an oxidation catalyst system on either combined-cycle or simple-cycle units has been shown to increase sulfuric acid emissions as a result of oxidation of a portion of the unit's SO_2 emissions to SO_3 and the subsequent reaction of SO_3 with water vapor to form sulfuric acid. The catalyst must also be regenerated periodically and must be disposed of or recycled at the end of its useful life.

There are no environmental impacts associated with the use of combustion controls on either combined-cycle or simple-cycle units.

5.4.1 Step 5 - Evaluation of RACT for VOC Control

Available VOC control alternatives for the existing simple-cycle and combined-cycle combustion turbines at CGS are the use of oxidation catalyst systems and good engineering practices. The existing Units 11 – 22 at the CGS are already equipped with oxidation catalyst systems, and thus this alternative is concluded to represent RACT for these units the existing emissions level of 1.49 pounds per hour. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

Considering the low rates that CGS Units 4 – 8 are projected to operate in the future, retrofitting these units with oxidation catalyst systems would result in very small reductions in VOC emissions at significant capital and annual operating expenses. As a result, and as summarized in Table 5-1, the cost effectiveness of retrofitting oxidation catalyst systems on these units is estimated to be extremely high. Therefore, the use of this alternative on these units is concluded to be unrepresentative of RACT on the basis of economic impacts.

Consequently, the use of good combustion practices is concluded to represent RACT for CGS Units 4 – 8 at the existing emission levels of 94.5 tons per year of VOC for Unit 4 and 5.01 pounds per hour for Units 5 – 8. No changes to the existing emission limits, monitoring, recordkeeping, or reporting requirements are needed to demonstrate compliance.

Appendix A

RACT/BACT/LAER Clearinghouse Search Results

TABLE A-1: 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 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
*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	
*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

TABLE A-1: 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 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
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
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

TABLE A-1: 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 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
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
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

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PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
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
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	

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PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
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	
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	

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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			
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/PETROCHEMICALS 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.
TX-0730	COLORADO BEND ENERGY CENTER	TX	4/1/2015	Combined-cycle gas turbine electric generating facility	1100	MW	efficient processes, practices, and designs				

TABLE A-1: 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 01/01/2012 and 8/29/2022
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	SCR and oxidation catalyst	2	PPMVD @ 15% O2	24-HR AVERAGE
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) combined cycle turbines	240	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
TX-0710	VICTORIA POWER STATION	TX	12/1/2014	combined cycle turbine	197	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	SCR & Dry Low-NOx Burners	2	PPM	@ 15% O2
TX-0712	TRINIDAD GENERATING FACILITY	TX	11/20/2014	combined cycle turbine	497	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
OH-0363	MIDDLETOWN ENERGY CENTER	OH	11/5/2014	Turbine generator with HRSG and duct burners (P001)	3278.5	MMBTU/H	Use of natural gas, low NOx burner, and selective catalytic reduction (SCR).	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	235	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
TX-0689	CEDAR BAYOU ELECTRIC GENERATION STATION	TX	8/29/2014	Combined cycle natural gas turbines	225	MW	DLN, SCR	2	PPM	24HR ROLLING AVG.
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Selective Catalytic Reduction System (SCR) and use of natural gas a clean burning fuel	2	PPMVD@15%O2	3-HR ROLLING AVE BASED ON 1-HR BLOCK
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Selective Catalytic reduction (SCR) and use of natural gas a clean burning fuel	2	PPMVD@15%O2	3-HR ROLLING AVE BASED ON 1-HR BLOCK
TX-0678	FREEPORT LNG PRETREATMENT FACILITY	TX	7/16/2014	Combustion Turbine	87	MW	Selective Catalytic Reduction	2	PPMVD	15@ O2, 3 HOUR ROLLING AVERAGE
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) combined cycle turbines	274	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD

TABLE A-1: 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 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258	mmBtu/hr	Low-NOx burners and SCR	2	PPM	30-DAY ROLLING AVG. @15% O2
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #2 -combined cycle	2258	mmBtu/hr	SCR, Low-NOx burner	2	PPM	30-DAY ROLLING AVERAGE
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	USE OF DRY LOW-NOX COMBUSTOR TURBINE DESIGN , USE OF PIPELINE QUALITY NATURAL GAS DURING NORMAL OPERATION AND SCR SYSTEM	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	Alstom Turbine	230.7	MW	Selective catalytic reduction	2	PPMVD	CORRECTED TO 15% O2, ROLLING 24 HR AVE
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Combined Cycle Combustion Turbine - Siemens turbine without Duct Burner	33691	MMCF/YR	Selective Catalytic Reduction and Dry Low NOx	2	PPMVD@ 15% O2	3-HR ROLLING AVE BASED ON 1-HR BLOCK
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Selective Catalytic Reduction System (SCR)	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK AVE
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Selective Catalytic Reduction Systems(SCR) and Dry Low NOx	2	PPMVD@15%O2	3-HR BLOCK AVERAGE BASED ON 1-HR BLOCK
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Selective Catalytic Reduction System (SCR) and Dry Low NOx	2	PPMVD@15%O2	3-HR ROLLING AVERAE BASED ON 1-HR BLOCK
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Mitsubishi M501-GAC combustion turbine, combined cycle configuration with duct burner.	2988	MMBTU/H	Utilize dry low-NOx burners when combusting natural gas; Utilize water injection when combusting ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown.	2	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	GE LMS-100 combustion turbines, simple cycle with water injection	1690	MMBTU/H	Utilize water injection when combusting natural gas or ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown.	2.5	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267	MMBTU/H	SCR	2	PPMVD	@ 15% OXYGEN

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PROCESS TYPE 15.210 (COMBINED CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H	Dry Low NOx Combustors & Selective Catalytic Reduction	2	PPMVD @ 15% O2	1 HR BLOCK AVG/DO NOT APPLY DURING SS
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046	MMBTU/H	SCR			
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each	SCR with DLNB (selective catalytic reduction with dry low NOx burners).	3	PPM	24-H ROLL.AVG. NOT STARTUP/SHUTDOWN
TX-0641	PINECREST ENERGY CENTER	TX	11/12/2013	combined cycle turbine	700	MW	selective catalytic reduction	2	PPMVD	24-HR ROLLING AVG, 15% OXYGEN
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2045	MMBTU/H	selective catalytic reduction (SCR) and dry low NOx combustors	2	PPM	BY VOLUME AT 15% O2
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Dry Low NOx burners (DLN) and Selective Catalytic Reduction (SCR) system.	2	PPMVOL	3-H ROLL AVG., EXCEPT STARTUP/SHUTDOWN
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Dry low NOx burner (DLN) and selective catalytic reduction system (SCR).	2	PPMVOL	3-H ROLL AVG., EXCEPT STARTUP/SHUTDOWN
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	Combustion Turbine with SCR/HRSG	607.1	MMBTU/hr	Selective Catalytic Reduction (SCR) and Water/Steam Injection	5	PPM@15% O2	12 MONTH AVERAGE
TX-0709	SAND HILL ENERGY CENTER	TX	9/13/2013	Natural gas-fired combined cycle turbines	173.9	MW	SCR	2	PPM	24HR ROLLING AVG.
TX-0698	BAYPORT COMPLEX	TX	9/5/2013	(4) cogeneration turbines	90	MW	DLN and Closed Loop Emissions Controls (CLEC)	5	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Turbines and duct burners - NG			Dry low NOx combustion technology and selective catalytic reduction.	2	PPMVD @ 15% O2	1 H
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGCCA or FGCCB--4 nat. gas fired CTG w/ DB for HRSG	2587	MMBTU/H heat inpu	Low NOx burners and selective catalytic reduction.	3	PPMV	24-H ROLLING AVERAGE
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	Combustion Turbine	360	MW	Dry Low-NOx burners with SCR.	2	PPMVD@15% O2	ONE-HR
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	360	MW	DRY LOW-NOx BURNER WITH SCR.	2	PPMVD@15% O2	ONE-HR
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines- Siemens, without duct burners	515600	MMSCF/rolling 12-m	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM	PPMVD AT 15% O2

TABLE A-1: 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 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-M	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-M	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917	MMSCF/rolling 12-M	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	2	PPM	PPMVD AT 15% O2
VA-0322	GREEN ENERGY PARTNERS/ STONEWALL, LLC	VA	4/30/2013	Large combustion turbines (>25MW) CCT1 and CCT2	2.23	MMBTU/H	Selective Catalytic Reduction (SCR), with ammonia injection and dry low NOx combusion.			
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Dry low NOx (DLN) burner and selective catalytic reduction (SCR) system.	2	PPM	EACH CTG; 24-H ROLLING AVG.
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Dry low NOx (DLN) burners and selective catalytic reduction (SCR) system.	2	PPM	24-H ROLLING AVG
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR	SCR	2	PPMVD @ 15% O2	WITH OR WITHOUT DUCT BURNER
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H	SCR	2	PPM	CORRECTED TO 15% OXYGEN
VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	3442	MMBTU/H	Selective catalytic reduction and ultra low NOx burners.	2	PPMVD @ 15% O2	1 H AVG
TX-0708	LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) combined cycle turbines	650	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVERAGE
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)			SCR	2	PPMDV	
DE-0024	GARRISON ENERGY CENTER	DE	1/30/2013	Unit 1	2260	million BTUs	Low NOx Combustors, Selective Catalytic Reduction	2	PPM	HOURLY AS BASELOAD ON NAT. GAS
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners Off	172	MW	Dry Low NOx burners and Selective Catalytic Reduction	3	PPM	PPMVD AT 15% O2 ON 3-H BLOCK AVERAGE
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners On	172	MW	Dry Low NOx burners and Selective Catalytic Reduction	3	PPM	PPMVD AT 15% O2 ON 3-H BLOCK AVERAGE
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300	MMBTU/H	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX BURNERS	2	PPMVD	3 HOURS
TX-0632	DEER PARK ENERGY CENTER LLC	TX	11/29/2012	CTG5/HRSG5(FD3-Series)						

TABLE A-1: 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 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
TX-0632	DEER PARK ENERGY CENTER LLC	TX	11/29/2012	CTG5/ HRSG5 (FD2- Series)						
TX-0633	CHANNEL ENERGY ENERGY CENTER, LLC	TX	11/29/2012	CTG3/HRSG3(FD2-Series) -Initial Phase						
TX-0633	CHANNEL ENERGY ENERGY CENTER, LLC	TX	11/29/2012	CTG3/HRSG3(FD3-Series) -Final Phase						
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Seleictive catalytic reduction (SCR) system	2	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Selective Catalytic Reduction (SCR) System and use of natural gas a clean burning fuel	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK AVE
DE-0023	NRG ENERGY CENTER DOVER	DE	10/31/2012	UNIT 2- KD1	655	MMBTU/H	Selective Catalytic Reduction	2.5	PPM	@ 15% OXYGEN BASED ON A 1 HOUR AVERAGE
TX-0618	CHANNEL ENERGY CENTER LLC	TX	10/15/2012	Combined Cycle Turbine	180	MW	Selective catalytic reduction	2	PPMVD	@15% O2 ON A 3-HR ROLLING AVG
FL-0337	POLK POWER STATION	FL	10/14/2012	Combine cycle power block (4 on 1)	1160	MW	SCR/DLN	2	PPMVD @15% O2	24-HR BLOCK (GAS) CEMS
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Dry low-NOx (DLN) combustor and selective catalytic reduction (SCR)	2	PPMVD	
TX-0619	DEER PARK ENERGY CENTER	TX	9/26/2012	Combined Cycle Turbine	180	MW	Selective Catalytic Reduction	2	PPMVD	@15% O2, 3-HR ROLLING AVG
TX-0620	ES JOSLIN POWER PLANT	TX	9/12/2012	Combined cycle gas turbine	195	MW	Selective catalytic reduction	2	PPMVD	@15% O2, 24-HR ROLLING AVG
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	SCR	3	PPMV AT 15% O2	1-HOUR
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	SCR	3	PPMV AT 15% O2	1-HOUR
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine with Duct Burner	40297.6	mmcubic ft/year	Low NOx burners and Selective Catalytic Reduction System	2	PPMVD	3 HR ROLLING AVE BASED ON 1-HR BLOCK AVE
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	DLN combustion system with SCR on each of the two combustion turbines and use of only natural gas as fuel.	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK

TABLE A-2: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
*AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Six Simple Cycle Gas-Fired Turbines	1113	MMBtu/hr	SCR, DLN combustors, and good combustion practices	2	PPMV @ 15% O2	3-HOURS
AL-0329	COLBERT COMBUSTION TURBINE PLANT	AL	9/21/2021	Three 229 MW Simple Cycle Combustion Turbines	229	MW		9	PPMVD	3 HOUR AVG @ 15% O2
TX-0908	NEWMAN POWER STATION	TX	8/27/2021	Simple Cycle Turbine	230	MW	Dry Low NOx Burners and SCR	2.5	PPMVD	
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGSC1-natural gas fired simple cycle CTG	667	MMBTU/H	DLNB and good combustion practices.	25	PPM	4-HR ROLL AVG EXCEPT LESS THAN 75% PEAK
TX-0900	ECTOR COUNTY ENERGY CENTER	TX	8/17/2020	Simple Cycle Turbines			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
AK-0085	GAS TREATMENT PLANT	AK	8/13/2020	Six (6) Simple Cycle Gas-Turbines (Power Generation)	386	MMBtu/hr	DLN combustors and Good Combustion Practices	15	PPMV @ 15% O2	3-HOUR AVERAGE
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	667	MMBTU/H	Dry low NOx burners (DLNB) and good combustion practices.	25	PPM	AT 15%O2;4-HR ROLL AVG; SEE NOTES BELOW
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MM BTU/h	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	25	PPMV	30 DAY ROLLING AVERAGE
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	927	MM BTU/h	Dry Low NOx Combustor Design, Good Combustion Practices, and Natural Gas Combustion.	9	PPMV	30 DAY ROLLING AVERAGE
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	2201	MM BTU/hr	Pipeline quality natural gas & dry-low-NOX burners	30	PPMVD @ 15% O2	
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	2201	MM BTU/hr	Pipeline quality natural gas & dry-low-NOX burners	30	PPMVD @ 15% O2	
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Pipeline quality natural gas & dry-low-NOX burners	9	PPMVD @15%O2	30-DAY ROLLING AVERAGE
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Pipeline quality natural gas & dry-low-NOX burners	9	PPMVD @15%O2	30-DAY ROLLING AVERAGE
WV-0028	WAVERLY POWER PLANT	WV	3/13/2018	GE 7FA.004 Turbine	167.8	MW	Dry LNB	9	PPM	
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines (normal operation)	920	MW	Dry low NOx burners	9	PPMVD	
TX-0826	MUSTANG STATION	TX	8/16/2017	Simple Cycle Turbine	162.8	MW	Dry low-NOx burners	9	PPMVD	
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Simple Cycle Turbine	227.5	MW	Dry Low NOx burners (control), natural gas, good combustion practices, limited operating hours (prevention)	9	PPMV	15% O2 3-H AVG

TABLE A-2: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
IN-0261	VERMILLION GENERATING STATION	IN	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES			
WV-0026	WAVERLY FACILITY	WV	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Dry Low-NOx Combustion System (DLNB), Water Injection	9	PPM	NATURAL GAS
IN-0264	MONTPELIER GENERATING STATION	IN	1/6/2017	PRATT & WHITNEY TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	WATER INJECTION	25	PPMV	AT 15% O2 FOR NATURAL GAS
CA-1238	PUENTE POWER	CA	10/13/2016	Gas turbine	262	MW		2.5	PPMVD	1 HOUR@15%O2
VA-0326	DOSWELL ENERGY CENTER	VA	10/4/2016	Two (2) GE 7FA simple cycle combustion turbines	1961	MMBTU/HR	Low NOx Burners/Combustion Technology	9	PPM	VD/12 MO ROLLING TOTAL
IL-0121	INVENERGY NELSON EXPANSION LLC	IL	9/27/2016	Two Simple Cycle Combustion Turbines	190	MW	Dry low-NOx combustion technology for natural gas and low-NOx combustion technology and water injection for ULSD.	9	PPMVD @ 15% O2	
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	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
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple cycle turbine	171	MW	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
TX-0788	NECHES STATION	TX	3/24/2016	Four Large Combustion Turbines >25 MW	232	MW	Dry low-NOx burners (DLN), good combustion practices	9	PPM	
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	Simple Cycle Electrical Generation Gas Turbines 15.210	34	MW	SELECTIVE CATALYTIC REDUCTION	5	PPM	ROLLING 24-HR AVERAGE
TX-0777	UNION VALLEY ENERGY CENTER	TX	12/9/2015	Simple Cycle Turbine	183	MW	dry low NOX burners	9	PPMVD @ 15% O2	3-HR ROLLING AVERAGE PEAK
TX-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	TX	10/27/2015	Simple Cycle Turbine	183	MW	DLN burners	9	PPMVD @ 15% O2	3-HR AVERAGE
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	TX	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Dry Low NOx burners, good combustion practices, limited operations	9	PPMVD @ 15% O2	
TX-0768	SHAWNEE ENERGY CENTER	TX	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	Dry Low NOx burners	9	PPMVD @ 15% O2	

TABLE A-2: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
FL-0355	FORT MYERS PLANT	FL	9/10/2015	Combustion Turbines	2262.4	MMBtu/hr gas	DLN and wet injection (for ULSD operation)	9	PPMVD@15% O2	GAS FIRING, 24-HR BLOCK AVG
TX-0733	ANTELOPE ELK ENERGY CENTER	TX	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Dry Low NOx burners	9	PPMVD AT 15% O2	
TX-0734	CLEAR SPRINGS ENERGY CENTER (CSEC)	TX	5/8/2015	Simple Cycle Turbine	183	MW	dry low-NOx (DLN) burners	9	PPMVD @ 15% O2	3-HR AVERAGE
TX-0694	INDECK WHARTON ENERGY CENTER	TX	2/2/2015	(3) combustion turbines	220	MW	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
TX-0688	SR BERTRON ELECTRIC GENERATION STATION	TX	12/19/2014	Simple cycle natural gas turbines	225	MW	DLN	9	PPM	3HR ROLLING AVG.
TX-0696	ROAN'S PRAIRIE GENERATING STATION	TX	9/22/2014	(2) simple cycle turbines	600	MW	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVG
TX-0695	ECTOR COUNTY ENERGY CENTER	TX	8/1/2014	(2) combustion turbines	180	MW	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVG
MD-0043	PERRYMAN GENERATING STATION	MD	7/1/2014	(2) 60-MW SIMPLE CYCLE COMBUSTION TURBINES, FIRING NATURAL GAS	120	MW	USE OF NATURAL GAS, WATER/STEAM INJECTION, AND A SELECTIVE CATAYTIC REDUCTION (SCR) SYSTEM	2.5	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	283	MMBTU/H, EACH	DRY LOW NOX COMBUSTORS	22.65	PPMVD AT 15% OXYGEN	3-HR AVERAGE AT >50% PEAK LOAD
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	283	MMBTU/H, EACH	DRY LOW NOX COMBUSTORS	22.65	PPMVD AT 15% OXYGEN	3-HR AVERAGE AT >50% PEAK LOAD
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	TX	5/20/2014	(6) simple cycle turbines	65	MW	DLN combustors	15	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
TX-0686	ANTELOPE ELK ENERGY CENTER	TX	4/22/2014	Combustion Turbine-Generator (CTG)	202	MW	DLN	9	PPM	15% O2, 3 HR. ROLLING AVG.
TX-0693	ANTELOPE ELK ENERGY CENTER	TX	4/22/2014	combustion turbine	202	MW	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	GE LMS-100 combustion turbines, simple cycle with water injection	1690	MMBTU/H	Utilize water injection when combusting natural gas or ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown.	2.5	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG

TABLE A-2: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR NITROGEN OXIDES (NOx)

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
ND-0030	LONESOME CREEK GENERATING STATION	ND	9/16/2013	Natural Gas Fired Simple Cycle Turbines	412	MMBTU/H	SCR	5	PPMVD	4 HOUR ROLLING AVERAGE EXCEPT STARTUP
ND-0029	PIONEER GENERATING STATION	ND	5/14/2013	Natural gas-fired turbines	451	MMBTU/H	Water injection plus SCR	5	PPPMVD	4 HR. ROLLING AVERAGE EXCEPT FOR STARTUP
TX-0701	ECTOR COUNTY ENERGY CENTER	TX	5/13/2013	Simple Cycle Combustion Turbines	180	MW	Dry low NOx combustor	9	PPMVD	15%O2, 3HR ROLLING BASIS
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	water injection	25	PPMDV	24-HR ROLLING AVE; CORRECTED TO 15% O
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	dry low NOx burners and fire only pipeline natural gas	9	PPMDV	24-HR ROLLING AVE, CORRECTED TO 15% O2
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE 7FA Simple Cycle Combustion Turbine	1780	MMBTU/HR	dry low NOx burners and fire only pipeline natural gas	9	PPMDV	24-HR ROLLING AVE, CORRECTED TO 15% O2
ND-0028	R.M. HESKETT STATION	ND	2/22/2013	Combustion Turbine	986	MMBTU/H	Dry low-NOx combustion (DLN)	9	PPMVD @15% OYYGEN	4 H.R.A. WHEN > 50MWE AND > 0 DEGREES F
CA-1223	PIO PICO ENERGY CENTER	CA	11/19/2012	COMBUSTION TURBINES (NORMAL OPERATION)	300	MW	WATER INJECTION, SCR	2.5	PPMVD	@15% O2, 1-HR AVG
TX-0690	CEDAR BAYOU ELECTRIC GERNERATION STATION	TX	9/12/2012	Simple Cycle Combustion Turbines	225	MW	DLN	9	PPM	3HR. ROLLING AVG.
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP03)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Trubine (EP04)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR AVERAGE
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP05)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	171	MMBTU/H	Dry low-NOx combustors	24	PPMVD @ 15% O2	

TABLE A-3: 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 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
*AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Four Combined Cycle Gas-Fired Turbines	384	MMBtu/hr	Oxidation catalyst 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	good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W/O DUCT FIRING
*WV-0033	MAIDSVILLE	WV	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 &; CT-02/HRSG2)	1275	mw	good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W/O DUCT FIRING
TX-0915	UNIT 5	TX	3/17/2021	COMBINED CYCLE TURBINE			OXIDATION CATALYST	1	PPMVD	3-HR ROLLING
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG1	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY EXCEPT STARTUP SHUTDOWN
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG2	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY; EXCEPT DURING STARTUP/SHUTDOWN
AL-0328	PLANT BARRY	AL	11/9/2020	Two 744 MW Combined Cycle Units	744	MW	Oxidation Catalyst	2	PPMDV @ 15% O2 as CH4	
*WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural-Gas-Fired Combined-Cycle Turbine (P01)	4671	MMBTU/H	Oxidation Catalyst, good combustion control	2.7	PPM AT 15% O2	168-HR AVG., NAT. GAS, DUCT FIRING
LA-0364	FG LA COMPLEX	LA	1/6/2020	Cogeneration Units	2222	mm btu/h	Good combustion practices and catalytic oxidation	4	PPMVD	
*MI-0445	INDECK NILES, LLC	MI	11/26/2019	FGCTGHRSG	3421	MMBTU/H	Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas.	4	PPM	PPMVD@15%O2, HOURLY; EACH
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	MI	8/21/2019	FGCTGHRSG	625	MW	Oxidation catalyst and good combustion practices.	3	PPMDV @ 15% O2 as CH4	
NJ-0088	COGEN TECH LINDEN VENTURE LP	NJ	7/30/2019	250 MW COMBINED CYCLE COMBUSTION TURBINE FIRING NATURAL GAS	21042	MMCubic ft/yr	Add on Oxidation Catalyst and use of Natural Gas as primary fuel for pollution prevention	1	PPMVD@15% O2	3 H ROLLING AV BASED ON ONE H BLOCK
VA-0332	CHICKAHOMINY POWER LLC	VA	6/24/2019	Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators	35000	MMCF/YR	Controlled by an oxidation catalyst and good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time)	0.7	PPMVD @ 15% O2	3 HR AVG
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	667	MMBTU/H	An oxidation catalyst for VOC control and good combustion practices.	3	PPM	PPMVD@15%O2; HOURLY; SEE NOTES

TABLE A-3: 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 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
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	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	PPMVD@15%O2; HOURLY EXC.START/SHUT; NOTE
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	921	MM BTU/h	Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices.	1.1	PPMV	3 HOUR AVERAGE
*WV-0032	BROOKE COUNTY POWER PLANT	WV	9/18/2018	GE 7HA.01 Turbine	2737.7	mmBtu/hr	Oxidation Catalyst, Good Combustion Practices	2	PPMDV @ 15% O2 as CH4	
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	2665.9	MMBtu/hr	Oxidation Catalyst	1	PPMDV	@15% O2
*PA-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	COMBUSTION TURBINE UNIT with DUCT BURNERS UNIT				1.4	PPMDV	@15% O2
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	An oxidation catalyst and good combustion practices.	1	PPMVD	HOURLY; EACH CT/HRSG TRAIN
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)			Oxidation catalyst technology and good combustion practices.	2	PPMDV @ 15% O2 as CH4	
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	Oxidation catalyst technology and good combustion practices.	4	PPMVD	AT 15%O2; NOT INCL. STARTUP/SHUTDOWN
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	Oxidation catalyst technology and good combustion practices.	4	PPMVD	AT 15%O2; HOURLY
VA-0328	C4GT, LLC	VA	4/26/2018	GE Combustion Turbine - Option 1 - Normal Operation	34000	MMCF/YR	Oxidation catalyst and good combustion practices	0.7	PPMVD @ 15% O2	3 HR AV/WITHOUT DB
VA-0328	C4GT, LLC	VA	4/26/2018	Siemens Combusion Turbine - Option 2 - Normal Operation	35000	MMCF/YR	Oxidation catalyst and good combustion practice	1	PPMVD @ 15% O2	3 H AV/WITHOUT DB
OH-0377	HARRISON POWER	OH	4/19/2018	General Electric (GE) Combustion Turbines (P005 & P006)	3459.6	MMBTU/H	Good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2 as CH4	
OH-0377	HARRISON POWER	OH	4/19/2018	Mitsubishi Hitachi Power Systems (MHPS) Combustion Turbines (P007 & P008)	3231	MMBTU/H	Good combustion practices and oxidation catalyst	2	PPMDV @ 15% O2 as CH4	
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	Oxidation catalyst	2	PPMVD	15% O2 3 HOUR AVERAGE
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	GE 7HA.02 Turbine	3496.2	mmBtu/hr	Oxidation Catalyst, Good Combustion Practices	3	PPMDV @ 15% O2 as CH4	

TABLE A-3: 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 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
FL-0364	SEMINOLE GENERATING STATION	FL	3/21/2018	2-on-1 natural gas combined-cycle unit (GE 7HA.02)	3514	MMBtu/hr	Oxidation catalyst	1	PPMVD@15% O2	WITHOUT DUCT BURNER FIRING
*PA-0316	RENOVO ENERGY CENTER, LLC	PA	1/26/2018	Combustion Turbine Firing NG				1	PPMDV	CORRTECTED TO 15% O2
FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	2-on-1 combined cycle unit (GE 7HA)	4000	MMBtu/hr	Clean fuels	1	PPMVD@15% O2	FOR NATURAL GAS OPERATION
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	General Electric Combustion Turbine (P004)	3544	MMBTU/H	Oxidation catalyst and good combustion practices as recommended by the manufacturer.	1	PPMDV @ 15% O2 as CH4	
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Mitsubishi Combustion Turbine (P005)	3320	MMBTU/H	oxidation catalyst and shall operate the emissions unit in accordance with good combustion practices as recommended by the manufacturer	2	PPMDV @ 15% O2 as CH4	
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Siemens Combustion Turbine (P006)	3602	MMBTU/H	oxidation catalyst and shall operate the emissions unit in accordance with good combustion practices as recommended by the manufacturer	2	PPMDV @ 15% O2 as CH4	
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Combined Cycle Combustion Turbines (3, identical) (P001 to P003)	3516	MMBTU/H	oxidation catalyst and good combustion practices as recommended by the manufacturer	3	PPMDV @ 15% O2 as CH4	
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3055	MMBTU/H	oxidation catalyst and good combustion control	2	PPMDV @ 15% O2 as CH4	
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3025	MMBTU/H	Good combustion controls and oxidation catalyst	2	PPMDV @ 15% O2 as CH4	
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/o Duct Firing	2969	MMBtu/hr	Oxidation Catalyst	0.7	PPMVD @15% O2	
CT-0161	KILLINGLY ENERGY CENTER	CT	6/30/2017	Natural Gas w/Duct Firing	2639	MMBtu/hr	Oxidation Catalyst	1.6	PPMVD @15% O2	
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	Oxidation catalyst and good combustion practices	3.5	PPMVD	15% O2
*PA-0315	HILLTOP ENERGY CENTER, LLC	PA	4/12/2017	Combustion Turbine without Duct Burner	3509	MMBtu/hr		1	PPMDV	CORRECTED TO 15% O2
*PA-0315	HILLTOP ENERGY CENTER, LLC	PA	4/12/2017	Combustion Turbine With Duct Burner	4367	MMBtu/hr		2	PPMDV	CORRECTED TO 15% O2
TX-0817	CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION	TX	2/17/2017	Combined Cycle Cogeneration	50	MW	OXIDATION CATALYST	1	PPMDV	
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Oxidation Catalyst Technology and Good Combustion Practices	4	PPM	TEST PROTOCOL WILL SPECIFY

TABLE A-3: 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 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
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	Oxidation catalyst technology and good combustion practices.	4	PPM AT 15% O2	TEST PROTOCOL WILL SPECIFY AVG TIME
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3131	MMBTU/H	Good combustion controls and oxidation catalyst	3	PPMDV @ 15% O2 as CH4	
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner NG only	3338	MMBtu/hr	Oxidation catalyst and good combustion practices	1.5	PPMDV @ 15% O2	
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG without duct burner NG only				1	PPMDV @ 15% O2	
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1A	3625	MMBTU/hr	Catalytic oxidation and good combustion practices for normal operations, and good combustion practices for startup/shutdown operations.	13	PPMDV @ 15% O2 as CH4	
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Combined Cycle Unit 1B	3625	MMBTU/hr	Catalytic oxidation and good combustion practices during normal operations, and good combustion practices during startup/shutdown operations.	13	PPMDV @ 15% O2 as CH4	
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	Oxidation Catalyst and good combustion practices	2	PPMVD@15%O2	AV OF THREE ONE H STACK TESTS EVERY 5 YR
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	Oxidation catalyst and good combustion practices	1	PPMVD@15%O2	AV OF THREE ONE H STACK TESTS EVERY 5 YR
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Oxidation Catalyst and good combustion practices	1.4	PPMVD	
TX-0788	NECHES STATION	TX	3/24/2016	Large Combustion Turbines >25 MW	232	MW	good combustion practices	2	PPM	
TX-0788	NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	2	PPM	
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Combined Cycle Combustion Turbine with Duct Burner firing natural gas			Oxidation Catalyst and good combustion practices	2	PPMVD	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	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	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	Complete combustion minimizes VOC	1	PPMVD@15%O2	GAS OPERATION
TX-0789	DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	2	PPM	

TABLE A-3: 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 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	PA	2/12/2016	Large Combustion turbine			Ox Cat and good combustion practices	1.4	PPMVD @ 15% O2	
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	PA	2/12/2016	Large combustion turbine			Ox Cat and good combustion practices	2.4	PPMDV@15% O2	
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Turbines and duct burners	228	mw	good combustion practices and oxidation catalyst	0.7	PPMVD @ 15% O2	1 H
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Combustion turbine with duct burner	3304.3	MMBtu/hr	Oxidation catalyst, combustion controls, exclusive natural gas	1.5	PPMDV @ 15% O2	
CT-0157	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months	Oxidation Catalyst	1	PPMVD @15% O2	
CT-0158	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	Oxidation Catalyst	1	PPMVD @15% O2	
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	3-HR BLOCK AVG. W/OUT DUCT FIRING
TX-0773	FGE EAGLE PINES PROJECT	TX	11/4/2015	Combined Cycle Turbines (>25 MW)	321	MW	Oxidation Catalyst	2	PPM	
TX-0767	LON C. HILL POWER STATION	TX	10/2/2015	Combined Cycle Turbines (>25 MW)	195	MW	oxidation catalyst	2	PPM	
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine With Duct Burner	3727	MMBtu/hr	Oxidation catalyst and good engineering practice	1.5	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	Good combustion controls and oxidation catalyst	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
PA-0305	SHELL CHEM APPALACHIA/PETROCHEMICALS COMPLEX	PA	6/18/2015	Combustion turbine wih duct burner and heat recovery steam generator	Three 40.6 MW turbines			1	PPMDV @ 15% O2	
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	Combined Cycle Turbines (>25 MW) natural gas	210	MW	Oxidation catalyst	2	PPM	
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Two combined cycle turbines with out duct burner	2291.64	MCF/hr	Oxidation catalyst, good combustion practices and low sulfur fuels	1.5	PPMDV @ 15% O2	
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	Oxidation catalyst, good combustion practices and low sulfur fuels	1.9	PPMDV @ 15% O2	
KY-0104	CASH CREEK GENERATING STATION	KY	6/10/2015	Combined cycle combustion turnbine with HRSG and duct firing	849	MW	burn Pipeline quality Natural Gas			

TABLE A-3: 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 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
OH-0365	ROLLING HILLS GENERATING, LLC	OH	5/20/2015	Combustion Turbines, Scenario 1 (4, identical) (P001, P002, P004, P005)	2022	MMBTU/H	good combustion practices along with clean fuels	1.4	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	good combustion practices along with clean fuels	0.84	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
TX-0730	COLORADO BEND ENERGY CENTER	TX	4/1/2015	Combined-cycle gas turbine electric generating facility	1100	MW	SCR and oxidation catalyst	4	PPMVD @ 15% O2	3-HR AVERAGE
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) combined cycle turbines	240	MW	oxidation catalyst	1	PPMVD	@15% O2
TX-0710	VICTORIA POWER STATION	TX	12/1/2014	combined cycle turbine	197	MW	oxidation catalyst	4	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	Oxidation Catalyst & Good Combustion Practices	2	PPM	@ 15% O2
TX-0712	TRINIDAD GENERATING FACILITY	TX	11/20/2014	combined cycle turbine	497	MW	oxidation catalyst	4	PPMVD	@15% O2 1-HR
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	W/OUT DUCT FIRING, 3-HR BLOCK AVG
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Oxidation catalysts and use of Natural gas a clean burning fuel	0.7	PPMVD215%O2	AVERAGE OF THREE ONE HOUR STACK TESTS
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Oxidation catalyst and use of natural gas a clean burning fuel	1	PPMVD@15%O2	AVERAGE OF THREE STACK TEST RUNS
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) combined cycle turbines	274	MW	oxidation catalyst	2	PPMVD	@15% O2, 3-HR AVERAGE
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	725	MW	EXCLUSIVE USE OF NATURAL GAS, AND AN OXIDATION CATALYST	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD

TABLE A-3: 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 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258	mmBtu/hr	catalytic oxidizer	1	PPM	AVG. OF 3 ONE HOUR TEST RUNS
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #2 -combined cycle	2258	mmBtu/hr		1	PPM	AVERAGE OF 3 ONE-HOUR TEST RUNS
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	USE OF PIPELINE NATURAL GAS, GOOD COMBUSTION PRACTICES, AND USE OF AN OXIDATION CATALYST	1.6	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	Alstom Turbine	230.7	MW	Oxidation catalyst, good combustion practices	2	PPMVD	CORRECTED TO 15% O2, ROLLING 3 HR AVE
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Combined Cycle Combustion Turbine - Siemens turbine without Duct Burner	33691	MMCF/YR	Good Combustion Practices and use of Natural gas as a clean burning fuel	1	PPMVD@ 15%O2	AVERAGE OF THREE TESTS
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Oxidation catalyst and pollution prevention (use of natural gas a clean burning fuel)	2	PPMVD	AVERAGE OF THREE ONE HOUR TESTS
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	CO Oxidation Catalyst and good combustion practices and use natural gas only as a clean burning fuel	2	PPMVD@15%O2	AVERAGE OF THREE ONE HOUR TESTS
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Oxidation Catalyst and use of natural gas a clean burning fuel	1	PPMVD@15%O2	AVERAGE OF THREE ONE-HOUR TESTS
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Mitsubishi M501-GAC combustion turbine, combined cycle configuration with duct burner.	2988	MMBTU/H	Oxidation catalyst; Limit the time in startup or shutdown.	2	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267	MMBTU/H	CO Catalyst	2	PPMVD	@ 15% OXYGEN
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H	Oxidation catalyst	1	PPMVD@15% O2	1 HR AVG EXCLUDING SS/NO DUCT FIRING
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046	MMBTU/H				

TABLE A-3: 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 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each	Oxidation catalyst technology and good combustion practices.	4	PPM	TEST PROTOCOL
TX-0641	PINECREST ENERGY CENTER	TX	11/12/2013	combined cycle turbine	700	MW	oxidation catalyst	2	PPMVD	INITIAL STACK TEST, 15% OXYGEN
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2045	MMBTU/H	oxidation catalyst	3	PPMDV @ 15% O2 as CH4	
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Catalytic oxidation system (COS)	2	PPMVOL	DRY AT 15% OXYGEN
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Catalytic oxidation system (COS)	2	PPMVOL	DRY AT 15% OXYGEN
TX-0709	SAND HILL ENERGY CENTER	TX	9/13/2013	Natural gas-fired combined cycle turbines	173.9	MW		2	PPM	1HR. AVG.
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Turbines and duct burners - NG			Good combustion practice and oxidation catalyst.	0.7	PPMVD @ 15% O2	1 H
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGCCA or FGCCB--4 nat. gas fired CTG w/ DB for HRSG	2587	MMBTU/H heat inp	Efficient combustion control plus catalytic oxidation system.			
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	Combustion Turbine	360	MW	Oxidation catalyst and good combustion practices.	5	PPMVD@15%O2	30-DAY
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	360	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES.	5	PPMVD@15% O2	30-DAY
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600	MMSCF/rolling 12-m	oxidation catalyst	1	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-N	oxidation catalyst	1.9	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-N	oxidation catalyst	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917	MMSCF/rolling 12-N	oxidation catalyst	2	PPM	PPMVD AT 15% O2
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Good combustion practices	1	PPMDV @ 15% O2 as CH4	
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Good combustion practices	3	PPMDV @ 15% O2 as CH4	

TABLE A-3: 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 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR	Oxidation Catalyst	1.5	PPMVD @ 15% OXYGEN	WITH OR WITHOUT DUCT BURNER
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H	Oxidation Catalyst	1	PPM	3 LB/HR, DUCT BURN NOT OPERATING, 15% O2
VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	3442	MMBTU/H	Oxidation catalyst; good combustion practices.	0.7	PPMVD	3 H AVG/WITHOUT DUCT BURNING
TX-0708	LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) combined cycle turbines	650	MW	oxidation catalyst	2	PPMVD	@15% O2, 3-HR ROLLING
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)			CO Catalyst	1	PPMDV	WITHOUT DUCT BURNER
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners Off	172	MW	Using efficient combustion technology			
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	Turbines (4) (model GE 7FA) Duct Burners On	172	MW	Using efficient combustion technology			
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300	MMBTU/H	OXIDIZED CATALYST	1	PPMVD	3 HOURS
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Oxidation catalyst	1	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Oxidation Catalyst and Good combustion Practices and use of natural gas a clean burning fuel			
DE-0023	NRG ENERGY CENTER DOVER	DE	10/31/2012	UNIT 2- KD1	655	MMBTU/H	Oxidation catalyst system	8	PPMDV @ 15% O2 as CH4	
TX-0618	CHANNEL ENERGY CENTER LLC	TX	10/15/2012	Combined Cycle Turbine	180	MW	Good combustion	2	PPMVD	@15% O2
FL-0337	POLK POWER STATION	FL	10/14/2012	Combine cycle power block (4 on 1)	1160	MW	fuel Sulfur limits	1.4	PPMVD @15% O2	
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Oxidation Catalyst	1	PPMVD	WITHOUT DUCT BURNER
TX-0619	DEER PARK ENERGY CENTER	TX	9/26/2012	Combined Cycle Turbine	180	MW	good combustion, use of natural gas	2	PPMVD	@15% O2
TX-0620	ES JOSLIN POWER PLANT	TX	9/12/2012	Combined cycle gas turbine	195	MW	good combustion and natural gas as fuel	2	PPMVD @15% O2	

TABLE A-3: 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 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	1-HOUR
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine with Duct Burner	40297.6	mmcubic ft/year	oxidation Catalyst and Good Combustion Practices and use of Clean fuel (Natural gas)	2	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLK
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	Oxidation catalyst and good combustion practices, use of natural gas a clean burning fuel	1	PPMVD	3H ROLLING AVE BASED ON 1H BLOCKS

TABLE A-4: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
*AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Six Simple Cycle Gas-Fired Turbines	1113	MMBtu/hr	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS
TX-0908	NEWMAN POWER STATION	TX	8/27/2021	Simple Cycle Turbine	230	MW	Use of Natural gas, good combustion practices, and oxidation catalyst	2	PPMVD	
TX-0915	UNIT 5	TX	3/17/2021	SIMPLE CYCLE TURBINE	14552539	MMBTU/YR	Oxidation catalyst	1.5	PPMVD	3-HR ROLLING
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGSC1-natural gas fired simple cycle CTG	667	MMBTU/H	Good combustion practices	6	PPMDV @ 15% O2 as CH4	
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG1	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY EXCEPT STARTUP SHUTDOWN
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG2	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY; EXCEPT DURING STARTUP/SHUTDOWN
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LA	9/3/2020	Turbines (EQT0020 - EQT0031)			Good combustion practices			
AK-0085	GAS TREATMENT PLANT	AK	8/13/2020	Six (6) Simple Cycle Gas-Turbines (Power Generation)	386	MMBtu/hr	Good Combustion Practices and burning clean fuels (NG)	2	PPMDV @ 15% O2 as CH4	
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	667	MMBTU/H	Good combustion practices.	6	PPMDV @ 15% O2 as CH4	
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MM BTU/h	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.5	PPMV	3 HOUR AVERAGE
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	927	MM BTU/h	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.4	PPMV	3 HOUR AVERAGE
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas			
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas			
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines (normal operation)	920	MW	Good combustion practices	2	PPMVD	
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Simple Cycle Turbine	227.5	MW	Pipeline quality natural gas; limited hours; good combustion practices	2	PPMVD	
IN-0261	VERMILLION GENERATING STATION	IN	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES			

TABLE A-4: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	Gas turbines (9 units)	1069	mm btu/hr	good combustion practices and fueled by natural gas	1.6	PPMVD	@15%O2
CA-1238	PUENTE POWER	CA	10/13/2016	Gas turbine	262	MW		2	PPMVD AS METHANE	1 HOUR@15%O2
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	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
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple cycle turbine	171	MW	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.			
TX-0788	NECHES STATION	TX	3/24/2016	Large Combustion Turbines >25 MW	232	MW	good combustion practices	2	PPM	
LA-0307	MAGNOLIA LNG FACILITY	LA	3/21/2016	Gas Turbines (8 units)	333	mm btu/hr	good combustion practices and fueled by natural gas			
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	Simple Cycle Electrical Generation Gas Turbines 15.210	34	MW	OXIDATION CATALYST	2	PPM	3-HR AVERAGE
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	PA	2/12/2016	Large Combustion turbine			Ox Cat and good combustion practices	1.4	PPMVD @ 15% O2	
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	PA	2/12/2016	Large combustion turbine			Ox Cat and good combustion practices	2.4	PPMDV@15% O2	
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	TX	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	2	PPMVD @ 15% O2	
TX-0768	SHAWNEE ENERGY CENTER	TX	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	Pipeline quality natural gas; limited hours; good combustion practices.	1.4	PPMV	
TX-0733	ANTELOPE ELK ENERGY CENTER	TX	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Good combustion practices	2	PPMVD @ 15% O2	
TX-0696	ROAN'S PRAIRIE GENERATING STATION	TX	9/22/2014	(2) simple cycle turbines	600	MW	good combustion	1.4	PPMVD	@15% O2 GE OPTION
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	2 COMBUSTION TURBINES	130	MW	THE USE OF PROCESS FUEL GAS AND PIPELINE NATURAL GAS, GOOD COMBUSTION PRACTICES, AND USE OF AN OXIDATION CATALYST	0.7	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	283	MMBTU/H, EACH	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	2.5	PPMVD AT 15% OXYGEN	1-HR AVERAGE
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	283	MMBTU/H, EACH	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	2.5	PPMVD AT 15% OXYGEN	1-HR AVERAGE
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	GE LMS-100 combustion turbines, simple cycle with water injection	1690	MMBTU/H	Oxidation catalyst; Limit the time in startup or shutdown.			

TABLE A-4: RACT/BACT/LAER CLEARINGHOUSE SEARCH RESULTS
PROCESS TYPE 15.110 (SIMPLE CYCLE TURBINES, NORMAL OPERATION), NATURAL GAS FIRED, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2012 and 8/29/2022
LISTINGS FOR VOC

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT		
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	GE LMS-100 combustion turbines, simple cycle with water injection	1690	MMBTU/H	Oxidation catalyst; Limit the time in startup or shutdown.			
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	171	MMBTU/H	Efficient combustion; natural gas fuel.	2	PPMDV @ 15% O2 as CH4	
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	utilize efficient combustion/design technology	11	PPMDV @ 15% O2 as CH4	
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE 7FA Simple Cycle Combustion Turbine	1780	MMBTU/HR	will utilize efficient combustion/design technology	1	PPMDV @ 15% O2 as CH4	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP03)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Trubine (EP04)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP05)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE

Appendix B

Capital and Annual Cost Calculation Summaries

Summary of Economic Impact of Alternative Emission Controls

	CGS4	CGS5	CGS6	CGS7	CGS8	SPGS3	SPGS4	SPGS5	*Basis*
Baseline Operation (hours/yr)	303	1,689	1,626	2,143	1,667	597	453	406	*Highest two-year average in past five years*
NOx CONTROL ALTERERNATIVES									
Baseline NOx Emissions Level									
(tons/yr)	37.65					32.19	24.30	21.69	*Highest two-year average in past five years*
(avg lb/MMBtu)	0.44					0.1357	0.1334	0.1348	*calculated*
(ppm @ 15% O2)	120					37	36	37	*calculated*
Selective Catalytic Reduction									
Achievable Emissions Level									
(ppm @ 15% O2)	4					2	2	2	*Vendor (PMC) estimate*
(tons/yr)	1.26					1.75	1.34	1.18	*calculated*
Annual Emissions Reduction (tons/yr)	36.39					30.44	22.96	20.51	*calculated*
Capital Equipment Cost	$10,100,000					$12,500,000	$12,500,000	$12,500,000	*Vendor (PMC) CAPX cost*
Sales Tax	$464,600					$575,000	$575,000	$575,000	*4.6% Nevada sales tax*
Direct Installation Cost	$7,000,000					$8,500,000	$8,500,000	$8,500,000	*Vendor (PMC) direct installation cost*
Indirect Installation Cost	$3,697,600					$4,576,300	$4,576,300	$4,576,300	*35% of capital equipment cost (OAQPS Manual)*
Total Capital Cost	$21,262,200					$26,151,300	$26,151,300	$26,151,300	
Annualized Capital Cost	$2,028,400					$2,494,800	$2,494,800	$2,494,800	*20 yr equipment life, 7.14% ROI*
O&M Costs									
Catalyst changeout	$156,100					$156,100	$156,100	$156,100	*5 year life, 7.14% ROI, Vendor (PMC) catalyst cost*
Annual maintenance	$106,300					$130,800	$130,800	$130,800	*0.5% of total capital investment (OAQPS Manual)*
Power cost	$12,700					$25,100	$19,100	$17,100	*$0.0754/kwhr, estimated power loss in kw*
Lost capacity cost	$36,200					$36,200	$36,200	$36,200	*$21.60/kw-month @ 3 months, est. power loss in kw*
NH3 usage	$13,700					$11,500	$8,600	$7,700	*Estimated NH3 consumption at $0.69/gal*
Total Annualized Cost	$2,353,400					$2,854,500	$2,845,600	$2,842,700	
Cost Effectiveness ($/ton)	**$64,672**					**$93,779**	**$123,944**	**$138,633**	
Dry Low NOx Combustor									
Achievable Emissions Level									
(ppm @ 15% O2)	25					9	9	9	*Vendor (GE) estimate*
(tons/yr)	7.88					7.86	6.04	5.33	*calculated*
Annual Emissions Reduction (tons/yr)	29.77					24.33	18.26	16.36	*calculated*
Capital Equipment Cost						$9,000,000	$9,000,000	$9,000,000	*Vendor (GE) estimate*
Sales Tax						$414,000	$414,000	$414,000	*4.6% Nevada sales tax*
Direct Installation Cost						$1,500,000	$1,500,000	$1,500,000	*Vendor (GE) estimate*
Indirect Installation Cost						$3,294,900	$3,294,900	$3,294,900	*35% of capital equipment cost (OAQPS Manual)*
Total Capital Cost	$19,000,000					$14,208,900	$14,208,900	$14,208,900	*Vendor (GE) estimate*
Annualized Capital Cost	$1,812,600					$1,355,500	$1,355,500	$1,355,500	*20 yr equipment life, 7.14% ROI*
O&M Cost									
Annual maintenance	$95,000					$71,000	$71,000	$71,000	*0.5% of total capital investment (OAQPS Manual)*
Power cost	$0					$342,500	$259,900	$232,700	*$0.0754/kwhr, estimated power loss in kw*
Lost capacity cost	$0					$492,800	$492,800	$492,800	*$21.60/kw-month @ 3 months, est. power loss in kw*
Total Annualized Cost	$1,907,600					$2,261,800	$2,179,200	$2,152,000	
Cost Effectiveness ($/ton)	**$64,069**					**$92,978**	**$119,316**	**$131,553**	
VOC CONTROL ALTERERNATIVE									
Baseline VOC Emissions Level (tons/yr)	2.05	3.77	3.55	4.57	3.38				*Highest two-year average in past five years*
Catalytic Oxidation									
Achievable Emissions Level (tons/yr)	0.41	0.75	0.71	0.91	0.68				*80% reduction*
Annual Emissions Reduction (tons/yr)	1.64	3.01	2.84	3.65	2.70				*calculated*
Capital Equipment Cost	$2,030,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000				*Vendor (PMC) CAPX cost*
Sales Tax	$93,400	$115,000	$115,000	$115,000	$115,000				*4.6% Nevada sales tax*
Direct Installation Cost	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000				*Vendor (PMC) direct installation cost*
Indirect Installation Cost	$743,200	$915,300	$915,300	$915,300	$915,300				*35% of capital equipment cost (OAQPS Manual)*
Total Capital Cost	$4,366,600	$5,030,300	$5,030,300	$5,030,300	$5,030,300				
Annualized Capital Cost	$416,600	$479,900	$479,900	$479,900	$479,900				*20 yr equipment life, 7.14% ROI*
O&M Cost									
Catalyst changeout	$130,100	$130,100	$130,100	$130,100	$130,100				*5 year life, 7.14% ROI, Vendor (PMC) catalyst cost*
Annual maintenance	$21,800	$25,200	$25,200	$25,200	$25,200				*0.5% of total capital investment (OAQPS Manual)*
Power cost	$12,700	$71,100	$68,400	$90,200	$70,100				*$0.0754/kwhr, estimated power loss in kw*
Lost capacity cost	$36,200	$36,200	$36,200	$36,200	$36,200				*$21.60/kw-month @ 3 months, est. power loss in kw*
Total Annualized Cost	$617,400	$742,500	$739,800	$761,600	$741,500				
Cost Effectiveness ($/ton)	**$376,082**	**$246,514**	**$260,493**	**$208,543**	**$274,223**				

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.*)

<u>Cost of Capital and Revenue Requirement</u>

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

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[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

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[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)

PUBLIC UTILITIES COMMISSION OF NEVADA
PUC

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

Nevada Power Company
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("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

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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.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

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).

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

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.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

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]

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

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.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

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.
Austin Jensen, Esq.

CAESARS ENTERPRISE SERVICES

____
Date

____
By: Fred Schmidt, Esq.
Austin Jensen, Esq.

SOUTHERN NEVADA GAMING GROUP

____
Date

____
By: Lucas Foletta, Esq.

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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

September 24, 2020
Date

By: Michael Saunders, Esq. 20-06003
for 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.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

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

Date ______________________

By: Lucas Foletta, Esq.

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

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

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.
9.24.20 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.

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

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

9/24/2020
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.

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

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

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

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	Percent 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

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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

56 nc = Classes with existing customers, but for which reconciled marginal costs cannot or have not been determined. — $ 1,045,573 Statement I Revenue Requirement 56

57 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 — $ (92,670) Change in Revenue Requiremer $ (9,370) 57

58 the value when all revenues are included in the calculations. — -8.15% Percent Change 58

59 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. 59

60 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. 60

61 3. No Customers in class 61

62 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. 62

63 5. All customers in class are DOS customers; no bundled customers. 63

64 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 64

65 customers. 65

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Unbundled Revenue Requirement and Rate Design Adjustments ($000's)

Line No.		Note	Total	Energy	Generation	Transmission	Distribution	Line No.
					28.71	7.01	17.27	
8								8
9	Marginal Cost Revenue		$ 1,043,396	[redacted]	$ 565,309	$ 138,071	$ 340,016	9
10								10
11	Unbundled Revenue Requirement	1	$ 1,045,573	[redacted]	$ 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)	[redacted]			(743)	15
16	Additional Facilities and Maintenance (AF&M)		(65)	[redacted]			(65)	16
17								17
18	Optional TOU Revenue		(7,255)	[redacted]	(3,931)	(960)	(2,364)	18
19	Optional TOU NEM revenues		(1,533)	[redacted]	(831)	(203)	(500)	19
20	Standby Customer Revenue (Inc. Part Req. Customers)	2	(2,937)	[redacted]	(1,591)	(389)	(957)	20
21	DOS BTGR Revenue (exc. IRR and Impact Fees)	3	(12,571)	[redacted]			(12,571)	21
22	DOS Interclass Rate-Rebalancing Revenue		(691)	[redacted]	(374)	(91)	(225)	22
23	OLGS-3P HLF & MPE Rate Design Revenue adjustment		552	[redacted]	299	73	180	23
24	MPE Revenue Adjustment		1,931	[redacted]	1,931			24
25	EVCCR Discount Revenue Adjustment		54	[redacted]	43	11		25
26	Total		$ (23,259)	[redacted]	$ (4,454)	$ (1,559)	$ (17,246)	26
27								27
28	Class Specific Revenue Requirement Adjustments							28
29	Other Revenue	4	(1,952)	[redacted]			(1,952)	29
30	Customer Specific Facilities		388	[redacted]			388	30
31	DOS Impact Fee revenue		(14,447)	[redacted]	(14,447)			31
32	BTER Energy Credits (WAPA, Hoover B, EDRR)		-	[redacted]				32
33	Total Class Specific Adjustments		$ (16,011)	[redacted]	$ (14,447)	$ -	$ (1,564)	33
34								34
35	Total Adjustments to Total Revenue Requirement		$ (39,270)	[redacted]	$ (18,901)	$ (1,559)	$ (18,810)	35
36								36
37	Target Revenue Requirement for Rate Design		$ 1,006,304	[redacted]	$ 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) 41

42 2. Includes LSR revenues and optional time-of-use revenues. 42

43 3. Includes all "non-tax" DOS revenues, but excludes subsidy-related revenues. 43

44 4. Other Revenue include misc. revenues, returned check, power pedestal, and misc. damage revenues. 44

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. 45

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Transmission Revenue by Class for Rate Design

					Rate Design Revenue Adjustments										
Line No.	Class	Unreconciled Cost-Based Transmission Revenue	Percent of Total	Reconciled Transmission Revenue Requirement	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	[redacted]		$ 5	$ 65,886	9
10	RM	16,406	11.88%	16,440	(114)	(24)	(46)	-	(11)	9	[redacted]		1	16,255	10
11	LRS	258	0.19%	259	(2)	(0)	(1)	-	(0)	0	[redacted]		0	256	11
12	GS	3,166	2.29%	3,173	(22)	(5)	(9)	-	(2)	2	[redacted]		0	3,137	12
13	LGS-1	21,467	15.55%	21,512	(149)	(32)	(60)	-	(14)	11	[redacted]		2	21,269	13
14	LGS-2S	11,641	8.43%	11,665	(81)	(17)	(33)	-	(8)	6	[redacted]		1	11,534	14
15	LGS-2P	293	0.21%	294	(2)	(0)	(1)	-	(0)	0	[redacted]		0	290	15
16	LGS-2T	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	16
17	LGS-3S	3,574	2.59%	3,581	(25)	(5)	(10)	-	(2)	2	[redacted]		0	3,541	17
18	LGS-3P	7,215	5.23%	7,230	(50)	(11)	(20)	-	(5)	4	[redacted]		1	7,149	18
19	LGS-3T	1,694	1.23%	1,697	(12)	(2)	(5)	-	(1)	1	[redacted]		0	1,678	19
20	LGS-XS	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	22
23	LGS-2S-WP	37	0.03%	37	(0)	(0)	(0)	-	(0)	0	[redacted]		0	36	23
24	LGS-2P-WP	50	0.04%	50	(0)	(0)	(0)	-	(0)	0	[redacted]		0	49	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	25
26	LGS-3S-WP	0	0.00%	0	(0)	(0)	(0)	-	(0)	0	[redacted]		0	0	26
27	LGS-3P-WP	47	0.03%	47	(0)	(0)	(0)	-	(0)	0	[redacted]		0	47	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	28
29	SL	93	0.07%	93	(1)	(0)	(0)	-	(0)	0	[redacted]		0	92	29
30	RS-Pal	0	0.00%	0	(0)	(0)	(0)	-	(0)	0	[redacted]		0	0	30
31	GS-Pal	1	0.00%	1	(0)	(0)	(0)	-	(0)	0	[redacted]		0	1	31
32	IAWP	-	0.00%	-	-	-	-	-	-	-	[redacted]		-	-	32
33	RS-NEM	5,581	4.04%	5,592	(39)	(8)	(16)	-	(4)	3	[redacted]		0	5,529	33
34	RM-NEM	22	0.02%	22	(0)	(0)	(0)	-	(0)	0	[redacted]		0	22	34
35	LRS-NEM	3	0.00%	3	(0)	(0)	(0)	-	(0)	0	[redacted]		0	3	35
36	GS-NEM	27	0.02%	27	(0)	(0)	(0)	-	(0)	0	[redacted]		0	26	36
37											[redacted]				37
38	TOTAL	$ 138,071	100.00%	$ 138,359	$ (960)	$ (203)	$ (389)	$ -	$ (91)	$ 73	[redacted]		$ 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

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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	[redacted]	$ -	$ 168,541	9
10	RM	46,698	13.90%	(698)		46,323	(329)	(69)	(133)	(1,747)	(31)	25	[redacted]		44,039	10
11	LRS	493	0.15%	(0)		496	(3)	(1)	(1)	(18)	(0)	0	[redacted]		472	11
12	GS	13,073	3.89%	(132)		13,031	(92)	(19)	(37)	(489)	(9)	7	[redacted]		12,392	12
13	LGS-1	40,770	12.13%	(21)		41,032	(287)	(61)	(116)	(1,525)	(27)	22	[redacted]		39,038	13
14	LGS-2S	17,909	5.33%	(1)		18,033	(126)	(27)	(51)	(670)	(12)	10	[redacted]		17,157	14
15	LGS-2P	536	0.16%	-		540	(4)	(1)	(2)	(20)	(0)	0	[redacted]		514	15
16	LGS-2T	-	0.00%	-		-	-	-	-	-	-	-	[redacted]		-	16
17	LGS-3S	5,565	1.66%	(0)		5,603	(39)	(8)	(16)	(208)	(4)	3	[redacted]		5,331	17
18	LGS-3P	15,776	4.69%	(0)	-	15,885	(111)	(23)	(45)	(590)	(11)	8	[redacted]		15,114	18
19	LGS-3T	7	0.00%	-	388	394.50	(0)	(0)	(0)	(0)	(0)	0	[redacted]		394	19
20	LGS-XS	-	0.00%	-		-	-	-	-	-	-	-	[redacted]		-	20
21	LGS-XP	-	0.00%	-		-	-	-	-	-	-	-	[redacted]		-	21
22	LGS-XT	-	0.00%	-		-	-	-	-	-	-	-	[redacted]		-	22
23	LGS-2S-WP	134	0.04%	-		135	(1)	(0)	(0)	(5)	(0)	0	[redacted]		128	23
24	LGS-2P-WP	100	0.03%	-		100	(1)	(0)	(0)	(4)	(0)	0	[redacted]		96	24
25	LGS-2T-WP	2	0.00%	-	-	2	(0)	(0)	(0)	(0)	(0)	0	[redacted]		2	25
26	LGS-3S-WP	101	0.03%	-		101	(1)	(0)	(0)	(4)	(0)	0	[redacted]		97	26
27	LGS-3P-WP	304	0.09%	-		306	(2)	(0)	(1)	(11)	(0)	0	[redacted]		291	27
28	LGS-3T-WP	9	0.00%	-	-	9	(0)	(0)	(0)	(0)	(0)	0	[redacted]		8	28
29	SL	937	0.28%	(5)		938	(7)	(1)	(3)	(35)	(1)	1	[redacted]		893	29
30	RS-Pal	25	0.01%	(0)		25	(0)	(0)	(0)	(1)	(0)	0	[redacted]		24	30
31	GS-Pal	80	0.02%	(0)		81	(1)	(0)	(0)	(3)	(0)	0	[redacted]		77	31
32	IAWP	-	0.00%			-	-	-	-	-	-	-	[redacted]		-	32
33	RS-NEM	16,429	4.89%	(69)		16,454	(116)	(24)	(47)	(615)	(11)	9	[redacted]		15,650	33
34	RM-NEM	53	0.02%	(1)		52	(0)	(0)	(0)	(2)	(0)	0	[redacted]		50	34
35	LRS-NEM	14	0.00%	(0)		14	(0)	(0)	(0)	(1)	(0)	0	[redacted]		13	35
36	GS-NEM	68	0.02%	(0)		68	(0)	(0)	(0)	(3)	(0)	0	[redacted]		65	36
37						not a sum							[redacted]			37
38	TOTAL	$ 338,059	100.00%	$ (1,952)	$ 388	$ 340,726	$ (2,364)	$ (500)	$ (957)	$ (12,571)	$ (225)	$ 180	[redacted]	$ -	$ 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

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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	CLGS-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	$ -	[redacted]		$ 21	$ 265,564	9
10	RM	70,665	12.50%	-	70,812	(491)	(104)	(199)		(47)	37	-	[redacted]		5	70,014	10
11	LRS	1,021	0.18%	-	1,023	(7)	(2)	(3)		(1)	1	-	[redacted]		0	1,012	11
12	GS	11,425	2.02%	-	11,449	(79)	(17)	(32)		(8)	6	-	[redacted]		1	11,320	12
13	LGS-1	85,607	15.14%	-	85,785	(595)	(126)	(241)		(57)	45	-	[redacted]		7	84,819	13
14	LGS-2S	46,945	8.30%	-	47,043	(326)	(69)	(132)		(31)	25	-	[redacted]		4	46,513	14
15	LGS-2P	1,239	0.22%	-	1,242	(9)	(2)	(3)		(1)	1	-	[redacted]		0	1,228	15
16	LGS-2T	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	16
17	LGS-3S	15,056	2.66%	-	15,087	(105)	(22)	(42)		(10)	8	-	[redacted]		1	14,917	17
18	LGS-3P	30,831	5.45%	-	30,895	(214)	(45)	(87)		(20)	16	-	[redacted]		2	30,547	18
19	LGS-3T	6,926	1.23%	-	6,941	(48)	(10)	(19)		(5)	4	-	[redacted]		1	6,862	19
20	LGS-XS	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	22
23	LGS-2S-WP	162	0.03%	-	162	(1)	(0)	(0)		(0)	0	-	[redacted]		0	160	23
24	LGS-2P-WP	168	0.03%	-	168	(1)	(0)	(0)		(0)	0	-	[redacted]		0	166	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	25
26	LGS-3S-WP	21	0.00%	-	21	(0)	(0)	(0)		(0)	0	-	[redacted]		0	20	26
27	LGS-3P-WP	188	0.03%	-	189	(1)	(0)	(1)		(0)	0	-	[redacted]		0	187	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	28
29	SL	1,894	0.34%	-	1,898	(13)	(3)	(5)		(1)	1	-	[redacted]		0	1,877	29
30	RS-Pal	8	0.00%	-	8	(0)	(0)	(0)		(0)	0	-	[redacted]		0	8	30
31	GS-Pal	27	0.00%	-	27	(0)	(0)	(0)		(0)	0	-	[redacted]		0	27	31
32	IAIWP	-	0.00%	-	-	-	-	-		-	-	-	[redacted]		-	-	32
33	RS-NEM	24,888	4.40%	-	24,940	(173)	(37)	(70)		(16)	13	-	[redacted]		2	24,658	33
34	RM-NEM	90	0.02%	-	91	(1)	(0)	(0)		(0)	0	-	[redacted]		0	90	34
35	LRS-NEM	13	0.00%	-	13	(0)	(0)	(0)		(0)	0	-	[redacted]		0	13	35
36	GS-NEM	104	0.02%	-	105	(1)	(0)	(0)		(0)	0	-	[redacted]		0	103	36
37					not a sum								[redacted]				37
38	TOTAL	$ 565,309	100.00%	$ -	$ 566,488	$ (3,931)	$ (831)	$ (1,591)		$ (374)	$ 299	$ -	[redacted]		$ 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	[redacted]	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

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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	Rate Design Revenue Adjustments: Optional TOU NEM revenues	Rate Design Revenue Adjustments: Standby Customer Revenue	Rate Design Revenue Adjustments: DOS Interclass Rate-Rebalancing Revenue	Rate Design Revenue Adjustments: OLGS-3P HLF Rate Design Revenue adjustment	Rate Design Revenue Adjustments: DOS R-BTER and BTER Impact Fee Revenue	Rate Design Revenue Adjustments: MPE Revenue Adjustment	Rate Design Revenue Adjustments: 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	[redacted]					[redacted]								[redacted]	[redacted]	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	[redacted]					[redacted]								[redacted]	[redacted]	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

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Class Revenue Results Summary

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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	[redacted]	$ 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	[redacted]	130,308	-	-	130,308	8,842	139,637	139,160	13.8%	(56)	0.06380	10
11	LRS	35,987	472	256	1,012	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	75,203	346	-	75,550	2,602	77,726	77,729	7.7%	3	0.03285	14
15	LGS-2P	67,742	514	290	1,228	[redacted]	2,032	6	-	2,038	(147)	1,804	1,804	0.2%	(0)	0.02663	15
16	LGS-2T	-	-	-	-	[redacted]	-	-	-	-	na		-	0.0%	—	—	16
17	LGS-3S	822,586	5,331	3,541	14,917	[redacted]	23,789	90	-	23,878	541	23,783	23,746	2.3%	(38)	0.02891	17
18	LGS-3P	1,646,866	15,114	7,149	30,547	[redacted]	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	[redacted]	8,935	9	-	8,943	(1,025)	6,959	6,958	0.7%	(0)	0.01751	19
20	LGS-XS	-	-	-	-	[redacted]	-	-	-	-	na		-	0.0%	—	—	20
21	LGS-XP	-	-	-	-	[redacted]	-	-	-	-	na		-	0.0%	—	—	21
22	LGS-XT	-	-	-	-	[redacted]	-	-	-	-	na		-	0.0%	—	—	22
23	LGS-2S-WP	6,831	128	36	160	[redacted]	325	2	-	327	(157)	143	149	0.0%	6	0.02099	23
24	LGS-2P-WP	12,229	96	49	166	[redacted]	311	3	-	314	(40)	274	274	0.0%	(0)	0.02243	24
25	LGS-2T-WP	-	2	-	-	[redacted]	2	-	-	2	na		-	0.0%	—	—	25
26	LGS-3S-WP	5,752	97	0	20	[redacted]	117	2	-	119	(26)	17	18	0.0%	1	0.00299	26
27	LGS-3P-WP	17,505	291	47	187	[redacted]	525	3	-	528	(84)	231	228	0.0%	(3)	0.01318	27
28	LGS-3T-WP	-	8	-	-	[redacted]	8	-	-	8	na		-	0.0%	—	—	28
29	SL	150,361	893	92	1,877	[redacted]	2,862	—	-	2,862	(1,510)	1,352	1,352	0.1%	(0)	0.00899	29
30	RS-Pal	648	24	0	8	[redacted]	32		-	32	9	40	40	0.0%	0	0.06240	30
31	GS-Pal	2,337	77	1	27	[redacted]	105	-	-	105	29	134	134	0.0%	(0)	0.05725	31
32	IAIWP	-	-	-	-	[redacted]	-	-	-	-	-	-	-	0.0%	-	—	32
33	RS-NEM	264,487	15,650	5,529	24,658	[redacted]	45,838	-	-	45,838	(793)	23,123	23,123	2.3%	—	0.08742	33
34	RM NEM	1,506	50	22	90	[redacted]	161			161	6	101	101	0.0%		0.06708	34
35	LRS-NEM	386	13	3	13	[redacted]	29	-	-	29	3	29	29	0.0%	—	0.07632	35
36	GS-NEM	2,005	65	26	103	[redacted]	195	-	-	195	23	71	71	0.0%	—	0.03526	36
37																	37
38	TOTAL	19,512,318	$ 320,385	$ 136,800	$ 560,104	[redacted]		$ 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

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Class Revenue Adjustments Due to Cap & Floor Criteria (1)

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
RS	$ 499,991	49.50%	$ 499,991	49.50%	$ 531,618	-5.95%	$ 531,618	-5.95%	-	-5.95%
RM	130,308	12.90%	130,308	12.90%	155,163	-16.02%	155,163	-16.02%	Floor	-9.00%
LRS	1,739	0.17%	1,739	0.17%	2,291	-24.08%	2,291	-24.08%	Floor	-9.00%
GS	26,848	2.66%	26,848	2.66%	37,466	-28.34%	37,466	-28.34%	Floor	-9.00%
LGS-1	145,165	14.37%	145,165	14.37%	168,894	-14.05%	168,894	-14.05%	Floor	-9.00%
LGS-2S	75,126	7.44%	75,126	7.44%	86,306	-12.95%	86,306	-12.95%	Floor	-9.00%
LGS-2P	1,951	0.19%	1,951	0.19%	1,921	1.57%	1,921	1.57%	Capped	-6.08%
LGS-2T	-	0.00%	-	0.00%	-		-			
LGS-3S	23,243	2.30%	23,243	2.30%	26,409	-11.99%	26,409	-11.99%	Floor	-9.00%
LGS-3P	47,599	4.71%	47,599	4.71%	51,261	-7.14%	51,261	-7.14%	-	-7.14%
LGS-3T	7,984	0.79%	7,984	0.79%	7,409	7.76%	7,409	7.76%	Capped	-6.08%
LGS-XS	-	0.00%	-	0.00%	-		-			
LGS-XP	-	0.00%	-	0.00%	-		-			
LGS-XT	-	0.00%	-	0.00%	-		-			
LGS-2S-WP	300	0.03%	300	0.03%	153	96.69%	153	96.69%	Capped	-6.08%
LGS-2P-WP	314	0.03%	314	0.03%	292	7.47%	292	7.47%	Capped	-6.08%
LGS-2T-WP	-	0.00%	-	0.00%	-		-			
LGS-3S-WP	44	0.00%	44	0.00%	18	138.34%	18	138.34%	Capped	-6.08%
LGS-3P-WP	315	0.03%	315	0.03%	246	28.32%	246	28.32%	Capped	-6.08%
LGS-3T-WP	8	0.00%	8	0.00%	-		-			
SL	2,862	0.28%	2,862	0.28%	1,440	98.79%	1,440	98.79%	Capped	-6.08%
RS-Pal	32	0.00%	32	0.00%	45	-29.07%	45	-29.07%	Floor	-9.00%
GS-Pal	105	0.01%	105	0.01%	149	-29.61%	149	-29.61%	Floor	-9.00%
IAWP	-									
RS-NEM	45,838	4.54%	45,838		24,289	88.72%	24,289	88.72%	Capped	-4.83%
RM-NEM	161	0.02%	161		113	43.13%	113	43.13%	Capped	-4.83%
LRS-NEM	29	0.00%	29		33	-14.17%	33	-14.17%	Floor	-9.00%
GS-NEM	195	0.02%	195		81	140.22%	81	140.22%	Capped	-4.83%
	Not a sum:				Not a Sum:	Overall Increase:				
Total	$ 1,045,573	100.00%	$ 1,045,573	100.00%	$ 1,137,429	-8.06%				
	$ 1,010,155	=sum=	$ 1,010,155		$ 1,095,596	$ (91,856)				
	$ 35,418	<Rev Credits: Revenue Credits sac PF and AF&M revenues								

Class	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
RS	$ 499,991	$ -	$ 499,991	$ (31,627)	40.45%	$ (2,173)	497,818	-6.36%
RM	141,199	(16,891)	-	(13,865)	17.88%	(953)	140,239	-9.62%
LRS	2,085	(348)	-	(206)	0.26%	(14)	2,071	-9.62%
GS	34,094	(7,246)	-	(3,372)	4.31%	(232)	33,863	-9.62%
LGS-1	153,693	(8,528)	-	(15,200)	19.44%	(1,044)	152,649	-9.62%
LGS-2S	78,539	(3,412)	-	(7,768)	9.93%	(534)	78,006	-9.62%
LGS-2P	1,804	147	-	-	0.00%	-	1,804	-6.08%
LGS-2T			-	-	0.00%	-		
LGS-3S	24,032	(789)	-	(2,377)	3.04%	(165)	23,869	-9.62%
LGS-3P	47,599	-	47,599	(3,883)	4.88%	(252)	47,347	-7.64%
LGS-3T	6,959	1,025	-	-	0.00%	-	6,959	-6.08%
LGS-XS			-	-	0.00%	-		
LGS-XP			-	-	0.00%	-		
LGS-XT			-	-	0.00%	-		
LGS-2S-WP	143	157	-	-	0.00%	-	143	-6.08%
LGS-2P-WP	274	40	-	-	0.00%	-	274	-6.08%
LGS-2T-WP			-	-	0.00%	-		
LGS-3S-WP	17	26	-	-	0.00%	-	17	-6.08%
LGS-3P-WP	231	84	-	-	0.00%	-	231	-6.08%
LGS-3T-WP			-	-	0.00%	-		
SL	1,352	1,510	-	-	0.00%	-	1,352	-6.08%
RS-Pal	41	(9)	-	(4)	0.01%	(0)	41	-9.62%
GS-Pal	135	(31)	-	(13)	0.02%	(1)	134	-9.62%
IAWP								
RS-NEM	$ 23,117	$ 22,721	$ -	$ -	0.00%	$ -	23,117	-4.83%
RM-NEM	$ 107	$ 54	$ -	$ -	0.00%	$ -	107	-4.83%
LRS-NEM	$ 30	$ (2)	$ -	$ (3)	0.00%	$ (0)	30	-9.62%
GS-NEM	$ 77	$ 118	$ -	$ -	0.00%	$ -	77	-4.83%
Total	$ 1,016,519	$ (5,372)	$ 547,590	$ (78,198)	100%	$ (5,372)		

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
RS	$ 497,818	-6.36%	-	-6.36%	$ 497,818	$ -	$ 497,818
RM	140,239	-9.62%	Floor	-9.00%	$ 141,199	$ (959)	$ -
LRS	2,071	-9.62%	Floor	-9.00%	$ 2,085	$ (14)	$ -
GS	33,863	-9.62%	Floor	-9.00%	$ 34,094	$ (232)	$ -
LGS-1	152,649	-9.62%	Floor	-9.00%	$ 153,693	$ (1,044)	$ -
LGS-2S	78,006	-9.62%	Floor	-9.00%	$ 78,539	$ (534)	$ -
LGS-2P	1,804	-6.08%	Capped	-6.08%	$ 1,804	$ -	$ 1,804
LGS-2T							$ -
LGS-3S	23,869	-9.62%	Floor	-9.00%	$ 24,032	$ (163)	$ -
LGS-3P	47,347	-7.64%	-	-7.64%	$ 47,347	$ -	$ 47,347
LGS-3T	6,959	-6.08%	Capped	-6.08%	$ 6,959	$ -	$ 6,959
LGS-XS							$ -
LGS-XP							$ -
LGS-XT							$ -
LGS-2S-WP	143	-6.08%	Capped	-6.08%	$ 143	$ -	$ 143
LGS-2P-WP	274	-6.08%	Capped	-6.08%	$ 274	$ -	$ 274
LGS-2T-WP							$ -
LGS-3S-WP	17	-6.08%	Capped	-6.08%	$ 17	$ -	$ 17
LGS-3P-WP	231	-6.08%	Capped	-6.08%	$ 231	$ -	$ 231
LGS-3T-WP							$ -
SL	1,352	-6.08%	Capped	-6.08%	$ 1,352	$ -	$ 1,352
RS-Pal	41	-9.62%	Floor	-9.00%	$ 41	$ (0)	$ -
GS-Pal	134	-9.62%	Floor	-9.00%	$ 135	$ (1)	$ -
IAWP							
RS-NEM	23,117	-4.83%	Capped	-6.08%	$ 22,813	$ 304	$ -
RM-NEM	107	-4.83%	Capped	-6.08%	$ 106	$ 1	$ -
LRS-NEM	30	-9.62%	Floor	-9.00%	$ 30	$ (0)	$ -
GS-NEM	77	-4.83%	Capped	-6.08%	$ 76	$ 1	$ -
Total						$ 2,642	$ 555,945

Class	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	$ (33,800)	41.92%	$ 1,107	$ 498,926	-6.15%	$ 498,926	-6.15%	$ (1,065)
RM	$ (13,865)	17.32%	458	$ 139,738	-9.94%	139,738	-9.94%	9,430
LRS	$ (206)	0.26%	7	$ 2,063	-9.94%	2,063	-9.94%	324
GS	$ (3,372)	4.18%	110	$ 33,741	-9.94%	33,741	-9.94%	6,893
LGS-1	$ (15,200)	18.85%	406	$ 152,103	-9.94%	152,103	-9.94%	6,938
LGS-2S	$ (7,768)	9.63%	254	$ 77,726	-9.94%	77,726	-9.94%	2,600
LGS-2P	$ -	0.00%	-	$ 1,804	-6.08%	1,804	-6.08%	(147)
LGS-2T	$ -	0.00%	-					
LGS-3S	$ (2,377)	2.95%	75	$ 23,783	-9.94%	23,783	-9.94%	541
LGS-3P	$ (3,914)	4.85%	128	$ 47,475	-7.39%	47,475	-7.39%	(123)
LGS-3T	$ -	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	$ -	0.00%	-	$ 143	-6.08%	143	-6.08%	(157)
LGS-2P-WP	$ -	0.00%	-	$ 274	-6.08%	274	-6.08%	(40)
LGS-2T-WP	$ -	0.00%	-					
LGS-3S-WP	$ -	0.00%	-	$ 17	-6.08%	17	-6.08%	(26)
LGS-3P-WP	$ -	0.00%	-	$ 231	-6.08%	231	-6.08%	(84)
LGS-3T-WP	$ -	0.00%	-					
SL	$ -	0.00%	-	$ 1,352	-6.08%	1,352	-6.08%	(1,510)
RS-Pal	$ (4)	0.01%	0	$ 40	-9.94%	40	-9.94%	9
GS-Pal	$ (13)	0.02%	0	$ 134	-9.94%	134	-9.94%	29
IAWP								
RS-NEM	$ -	0.00%	-	$ 23,420	-3.58%	23,420	-3.58%	(22,417)
RM-NEM	$ -	0.00%	-	$ 109	-3.58%	109	-3.58%	(53)
LRS-NEM	$ (3)	0.00%	0	$ 30	-9.94%	30	-9.94%	1
GS-NEM	$ -	0.00%	-	$ 78	-3.58%	78	-3.58%	(117)
Total	$ (80,622)	100.0%	$ 2,642	$ 1,010,147		$ 1,010,147		
						$ (8)		

(1) Increases in rates cannot exceed the total average percentage increase 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

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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	$ 547,955	$ 526,039	$ (21,916)	$ (0.00300)	$ 3		8
9	RM	2,188,600,072		2,190,106,091	130,983	139,824	8,841	0.00404	7		9
10	LRS	35,987,038		36,373,364	1,773	2,093	319	0.00878	(0)		10
11	GS	584,168,954		586,174,249	27,186	33,814	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)	0.00001	157		22
23	LGS-2P-WP	12,228,600		12,228,600	314	274	(40)	0.00001	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
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). 58
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. 59

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Comparison of Present and Proposed Rate Revenue

Line No	Class	Sales (kWh)	BTGR Revenue		Percent Change	BTGR & BTER[1] Revenue		Percent Change	Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1]		Percent Change	Line No
			Present	Proposed		Present	Proposed		Present	Proposed		
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	2,168,600,072	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	35,987,038	2,291,094	2,056,845	-10.22%	2,291,094	2,056,845	-10.22%	2,356,231	2,122,082	-9.84%	10
11	GS	584,168,954	37,466,138	33,538,537	-10.48%	37,466,138	33,536,537	-10.48%	38,231,399	34,303,798	-10.27%	11
12	LGS-1	3,897,463,666	168,893,509	152,128,952	-9.93%	168,893,509	152,128,952	-9.93%	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	1,296,176,582	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	291,815,628	5,203,130	4,781,628	-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%	154,428	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	IAWP	-	-	-	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	5,598,580	246,893	227,871	-7.70%	246,883	227,871	-7.70%	259,043	240,020	-7.34%	35
39	ORM-TOU	580,195	35,856	31,036	-13.44%	35,858	31,038	-13.44%	36,930	32,112	-13.05%	39
40	ORM-TOU OPT A	968,040	64,324	58,802	-8.58%	64,324	58,802	-8.58%	68,149	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	-4.18%	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	17,869,841	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%	509,806	480,513	-5.75%	56
57	ORS-TOU Opt B EVRR	6,152,619	225,210	212,741	-5.54%	225,210	212,741	-5.64%	238,561	226,092	-5.23%	57
60	ORM-TOU EVRR	441,642	25,968	22,438	-13.59%	25,966	22,438	-13.59%	26,783	23,255	-13.17%	60
61	ORM-TOU OPT A EVRR	78,095	5,520	4,979	-9.80%	5,520	4,979	-9.80%	5,667	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	264,486,631	24,288,978	23,122,592	-4.80%	24,286,978	23,122,592	-4.80%	24,862,917	23,698,531	-4.69%	73
74	RM-NEM	1,606,019	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	2,005,285	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	-11.57%	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	137,919	-5.54%	146,012	137,919	-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	360,504	17,998	16,430	-8.66%	17,998	16,430	-8.66%	18,916	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	4,021,630	69,891	64,737	-7.36%	69,881	64,737	-7.36%	73,580	68,436	-6.99%	120
121	LSR - LGS-3S	-	-	-	na	-	-	na	-	-	na	121
122	LSR - LGS-3P	22,497,619	811,759	742,668	-8.51%	811,759	742,668	-8.51%	939,207	770,116	-8.23%	122
123	LSR - LGS-3T	61,166,025	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	-2.19%	$ 4,762	$ 4,658	-2.18%	$ 4,755	$ 4,651	-2.19%	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	1,590,897	1,361,286	-14.44%	1,590,897	1,361,286	-14.44%	1,590,223	1,360,512	-14.45%	152
153	LGS-2P-DOS	15,934,490	250,848	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	85,786,342	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	166,717	151,088	-9.37%	166,717	151,088	-9.37%	167,900	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%	1,355,368	1,228,973	-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	1,289,139	30,248	16,567	-45.23%	30,248	16,567	-45.23%	30,248	16,567	-45.23%	163
164	LGS-3S-WP-DOS	28,160,162	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	58,791,258	160,344	92,663	-42.21%	160,344	92,663	-42.21%	160,344	92,663	-42.21%	166
167												167
168	**DOS TOTAL**	2,608,912,840	$ 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	$ 1,078,836,200	-7.92%	170

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. 172

173 1. Present BTER and DEAA revenues are based on July 1, 2020 rates. 173

174 2. Partial requirements customers included in LGS-3P and LGS-3T for rate design purposes are presented in their respective standby schedules. 174

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Verification of Present Rate Components & Comparison to Proposed Revenue

Line No.	Class	Sales	BTER Revenue Present	BTER Revenue Proposed	Percent Change	DEAA Revenue Present	DEAA Revenue Proposed	Percent Change	EE Revenue Present	EE Revenue Proposed	Percent Change	REPR Revenue Present	REPR Revenue Proposed	Percent Change	Line No.
9		Residential Rate	[redacted]	[redacted]		[redacted]	[redacted]		Rates vary by Class			$ (0.00039)	$ (0.00039)		9
10		Non-Residential Rate	[redacted]	[redacted]		[redacted]	[redacted]					$ (0.00039)	$ (0.00039)		10
11															11
12	RS	7,039,880,433	[redacted]	[redacted]	na	[redacted]	[redacted]	na	$ 18,022,094	$ 18,022,094	0.0%	$ (2,745,553)	$ (2,745,553)	0.0%	12
13	RM	2,188,600,072	[redacted]	[redacted]	na	[redacted]	[redacted]	na	4,902,465	4,902,465	0.0%	(853,554)	(853,554)	0.0%	13
14	LRS	36,987,038	[redacted]	[redacted]	na	[redacted]	[redacted]	na	79,172	79,172	0.0%	(14,036)	(14,036)	0.0%	14
15	GS	584,168,954	[redacted]	[redacted]	na	[redacted]	[redacted]	na	993,087	993,087	0.0%	(227,826)	(227,826)	0.0%	15
16	LGS-1	3,897,463,666	[redacted]	[redacted]	na	[redacted]	[redacted]	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	[redacted]	[redacted]	na	[redacted]	[redacted]	na	3,430,318	3,430,318	0.0%	(922,637)	(922,637)	0.0%	17
18	LGS-2P	67,742,230	[redacted]	[redacted]	na	[redacted]	[redacted]	na	90,775	90,775	0.0%	(26,419)	(26,419)	0.0%	18
19	LGS-2T	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	19
20	LGS-3S	800,640,755	[redacted]	[redacted]	na	[redacted]	[redacted]	na	1,377,102	1,377,102	0.0%	(312,250)	(312,250)	0.0%	20
21	LGS-3P	1,296,176,562	[redacted]	[redacted]	na	[redacted]	[redacted]	na	2,086,845	2,086,845	0.0%	(505,509)	(505,509)	0.0%	21
22	LGS-3T	291,915,629	[redacted]	[redacted]	na	[redacted]	[redacted]	na	522,529	522,529	0.0%	(113,847)	(113,847)	0.0%	22
23	LGS-XS	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	23
24	LGS-XP	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	24
25	LGS-XT	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	25
26	LGS-2S-WP	6,831,160	[redacted]	[redacted]	na	[redacted]	[redacted]	na	4,440	4,440	0.0%	(2,664)	(2,664)	0.0%	26
27	LGS-2P-WP	12,228,600	[redacted]	[redacted]	na	[redacted]	[redacted]	na	13,329	13,329	0.0%	(4,769)	(4,769)	0.0%	27
28	LGS-2T-WP	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	28
29	LGS-3S-WP	5,751,817	[redacted]	[redacted]	na	[redacted]	[redacted]	na	5,004	5,004	0.0%	(2,243)	(2,243)	0.0%	29
30	LGS-3P-WP	17,504,868	[redacted]	[redacted]	na	[redacted]	[redacted]	na	16,806	16,806	0.0%	(6,827)	(6,827)	0.0%	30
31	LGS-3T-WP	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	31
32	SL	150,361,312	[redacted]	[redacted]	na	[redacted]	[redacted]	na	138,333	138,333	0.0%	(58,641)	(58,641)	0.0%	32
33	RS-Pal	647,868	[redacted]	[redacted]	na	[redacted]	[redacted]	na	557	557	0.0%	(253)	(253)	0.0%	33
34	GS-Pal	2,337,372	[redacted]	[redacted]	na	[redacted]	[redacted]	na	2,010	2,010	0.0%	(912)	(912)	0.0%	34
35	IAIWP	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	35
36	**Optional Time of Use**														36
37	ORS-TOU	4,722,752	[redacted]	[redacted]	na	[redacted]	[redacted]	na	12,090	12,090	0.0%	(1,842)	(1,842)	0.0%	37
38	ORS-TOU OPT A	26,831,203	[redacted]	[redacted]	na	[redacted]	[redacted]	na	68,688	68,688	0.0%	(10,464)	(10,464)	0.0%	38
39	ORS-TOU OPT B	5,598,560	[redacted]	[redacted]	na	[redacted]	[redacted]	na	14,333	14,333	0.0%	(2,183)	(2,183)	0.0%	39
43	ORM-TOU	580,195	[redacted]	[redacted]	na	[redacted]	[redacted]	na	1,300	1,300	0.0%	(226)	(226)	0.0%	43
44	ORM-TOU OPT A	986,040	[redacted]	[redacted]	na	[redacted]	[redacted]	na	2,210	2,210	0.0%	(385)	(385)	0.0%	44
45	ORM-TOU OPT B	133,774	[redacted]	[redacted]	na	[redacted]	[redacted]	na	300	300	0.0%	(52)	(52)	0.0%	45
55	OGS-TOU	23,843,869	[redacted]	[redacted]	na	[redacted]	[redacted]	na	40,535	40,535	0.0%	(9,299)	(9,299)	0.0%	55
56	OLGS-1 TOU	81,567,130	[redacted]	[redacted]	na	[redacted]	[redacted]	na	139,479	139,479	0.0%	(31,811)	(31,811)	0.0%	56
57	OLGS-3P-HLF	262,854,722	[redacted]	[redacted]	na	[redacted]	[redacted]	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	[redacted]	[redacted]	na	[redacted]	[redacted]	na	45,747	45,747	0.0%	(6,969)	(6,969)	0.0%	59
60	ORS-TOU Opt A EVRR	9,481,782	[redacted]	[redacted]	na	[redacted]	[redacted]	na	24,273	24,273	0.0%	(3,698)	(3,698)	0.0%	60
61	ORS-TOU Opt B EVRR	6,152,819	[redacted]	[redacted]	na	[redacted]	[redacted]	na	15,751	15,751	0.0%	(2,400)	(2,400)	0.0%	61
64	ORM-TOU EVRR	441,642	[redacted]	[redacted]	na	[redacted]	[redacted]	na	989	989	0.0%	(172)	(172)	0.0%	64
65	ORM-TOU OPT A EVRR	79,095	[redacted]	[redacted]	na	[redacted]	[redacted]	na	178	178	0.0%	(31)	(31)	0.0%	65
66	ORM-TOU OPT B EVRR	58,981	[redacted]	[redacted]	na	[redacted]	[redacted]	na	132	132	0.0%	(23)	(23)	0.0%	66
69	OLRS-TOU EVRR	260,038	[redacted]	[redacted]	na	[redacted]	[redacted]	na	571	571	0.0%	(101)	(101)	0.0%	69
74	OGS-TOU EVRR	3,241	[redacted]	[redacted]	na	[redacted]	[redacted]	na	6	6	0.0%	(1)	(1)	0.0%	74
75	OLGS-1-TOU EVRR	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	75
76	**Net Metering:**														76
77	RS-NEM	264,486,931	[redacted]	[redacted]	na	[redacted]	[redacted]	na	677,089	677,089	0.0%	(103,150)	(103,150)	0.0%	77
78	RM-NEM	1,506,019	[redacted]	[redacted]	na	[redacted]	[redacted]	na	3,373	3,373	0.0%	(587)	(587)	0.0%	78
79	LRS-NEM	386,326	[redacted]	[redacted]	na	[redacted]	[redacted]	na	849	849	0.0%	(151)	(151)	0.0%	79
80	GS-NEM	2,005,295	[redacted]	[redacted]	na	[redacted]	[redacted]	na	3,411	3,411	0.0%	(782)	(782)	0.0%	80
81	LGS-1 NEM	41,534	[redacted]	[redacted]	na	[redacted]	[redacted]	na	70	70	0.0%	(16)	(16)	0.0%	81
82	ORS-NEM	952,989	[redacted]	[redacted]	na	[redacted]	[redacted]	na	2,440	2,440	0.0%	(372)	(372)	0.0%	82
83	ORS-NEM OPT A	3,564,821	[redacted]	[redacted]	na	[redacted]	[redacted]	na	9,128	9,128	0.0%	(1,390)	(1,390)	0.0%	83
84	ORS-NEM OPT B	226,466	[redacted]	[redacted]	na	[redacted]	[redacted]	na	581	581	0.0%	(88)	(88)	0.0%	84
101	**NEM EVRR**														101
102	ORS-NEM EVRR	2,947,034	[redacted]	[redacted]	na	[redacted]	[redacted]	na	7,643	7,643	0.0%	(1,149)	(1,149)	0.0%	102
103	ORS-NEM OPT A EVRR	1,703,792	[redacted]	[redacted]	na	[redacted]	[redacted]	na	4,362	4,362	0.0%	(664)	(664)	0.0%	103
104	ORS-NEM OPT B EVRR	380,504	[redacted]	[redacted]	na	[redacted]	[redacted]	na	976	976	0.0%	(148)	(148)	0.0%	104
107	ORM-NEM EVRR	20,514	[redacted]	[redacted]	na	[redacted]	[redacted]	na	46	46	0.0%	(8)	(8)	0.0%	107
118	**Standby**														118
120	SSR - GS	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	120
121	SSR - LGS-1	1,115,600	[redacted]	[redacted]	na	[redacted]	[redacted]	na	1,908	1,908	0.0%	(435)	(435)	0.0%	121
122	LSR - LGS-2S	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	122
123	LSR - LGS-2P	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	123
124	LSR - LGS-2T	4,021,830	[redacted]	[redacted]	na	[redacted]	[redacted]	na	5,268	5,268	0.0%	(1,569)	(1,569)	0.0%	124
125	LSR - LGS-3S	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	125
126	LSR - LGS-3P	22,497,819	[redacted]	[redacted]	na	[redacted]	[redacted]	na	36,222	36,222	0.0%	(8,774)	(8,774)	0.0%	126
127	LSR - LGS-3T	91,166,025	[redacted]	[redacted]	na	[redacted]	[redacted]	na	163,188	163,188	0.0%	(35,555)	(35,555)	0.0%	127
137	**EVCCR**														137
138	LGS-2S EVCCR	3,419,851	[redacted]	[redacted]	na	[redacted]	[redacted]	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	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	(7)	(7)	0.0%	154
155	LGS-1-DOS	6,590,602	[redacted]	[redacted]	na	[redacted]	[redacted]	na	614	614	0.0%	(1,611)	(1,611)	0.0%	155
156	LGS-2S-DOS	60,121,153	[redacted]	[redacted]	na	[redacted]	[redacted]	na	23,459	23,459	0.0%	(24,233)	(24,233)	0.0%	156
157	LGS-2P-DOS	15,934,490	[redacted]	[redacted]	na	[redacted]	[redacted]	na	4,338	4,338	0.0%	(2,996)	(2,995)	0.0%	157
158	LGS-2T-DOS	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	158
159	LGS-3S-DOS	95,786,342	[redacted]	[redacted]	na	[redacted]	[redacted]	na	32,064	32,064	0.0%	(27,785)	(27,785)	0.0%	159
160	LGS-3P-DOS	1,282,094,633	[redacted]	[redacted]	na	[redacted]	[redacted]	na	89,018	89,018	0.0%	(237,266)	(237,266)	0.0%	160
161	LGS-3T-DOS	518,278,106	[redacted]	[redacted]	na	[redacted]	[redacted]	na	61,946	61,946	0.0%	(137,949)	(137,949)	0.0%	161
162	LGS-XS-DOS	7,591,814	[redacted]	[redacted]	na	[redacted]	[redacted]	na	4,144	4,144	0.0%	(2,961)	(2,961)	0.0%	162
163	LGS-XP-DOS	279,670,254	[redacted]	[redacted]	na	[redacted]	[redacted]	na	51,150	51,150	0.0%	(109,071)	(109,071)	0.0%	163
164	LGS-XT-DOS	155,676,032	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	(60,714)	(60,714)	0.0%	164
165	LGS-2S-WP-DOS	5,301,743	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	165
166	LGS-2P-WP-DOS	-	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	166
167	LGS-2T-WP-DOS	1,289,139	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	167
168	LGS-3S-WP-DOS	26,160,182	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	168
169	LGS-3P-WP-DOS	74,574,362	[redacted]	[redacted]	na	[redacted]	[redacted]	na	-	-	na	-	-	na	169
170	LGS-3T-WP-DOS	59,791,256	[redacted]	[redacted]	na	[redacted]	[redacted]	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

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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	T and G Demand Charges, metered kW: Summer Mid Peak	T and G Demand Charges, metered kW: Winter -OR - All Periods	BTGR Energy, per kWh (includes IRR): Critical Peak	BTGR Energy: Summer On Peak	BTGR Energy: Summer Mid Peak	BTGR Energy: Summer Off Peak	BTGR Energy: Winter -OR - All Periods	BTGR Energy: Summer EVRR	BTGR Energy: Winter EVRR	BTER Energy, per kWh	Line No.
9	RS		$ 12.50										$ 0.05995			[redacted]	9
10	RM		7.70										0.05186			[redacted]	10
11	LRS		70.70										0.05216			[redacted]	11
12	GS		25.50	$ 2.50									0.01802			[redacted]	12
13	LGS-1		15.80	6.25	$ 3.68			$ 4.01					0.01522			[redacted]	13
14	LGS-2S		122.40	9.75	2.68	$ 12.81	$ 2.65	0.60		$ 0.03242	$ 0.01573	$ 0.00053	0.00572			[redacted]	14
15	LGS-2P		207.70	65.00	2.34	10.59	2.47	0.60		0.03817	0.01763	0.00107	0.00464			[redacted]	15
16	LGS-2T		182.00	23.00	0.61	11.46	2.67	0.75		0.04425	0.00766	0.00001	0.00066			[redacted]	16
17	LGS-3S		122.00	3.00	2.82	12.44	3.00	0.80		0.03591	0.01718	0.00130	0.00483			[redacted]	17
18	LGS-3P		214.10	78.25	2.73	13.61	3.36	0.85		0.03856	0.01300	0.00116	0.00279			[redacted]	18
19	LGS-3T		182.00	23.00	0.61	11.46	2.67	0.75		0.04425	0.00766	0.00001	0.00066			[redacted]	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			[redacted]	20
21	LGS-XP		4,743.00	86.85	1.63	13.61	3.36	0.85		0.03856	0.01300	0.00116	0.00279			[redacted]	21
22	LGS-XT		4,743.00	139.05	-	11.46	2.67	0.75		0.04425	0.00766	0.00001	0.00066			[redacted]	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			[redacted]	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			[redacted]	24
25	LGS-2T-WP		169.10	-	0.61	14.13	14.13	0.75		0.05435	0.10098	0.00117	0.00117			[redacted]	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			[redacted]	26
27	LGS-3P-WP		234.20	78.25	0.92	16.97	16.97	0.85		0.03723	0.06984	0.00080	0.00081			[redacted]	27
28	LGS-3T-WP		189.10	23.00	0.61	17.42	17.42	0.85		0.03622	0.07071	0.00089	0.00090			[redacted]	28
29	IAWP															[redacted]	29
30																[redacted]	30
31	ORS-TOU		12.50							0.30471		0.01018	0.01831	0.00526	0.01078	[redacted]	31
32	ORS-TOU Opt A		12.50							0.26792		0.00671	0.00601	0.00214	0.00151	[redacted]	32
33	ORS-TOU Opt B		26.90							0.40478		0.00914	0.00469	0.00432	0.00032	[redacted]	33
34	ORS-TOU DDP		5.75		0.16	0.16		0.05					0.03642			[redacted]	34
35	ORS-TOU CPP		12.50						0.62872	0.27394		0.01391	0.00583	0.00862	0.00135	[redacted]	35
36	ORS-TOU CPP DDP		12.50			0.16		0.05	0.62872	0.16594		0.01251	0.01631	0.00736	0.01078	[redacted]	36
37	ORM-TOU		7.70							0.26153		0.03523	0.01164	0.02781	0.00857	[redacted]	37
38	ORM-TOU Opt A		7.70							0.24830		0.02469	0.00596	0.01832	0.00146	[redacted]	38
39	ORM-TOU Opt B		13.20							0.24920		0.05629	0.01616	0.04676	0.01064	[redacted]	39
40	ORM-TOU DDP		5.25		0.07	0.07		0.05					0.03873			[redacted]	40
41	ORM-TOU CPP		7.70						0.41715	0.23578		0.02984	0.01504	0.02277	0.00963	[redacted]	41
42	ORM-TOU CPP DDP		7.70			0.07		0.05	0.41715	0.21104		0.02984	0.00593	0.02277	0.00144	[redacted]	42
43	OLRS-TOU		70.70							0.30090		0.01793	0.01582	0.01224	0.01034	[redacted]	43
44	OLRS-TOU Opt A		70.70							0.27813		0.00868	0.00866	0.00391	0.00389	[redacted]	44
45	OLRS-TOU Opt B		181.10							0.23279		0.03210	0.00786	0.02499	0.00317	[redacted]	45
46	OLRS-TOU DDP		13.00		0.18	0.23		0.05					0.03868			[redacted]	46
47	OLRS-TOU CPP		70.70						0.33064	0.27169		0.01496	0.02229	0.00956	0.01616	[redacted]	47
48	OLRS-TOU CPP DDP		70.70			0.23		0.05	0.33064	0.22227		0.01496	0.01693	0.00956	0.01314	[redacted]	48
49	OGS-TOU		25.50	2.50						0.06215		0.01391	0.01260	0.00854	0.00736	[redacted]	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	[redacted]	50
51	OLGS-3P-HLF		214.10	78.25	1.06	20.79	5.63	0.90		0.01088	0.00096	0.00043	0.00044			[redacted]	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			0.00079	(0.00419)	(0.00410)		59
60	LGS-2S EVCCR					(11.53)	(2.38)	(0.54)		0.08897	0.01984	-	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

Additional Charges:

Separate Billing

LGS-X & LGS-WP-X:	$	93.50	Per additional bill
DOS LGS-X & LGS-WP-X:	$	93.50	Per additional bill

Power Factor Charges ($/kVarh):

Summer:	$	0.00200	$/kVarh
Winter:	$	0.00100	$/kVarh

Customer Specific Facilities Charges	Charge per $ of: Utility	Charge per $ of: 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

Notes:

(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 recovers both the Rule 9 and primary distibution facilty 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).

(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 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 facilty calculations be incomplete at the start 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.

(3) The per kW facilty 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 facilities identified to serve them. See page 22 in Statement O for the CSFCs by LGS-X customer.

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		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	Class	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	Line No
8																				8
9	RS					$ 0.05995			$ (0.00039)	$ 0.00070	[redacted]	$ 0.00256					$ 0.06282			9
10	RM					0.05186			(0.00039)	0.00070	[redacted]	0.00224					0.05441			10
11	LRS					0.05216			(0.00039)	0.00070	[redacted]	0.00220					0.05467			11
12	GS					0.01802			(0.00039)	0.00068	[redacted]	0.00170					0.02001			12
13	LGS-1					0.01522			(0.00039)	0.00068	[redacted]	0.00171					0.01722			13
14	LGS-2S		$ 0.03242	$ 0.01573	$ 0.00053	0.00572			(0.00039)	0.00068	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	0.00096		0.03747	0.07196	0.00214	0.00215			28
29	IAIWP					-			-	-	[redacted]						-			29
30											[redacted]									30
31	ORS-TOU		0.30471		0.01018	0.01631	$ 0.00526	$ 0.01078	(0.00039)	0.00070	[redacted]	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	[redacted]	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	[redacted]	0.00256		0.40765		0.01201	0.00756	0.00719	0.00319	33
34	ORS-TOU DDP					0.03642			(0.00039)	0.00070	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	0.00224		0.25175		0.05884	0.01871	0.04931	0.01319	39
40	ORM-TOU DDP					0.03673			(0.00039)	0.00070	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	0.00220		0.23530		0.03461	0.01037	0.02750	0.00568	45
46	OLRS-TOU DDP					0.03668			(0.00039)	0.00070	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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 53

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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	[redacted]	**1.16**	-	0.05	0.03	(0.03)	—	1.21	14
15	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.38	[redacted]	**1.38**	-	0.07	0.04	(0.04)	—	1.45	15
16	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.38	[redacted]	**1.38**	-	0.07	0.04	(0.04)	—	1.45	16
17	Mercury Vapor	Non-Metered	200W	CLS 22		165	1.80	[redacted]	**1.80**	-	0.11	0.06	(0.06)	—	1.91	17
18	Mercury Vapor	Non-Metered	200W	CLS 22		165	1.80	[redacted]	**1.80**	-	0.11	0.06	(0.06)	—	1.91	18
19	High Pressure	Non-Metered	200W	CLS 24		83	0.81	[redacted]	**0.81**	-	0.06	0.03	(0.03)	—	0.87	19
20	High Pressure	Non-Metered	200W	CLS 24		83	1.23	[redacted]	**1.23**	-	0.06	0.03	(0.03)	—	1.29	20
21	Municipal Street Lights - Public							[redacted]								21
22	Incandescent	n/a	100W	CLS 30		73	8.95	[redacted]	**8.95**	-	0.05	0.03	(0.03)	—	9.00	22
23	Incandescent	n/a	200W	CLS 31		120	8.55	[redacted]	**8.55**	-	0.08	0.05	(0.05)	—	8.63	23
24	Incandescent	n/a	200W	CLS 32		167	8.06	[redacted]	**8.06**	-	0.11	0.07	(0.07)	—	8.17	24
25	Mercury Vapor	Wood Pole	200W	CLS 33		73	8.90	[redacted]	**8.90**	-	0.05	0.03	(0.03)	—	8.95	25
26	Mercury Vapor	Wood Pole	200W	CLS 34		103	8.73	[redacted]	**8.73**	-	0.07	0.04	(0.04)	—	8.80	26
27	Mercury Vapor	Wood Pole	200W	CLS 35		165	8.09	[redacted]	**8.09**	-	0.11	0.06	(0.06)	—	8.20	27
28	Mercury Vapor	Steel Pole	200W	CLS 43		73	8.90	[redacted]	**8.90**	-	0.05	0.03	(0.03)	—	8.95	28
29	Mercury Vapor	Steel Pole	200W	CLS 44		103	8.73	[redacted]	**8.73**	-	0.07	0.04	(0.04)	—	8.80	29
30	Mercury Vapor	Steel Pole	200W	CLS 45		165	8.09	[redacted]	**8.09**	-	0.11	0.06	(0.06)	—	8.20	30
31	Sodium Vapor	n/a	100W	CLS 89		42	9.22	[redacted]	**9.22**	-	0.03	0.02	(0.02)	—	9.25	31
32	Sodium Vapor	n/a	200W	CLS 90		83	8.92	[redacted]	**8.92**	-	0.06	0.03	(0.03)	—	8.98	32
33	Municipal Street Lights - Customer Owned							[redacted]								33
34	Incandescent	n/a	200W	CLS 51		120	1.10	[redacted]	**1.10**	-	0.08	0.05	(0.05)	0.05	1.23	34
35	Mercury Vapor	n/a	200W	CLS 53		73	1.54	[redacted]	**1.54**	-	0.05	0.03	(0.03)	0.03	1.62	35
36	Mercury Vapor	n/a	200W	CLS 54		103	1.24	[redacted]	**1.24**	-	0.07	0.04	(0.04)	0.04	1.35	36
37	Mercury Vapor	n/a	200W	CLS 55		165	0.60	[redacted]	**0.60**	-	0.11	0.06	(0.06)	0.06	0.77	37
38	Street Lights - LED							[redacted]								38
39	LED	Non-Metered	100W	CLS 20		70	0.10	[redacted]	**0.10**	-	0.05	0.03	(0.03)	—	0.15	39
40	LED	Non-Metered	200W	CLS 21		35	0.10	[redacted]	**0.10**	-	0.02	0.01	(0.01)	—	0.12	40
41	LED	Non-Metered	200W	CLS 22		70	0.12	[redacted]	**0.12**	-	0.05	0.03	(0.03)	—	0.17	41
42	LED	Non-Metered	200W	CLS 24		70	0.12	[redacted]	**0.12**	-	0.05	0.03	(0.03)	—	0.17	42
43	Municipal Street Lights - LED							[redacted]								43
44	LED	n/a	100W	CLS 30		35	8.91	[redacted]	**8.91**	-	0.02	0.01	(0.01)	—	8.93	44
45	LED	n/a	200W	CLS 31		70	8.48	[redacted]	**8.48**	-	0.05	0.03	(0.03)	—	8.53	45
46	LED	n/a	200W	CLS 32		70	7.96	[redacted]	**7.96**	-	0.05	0.03	(0.03)	—	8.01	46
47	LED	Wood Pole	200W	CLS 33		70	8.86	[redacted]	**8.86**	-	0.05	0.03	(0.03)	—	8.91	47
48	LED	Wood Pole	200W	CLS 34		70	8.67	[redacted]	**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

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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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**11.91**	-	0.02	0.03	(0.01)	0.01	11.96	32
33																33
34																34

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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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**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	[redacted]	**11.77**	-	0.05	0.06	(0.03)	0.03	11.88	36
37																37
38																38

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Proposed Standby Rates

			Distribution Charges				Contract Demand Charges, contract kW[4]			Backup Service Variable T&G Demand Charges, metered kW			BTGR Energy, per kWh (including interclass rate rebalancing)[5,6]				Maintenance Back-up Service[7]		
Line No.	Class		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]	Sum On Peak:	Sum Mid Peak:	Other:	Sum On Peak:	Sum Mid Peak:	Other:	Sum On Peak:	Sum Mid Peak:	Sum Off Peak:	Other:	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		[redacted]	9
10	SSR III	LGS-1	15.80	6.25	3.68	$ 3.68			$ 1.00			$ 3.01				0.01522	$ 1.51	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	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	[redacted]	25

note: while not shown in this table, DEAA is applicable to standby service.

1. CSF = customer specific facilities charges.
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 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 (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
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 facilities. This alternative facilities charge is not applicable to SSR I and SSR II, and is not applicable when a CSF charge applies instead.
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.
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
6. Other than as explained in note 5, the BTGR rates are those of the otherwise applicable class including the IRR.
7. Energy rates in maintenance periods are the same as those during non-maintenance periods -- see BTGR and BTER columns for applicable rates.
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:
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

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Proposed Distribution Only Service (DOS) Rates

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)
GS	1	$ 25.50		$ 2.50		$ 0.01131
LGS-1	1	15.80	$ 3.68	6.25		0.00178
LGS-2S		122.40	2.68	9.75		0.00110
LGS-2P		207.70	2.34	65.00		0.00001
LGS-2T	2	182.00	0.61	23.00		0.00178
LGS-3S		122.00	2.82	3.00		0.00066
LGS-3P		214.10	2.73	76.25		0.00001
LGS-3T	2	182.00	0.61	23.00		0.00001
LGS-XS	3	4,743.00	0.91	20.52	$ 1,608.00	0.00001
LGS-XP	3	4,743.00	1.63	86.85	$ 49,797.00	0.00131
LGS-XT	3	4,743.00	-	139.05	$ 29,105.00	0.00090
LGS-2S-WP		128.70	0.80	9.75		0.00001
LGS-2P-WP		208.60	1.17	65.00		0.00001
LGS-2T-WP	2	169.10	0.61	-		0.00001
LGS-3S-WP		149.90	0.45	3.00		0.00001
LGS-3P-WP		234.20	0.92	76.25		0.00001
LGS-3T-WP	2	189.10	0.61	23.00		0.00001
SL	4					
GS-Pal	4					

<u>Additional Charges:</u>

Separate Billing			
DOS LGS-X & LGS-WP-X:	$	93.50	Per additional bill
Power Factor Charges ($/kVarh)[5]:			
Summer:	$	0.00200	$/kVarh
Winter:		0.00100	$/kVarh
Non-X class Customer Specific Facilities:		0.00313	Per $ of Utility Investment
		0.00057	$ per Customer Contributed Investment
R-BTER - 2016 charge ($/kWh)[6]:		-	
R-BTER - 2017 charge ($/kWh)[6]:		-	

(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.

(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.

(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.

(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.

(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%.

(6) Rates do not apply to all DOS customers and are charged only to applicable customers.

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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

1. Rates are shown only for classes containing customers with the potential of going open access under AB 661 or SB 211 provisions.
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 applicable schedule (OAS). For these classes that presently have customers served, the applicable OAS is shown in the table.

2. This rate is the marginal generation cost reconciled to the generation revenue requirement stated on a per kWh basis for the class.

Reconciliation factor is: 100.0%

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Calculation of Customer Specific Facilities Charges

Line No.	Customer Specific Facility Investment & Revenue Requirement		Total	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

Line No.	Individual CSFC	Class	Group	NVE Investment	Annual $ Per $ of Facility Investment	Annual Fac Rev By Customer	Monthly Per $ of Fac Invest. Factor	Monthly Fac Revenue By Customer	Line No.
13	CSF Charges By Customer Per Dollar of Facilities Investment Factor Developed above								13
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									46
47									47
48									48
49									49
50	Subtotals by Class and Service								50
51	LGS-3T - Bundled	LGS-3T	Bundled	$ 6,178,305	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

Line No.	Temporary Transmission level per kW Facility Charge (Charged until CSF charge is developed)				Line No.
61				^^^^^^^^^^	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

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Calculation of Transmission Level Customer Specific Facilities O&M and A/G Customer Specific Rates Relating to Contributed (CIAC) Investment

Line No.	**Development of Annual & Monthly Per Dollar of Investment Recovery Rate**	(a)		(b)			(c)
7							
8	Annual: Dist Reconciliation Factor	x		Dollar O&M/A&G Recovery Per Dollar of Contributed Investment			
9	100.0%	x		$0.00992	=	$	0.00992
10	Monthly: (annual rate divided by 12)				=	$	0.00057
11							
12							

Line No.	CIAC Investment & O&M and A&G Revenue Requirement					Dollar Per Dollar of Investment $ (cost based -- before reconciliation)	Per Dollar O&M/A&G Recovery Per Dollar of CIAC'd Facility Investment & Charges by Customer			
16	Customer	Class	Group	Contributed Investment	Annual Revenue Requirement	[(b) / (a)]	Original CIAC Investment	Monthly Per $ of CIAC'd Investment	Monthly Payment [(d) * (e)]	Annual Payment
17										
18	LHOIST	LGS-3T	Bundled	-	$ -	$0.00992	$ -	$ 0.00057	$ -	$ -
19	SA RECYCLING	LGS-3T	Bundled	-	-	$0.00992	-	0.00057	-	-
20	VENETIAN	LGS-3T	Bundled	-	-	$0.00992	-	0.00057	-	-
21	HOLDER	LGS-3T	Bundled	11,791,553	117,025	$0.00992	11,791,553	0.00057	6,721.19	80,654.28
22	SNWA LAMB	LGS-3T	DOS	453,810	4,504	$0.00992	453,810	0.00057	258.67	3,104.04
23	SNWA LAMB	LGS-3T	DOS	453,810	4,504	$0.00992	453,810	0.00057	258.67	3,104.04
24	SNWA SLOAN	LGS-3T	DOS	826,580	8,203	$0.00992	826,580	0.00057	471.15	5,653.80
25	CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	11,820	$0.00992	1,191,000	0.00057	678.87	8,146.44
26	CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	11,820	$0.00992	1,191,000	0.00057	678.87	8,146.44
27	CCWRD2	LGS-3T	DOS	374,615	3,718	$0.00992	374,615	0.00057	213.53	2,562.36
28	CCWRD2	LGS-3T	DOS	211,779	2,102	$0.00992	211,779	0.00057	120.71	1,448.52
29	CCWRD2	LGS-3T	DOS	2,348,976	23,312	$0.00992	2,348,976	0.00057	1,338.92	16,067.04
30	MGM	LGS-3T	DOS	-	-	$0.00992	-	0.00057	-	-
31	MGM	LGS-3T	DOS	-	-	$0.00992	-	0.00057	-	-
32	CAESAR'S	LGS-3T	DOS	-	-	$0.00992	-	0.00057	-	-
33	SNWA PP4	LGS-3T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
34	SNWA PP5	LGS-3T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
35	SNWA PP6	LGS-3T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
36	SNWA HACIENDA	LGS-3T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
37	SNWA PP3	LGS-2T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
38	CLEARWATER PAPER CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
39	NP RED ROCK LLC	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
40	POLY-WEST INC	OLGS-3P HLF	Bundled	51,773	514	$0.00992	51,773	0.00057	29.51	354.12
41	STATION GVR ACQUISITION LLC	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
42	TRUMP RUFFIN COMMERCIAL LLC	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
43	SUNSET STATION 1641830	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
44	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
45	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.00992	-	0.00057	-	-
46	POLY-WEST 2089379	OLGS-3P HLF	Bundled	51,773	514	$0.00992	51,773	0.00057	29.51	354.12
47										
48										
49										
50	Subtotals by Class and Service									
51	LGS-3T - Bundled	LGS-3T	Bundled	11,791,553	117,025	$0.00992	11,791,553	0.00057	6,721.19	80,654.28
52	LGS-3T - DOS	LGS-3T	DOS	7,051,570	69,983	$0.00992	7,051,570	0.00057	4,019.39	48,232.68
53	LGS-2T-WP - Bundled	LGS-2T-WP	Bundled	-	-	$0.00992	-	0.00057	-	-
54	LGS-2T-WP - DOS	LGS-2T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
55	LGS-3T-WP - Bundled	LGS-3T-WP	Bundled	-	-	$0.00992	-	0.00057	-	-
56	LGS-3T-WP - DOS	LGS-3T-WP	DOS	-	-	$0.00992	-	0.00057	-	-
57	OLGS-3P-HLF Bundled	OLGS-3P HLF	Bundled	103,546	1,028	$0.00992	103,546	0.00057	59.02	708.24
58										
59	Total			$ 18,946,669	$ 188,036	$0.00992	$ 37,893,338		$ 10,799.60	$ 129,595.20
60						Marginal O&M from MCS				
61						$188,036				

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Calculation of LGS-X Specific Charges

Line No.		Basic Service Charge: Billing Units	Basic Service Charge: Cost-Based Revenue	Basic Service Charge: Rate	Additional Meter Charge: Billing Units	Additional Meter Charge: Cost-Based Revenue	Additional Meter Charge: Rate	Separate Bill: Billing Units	Separate Bill: Cost-Based Revenue	Separate Bill: Rate	Line No.
7	**Basic Service, Additional Meter and Separate Billing Charges**										7
8											8
9											9
10											10
11	LGS-XS	-	$ -		60	$ 1,362.75	$ 22.70	-	$ -		11
12	LGS-XP	24	$ 1,244,282.46	$ 51,845.10	156	$ 6,262.71	$ 40.10	24	$ 630.43	$26.27	12
13	LGS-XT	12	$ 363,617.42	$ 30,301.45	36	$ 756.91	$ 21.00	12	$ 157.61	$13.13	13
14	Total	36	$ 1,607,899.88	$4,743.00	252	$ 8,382.37	$33.30	36	$ 788.03	$93.50	14
15			Present DOS Rate:	$5,580.00					Present Rate:	$110.00	15
16			Percent Change:	-15.0%					Percent Change:	-15.0%	16
17											17

Line No.	Customer	Premise	Rate Schedule	Current Charges: Monthly Facilities Charge	Current Charges: Annual Facilities Revenue	Current Charges: Investment	Proposed Charges: Monthly Facilities Charge	Proposed Charges: Annual Facilities Revenue	Proposed Charges: Investment	Line No.
18	**LGS-X Customer Specific Facilities**									18
19										19
20										20
21										21
22	Bally	1231089	LGS-XP DOS	$ 4,228	$ 50,736		$ 3,740	$ 44,880		22
23	Bally	1231091	LGS-XS DOS	1,818	21,816		1,608	19,296		23
24	Paris	1735149	LGS-XP DOS	5,729	68,748		5,068	60,816		24
25	Paris	1735152	LGS-XP DOS	5,729	68,748		5,068	60,816		25
26				$ 17,504	$ 210,048	$ 2,020,383	$ 15,484	$ 185,808	$ 2,066,291	26
27										27
34	New Castle Corp (Excalibur)	1398169	LGS-XP DOS	$ 5,257	$ 63,084		$ 4,710	$ 56,520		34
35	New Castle Corp (Excalibur)	1396170	LGS-XP DOS	5,232	62,784		4,687	56,244		35
36	New Castle Corp (Excalibur)	1415346	LGS-XS DOS	-	-		-	-		36
37	New Castle Corp (Excalibur)	1415347	LGS-XS DOS	-	-		-	-		37
38	Luxor	1500684	LGS-XP DOS	6,295	75,540		5,640	67,680		38
39	Luxor	1500685	LGS-XP DOS	7,820	93,840		7,006	84,072		39
40	Luxor	1511139	LGS-XS DOS	-	-		-	-		40
41	Luxor	1652129	LGS-XP DOS	1,895	22,740		1,698	20,376		41
42	Mandalay Bay	1714502	LGS-XP DOS	6,798	81,576		6,090	73,080		42
43	Mandalay Bay	1714503	LGS-XP DOS	6,798	81,576		6,090	73,080		43
44	New Castle Corp (Excalibur)	1758368	LGS-XP DOS	-	-		-	-		44
45				$ 40,095	$ 481,140	$ 4,885,159	$ 35,921	$ 431,052	$ 4,885,159	45
46										46
47	Monte Carlo	1607748	LGS-XT DOS	$ -	$ -		$ -	$ -		47
48	Monte Carlo	1607750	LGS-XT DOS	10,739	128,868		9,790	117,480		48
49	Bellagio	1656755	LGS-XP DOS	-	-		-	-		49
50	Bellagio	1656777	LGS-XP DOS	-	-		-	-		50
51	Bellagio	1693991	LGS-XT DOS	21,186	254,232		19,315	231,780		51
52	Monte Carlo	1782548	LGS-XP DOS	-	-		-	-		52
53				$ 31,925	$ 383,100	$ 3,727,626	$ 29,105	$ 349,260	$ 3,727,626	53
54										54
55		Subtotals by Class and Service	LGS-XS	$ -	$ -	$ -	$ -	$ -	$ -	55
56			LGS-XP	-	-	-	-	-	-	56
57			LGS-XT	-	-	-	-	-	-	57
58			LGS-XS DOS	**1,818**	**21,816**	-	**1,608**	**19,296**	-	58
59			LGS-XP DOS	**55,781**	**669,372**	-	**49,797**	**597,564**	-	59
60			LGS-XT DOS	**31,925**	**383,100**	-	**29,105**	**349,260**	-	60
61			Total for Class	$ 89,524	$ 1,074,288	$ -	$ 80,510	$ 966,120	$ -	61
62										62

63 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 63
64 Primary charges. 64

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,

<u>/s/Lynn D'Innocenti</u>
Lynn D'Innocenti
Sr. Legal Administrative Assistant

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

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 7a

NV Energy Supporting Documentation (01/30/2023)

NV Energy

January 30, 2023

Mr. Ted Lendis
Permitting Manager
Clark County Department of Environmental and Sustainability, Division of Air Quality
4701 W. Russel Road, Suite 200
Las Vegas, Nevada 89118

RE: RACT Analyses Request for Supporting Documentation
Clark Generating Station (Source: 7) & Sun Peak Generating Station (Source: 423)

Dear Mr. Lendis:

Per the email dated December 21, 2022, from Rob Barton of RTP, Air Quality's consultant, to NV Energy (NVE) requesting response to additional questions and supporting documentation related to the Reasonably Available Control Technology Analyses for the Clark Generating Station (Source: 7) and Sun Peak Generating Station (Source: 423) previously submitted by NVE on October 3, 2022, NVE hereby submits the attached supplemental information.

NVE anticipates further communication from DAQ on this topic in the near future. If you require additional information or have any questions, please contact Sean Spitzer at (702) 402-5132, or via email at sean.spitzer@nvenergy.com.

I certify that, based on the information and belief formed after reasonable inquiry, the statements and information in this document are true, accurate, and complete.

Sincerely,

Jason Hammons
Vice President, Generation
NV Energy
Responsible Official

Q1: Provide documentation for the vendor cost estimates provided in Table 4-1 of the RACT Analysis for NOx control options for Clark Generating Station Unit 4.

A1: Table 4-1 of the RACT Analysis summarizes the estimated economic impact of three nitrogen oxide (NOx) control alternatives for Clark Generating Station Unit 4: selective catalytic reduction (SCR) plus dry low NOx (DLN) combustors, SCR alone, and DLN combustors alone. Detailed information about the cost of each alternative was provided in Appendix B of the analysis. The cost information presented in Appendix B and summarized in Table 4-1 is based on equipment quotations received from CECO/Peerless (for SCR) and General Electric (for DLN combustors). Copies of the vendor quotations that were received are provided with this letter in Attachment 1: Vendor Cost Information. Also included in Attachment 1 are copies of the response that was received from CECO/Peerless when NVE requested clarification about certain aspects of their equipment quotations, and an explanation about how the various cost elements used in Appendix B were derived from the information provided by CECO/Peerless and GE.

"Unit A" in the Budgetary Price Summary provided by CECO/Peerless corresponds to Clark Station Unit 4. Note that the emission control system that the vendor quoted is a combined SCR/oxidation catalyst system. Equipment and installation costs for a stand-alone SCR system were subsequently derived using the budgetary price summary and clarifications to it that the vendor provided. Items 1 and 2 of Attachment 2: Workup of Vendor Cost Information show how the SCR equipment and installation costs were derived from the vendor's budget quote and other information provided. Item 3 of this attachment shows how the annual SCR catalyst replacement cost estimate was developed.

GE provided a total installed cost estimate for retrofitting Clark Station Unit 4 with DLN combustors. Item 4 of Attachment 2 shows that the midpoint of the range of GE's estimated costs was used for the total installed cost estimate for the DLN combustor alternative for Unit 4.

Q2: Provide documentation for the vendor cost estimates provided in Table 5-1 of the RACT Assessment for VOC control options for Clark Generating Station Unit 4.

A2: Table 5-1 of the RACT analysis summarizes the estimated economic impact associated with controlling VOC emissions from Clark Generating Station Units 4 – 8 by retrofitting them with oxidation catalyst systems. Cost estimate details for each unit were provided in Appendix B to the RACT analysis. The basis for this cost information was the quotation received from CECO/Peerless and has been provided in Attachment 1.

"Unit C" in the vendor's Budgetary Price Summary corresponds to Clark Station Units 5 - 8. "Unit A" in the vendor's price summary corresponds to Clark Station Unit 4, although as described above the vendor did not supply a stand-alone equipment cost estimate for retrofitting an oxidation catalyst system onto Unit 4. Accordingly, an equipment cost estimate for Unit 4 was developed using the cost information that was supplied for Units 5 – 8, as detailed in Item 5 of Attachment 2. For this estimate the "six-tenths" scaling factor methodology described on page 25-16 of Perry

& Chilton's Chemical Engineer's Handbook (fifth edition) was used to estimate the cost of an oxidation catalyst system for Unit 4 based on the cost estimate provided for the slightly larger Units 5 – 8.

Items 6 and 7 of Attachment 2 show how the oxidation catalyst system installation cost estimate and annual catalyst replacement cost estimate for Clark Unit 4 were derived.

Q3: Provide information about the technical feasibility of Clark Generating Station Unit 4 meeting a VOC emission limit in the range of 1 – 3 ppmvd @ 15% O_2 based on good combustion practices.

A3: NVE asked GE about the technical feasibility of Clark Station Unit 4 meeting a VOC emission limit in the range of 1 – 3 ppmvd @ 15% O_2 without utilizing an oxidation catalyst system. We were informed that this emission level is not feasible with the combustor that is currently installed on the unit, and that because of its age (Unit 4 went into service in 1973) an engineering study would need to be performed to ascertain whether a VOC emissions limit lower than the current emissions level (0.024 lb/MMBtu) would be feasible.

Q4: Provide the equivalent stack concentration (expressed as ppmvd @ 15% O_2) used to derive the VOC emission limit of 5.01 lb/hr for Clark Generating Station Units 5 – 8.

A4: The operating permit for Clark Station contains no concentration-based VOC emission limits for Units 5 – 8. Rather, the mass emission limit of 5.01 lb/hr for each unit shown in Table III-C-2 of the facility's permit represents their only short-term limitation on VOC emissions. Documentation as to the concentration basis of this mass limit is not available. Nonetheless, using the maximum heat input rate of each unit (1,081 MMBtu/hr) and EPA's published F-factor for natural gas firing (8,710 dscf/MMBtu, per 40 CFR 60 Appendix A, Method 19), a mass limit of 5.01 lb/hr converts to a stack concentration of 1.3 ppmvd @ 15% O_2, as propane or 3.6 ppmvd @ 15% O_2, as methane.

Q5: Provide documentation for the vendor performance estimates provided in Appendix B for selective catalytic reduction (2 ppm @ 15% O_2) and dry low NOx combustors (9 ppm @ 15% O_2) for Sun Peak Generating Station Units 3 – 5.

A5: As summarized in Section 4-4 of the RACT Analysis, the results of the RACT/BACT/LAER Clearinghouse (RBLC) search that was conducted for this effort show that natural gas-fired simple-cycle combustion turbines equipped with SCR and DLN combustors have NOx emission limits in the range of 2 – 5 ppmv @ 15% O_2. Accordingly, NVE requested that the vendor's SCR equipment cost quote be based on a system sized to provide a stack concentration of 2 ppmv NOx @ 15% O_2. The RBLC search found that units equipped with DLN combustors alone have limits in the range of 9 – 30 ppmv @ 15% O_2, and accordingly 9 ppm NOx @ 15% O_2 was used as the equipment performance basis in the cost effectiveness calculations for this alternative.

Q6: Provide documentation for the vendor cost estimates provided in Tables 4-2 through 4-4 for the NOx control options for the Sun Peak Generating Station Units 3-5.

A6: Tables 4-2 through 4-4 of the RACT analysis summarize the estimated economic impact of alternative NOx controls for the Sun Peak Generating Station Units 3 - 5; detailed cost information about each alternative was provided in Appendix B of the analysis. Like the cost estimates for Clark Station Unit 4, the basis of the cost information presented in Appendix B and summarized in these tables for Sun Peak Units 3 – 5 are the SCR equipment quotation received from CECO/Peerless and the dry low NOx combustor cost information received from GE; copies of the vendor information received are provided in Attachment 1 to this letter. "Unit B" in the Budgetary Price Summary provided by CECO Peerless corresponds to Sun Peak Station Units 3- 5, and Items 8, 9 and 10 on Attachment 2 describe how the SCR equipment cost, installation cost, and SCR catalyst replacement cost (respectively) were derived from the vendor-provided information. Item 11 describes how the midpoint of the range of GE's estimated costs was used for the total installed cost estimate for the DLN combustor alternative for Units 3 – 5.

Q7: Provide information about the technical feasibility of Sun Peak Generating Station Units 3 – 5 meeting a NOx emission limit of 25 ppmvd @ 15% O_2 based on water injection and good combustion practices.

A7: NVE asked GE whether it would be technically feasible for the Sun Peak Units 3 – 5 to meet a NOx emission limit of 25 ppmv @ 15% O_2 using water injection and good combustion practices. We were informed that the combustors that are currently installed on these units are not capable of meeting this emission level. GE stated that these units would need to be retrofitted with new combustors for them to achieve 25 ppmv NOx @ 15% O_2 using water injection and that operating them at the water injection rate needed to meet this emission level could be expected to cause the units to emit carbon monoxide at a much higher level than they do currently.

Attachment 1: Vendor Cost Information

CECO ENVIRONMENTAL Peerless

Peerless Manufacturing Co (PMC)
CECO SCR Technologies
14651 North Dallas Parkway
Suite 500
Dallas, TX 75254
Ph. (214) 357-6181
Fax. (214) 351-0194

August 31, 2022

Steve Jelinek, PE
Senior Process Engineer
Steve.jelinek@aecom.com
AECOM
Office: (978) 905-2256

Subject: Budgetary Cost Estimate for SCR/CO Systems for a 60 and 85 MW Simple Cycle Combustion turbine

Dear Steve,

We are pleased to provide this proposal for the design and supply of various retrofit options for your client's Simple-Cycle and Combined-Cycle gas turbine exhaust systems in located in Nevada.

Best Regards,

Vaughn Watson
Director, Power Retrofit
(214) 668-1014
vwatson@onececo.com

I. BUDGETARY PRICE SUMMARY/SCOPE OF SUPPLY:

A. COMPLETE SIMPLE CYCLE SCR & CO/VOC EXHAUST SYSTEM FOR "UNIT A": A 1974 GENERAL ELECTRIC 7B (7000) TURBINE (60 MW) OPERATING IN SIMPLE-CYCLE PEAKING SERVICE (PRESSURE DROP GUARANTEE = 12" W.C.)

ITEM	QUANTITY	DESCRIPTION	PRICE
A	1	GT Outlet Expansion Joint	
B	1	Reactor Housing (includes access ladders and platforms)	
C	1	Flow Distribution/Mixing Device	
D	1	Outlet transition ductwork	
E	1	Expansion joint at stack	
F	1	Aqueous Ammonia Flow Control Unit	
G	1	Interconnecting piping from AFCU to manifold, manifold to AIG	
H	1	Ammonia Distribution Manifold	
I	1	Peerless EDGE™ - Ammonia Injection Grid	
J	1	SCR Catalyst – 120ppm > 4ppm - 96% NOx reduction; 10ppm NH3 slip	
K	1	SCR Catalyst Support Structure and Seals	
L	1	CO/VOC Catalyst	
M	1	CO Catalyst Support Structure and Seals	
N	1	Stack	
O	1	Acoustical Stack Silencer Baffles	
P	1	Stack Expansion Joint	
Q	1	Ammonia Storage Tank	
R	1	Ammonia Forwarding Pump Skid	
S	1	Ammonia Truck Unloading Skid	
T	Lot	Interconnecting Piping	
U	-	Engineering	
V	1	Computational fluid dynamics modeling	
W	1	Start-up and commissioning spares	
X	1	2 X 100% Tempering air / purge fan system	
Y	1	Freight	
		TOTAL BUDGET PRICE FOR ONE (1) SCR/CO/VOC SYSTEM	$ 11,000,000
O1	1	Budget Estimate for Mechanical Installation and Erection of Exhaust System (Excluding Civil, Electrical/Controls Integration & Piping Insulation)	**$7,625,000**

B. COMPLETE SIMPLE CYCLE SCR EXHAUST SYSTEM FOR "UNIT B": A 1991 GENERAL ELECTRIC PG7111-EA (84.5 MW) OPERATING IN SIMPLE CYCLE PEAKING SERVICE (PRESSURE DROP GUARANTEE = 12" W.C.)

ITEM	QUANTITY	DESCRIPTION	PRICE
A	1	GT Outlet Expansion Joint	
B	1	Reactor Housing (includes access ladders and platforms)	
C	1	Flow Distribution/Mixing Device	
D	1	Outlet transition ductwork	
E	1	Expansion joint at stack	
F	1	Aqueous Ammonia Flow Control Unit	
G	1	Interconnecting piping from AFCU to manifold, manifold to AIG	
H	1	Ammonia Distribution Manifold	
I	1	Peerless EDGE™ - Ammonia Injection Grid	
J	1	SCR Catalyst – 42ppm > 2ppm - 95% NOx reduction; 5ppm NH3 slip	
K	1	SCR Catalyst Support Structure and Seals	
L	1	Stack	
M	1	Acoustical Stack Silencer Baffles	
N	1	Stack Expansion Joint	
O	1	Ammonia Storage Tank	
P	1	Ammonia Forwarding Pump Skid	
Q	1	Ammonia Truck Unloading Skid	
R	Lot	Interconnecting Piping	
S	-	Engineering	
T	1	Computational fluid dynamics modeling	
U	1	Start-up and commissioning spares	
V	1	2 X 100% Tempering air / purge fan system	
W	1	Freight	
		TOTAL BUDGET PRICE FOR ONE (1) SCR SYSTEM	$ 12,500,000
O1	1	Budget Estimate for Mechanical Installation and Erection of Exhaust System (Excluding Civil, Electrical/Controls Integration & Piping Insulation)	**$8,500,000**

C. COMBINED-CYCLE RETROFIT CO/VOC CATALYST SYSTEM FOR UNIT C: A LATE 1970S WESTINGHOUSE MODEL 501B6 (85 MW) COMBINED CYCLE TURBINE

ITEM	QUANTITY	DESCRIPTION	PRICE
A	1	Reactor Housing (includes access ladders and platforms)	
B	1	Flow Distribution/Mixing Device/Transitions (As Required)	
C	1	CO/VOC Catalyst	
D	1	CO Catalyst Support Structure and Seals	
E	-	Engineering	
F	-	Computational fluid dynamics modeling	
G	1	Start-up and commissioning spares	
H	1	Freight	
		TOTAL BUDGET PRICE FOR ONE (1) RETROFIT CO/VOC SYSTEM	$ 2,500,000
01	1	Budget Estimate for Mechanical Installation and Erection of Exhaust System ***ASSUMES ADEQUATE SPACE BETWEEN SUPERHEATER/EVAPORATOR SECTION (TEMP RANGE OF 700-1000F.***	**$1,500,000**

All Purchase Orders based on this Quote, which is not an offer, are subject to acceptance by Seller at its principal office in Dallas, Texas. Unless otherwise expressly provided in Seller's acceptance, the terms and conditions set forth herein shall constitute a part of any agreement resulting from Seller's acceptance of an order for all or part of the goods covered by this Quote. This Quote serves as notice to Buyer of Seller's objection to any terms and conditions of Buyer that in any way conflict with, modify, condition, add to, or differ from the terms and conditions specified herein, unless such terms and conditions of Buyer are expressly included in Seller's acceptance of Buyer's order. Silence on the part of Seller shall not be construed, under any circumstances, as acceptance of Buyer's terms and conditions. If not previously revoked or otherwise provided herein, this Quote shall terminate and cease to exist thirty (30) days from the date of this Quote.

D. COMMERCIAL TERMS

A. PROPOSAL PRICE: The price proposed is for the design, materials, or components listed. If specific design conditions differ from the inquiry, the specifications shall be modified and an equitable adjustment shall be made in the contract price or delivery schedule, or both. Any changes in this quotation will be submitted and approved in writing.

B. DELIVERY: Typical delivery for all equipment is within FIFTY (50) weeks from the order date, contingent upon the timely return of approved drawings/documents. Storage fees will be charged if delivery is delayed beyond the project schedule for delays not caused by Peerless Mfg. Co. (Peerless). These charges will be imposed at the time of the delay.

C. TRANSPORTATION: Shipment of the equipment shall be via Motor Freight, DAP Job Site.

D. EXCLUDED ITEMS: The quoted price does not include any custom duties, tariffs, import fees, income tax, nor any other taxes, duties, levies, etc., imposed by governmental organizations. Equipment delivered to the following states will require a Tax Exemption Certificate to exclude those current state taxes from our invoice: Arizona, California, Georgia, Kentucky, Tennessee, and Texas.

E. VALIDITY: The offered price is valid for thirty (30) days from the proposal date, and thereafter, is subject to our acceptance. Due to the current fluctuation in steel prices, all pricing in this proposal must be confirmed at time of purchase order.

F. PAYMENT TERMS: Payment shall be made, net 30 days, per the following schedule:

25% - upon receipt of order
25% - upon submittal of approval drawings
25% - upon Peerless' Release for Procurement
15% - upon Delivery of Equipment
10% - upon Final Acceptance

G. CHANGES / CANCELLATION SCHEDULE: Any changes to or cancellation of the Agreement, once accepted, are subject to written approval by Peerless under conditions that shall include, among other things, protection against any loss to Peerless.

Cancellation Schedule:
25% - after receipt of purchase order
50% - after submittal of general arrangement drawings
90% - after release to purchase materials
100% - upon release to fabricate

H. WARRANTY: All hardware is under warranty for eighteen (18) months from contracted delivery or twelve (12) months from scheduled start-up, whichever occurs first. The extent of the warranty includes replacement of defective components and is limited to material only.

Peerless is not responsible for any damage resulting from mis-operation or improper maintenance of the unit as described in the Peerless Operation & Maintenance Manuals for this project. Warranty is voided if the system is not operated and maintained in accordance with the Operation & Maintenance Manual.

The aqueous ammonia must be reagent grade, diluted with fully de-ionized water to 19% by weight.

I. **PROPRIETARY RIGHTS:** All engineering and application information given in Peerless' Proposal is proprietary. Such information is to be used only in the evaluation of this offer. If an order does not result from this Proposal, such proprietary information must be held in confidence, and never used in any manner by the prospective purchaser.

If an order results from the Proposal, such proprietary information becomes the property of the Purchaser for use in the design, manufacture, and operation of the specific unit proposed, and cannot be used on any other item or in any other manner without approval from Peerless.

K. **NON-UNION LABOR:** Peerless labor facilities are non-union. Non-union craft will complete all fabrication work.

DESIGN CRITERIA

A. Design Conditions: The proposed SCR System design is based on the following design conditions; the data is for one (1) unit. Should the actual gas conditions be different from the design data, the performance shall be re-evaluated, based on the corrected design data.

Unit A: A 1974 General Electric 7B (7000) turbine (60 MW) operating in simple-cycle peaking service

- **We'll need cost information for both SCR and Oxidation Catalyst**
- Current NOx performance: assume 120 ppm NOx at 15% O2. (0.44 lb/mmbtu)
- Desired SCR performance of 4 ppm NOx with < 5 ppm ammonia slip
- Current VOC performance 0.024 lb/mmbtu. Desired OC performance 80% control.
- Typical exhaust temperature range 950F to 1080F.
- Maximum Exhaust mass flow rate 2,353,000 lb/hr
- Elevation 1700 ft.

Unit B: A 1991 General Electric PG7111-EA (84.5 MW) operating in simple cycle peaking service

- **Cost for SCR only (not Ox. Catalyst)**
- Current performance with water injection about 42 ppm NOx at 15% O2
- Desired SCR performance of 2 ppm with < 5 ppm ammonia slip
- Exhaust Temperature range 970 – 1010°F
- Maximum Exhaust mass flow Rate. 2,350,000 lb/hr
- Elevation 1700 ft.

Unit C: A late 1970s Westinghouse Model 501B6 (85 MW) combined cycle turbine

- **Cost for Oxidation Catalyst Only (not SCR)**
- Current VOC performance 0.0046 lb/mmbtu. Desired OC performance 2 ppm at 5% O2.
- Exhaust (stack) temperature ~270 - 280°F.
- Exhaust (stack) volumetric flow rate 1,010,000 acfm (685,000 wscfm).
- Assume the HRSG contains sufficient space for the catalyst grid.
- Elevation 1700 ft.

Jelinek, Steve

From:	Vaughn Watson <vwatson@OneCECO.com>
Sent:	Monday, September 12, 2022 12:20 PM
To:	Jelinek, Steve; Jake Moses
Cc:	Royer, Todd
Subject:	[EXTERNAL] RE: [EXT] RE: Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Steve,

Thanks for your patience on this response. I was unfortunately out all last week with Covid.

1. For each of the three options, we need to estimate an annualized cost for period catalyst replacement. Can you tell us:
    a. The expected catalyst life (years)? The guaranteed catalyst performance life is 3 years, that said we typically see catalyst replacement intervals greater than 5-6 years.
    b. The approximate percentage of the total equipment cost for each option that the catalyst represents?
        1. For Unit A: The SCR Catalyst cost for replacement is roughly $900,000. The CO Catalyst cost for replacement is roughly $750,000.
        2. For Unit B: The SCR Catalyst cost for replacement is roughly $900,000.
        3. For Unit C: The CO Catalyst cost for replacement is roughly $750,000.

2. Regarding Option A (the system for the GE 7B CT), we're evaluating economic feasibility on a pollutant-specific basis. Recognizing that you've given us equipment and installation costs for the "total" system (SCR and oxidation catalyst combined)
    a. Are you quoting a single catalyst reactor that would house both catalyst grids?
    b. Can you provide an approximate break out the equipment cost as follows:
        i. SCR catalyst & catalyst support The SCR Catalyst cost for Frame and Catalyst is roughly $1,100,000.
        ii. Oxidation catalyst & catalyst support The SCR Catalyst cost for Frame and Catalyst is roughly $900,000.
        iii. Ammonia storage, handling, distribution and controls, The approximate costs of this is $2,500,000
        iv. Balance of equipment (tempering air fans, expansion joints, catalyst housing, stack, engineering, freight, etc.) The approximate costs of this is $6,500,000

Let us know if you have any further questions.

Vaughn R. Watson | Director, Power Retrofit
CECO Peerless

CECO Environmental
14651 North Dallas Pkwy, Ste. 500 | Dallas, TX 75254
M: 214.668.1014 |**E:** vwatson@onececo.com

CECO Peerless

From: Jelinek, Steve <Steve.Jelinek@aecom.com>
Sent: Friday, September 9, 2022 1:42 PM
To: Vaughn Watson <vwatson@OneCECO.com>; Jake Moses <DMoses@OneCECO.com>
Cc: Royer, Todd <todd.royer@aecom.com>
Subject: RE: [EXT] RE: Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Sorry to hear that, Vaughn. A reply next week will be fine; I just didn't want this to fall through the cracks as the timeline for things on our end is pretty tight.

Thanks!

From: Vaughn Watson <vwatson@OneCECO.com>
Sent: Friday, September 9, 2022 2:38 PM
To: Jelinek, Steve <Steve.Jelinek@aecom.com>; Jake Moses <DMoses@OneCECO.com>
Cc: Royer, Todd <todd.royer@aecom.com>
Subject: [EXTERNAL] Re: [EXT] RE: Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Steve,

My apologies, I've been out all week with Covid. Ill get you a response early next week.

Thanks for your patience.

Vaughn R. Watson | Director, Power Retrofit & Refinery Services

CECO Peerless
CECO Environmental
14651 North Dallas Pkwy, Ste. 500 | Dallas, TX 75254
M: 214.668.1014 |**E:** vwatson@onececo.com

From: Jelinek, Steve <Steve.Jelinek@aecom.com>
Sent: Friday, September 9, 2022 1:30:55 PM
To: Jake Moses <DMoses@OneCECO.com>
Cc: Vaughn Watson <vwatson@OneCECO.com>; Royer, Todd <todd.royer@aecom.com>
Subject: [EXT] RE: Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Hi Jake –

I don't believe I've seen answers to these questions yet; can you give me an idea of when you folks might be able to get back to us on these?

Thanks,
Steve

From: Jelinek, Steve
Sent: Friday, September 2, 2022 10:15 AM
To: Jake Moses <DMoses@OneCECO.com>
Cc: Vaughn Watson <vwatson@OneCECO.com>; Royer, Todd <todd.royer@aecom.com>
Subject: RE: Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Good morning, Jake –

After reviewing your proposal, we had a couple of followup questions.

1. For each of the three options, we need to estimate an annualized cost for period catalyst replacement. Can you tell us:
    a. The expected catalyst life (years)?
    b. The approximate percentage of the total equipment cost for each option that the catalyst represents?
2. Regarding Option A (the system for the GE 7B CT), we're evaluating economic feasibility on a pollutant-specific basis. Recognizing that you've given us equipment and installation costs for the "total" system (SCR and oxidation catalyst combined)
    a. Are you quoting a single catalyst reactor that would house both catalyst grids?
    b. Can you provide an approximate break out the equipment cost as follows:
        i. SCR catalyst & catalyst support
        ii. Oxidation catalyst & catalyst support
        iii. Ammonia storage, handling, distribution and controls, and
        iv. Balance of equipment (tempering air fans, expansion joints, catalyst housing, stack, engineering, freight, etc.)

Thanks very much for these clarifications. Feel free to give me a call if you need any clarification.

Best regards,

Steve Jelinek, PE
Senior Process Engineer

AECOM
250 Apollo Dr.
Chelmsford, MA 01824
(978) 905-2256 (office)

From: Jake Moses <DMoses@OneCECO.com>
Sent: Wednesday, August 31, 2022 10:47 AM
To: Jelinek, Steve <Steve.Jelinek@aecom.com>
Cc: Vaughn Watson <vwatson@OneCECO.com>; Royer, Todd <todd.royer@aecom.com>
Subject: [EXTERNAL] Peerless P2213323 - Budgetary Proposal for Installation of SCR/CO Systems on Three Turbines

Steve,

Peerless is pleased to submit our budgetary proposal for the installation of SCR/CO Systems on the requested units.

Please let us know if you have any questions or concerns.

Best regards,

Jake Moses | Applications Engineer
CECO Peerless
CECO Environmental
14651 North Dallas Pkwy, Ste. 500 | Dallas, TX 75254
M: 469-203-7672 | **E:** dmoses@onececo.com

CECO Peerless

Jelinek, Steve

From:	Spitzer, Sean (NV Energy) <Sean.Spitzer@nvenergy.com>
Sent:	Thursday, September 15, 2022 2:08 PM
To:	Jelinek, Steve; Royer, Todd
Cc:	Heintz, Christopher (NV Energy); Giannantonio, Anthony (NV Energy); Elkins, Sydney (NV Energy)
Subject:	[EXTERNAL] FW: NOx controls at Clark 4

Hi Steve/Todd, take a look at the reply for Clark 4 NOx controls. Let's discuss once you've had a chance to review,
Sean

From: Nell, Michael (NV Energy) <Michael.Nell@nvenergy.com>
Sent: Thursday, September 15, 2022 10:51 AM
To: Spitzer, Sean (NV Energy) <Sean.Spitzer@nvenergy.com>
Subject: NOx controls at Clark 4

Sean,

Below is the only option that is potentially available for Clark 4 according to GE:

Combustor: **7B DLN1+ Low NOx Gas Only, 25 ppmvd Nox @ 15% O2 / 25 ppm CO**

Operation / Emissions							
Fuel	**Operation**	**Diluent**	**NOx (15% O2) ppmvd**	**CO ppmvd**	**UHC / VOC ppmvw (6)**	**Ambient Temperature Range**	**Mai**
Natural Gas (41040)	Base & Part	dry	25	25	7 / 1.4	-20 to 120 F	No

Pre-requisites / Notes
Mark VIe Controls
Gas Only

Feasibility study $1.5-2.5M (initial requirement) – this has never been implemented before so a study would be required to confirm that its capable of being implemented.

Potential custom development Cost: $2-4M (this is an estimated value, however the SOW/final cost is driven as a result of the feasibility study)
Known needs:

- Requires new 7E/7EA S1N and Support Ring with possible rotor impacts
- Assumes: 1042F Isotherm, Requires Autotune, Combustion Dynamics Monitoring (CDM) => study could turn up option to improve performance but may require generator major upgrade or a swap due to the lack of margin on the presently installed open-ventilated generator.
- Lab testing is required
- Fleet leader inspections will be required

Background:
The model 71B gas turbines were sold (in the early 1970's) with 1840 F firing temperature. The 1840 F firing temperature is substantially colder than the 2020 F firing temperature on production 7EA turbines when DLN was developed (in the early 1990's). Uprating the 71B turbines to a substantially higher firing temperature is not an option without further custom evaluation.
Therefore, NPI development is needed to adapt the 7E/7EA DLN product to the colder firing temperature of the 71B turbines at minimum. The most critical design parameter is that the radial temperature distribution into the nozzles and buckets does not have a hot spot. The second design parameter is dynamics, with the dynamics required to be low enough for a reasonable combustion inspection interval, and for the flame to be evenly distributed and stable enough for CO to be in control.

Upgrade estimated cost could range from $15M -23M

Thanks,
Mike Nell

From: Nell, Michael (NV Energy)
Sent: Tuesday, September 13, 2022 12:41 PM
To: Spitzer, Sean (NV Energy) <Sean.Spitzer@nvenergy.com>
Cc: Jelinek, Steve <steve.jelinek@aecom.com>; Royer, Todd <todd.royer@aecom.com>
Subject: RE: Ballpark quote for NOx controls at Sun Peak

Sean,

I received two options from GE for the Sun Peak units – breakdown below:

Option 1

Model:	**PG7121 (Generator), New Unit Cycle (PIP)**
Combustor:	**7EA.03 DLN1+ Low NOx 9/15/25 ppmvd NOx @ 15% O2 without Late Fuel Staging**

Operation / Emissions					
Fuel	**Operation**	**Diluent**	**NOx (15% O2) ppmvd**	**CO ppmvd**	**UHC / V(ppmvw**
Natural Gas (GEI41040)	Base & Part	dry	9	25	7 / 1.4
	Base & Part	dry	15	25	7 / 1.4

	Base & Part	dry	25	15	7 / 1.4
	+65F Tfire Peak	dry	25 (for 9 ppm NOx) 40	15	7 / 1.4

Budgetary range ~8M to 10M + Install (per GE, install roughly 1.5 million)

Option 2

Model: **PG7121 (Generator), New Unit Cycle (PIP and AO)**

Combustor: **7EA.03 DLN1+ Ultra Low NOx 4/5 ppmvd NOx @ 15% O2 without Late Fuel Staging**

	Operation / Emissions				
Fuel	**Operation**	**Diluent**	**NOx ppmvd (15% O2 Corrected)**	**CO ppmvd (15% O2 Corrected)**	**UHV / V(ppmvw (**
Natural Gas (41040)	Base & part	dry	4	25	7 / 1.4
	Base & part	dry	5	25	7 / 1.4
	Emissions Limited Peak	dry	7.5	25	7 / 1.4

Budgetary range ~10M to 13M + Install (per GE, install roughly 1.5 million)

Pre-requisites / Notes

Mark VIe Controls

Gas Only

GT output will be adversely affected if not off-set with other performance enhancements. This is due to the additional pressure drop through the venturi of the DLN liner. For cases where the unit currently utilizes water or steam injection, the reduction in output will be more significant.

Thanks,

Mike Nell
Turbine Maintenance Manager
Office (702) 402-5764
Mobile (725) 210-2569
Email: michael.nell@nvenergy.com
NVEnergy
a subsidiary of Berkshire Hathaway Energy

From: Spitzer, Sean (NV Energy) <Sean.Spitzer@nvenergy.com>
Sent: Thursday, September 8, 2022 9:46 AM
To: Nell, Michael (NV Energy) <Michael.Nell@nvenergy.com>
Cc: Jelinek, Steve <steve.jelinek@aecom.com>; Royer, Todd <todd.royer@aecom.com>
Subject: RE: Ballpark quote for NOx controls at Sun Peak

Mike, one more addition to this request. We are also performing an analysis on Unit 4 at the Clark Station, which is a GE 7B (7000) from 1973. Can you also ask GE to confirm that there is no DLN retrofit available for this unit due to age of technology? If there is, then the request would be a ballpark estimate for cost as well as expected emission rates with the new burners. Currently they are permitted at 0.44 lb/mmbtu NOx rate and 0.024 lb/mmbtu VOC.

Thanks again in advance,
Sean

From: Spitzer, Sean (NV Energy)
Sent: Thursday, September 1, 2022 2:02 PM
To: Nell, Michael (NV Energy) <Michael.Nell@nvenergy.com>
Cc: Jelinek, Steve <steve.jelinek@aecom.com>; Royer, Todd <todd.royer@aecom.com>
Subject: Ballpark quote for NOx controls at Sun Peak

Hi Mike,
Per our conversation, we are required to perform an emission control technology analysis on the Sun Peak units and are looking to get some ballpark quotes of potential NOX/VOC controls to use in our cost effectiveness calculations. For reference, the Sun Peak units are simple cycle GE PG7111-EA gas fired turbines, 1991 vintage. Their current NOx emission rate is 42 ppmvdc, and 143 lb/hr at that rate. The VOC emission rate is permitted at 1.8 lb/hr.

We're looking for any potential options for NOx reduction such as Dry Low NOx burner retrofit or otherwise. We're interested in how any controls affect the VOC emission rate as well, if that can also be specified in any responses. Our analysis is due at the end of the month so getting a budgetary estimate in the next week or two would be ideal to give us time to incorporate the findings.

I've included our consultants from Aecom, Steve Jelinek and Todd Royer, in the cc of this email as they are the lead authors of our analysis. Please include them in any responses you get. Thanks so much in advance for your help,

Sean Spitzer
Environmental Services Supervisor
NV Energy
6226 W Sahara ave M/S 30
Las Vegas, NV 89146
(702) 513-5010 (cell)

Jelinek, Steve

From:	Nell, Michael (NV Energy) <Michael.Nell@nvenergy.com>
Sent:	Tuesday, September 13, 2022 3:41 PM
To:	Spitzer, Sean (NV Energy)
Cc:	Jelinek, Steve; Royer, Todd
Subject:	[EXTERNAL] RE: Ballpark quote for NOx controls at Sun Peak

Sean,

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Option 1

Model:	**PG7121 (Generator), New Unit Cycle (PIP)**
Combustor:	**7EA.03 DLN1+ Low NOx 9/15/25 ppmvd NOx @ 15% O2 without Late Fuel Staging**

	Operation / Emissions				
Fuel	Operation	Diluent	NOx (15% O2) ppmvd	CO ppmvd	UHC / V(ppmvw (
Natural Gas (GEI41040)	Base & Part	dry	9	25	7 / 1.4
	Base & Part	dry	15	25	7 / 1.4
	Base & Part	dry	25	15	7 / 1.4
	+65F Tfire Peak	dry	25 (for 9 ppm NOx) 40	15	7 / 1.4

Budgetary range ~8M to 10M + Install (per GE, install roughly 1.5 million)

Option 2

Model:	**PG7121 (Generator), New Unit Cycle (PIP and AO)**
Combustor:	**7EA.03 DLN1+ Ultra Low NOx 4/5 ppmvd NOx @ 15% O2 without Late Fuel Staging**

			Operation / Emissions		
Fuel	Operation	Diluent	NOx ppmvd (15% O2 Corrected)	CO ppmvd (15% O2 Corrected)	UHV / V(ppmvw (
Natural Gas (41040)	Base & part	dry	4	25	7 / 1.4
	Base & part	dry	5	25	7 / 1.4
	Emissions Limited Peak	dry	7.5	25	7 / 1.4

Budgetary range ~10M to 13M + Install (per GE, install roughly 1.5 million)

Pre-requisites / Notes

Mark VIe Controls

Gas Only

GT output will be adversely affected if not off-set with other performance enhancements. This is due to the additional pressure drop through the venturi of the DLN liner. For cases where the unit currently utilizes water or steam injection, the reduction in output will be more significant.

Thanks,

Mike Nell
Turbine Maintenance Manager
Office (702) 402-5764
Mobile (725) 210-2569
Email: michael.nell@nvenergy.com

NVEnergy

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Cc: Jelinek, Steve <steve.jelinek@aecom.com>; Royer, Todd <todd.royer@aecom.com>
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Thanks again in advance,
Sean

From: Spitzer, Sean (NV Energy)
Sent: Thursday, September 1, 2022 2:02 PM
To: Nell, Michael (NV Energy) <Michael.Nell@nvenergy.com>

Cc: Jelinek, Steve <steve.jelinek@aecom.com>; Royer, Todd <todd.royer@aecom.com>
Subject: Ballpark quote for NOx controls at Sun Peak

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We're looking for any potential options for NOx reduction such as Dry Low NOx burner retrofit or otherwise. We're interested in how any controls affect the VOC emission rate as well, if that can also be specified in any responses. Our analysis is due at the end of the month so getting a budgetary estimate in the next week or two would be ideal to give us time to incorporate the findings.

I've included our consultants from Aecom, Steve Jelinek and Todd Royer, in the cc of this email as they are the lead authors of our analysis. Please include them in any responses you get. Thanks so much in advance for your help,

Sean Spitzer
Environmental Services Supervisor
NV Energy
6226 W Sahara ave M/S 30
Las Vegas, NV 89146
(702) 513-5010 (cell)

Attachment 2: Workup of Vendor Cost Information

Workup of Vendor Cost Information

Basis: Quotations received from Peerless Manufacturing Co (PMC), 8/31/2022
and esimated costs from General Electric 9/13/2022 and 9/15/2022

1. SCR equipment cost estimate for Clark Generating Station Unit 4

PMC Quotation dated August 31, 2022, Item I A:
- Complete Simple Cycle SCR & CO/VOC Exhaust System for "Unit A": A 1974 General Electric 7B (7000) Turbine (60 MW) Operating in Simple-Cycle Peaking Service

Budget Price for One (1) SCR/CO/VOC System:	$11,000,000

Equipment cost breakdown (email from PMC 9/12/2022)

SCR catalyst plus SCR catalyst support:	$1,100,000
SCR catalyst cost:	$900,000
Ammonia storage and handling equipment:	$2,500,000
Oxidation catalyst and catalyst support:	$900,000
Oxidation catalyst cost:	$750,000
Other system components:	$6,500,000
SCR catalyst support cost (by difference):	$200,000

Estimated equipment cost for SCR system alone:

SCR catalyst :	$900,000
SCR catalyst support:	$200,000
Ammonia storage and handling equipment:	$2,500,000
Other system components:	$6,500,000
Total SCR system equipment cost:	**$10,100,000**

2. Direct SCR installation cost estimate for Clark Unit 4

PMC Quotation dated August 31, 2022, Item I A:
- Complete Simple Cycle SCR & CO/VOC Exhaust System for "Unit A": A 1974 General Electric 7B (7000) Turbine (60 MW) Operating in Simple-Cycle Peaking Service

Budget Estimate for System Mechanical Installation:	$7,625,000

Estimated direct installation cost for SCR system alone:
(installation cost assumed to be proportional to equipment cost)

Combined system equipment cost estimate:	$11,000,000
Estimated cost for SCR system alone:	$10,100,000
Ratio, estimated SCR system cost/total system cost:	0.9182

Estimated direct installation cost for SCR system:

(0.9182)*(7625000) =	$7,001,275
say:	**$7,000,000**

3. SCR catalyst replacement cost for Clark Unit 4

SCR catalyst cost per PMC email 9/12/2022:	\$900,000
Estimated catalyst life (n):	5 years
Allowable NVE return on capital (i):	7.14%
Capital recovery factor: CRF = $(i*(1/((1+i)^n-1)$	0.1734
Annual catalyst replacement charge:	
(0.1734)*(900000) =	\$156,060 /yr
say:	**\$156,100** /yr

4. Total installed cost for Dry Low NOx combustors for Clark Unit 4

Email from Michael Nell (NV Energy) to Sean Spitzer (NV Energy) September 15, 2022 summarizing information from General Electric about the feasibility and estimated cost of Dry Low NOx Equipment for Clark Unit 4

Budgetary range for total installed cost: \$15 MM to \$23 MM
use midpoint of estimated cost range; say: **\$19,000,000**

5. Oxidation catalyst equipment cost estimate for Clark Unit 4

PMC Quotation dated August 31, 2022, Item I C:
- Combined-Cycle Retrofit CO/VOC Catalyst System for "Unit C": A late 1970s Westinghouse Model 501B6 (85 MW) Combined Cycle Turbine

Budget Price for One (1) Retrofit CO/VOC System: \$2,500,000

Clark Generating Station Unit 4 Output:	60 MW
Vendor Quotation Output Basis:	85 MW

Estimated CO/VOC system equipment cost for CGS Unit 4:
(scaled using "six-tenths" factor; Chemical Engineer's Handbook (fifth edition) equation 25-9: $C_2 = r^{0.6} * C_1$)

C_1 = Equipment cost for Unit 1 (i.e., "Unit C" from PMC Quotation)
= \$2,500,000

r = ratio of capacities; Unit 2/Unit 1 (i.e., 60 MW/85 MW)
= 0.706

C_2 = Equipment cost for Unit 2 (i.e., CGS Unit 4)
$= (0.706)^{0.6} * \$2,500,000 =$ \$2,028,521
say: **\$2,030,000**

6. Direct oxidation catalyst installation cost estimate for Clark Unit 4

PMC Quotation dated August 31, 2022, Item I C:
- Combined-Cycle Retrofit CO/VOC Catalyst System for "Unit C": A late 1970s Westinghouse Model 501B6 (85 MW) Combined Cycle Turbine

Budget Estimate for System Mechanical Installation: $1,500,000

Assume equivalent installation cost for Clark Generating Station Unit 4

$1,500,000

7. Oxidation catalyst replacement cost for Clark Unit 4

Oxidation catalyst cost per PMC email 9/12/2022:	$750,000
Estimated catalyst life (n):	5 years
Allowable NVE return on capital (i):	7.14%
Capital recovery factor: CRF = $(i^*(1/((1+i)^n-1)$	0.1734
Annual catalyst replacement charge:	
(0.1734)*(750000) =	$130,050
say:	**$130,100**

8. SCR equipment cost estimate for Sun Peak Generating Station Units 3 -5

PMC Quotation dated August 31, 2022, Item I B:
- Complete Simple Cycle SCR Exhaust System for "Unit B": A 1991 General Electric PG-7111-EA (84.5 MW) Operating in Simple Cycle Peaking Service

Budget Price for One (1) SCR System: **$12,500,000**

9. Direct SCR installation cost estimate for Sun Peak Units 3 - 5

PMC Quotation dated August 31, 2022, Item I B:
- Complete Simple Cycle SCR Exhaust System for "Unit B": A 1991 General Electric PG-7111-EA (84.5 MW) Operating in Simple Cycle Peaking Service

Budget Estimate for System Mechanical Installation: **$8,500,000**

10. SCR catalyst replacement cost for Sun Peak Units 3 - 5

Assume equivalent to catalyst replacement cost for Clark Generating Station Unit 4

$156,100 /yr

11. Equipment cost for Dry Low NOx combustors for Sun Peak Units 3 - 5

Email from Michael Nell (NV Energy) to Sean Spitzer (NV Energy) September 13, 2022
summarizing General Electric Dry Low NOx Equipment Estimates for the Sun Peak Units
Option 1 - Model: PG7121
Combustor: 7EA.03 DLN1+Low NOx 9/15/25 ppmvd NOx @15% O2 without Late Fuel

Budgetary range: $8 MM to $10 MM
use midpoint of estimated cost range; say: **$9,000,000**

12. Direct Dry Low NOx combustors installation cost estimate for Sun Peak Units 3 - 5

Email from Michael Nell (NV Energy) to Sean Spitzer (NV Energy) September 13, 2022
summarizing General Electric Dry Low NOx Equipment Estimates for the Sun Peak Units
Option 1 - Model: PG7121
Combustor: 7EA.03 DLN1+Low NOx 9/15/25 ppmvd NOx @15% O2 without Late Fuel

Installation (per GE, install roughly $1.5 MM) **$1,500,000**

Appendix7b

NV Energy Supporting Documentation (03/30/2023)

NVEnergy

March 30, 2023

Mr. Ted Lendis
Permitting Manager
Clark County Department of Environmental and Sustainability, Division of Air Quality
4701 W. Russel Road, Suite 200
Las Vegas, NV 89118

Subject: Response to Additional RACT Analysis Questions – NV Energy Clark and Sun Peak Generating Stations

Dear Mr. Lendis:

NV Energy (NVE) is pleased to provide you with the following information to augment the Reasonably Available Control Technology (RACT) Analysis that was submitted to you on October 3, 2022 for our Clark and Sun Peak Generating Stations. This information is being provided in response to the questions raised by your consultant (RTP Environmental Associates) in their two email transmittals to us on February 6, 2023 and our subsequent conference call with them on February 21. The information that RTP has requested, along with our responses to those information requests, is presented on the following pages.

NV Energy anticipates further communication from DAQ on this topic in the near future. If you require additional information or have any questions, please contact Chris Heintz at (702) 402-2048 or Christopher.Heintz@nvenergy.com.

I certify that, based on the information and belief formed after reasonable inquiry, the statements and information in this document are true, accurate, and complete.

Sincerely,

Jason Hammons
Vice President, Generation
NV Energy
Responsible Official

Cc: Rob Barton – RTP Environmental Associates

Q1: What is the source of the current Clark Generating Station Unit 4 VOC limit (0.024 lb/MMBtu)? Does this represent design specifications?

A1: As was explained during our conference call on February 21, the baseline VOC emission rate for Clark Generating Station Unit 4 of 0.024 lb VOC/MMBtu is not an emission limit or design specification. Rather, this figure is back calculated based on the originally established potential-to-emit emission rate for the unit. This unit was installed in 1973 and none of the unit's original design specifications are available.

Q2: What is the source of the current Clark Generating Station Unit 4 NOx performance (120 ppm)? Does this represent design specifications?

A2: As in the response to the previous question, none of Unit 4's original design specifications are available. 120 ppm NOx @15% O2 (0.44 lb/MMBtu) is the emission rate that has historically been used to quantify actual NOx emissions from this unit.

Q3: The 'Design Criteria' section of the CECO cost estimate shows 'Desired OC performance 80% control' for Unit A (Clark Generating Station Unit 4), whereas the OC performance for Unit C (Clark Generating Station Units 5 – 8) is 2 ppm. What is the reason for the lower control efficiency for Unit 4? Temperature?

A3: The rationale for requesting different performance specifications for the oxidation catalyst system quotations for Clark Generating Station Units 4 and 5 – 8 is the different VOC concentrations in the turbine exhausts for these units. For Unit 4, the current VOC exhaust concentration based on an emission rate of 0.024 lb/MMBtu is approximately 85 ppm @ 15% O_2 on an as-propane basis. For Units 5 - 8, the VOC exhaust concentration is much lower; based on an emission rate of 0.0046 lb/MMBtu it is approximately 16 ppm @ 15% O_2 on an as-propane basis.

Regardless of whether the oxidation catalyst system quoted for Clark Unit 4 can achieve the marginally higher VOC control performance specified for Units 5 - 8, an oxidation catalyst system is unrepresentative of RACT for Unit 4 based on unreasonable cost effectiveness given this unit's historically low utilization rate and the low rate that it is projected to be utilized in the future. As presented in Table 5-1 of our original RACT assessment, an oxidation catalyst system that achieves 80% reduction in VOC emissions from Unit 4 would reduce annual VOC emissions from the unit by 1.64 tons/yr and have a cost effectiveness of over $376,000 per ton removed. If, however, the system that was quoted could achieve the VOC control performance specified for Units 5 - 8 (approximately 87.5%), it would reduce annual VOC emissions from Unit 4 by an only very slightly greater amount (1.79 tons/yr) and have a cost effectiveness of $344,900 per ton removed.

Q4: The 'Design Criteria' section of the CECO cost estimate for Unit C (CCUs) shows VOC performance of '2 ppm @ 5% O_2'. Is this correct or is the O_2 correction 15%?

A4: The correct turbine exhaust oxygen concentration for the CECO cost estimate for Unit C should be 15% O_2, not 5% O_2.

Q5: The 'Design Criteria' section of the CECO cost estimate for Unit A (Clark Generating Station Unit 4) shows selective catalytic reduction (SCR) system performance of 4 ppm NOx with < 5 ppm slip, whereas SCR performance for Unit B (SPGS) is 2 ppm NOx with < 5 ppm slip. Is 2 ppm achievable for Clark Generating Station Unit 4? If not, what is the technical basis for not lowering the target to 2 ppm?

A5: The rationale for the higher outlet concentration specification for the SCR system for Clark Generating Station Unit 4 compared to the system for Sun Peak Generating Station Units 3 - 5 was the higher inlet NOx concentration (120 ppm vs 42 ppm). In both quotations, the basis for CECO's quotation was a single stage of SCR catalyst, capable of approximately 95% NOx conversion. Achieving an outlet NOx emission rate of 2 ppm for Clark Unit 4 would require approximately 98% NOx conversion, which would not be achievable with the catalyst system design quoted. CECO subsequently explained that a system containing approximately twice as much catalyst as originally quoted would be required to achieve 98% conversion. In addition to the cost considerations, an SCR catalyst system imposes backpressure on a turbine exhaust system that has the effect of reducing the system's output capacity. CECO stated that a single stage of SCR catalyst typically imposes an exhaust system backpressure of between 3 and 4 inches of water, which can reduce the output of a simple cycle turbine by approximately 2%. Consequently, providing sufficient catalyst to achieve an outlet concentration of 2 ppm on Unit 4 may reduce the output of this unit by approximately 4%.

Q6: Is it technically feasible to add water injection for Clark Generating Station Units 5-8 or is that limited by combustor design?

A6: NV Energy was required by the terms of a Consent Decree issued on August 9, 2007 by the United States Environmental Protection Agency to replace the original combustors on Clark Generating Station Units 5 – 8 with Ultra Low NOx Burner (ULNB) combustors. These UNLB combustors employ lean premixed combustion principles that enable the units to comply with an emission limit of 5 ppm @ 15% O_2. The combustors on Units 5 – 8 are designed to operate without the use of water or steam injection, thus further reduction of NOx emissions using water injection is not a technically feasible alternative for these units.

Q7: Is it technically feasible to increase ammonia injection on Clark Generating Station Units 11-28 to achieve 2 ppmvd? If so, what is the expected slip?

A7: Units 11 – 28 at Clark Generating Station are equipped with SCR systems designed to achieve an emission limit from each unit of 5 ppm @ 15% O2. The SCR system supplier stated that these systems are designed with sufficient catalyst to achieve compliance with the NOx emission limit while minimizing emissions of unreacted ammonia. The supplier noted that it is not feasible to simply raise the rate of ammonia injection to achieve a lower NOx emission target with the same amount of catalyst, which is an operational measure that the supplier referred to as "spray and pray." The supplier stated that adding an excess of ammonia beyond the stoichiometric amount needed to achieve the design NOx emissions rate would have the effect of flooding the catalyst with ammonia, thereby reducing its NOx reduction effectiveness. The supplier explained that injecting too much reagent into the catalyst causes the active catalyst sites to become blinded with ammonia, thereby precluding their ability to be available to allow the NOx reduction reactions to occur.

Q8: Oil-firing capability – The RACT analysis indicates that #2 oil was not fired in the Sun Peak Generating Station units during the baseline period and is not expected to be used in the future. Is NV Energy planning to remove oil combustion capability from the permit?

A8: Although distillate oil has not been utilized in the Sun Peak Generating Station combustion turbines for quite some time, NV Energy has no plans to remove oil-firing capability from the facility's air permit. It is prudent for NV Energy to preserve the capability to utilize oil in these units in terms of maintaining the Station's reliability to provide power to the grid should the natural gas supply to the facility be curtailed at some point in the future.

Q9: Increased water injection – In your January 30, 2023 response to RTP's request for supplemental RACT information for the Sun Peak Generating Station, GE indicated that the water injection rate needed to meet a potential limit of 25 ppm "could be expected to cause the Sun Peak Generating Station units to emit CO at a much higher level than they do currently". Can you confirm with GE what the expected CO emissions would be if NOx were reduced with increased water injection from current 42 ppm to 25 ppm and whether it would cause the units to exceed the CO limit of 10 ppm? Do you have design specs for the system (uncontrolled/controlled NOx, WFR, efficiency, etc.)? This option will likely receive increased scrutiny because of relatively low cost. The more supporting information you can provide regarding technical feasibility the better.

A9: As we explained in our response to RTP's first set of questions, GE stated that it is not technically feasible to achieve a NOx emission level of 25 ppm @ 15% O_2 using water injection with the combustors that are currently installed on Sun Peak Units 3 – 5. To achieve this emissions level with water injection, the units would need to be retrofitted with new combustors. GE estimated that the new combustors would have an equipment cost of between $4 and $6 million per unit, plus another $2 million per unit in combustor process control system and software upgrades. Considering that these units are limited to operate no more than 12 hours per day and typically only operate for less than 500 hours per year, the capital expenditure needed to achieve this marginal reduction in NOx emissions is not justifiable. Moreover, GE estimates that that the uncontrolled CO emission rate at the water injection rate needed to achieve a NOx emission rate of 25 ppmvd @15% O_2 would be 150 ppmvd @ 15% O_2, which is considerably higher than the current CO emission limit for these units (10 ppmvd @15% O_2).

Appendix 8

Saguaro RACT Analysis

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**

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:
00393	SAGUARO POWER COMPANY

Certification

Name of Responsible Official:	Responsible Official's Title:	Company/Organization:
ROB MAY	PLANT MANAGER	SAGUARO POWER COMPANY

Responsible Official's Signature	Certification Date
Rmy	10-3-22

Reasonably Available Control Technology Analysis

Clark County Department of Environment and Sustainability
Division of Air Quality

Saguaro Power Company
435 Fourth Street
Henderson, NV 89015

Source ID 393

October 03, 2022

Prepared by:

BROADBENT
8 W. Pacific Avenue
Henderson, Nevada 89015

Project No. 05-01-239

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TABLES

APPENDICES

1. Background

Clean Air Act (CAA) Section 181(a) includes a classification system for areas designated nonattainment for the ozone National Ambient Air Quality Standard (NAAQS). This classification system is based on the severity of the air quality as determined by the area's ozone design value and includes five categories: marginal, moderate, serious, severe and extreme. In 2018, the U.S. Environmental Protection Agency (EPA) designated hydrographic area (HA) 212 in Clark County, Nevada as nonattainment for the 2015 ozone NAAQS and assigned a classification of marginal to the area. The area was required to reach attainment of the 2015 ozone NAAQS by August 3, 2021. In July 2022, EPA determined that HA 212 failed to meet this deadline and, in addition, proposed to reclassify HA 212's attainment status classification to moderate based on its own ozone design value.

In response to this proposed EPA action, the Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) is required to establish emissions control requirements in its State Implementation Plan (SIP) that include Reasonably Available Control Technology (RACT) requirements. RACT is defined by the EPA as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 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.

The CAA requires moderate ozone nonattainment areas to implement RACT for sources of ozone forming emissions. Ozone forming emissions include volatile organic compounds (VOC) and nitrogen oxides (NO_x). More specifically, the DAQ is required to adopt RACT level controls for sources subject to an EPA Control Techniques Guidelines (CTG) document (addressing sources of VOC) and for any other major sources of VOC and NO_x. The major source threshold for an area classified as moderate is 100 tons per year and is applied to a stationary source's potential to emit (PTE) to determine whether RACT requirements need to be evaluated for any particular stationary source. DAQ has determined that it will use a stationary source's PTE as applied in the major New Source Review program and Title V (Part 70) operating permits program to identify the major stationary sources subject to RACT. In addition, DAQ has requested that each major stationary source located in HA 212 make a determination as to whether it is to be considered a major stationary source subject to a RACT evaluation and, if so, perform the evaluation and submit the evaluation to DAQ for review and inclusion in the SIP revisions required as a result of the EPA's attainment area status reclassification action.

This report summarizes the RACT analysis performed by the Saguaro Power Company (Saguaro) and contains its source specific recommendations for RACT.

2. RACT Applicability

Saguaro's Henderson facility is an electricity and steam generating operation located in HA 212. The facility operates 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 facility operates a 29.1 MW extraction/condensing steam turbine generator system and an ammonia storage and injection system as insignificant activities. 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. A copy of the current permit is included in Appendix A. Since the 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 Table 1 contained in the facility's current Part 70 operating permit, the PTE for NO_x emissions is 163.77 tons per year and the PTE for VOC emissions is 13.36 tons per year therefore, only NO_x emissions exceed both the Part 70 major source and moderate area major source thresholds. This analysis is limited to emissions of NO_x.

3. Emission Units Subject to RACT

In their request for individual stationary source RACT analyses, DAQ further delineated the applicability requirement to a so-called Phase 1 level 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 Saguaro facility that exceed this threshold.

Table 1 – 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, diesel	69.24[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, diesel	69.24[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	
A05	Auxiliary Boiler #1	218 MMBtu/hr	Indeck/ Volcano	0-7-2000	Natural gas	13.94[5]
A06	Auxiliary Boiler #2	86 MMBtu/hr	Nebraska	NOS 2A/S-55	Natural gas	9.33[6]

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] Annual emissions based on worst-case scenario of 480 hours/consecutive 12-months of diesel. combustion and 8,280 hours/consecutive 12-months of natural gas combustion.

[5] Emissions based on 8,760 hours per year operation.
[6] Emissions based on 6,000 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
	Diesel	26.30	17 @ 15% O_2
A02, F06, F06a	Natural gas	15.20	10 @ 15% O_2
	Diesel	26.30	17@ 15% O_2
A05	Natural gas	3.18	12 @ 3% O_2
A06	Natural gas	3.11	30 @ 3% 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
	Diesel	3,035 gal	-
A02	Natural gas	447 MMBtu	3,915,720 MMBtu
	Diesel	3,035 gal	-
F05, F05a	Natural gas	25 MMBtu	219,000 MMBtu
F06, F06a	Natural gas	25 MMBtu	219,000 MMBtu
A05	Natural gas	218 MMBtu	1,909,680 MMBtu
A06	Natural gas	86 MMBtu	510,000 MMBtu

Actual emissions of NO_x for the entire source and each emission unit for calendar years 2019-2021 are summarized in Table 4.

Table 4 - Actual NO_x Emissions 2019-2021

Emission Unit ID	Actual NO_x Emissions[1] (tons)			Maximum Annual 2019-2021 (tons)	NO_x PTE (tons/year)	Maximum Annual/ PTE
	2019	2020	2021			
Entire Source	107.54	109.64	106.79	109.64	163.77	66.9%
A01/F05/F05a	54.45	54.35	50.70	54.45	69.24	78.6%
A02/F06/F06a	52.22	54.03	55.17	55.17	69.24	79.7%
A05	0.20	0.40	0.12	0.40	13.94	2.9%
A06	0.56	0.72	0.63	0.72	9.33	7.7%

Notes: [1] Entire source actual emissions based on 2019, 2020 and 2021 Emissions Inventories. Individual emission unit actual emissions for the EUs A01, A02 and A05 are based on actual data from continuous emissions monitors and maximum hourly emission rates and actual hours of operation for periods the continuous emissions monitors were not functioning. Emissions for EU A06 are based on maximum hourly emission rates and actual hours of operation.

As shown in Table 4, maximum actual emissions for the entire source are 66.9% of the entire sources' PTE. Individual emission units' maximum actual emissions are approximately 80% of PTE for the turbines and between 3% and 8% for the boilers.

Actual hours of operation for each emission unit for calendar years 2019-2021 are summarized in Table 5.

Table 5 - Actual Hours of Operation 2019-2021

Emission Unit ID	Actual Operation (hours)		
	2019	2020	2021
A01/F05/F05a	8387	8309	8041
A02/F06/F06a	8409	8341	8402
A05	18	326	33
A06	363	461	405

During these years, the turbines operated consistently year-round. The Volcano boiler (EU: A05) operated for tunings and Relative Accuracy Test Audits (RATAs). The Nationwide/Nebraska boiler operated to supply steam to Ocean Spray and for tunings. Future operating schedules of the equipment are uncertain at this time, however, it is not anticipated that there would be significant increases in operation of any emission unit.

4. 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, DAQ has requested that major sources use a 6% interest rate to compute costs. This rate was used in all cost analyses contained in this report.

Regarding the base case for emissions, DAQ has stated that, if a major source's actual emissions over three consecutive, representative years are less than 70% of the major source's PTE, then the major source can elect to use actual emissions for the base case. Since this is the case for Saguaro, the maximum actual annual emissions will be used for each emission unit evaluated for RACT in this report.

A detailed RACT analysis for each emission unit subject to RACT review identified above is included in Appendices B, C and D.

5. Results

Each RACT determination is summarized in Section 3.0 of Appendices B, C, and D.

Appendix A

Part 70 Operating Permit

DES
DEPARTMENT OF ENVIRONMENT AND 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: 393

Saguaro Power Company
435 Fourth Street
Henderson, NV 89015

ISSUED ON: December 8, 2020 **EXPIRES ON: December 7, 2025**

REVISION ON: November 17, 2021

Current action: Reopening for Cause

Issued to:	**Responsible Official:**
Saguaro Power Company	Rob May
PO Box 90849	Site Manager
Henderson, Nevada 89009	Phone: (702) 558-1131 Fax: (702) 564-2753
	Email: rob.may@camsops.com

NATURE OF BUSINESS:
SIC code 4931, "Electric and other Services Combined"
NAICS code 221112, "Fossil Fuel Electric Power Generation"

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.

Theodore A. Lendis, Permitting Manager

EXECUTIVE SUMMARY

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 marginal nonattainment for the 2015 ozone National Ambient Air Quality Standards (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."

Saguaro is a categorical stationary source, as defined by AQR 12.2.2(j)(22). The source has a combined total fossil-fuel boiler rating of more than 250 MMBtu/hr. Saguaro operates under the Part 70 Operating Permit (OP) program and is a major stationary source for NO_x, a minor source for PM_{10}, $PM_{2.5}$, CO, SO_2, VOCs, and HAPs, and a source of greenhouse gas (GHG) emissions. Saguaro operates 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, Saguaro Power Company operates a 29.1 MW extraction/condensing steam turbine generator system and an ammonia storage and injection system as insignificant activities.

This Title V OP is issued based on a renewal application submitted on January 31, 2019. Table 1 summarizes the potential to emit (PTE) for each regulated air pollutant.

Table 1: Source-wide PTE (tons per year)

Pollutant	PM_{10}	$PM_{2.5}$	NO_X	CO	SO2	VOC	HAP	GHG
PTE	38.75	38.03	163.77	90.13	13.36	13.36	9.04	551,984
Major Stationary Source Thresholds (Categorical)	100	100	100	100	100	100	100	

[1]Expressed as metric tons of CO_2e.

Pursuant to AQR 12.5, all terms and conditions in this permit and the attachment are federally enforceable unless explicitly denoted otherwise.

DAQ will continue to require sources to estimate their GHG PTEs in terms of each individual pollutant (CO_2, CH_4, N_2O, SF_6 etc.), and the TSD includes these PTEs for informational purposes.

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COMMON ACRONYMS AND ABBREVIATIONS

(These terms may be seen in the permit)

Term	Definition
APP	application
AQR	Clark County Air Quality Regulations
ATC	authority to construct
CAAA	Clean Air Act, as amended, or Clean Air Act Amendments
CEMS	continuous emissions monitoring system
CFC	chlorofluorocarbon
CFR	United States Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
DAQ	Division of Air Quality
dscf	dry standard cubic feet
DOM	date of manufacturer
EPA	United States Environmental Protection Agency
EU	emission unit
GHG	greenhouse gases
HAP	hazardous air pollutant
HCFC	hydrochlorofluorocarbon
HHV	high heating value
hp	horse Power
HRSG	heat recovery steam generator
MMBtu	millions of British thermal units
MW	megawatt
N_2O	nitrous oxide
NAICS	North American Industry Classification System
NESHAP	National Emission Standard for Hazardous Air Pollutants
NO_X	nitrogen oxides
NRS	Nevada Revised Statutes
NSPS	New Source Performance Standards
O_2	oxygen
OP	operating permit
$PM_{2.5}$	particulate matter less than 2.5 microns
PM_{10}	particulate matter less than 10 microns
ppmvd	parts per million, volumetric dry
psia	pounds per square inch absolute
PSD	prevention of significant deterioration
PTE	potential to emit
QA/QC	quality assurance/quality control
QAP	quality assurance plan
RATA	relative accuracy test audit
RMP	risk management plan
scf	standard cubic feet
SCR	selective catalytic reduction

Term	Definition
SF_6	sulfur hexafluoride
SIC	Standard Industrial Classification
SIP	state implementation plan
SO_2	sulfur dioxide
TDS	total dissolved solid
TSD	technical support document
U.S.C.	United States Code
VOC	volatile organic compound

I. GENERAL CONDITIONS

A. GENERAL REQUIREMENTS

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; AQR 12.5.2.8(b)]*

6. The permittee shall allow the Control Officer, upon presentation of credentials, to: *[AQR 4.1 & 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 supplementary facts or corrected information. The permittee shall also provide any additional information necessary to address any requirements that become applicable to the source after it filed a complete application but before the 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)]*

B. 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 Authority to Construct (ATC) from the Control Officer. *[AQR 12.4.1.1(a)]*

2. The 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. A permit, permit revision, or renewal may be approved only if all of 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 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.

4. 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]*

5. 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)]*

6. 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)]*

7. For purposes of permit renewal, a timely application is a complete application that is submitted at least six 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)]*

C. REPORTING, NOTIFICATIONS, AND INFORMATION REQUIREMENTS

1. The permittee shall submit all compliance certifications to the U.S. Environmental Protection Agency (EPA) and to the Control Officer. *[AQR 12.5.2.8(e)(4)]*

2. 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, 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)]*

3. 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)]*

4. Upon request of the Control Officer, 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]*

5. The permittee shall submit annual emissions inventory reports based on the following: *[AQR 18.6.1]*

   a. The annual emissions inventory must be submitted to DAQ by March 31 of each calendar year (if March 31 falls on a Saturday or Sunday, or on a Nevada or federal holiday, 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 potential to emit (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).

6. Stationary sources that emit 25 tons or more of nitrogen oxide (NOx) and/or 25 tons or more of volatile organic compounds (VOCs) during a calendar year from emission units, insignificant activities, and exempt activities shall submit an annual emissions statement for both pollutants. This statement must include actual annual NOx 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 report). *[AQR 12.9.1]*

D. COMPLIANCE REQUIREMENTS

1. 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)]*

2. 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]*

3. 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]*

4. The permittee shall comply with the requirements of Title 40, Part 61 of the Code of Federal Regulations (40 CFR Part 61), Subpart M—the National Emission Standard for Asbestos—for all demolition and renovation projects. *[AQR 13.1(b)(8)]*

5. 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)]*

6. 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 Toxics Divisions, 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)]*

    a. The identification of each term or condition of the permit that is the basis of the certification;

    b. The identification of the methods or other means used by the permittee for determining the compliance status 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 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 (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.

7. 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 event, 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 required notification, the permittee shall submit a detailed written report to DAQ containing the information required by AQR 25.6.3.

8. 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)]*

9. 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]*

E. PERFORMANCE TESTING REQUIREMENTS

1. Upon request of the Control Officer, 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 Control Officer may specify testing methods to be used in accordance with good professional practice. The Control Officer may observe the testing. All tests shall be conducted by reputable, qualified personnel. *[AQR 4.2]*

2. Upon request of the Control Officer, 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]*

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 Section III.F of this permit. *[AQR 12.5.2.8]*

4. The permittee shall submit to EPA for approval any alternative test methods EPA has not already approved to demonstrate compliance with a requirement under 40 CFR Part 60. *[40 CFR Part 60.8(b)]*

5. 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 test. *[AQR 12.5.2.8]*

II. EMISSION UNITS AND APPLICABLE REQUIREMENTS

A. EMISSION UNITS

1. The stationary source covered by this Part 70 OP is defined to consist of the emission units and associated appurtenances summarized in Table II-A-1. *[Renewal Application 1/31/2019, AQR 12.5.2.3 and AQR 12.5.6.2]*

Table II-A-1: List of 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

B. INSIGNIFICANT ACTIVITIES

1. The units in Table II-B-1 are present at this source, but are insignificant activities pursuant to AQR 12.5.

Table II-B-1: Insignificant Activities

Description
Facility Maintenance (Painting)
Sandblaster
Degreaser that uses Mirachem 500
Fuel Oil Transfer Pumps
Fuel Oil Unloading
Natural Gas Metering Station
Natural Gas Coalescing Filters
Lube Oil System-CTG-01
Lube Oil System-CTG-02

Description
Lube Oil System-CTG-03
Water Storage Tank (750,000 gallon)
21.8 hp Water Pump
Ammonia Storage/Injection (12,000 gallons)
29.1-MW extraction/condensing steam turbine generator system[1]
Temporary Fuel Storage Tank (21,000 gallons)

[1]This unit has been identified as process equipment with no emissions.

C. NONROAD ENGINES

1. 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 less than 12 consecutive months. *[AQR 12.5.6.2]*

2. Nonroad engines used on self-propelled equipment do not have this 12-month limitation or the associated recordkeeping requirements. *[AQR 12.5.6.2]*

D. EMISSION LIMITS AND STANDARDS

1. **Emission Limits**

   a. The permittee shall, under all conditions, maintain and operate the source in a manner consistent with good air pollution control practice for minimizing emissions as required by 40 CFR Part 60.11. *[AQR 12.5.2]*

   b. Neither the actual nor the allowable emissions shall exceed the calculated PTE for each emission unit listed in Table II-D-1. Tons-per-year emission limits for each emission unit are based on consecutive 12-month totals and include startup and shutdown emissions. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008) and Application for Minor Revision of Part 70 OP (11/24/2015)]*

Table II-D-1: Emission Unit PTE, Including Startup and Shutdowns (tons per year)

EU	Condition	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
A01[1]	8,760 hr/yr combined fuel	14.43	14.43	69.24	39.42	6.31	4.29	2.03
F05, F05a[2]								
A02[1], F06, F06a[2]	8,760 hr/yr combined fuel	14.43	14.43	69.24	39.42	6.31	4.29	2.03
A03	125 hr/yr	0.07	0.07	1.01	0.22	0.01	0.08	0.01
A04	125 hr/yr	0.07	0.07	1.01	0.22	0.01	0.08	0.01
A05	8,760 hr/yr	6.66	6.66	13.94	0.86	0.57	4.47	4.47
A06	6,000 hr/yr	1.29	1.29	9.33	9.99	0.15	0.15	0.49
A09	8,760 hr/yr	1.80	1.08	0	0	0	0	0

[1] Annual emissions based on worst-case scenario of 480 hours/consecutive 12-months of diesel combustion and 8,280 hours/consecutive 12-months of natural gas combustion.
[2]The supplemental-firing duct burners make up the HRSG.

Table II-D-2: Emission Rate (pounds per hour) Limitations, Excluding Startup and Shutdowns

EU	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP
A01[1]	2.50	2.50	15.20	9.00	0.27	0.92	0.46
A01[2]	17.00	17.00	26.30	9.00	21.64	2.00	0.54
A02[1]	2.50	2.50	15.20	9.00	0.27	0.92	0.46
A02[2]	17.00	17.00	26.30	9.00	21.64	2.00	0.54
A05	1.52	1.52	3.18	0.20	0.13	1.02	1.02
A06	0.43	0.43	3.11	3.33	0.05	0.05	0.16

[1]Emissions based on natural gas combustion in the turbines.
[2]Emissions from the combustion of diesel fuel only.
[3]Only emission units that require performance testing are included in this table.

Table II-D-3: Emission Concentration (ppmvd) Limitations, Excluding Startup and Shutdowns

EU	O_2 Standard	NO_X (ppmvd)		CO (ppmvd)	
		Natural Gas	Diesel	Natural Gas	Diesel
A01[1]	15%	10	17	10	10
F05, F05a					
A02[1]	15%	10	17	10	10
F06, F06a					
A05[2]	3%	12		1.2	
A06	3%	30		400	

[1]Emissions from the combustion of natural gas or distillate are calculated using a 4-hour rolling average (except CO for EU: A05), not to include startup or shutdown.
[2]CO for EU: A05 is based on 24 hours.

Turbines/Duct Burners

c. The permittee shall not exceed emission rate limits listed in Table II-D-2 for NO_X and CO for the turbines (EUs: A01 and A02) as determined by the CEMS as described in Section II-F, excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

d. The permittee shall operate each turbine and duct burner combination (EUs: A01, F05, F05a, A02, F06, and F06a) such that they do not emit NO_X in concentrations greater than 17 ppmvd at 15% O_2 while combusting diesel or greater than 10 ppmvd at 15% O_2 while combusting natural gas during any 4-hour rolling averaging period, excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

e. The permittee shall operate each turbine and duct burner combination (EUs: A01, F05, F05a, A02, F06, and F06a) such that they do not emit CO in concentrations greater than 10 ppmvd at 15% O_2 while combusting either diesel or natural gas during any 4-hour rolling averaging period, excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

Boilers

f. The permittee shall not exceed emission rate limits listed in Table II-D-2 for NO_X and CO for the boiler (EU: A05) as determined by the CEMS as described in Section II-F, excluding any startup or shutdown period. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

g. The permittee shall not exceed emission concentration limits listed in Table II-D-3 for NO_X, for any 4-hour rolling averaging period, or CO, for any 24-hour rolling averaging period, for the boiler (EU: A05) as determined by the CEMS as described in Section II-F, excluding any startup or shutdown period. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

h. The permittee shall operate the boiler (EU: A05) such that it emits neither more than 12 ppmvd NO_X, during a 4-hour rolling average, nor 1.2 ppmvd CO, during a 24-hour rolling average, corrected to 3% O_2, excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

i. The permittee shall not exceed emission rate limits listed in Table II-D-2 for NO_X and CO for the boiler (EU: A06), excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

j. The permittee shall operate the boiler (EU: A06) such that it emits neither more than 30 ppmvd NO_X nor 400 ppmvd CO, corrected to 3% O_2, excluding any startup or shutdown period. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

Other

k. The permittee shall not discharge into the atmosphere, from any emission unit, any air contaminant in excess of an average of 20% opacity for a period of more than 6 consecutive minutes. *[AQR 26.1]*

2. **Operational Limits**

a. The permittee shall limit the fuel inputs for each emission unit to the values listed in Table II-D-4. *[NSR ATC 393, Modification 7 (03/19/2008) and Title V Renewal (00393_20131020_APP) incorporated into the Title V]*

Table II-D-4: Fuel Limitations for Combustion Equipment

EU	Equipment	Fuel Type	Max. Hourly (MMBtu)	Max. Consecutive 12 months (MMBtu)
A01/A02	Each Combustion Turbine[1]	Natural gas	447	3,915,720
F05/F05a F06/F06a	Each Duct Burner	Natural gas	25	219,000
A05	Indeck/Volcano Boiler	Natural gas	218	1,909,680
		Hydrogen		
A06	Nebraska Auxiliary Boiler	Natural gas	86	510,000

[1]Based upon 8,760 hours at 100% load at 105^{0}F.

Turbines/Duct Burners

b. The permittee shall limit the natural gas fuel rate to 447 MMBtu/hour for each combustion turbine (EUs: A01 and A02) based on an annual average, the lower heating value (LHV), and standard conditions. Standard conditions shall be defined as 105ºF and 13.78 pounds per square inch absolute (psia) at 16% relative humidity. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

c. The permittee may operate each turbine unit (EUs: A01 and A02), upon demonstration of compliance with the emission standards, up to 480 hours per year based on consecutive 12-months while combusting low sulfur diesel fuel (<0.05% by weight). *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

d. The permittee shall not combust diesel in the turbines (EUs: A01 and A02) during the summer months (June 1 - August 31) except when there is a loss of natural gas, or testing is required. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

e. The permittee shall limit the diesel fuel consumption to 3,035 gallons per hour for each turbine (EUs: A01 and A02). *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

f. The permittee shall limit heat input of each duct burner (EUs: F05, F05a, F06 and F06a) to 25 MMBtu/hour. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

g. A startup period for turbines (EUs: A01 and A02) is defined as the period of time of no more than 1 hour immediately following the application of a load. Startup periods shall be included in determining compliance with consecutive 12-months emissions limits for the emission units being started. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

h. A shutdown period for turbines (EUs: A01 and A02) shall begin when heat input falls below 50% of nameplate capacity and ends when combustion has ceased, the duration of the shutdown period should not exceed 60 minutes. Shutdown periods shall be

included in determining compliance with consecutive 12-months emissions limits for the emission units being shutdown. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

i. Emissions from startup and shutdown events when combined with the turbine emissions during normal operations, shall not exceed the consecutive 12-months limits outlined in Table II-D-1. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

j. The permittee shall use emission factors presented in the TSD for any clock hour in which a startup/shutdown event occurs, if the CEMS data does not include the actual startup/shutdown emissions. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

Engines

k. The permittee shall limit operation of each turbine starter engine (EUs: A03 and A04) to 125 hours per year based on consecutive 12-months. [NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]

Boilers

l. The permittee shall combust only natural gas, hydrogen fuel, or a combination of natural gas and hydrogen fuel in the Indeck/Volcano boiler (EU: A05). *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

m. The permittee shall limit the operation of the Indeck/Volcano boiler (EU: A05) to 1,909,680 MMBtu per year of natural gas and hydrogen fuel. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

n. A startup period of the Indeck/Volcano boiler (EU: A05) is defined as the period of time of no more than one hundred (100) minutes immediately following the firing of the burner. Startup periods shall be included in determining compliance with consecutive 12-months emissions for the Indeck/Volcano boiler. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

o. A shutdown period of the Indeck/Volcano boiler (EU: A05) shall begin when heat input falls below 15 percent of nameplate capacity and ends when combustion has ceased and shall not exceed 1 hour. Shutdown periods shall be included in determining compliance with consecutive 12-months emissions limits for the Indeck/Volcano boiler. *[NSR ATC 393, Modification 7, Revision 2 (12/15/2008)]*

p. The permittee shall limit the operation of the Nebraska boiler (EU: A06) to 510,000 MMBtu per consecutive 12-months. Only natural gas fuel shall be combusted in the boiler. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

q. The permittee shall limit the hours of operation of the Nebraska boiler (EU: A06) to 6,000 hours per any consecutive 12-months. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

E. EMISSION CONTROLS

1. Control Requirements

a. The permittee must comply with the control requirements contained in this section. If there is inconsistency between standards or requirements, the most stringent standard or requirement shall apply. *[AQR 12.5.2.6(a)]*

Turbines/Duct Burners

b. The permittee shall install, maintain and operate SCR on each of the turbine units (EUs: A01 and A02). The permittee shall operate SCR at all times the associated turbine unit is operating excluding periods of startup and shutdown. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

c. The permittee shall operate each SCR system on all turbine units in accordance with the operations and maintenance (O&M) manual. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

d. The permittee shall further control NO_X emissions from turbine units (EUs: A01 and A02) with steam injection, except during startup. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006) and Title V Renewal (00393_20131020_APP) incorporated into the Title V]*

e. The permittee shall operate each SCR system such that NO_X emissions do not exceed the limitations listed in Tables II-D-2 and II-D-3 excluding startups and shutdowns. *[AQR 12.5.2.6(a)]*

f. The permittee shall control SO_2 exhaust emissions from each combined cycle system by the exclusive use of pipeline quality natural gas with a maximum total sulfur content of 0.50 grains/100 dscf and good combustion practice. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

g. The permittee shall control PM_{10} exhaust emissions from each combined cycle system by properly maintained and periodically replaced inlet air filters preceding each turbine, per O&M manual and good operating practice. *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

Engines

h. The permittee shall operate and maintain each turbine starter engine in accordance with the manufacturer's operations and maintenance (O&M) manual for emissions-related components (EUs: A03 and A04)

i. The permittee shall combust only low sulfur (<0.05% sulfur by weight) diesel fuel in each turbine starter engines (EUs: A03 and A04). *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

Boilers

j. The permittee shall combust only natural gas and hydrogen fuel in boiler (EU: A05).

k. The permittee shall combust only natural gas in boiler (EU: A06).

l. The permittee shall operate and maintain each boiler (EU: A05 and A06) in accordance with the manufacturer's operations and maintenance (O&M) manual for emissions-related components and good combustion practices.

Cooling Tower

m. The permittee shall operate and maintain the cooling tower in accordance with the manufacturer's recommendations. No chromium-containing compounds shall be used for water treatment (EU: A09). *[AQR 12.5.2.6(a)]*

n. The permittee shall equip each cooling tower with drift eliminators with a manufacturer's maximum drift rate of 0.002% (EU: A09). *[Title V Renewal 11/20/2014]*

o. The permittee shall maintain the cooling water such that the maximum TDS content shall not exceed 3,800 ppm (EU: A09). *[NSR ATC 393 Modification 6, Amendment 1 (10/04/2006)]*

F. MONITORING

1. Visible Emissions

a. The permittee shall perform visual emissions checks each calendar quarter on each fuel-burning emission unit (EUs: A01, A02, A03, and A04) while it is in operation and when firing diesel fuel. If visible emissions are observed, then corrective actions shall be taken to minimize the emissions, and the opacity of the emissions shall be visually determined in accordance with 40 CFR Part 60, Appendix A-4 (Test Method 9). *[AQR 12.5.2.6(d) and 40 CFR Part 70.6]*

2. Continuous Emissions Monitoring System

b. To demonstrate continuous direct compliance with all emission limitations for NO_x and CO specified in this permit, the permittee shall install, calibrate, maintain, operate, and certify CEMS for NO_x, CO, and O_2 on each stationary gas turbine unit (EUs: A01 and A02) in accordance with 40 CFR Part 60. Each CEMS shall include an automated data acquisition and handling system. Each system shall monitor and record at least the following data: *[AQR 12.5.2.6(d)]*

i. 4-hour rolling averages of exhaust gas concentration for each of NO_x, CO, and diluent O_2;

ii. Exhaust gas flow rate (by direct or indirect methods);

iii. Fuel flow rate;

iv. Hours of operation;

v. Hourly, daily and quarterly accumulated mass emissions of NO_x and CO; and

vi. Hours of downtime of the CEMS.

c. The permittee shall install, calibrate, maintain, operate, and certify CEMS for NO_x, CO, and O_2 on the Indeck/Volcano boiler (EU: A05) in accordance with 40 CFR Part 60. Each CEMS shall include an automated data acquisition and handling system. Each system shall monitor and record at least the following data: *[AQR 12.5.2.6(d)]*

i. 4-hour rolling averages of exhaust gas concentration for NO_x and diluent O_2;

ii. 24-hour rolling averages of exhaust gas concentration for CO and diluent O_2;

iii. Exhaust gas flow rate (by direct or indirect methods);

iv. Fuel flow rate;

v. Hours of operation;

vi. Hourly, daily and quarterly accumulated mass emissions of NO_X and CO; and

vii. Hours of downtime of the CEMS.

d. The permittee shall submit all periodic audit procedures and QA/QC procedures for CEMS to conform to the provisions of 40 CFR Part 60, Appendix F.

e. The permittee shall conduct annual relative accuracy test audits (RATA) of the CO, NO_x, and O_2 CEMS. *[AQR 12.5.2.6(d)]*

3. **Other**

Boilers

f. The permittee shall install a fuel flow meter for the Nebraska boiler (EU: A06), and shall monitor the monthly fuel consumption. *[AQR 12.5.2.6(d)]*

g. The permittee shall operate the Nebraska boiler with a nonresettable hour meter (or other device the Control Officer has approved in advance), monitor its hours of operation, and calculate them on a monthly basis as a consecutive 12-month total (EU: A06). *[AQR 12.5.2.6(d)]*

h. The permittee shall conduct a burner efficiency test (boiler tune-up) and inspection on the auxiliary boilers (EUs: A05 and A06) semiannually. *[AQR 12.5.2.6(d)]*

i. The permittee shall conduct burner efficiency test in accordance with the manufacturer's recommendations and specifications for good combustion practices. The permittee may use an alternative method to determine burner efficiency upon prior approval from the Control Officer. *[AQR 12.5.2.6(d)]*

j. The permittee may perform a burner efficiency test once each calendar year if the actual hours of operation are less than 50. To exercise this option, the permittee must install an hour meter and begin keeping written records before the start of the calendar year (EUs: A05 and A06*). [AQR 12.5.2.6(d)]*

k. The permittee may replace one contemporaneously-required burner efficiency test with a performance test that has acceptable results (EUs: A05 and A06*). [AQR 12.5.2.6(d)]*

Cooling Tower

l. The permittee shall monitor the TDS of the cooling tower recirculation water monthly using a conductivity meter or another device the Control Officer has approved in advance (EU: C01). *[AQR 12.5.2.6(d)]*

G. TESTING

1. The permittee is subject to performance testing in accordance with 40 CFR Part 60, Subparts A, Db, Dc, and GG, and *DAQ's Source Testing Guidelines* (as revised). *[AQR 12.5.2.6(d) and 40 CFR Part 60.335]*

Turbines/Duct Burners

2. The permittee shall conduct initial performance tests for NO_x and CO while using natural gas on each of the turbine units (EUs: A01 and A02) to demonstrate compliance with the emission limitations. Table II-G-1 summarizes performance test methods, including for NO_x and CO, for the turbine package units. The initial performance tests for both units were completed on April 7, 2008. *[AQR 12.5.2.6(d)]*

Table II-G-1: Performance Testing Requirements (40 CFR Part 60, Appendix A)

Test Point	Pollutant	Method
Turbine Exhaust Stack	NO_X	Chemiluminescence Analyzer (EPA Method 7E)
Turbine Exhaust Stack	CO	EPA Method 10
Turbine Exhaust Stack	PM_{10}	EPA Method 201/202 or 201A/202
Turbine Exhaust Stack	Opacity	EPA Method 9
Stack Gas Parameters	—	EPA Methods 1, 2, 3, 4

3. Subsequent performance testing for NO_x and CO while firing natural gas in the turbines (EUs: A01 and A02) shall be conducted upon written notification from the Control Officer. *[AQR 12.5.2.6(d)]*

Boilers

4. The permittee shall conduct a performance test on the auxiliary boilers (EUs: A05 and A06) to demonstrate initial compliance with the CO and NO_x emissions limitations. Table II-G-2 summarizes performance test methods, including for NO_x and CO, for the turbine package units.no later than 180 days after initial startup and within 60 days of achieving the maximum production rate at which the affected facility will be operated. This testing was completed for EUs: A05 and A06 in February 2016 and February 2017, respectively.

5. An initial performance test shall be performed on EU: A05 after installation of the low-NO_x burner coupled with the CO oxidation catalyst. This testing has been completed for EU: A05. *[AQR 12.5.2.6(d), NSR Mod. 7, Rev 2]*

6. Subsequent performance testing shall be conducted on the auxiliary boiler (EU: A06) at least once every five years.

7. Subsequent performance testing for NO_x and CO while firing natural gas in the boiler (EU: A05) may be required by the Control Officer. *[AQR 12.5.2.6(d)]*

Table II-G-2: Performance Testing Requirements (40 CFR Part 60, Appendix A)

Test Point	Pollutant	Method
Boiler Exhaust Stack	NO_X	Chemiluminescence Analyzer (EPA Method 7E)
Boiler Exhaust Stack	CO	EPA Method 10
Stack Gas Parameters	—	EPA Methods 1, 2, 3, 4

H. RECORDKEEPING

1. The permittee shall keep on-site all records and logs, or copies thereof, for a minimum of five years from the date the measurement or data was entered. *[AQR 12.5.2.6(d)]*

2. The permittee shall maintain records on-site that include, at a minimum: *[AQR 12.5.2.6]*

Turbines/Duct Burners

a. Dates, times, and duration of each startup and shutdown cycle (EUs: A01, A02);

b. Startup and shutdown emissions per turbine (EUs: A01, A02) in pounds per hour and yearly emissions, including startup, shutdown and normal operations, in tons per each consecutive 12-month period;

c. Sulfur content of natural gas, as certified by the supplier. Sulfur content of natural gas fuel shall be verified by the permittee at least quarterly, and verifications shall be based on reports or written data from the gas supplier, as required by 40 CFR Part 60; *[AQR 12.5.2.6(d)]*

d. Name of diesel fuel supplier, sulfur content of diesel fuel, and method used to determine sulfur content of diesel fuel;

e. Supplier certification of sulfur content of diesel fuel, which shall accompany each fuel delivery*; [AQR 12.5.2.6(d]*

Boilers

f. Dates, times, and duration of each startup and shutdown cycle (EU: A05);

g. Monthly, consecutive 12-month total quantity of natural gas and hydrogen fuel used for the Indeck/Volcano boiler in MMBtu (EU: A05);

h. Monthly, consecutive 12-month total quantity of natural gas fuel used for the Nebraska boiler in MMBtu (EU: A06);

Cooling Tower

i. Daily TDS content of cooling tower circulation water, when operating (EU: A09);

Other

j. Results of the last performance test conducted, in addition to any other performance tests conducted within the last five years;

k. Burner efficiency test results

l. Quality assurance plan for all CEMS;

m. All CEMS information required by 40 CFR Part 60, including a CEMS monitoring plan;

n. Log of visible emission checks;

o. Records of location changes for nonroad engines, if applicable; and

p. For all inspections, visible emission checks, and testing required under monitoring, all the logs, reports, and records shall include at least the date and time, the name of the person performing the action, the results or findings, and the type of corrective action taken (if required). *[AQR 12.5.2.6(d)]*.

3. The permittee shall maintain records on-site that require semiannual reporting and include, at a minimum: *[AQR 12.5.2.6]*

Turbines/Duct Burners

a. The magnitude and duration of excess emissions, permit deviations, notifications, monitoring system performance, malfunctions, corrective actions taken, etc., as required by 40 CFR Part 60.7;

b. Monthly, consecutive 12-month total hours of operation for each turbine, with diesel and natural gas noted separately, and, as applicable, for each duct burner;

c. Monthly, consecutive 12-month total quantity of natural gas and diesel fuel consumed in each gas turbine in MMBtu;

Boilers

d. Monthly, consecutive 12-month total quantity of combined fuel input of natural gas and hydrogen fuel in the Indeck/Volcano boiler (EU: A05) in MMBtu;

e. Monthly, consecutive 12-month total quantity of natural gas fuel input to the Nebraska boiler (EU: A06) in MMBtu;

f. Monthly, consecutive 12-month total hours of operation of the Nebraska boiler (EU: A06);

Engines

g. Monthly and consecutive 12-month total hours of operation for each starter engine (EUs: A03 and A04); and

Other

h. CEMS audit results or accuracy checks, corrective actions, etc., as required by 40 CFR Part 60, Appendix F, and the CEMS quality assurance plan (EUs: A01, A02 and A05);

i. Time, duration, nature and probable cause of any CEMS downtime and corrective actions taken;

j. Monthly CEMS NO_X and CO (EUs: A01, A02 and A05);

k. Monthly, consecutive 12-month total emissions for each emission unit in tons per year.

4. Records and data required by this permit to be maintained by the permittee may, at the permittee's expense, be audited at any time by a third party selected by the Control Officer. This third party shall be subject to the same business confidentiality terms binding DAQ during investigations and data gathering. *[AQR 12.5.2.6(d)]*

I. REPORTING

1. The permittee shall comply with all applicable notifications and reporting requirements of 40 CFR Part 60.7, 40 CFR Part 60, Subparts Db, Dc, and GG, and 40 CFR Part 63, Subpart ZZZZ. *[AQR 12.5.2.6(d)]*
2. All report submissions shall be addressed to the attention of the Control Officer. *[AQR 12.5.2.8(e)(4)]*
3. Regardless of the date of issuance of this permit, the source shall comply with the schedule for report submissions outlined in Table II-I-1 *[AQR 12.5.2.6(d)]*.

Table II-I-1: Required Submittal Dates for Various Reports

Required Report	Applicable Period	Due Date[1]
Semiannual report for 1st six-month period	January, February, March, April, May, June	July 30 each year
Semiannual report for 2nd six-month period, and any additional annual records required	July, August, September, October, November, December	January 30 each year
Annual Compliance Certification	Calendar year	January 30 each year
Annual Emissions Inventory Report	Calendar year	March 31 each year
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 time the permittee learns of the event
Report of Malfunctions, Startup, Shutdowns or Deviations with Excess Emission	As required	Within 72 hours of DAQ notification
Deviation Report without Excess Emissions	As required	With semiannual reports
Excess Emissions that Pose a Potential Imminent and Substantial Danger	As required	Within 12 hours of the permittee learns of the event
Performance Testing Protocol	As required	No less than 45 days, but no more than 90 days, before the anticipated test date[1]
Performance Testing	As required	Within 60 days of the end of the test

[1]If the due date falls on a Saturday, Sunday, or federal or Nevada holiday, then the submittal is due on the next regularly scheduled business day.

[2] Required only for stationary sources that emit 25 tons or more of nitrogen oxide (NO_X) and/or emit 25 tons or more of volatile organic compounds (VOC) during a calendar year.

4. All reports shall contain the following: *[AQR 12.5.2.6(d)]*

   a. A certification statement on the first page, i.e., "I certify that, based on information and belief formed after reasonable inquiry, the statements contained in this document is true, accurate and complete." (A sample form is available from Air Quality); and

   b. A certification signature from a responsible official of the company and the date certification.

5. The permittee shall submit semiannual reports to the Control Officer. *[AQR 12.5.2.6(d)]*

6. The following requirements apply to semiannual reports: *[AQR 12.5.2.6(d)]*

   a. The report shall include each item listed in Section II-H-3.

   b. The report shall include semiannual summaries of any permit deviations, their probable cause, and corrective or preventative actions taken.

7. The Control Officer reserves the right to require additional reports and reporting to verify compliance with permit conditions, permit requirements, and requirements of applicable federal regulations. *[AQR 4.1 and AQR 12.5.2.6(d)]*

III. OTHER REQUIREMENTS

1. 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 record of all paperwork relevant to the applicable requirements of 40 CFR Part 82 on-site. *[40 CFR Part 82]*
2. Saguaro is exempted, based on the applicability criteria defined in 40 CFR Part 72.6(b)(5); therefore, the provisions of the acid rain regulations do not apply. *[40 CFR Part 72.6]*

IV. PERMIT SHIELD

1. Compliance with the terms contained in this permit shall be deemed compliance with the following applicable requirements in effect on the date of permit issuance: *[Renewal Application 1/31/2019, AQR 12.5.2.9]*

Table IV-1: Applicable Requirements Related to Permit Shield

Citation	Title
40 CFR Part 60, Subpart Db	NSPS – Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60, Subpart Dc	NSPS – Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60, Subpart GG	NSPS – Stationary Gas Turbines
40 CFR Part 63, Subpart ZZZZ	NESHAP – Stationary Reciprocating Internal Combustion Engines

Table IV-2: Streamlined Requirements Related to Permit Shield

				Value Comparison (in Units of the Permit Limit)			Averaging Period Comparison			
EU	Regulation (40 CFR)	Regulatory Standard	Permit Limit	Standard Value	Permit Limit Value	Is Permit Limit Equal or More Stringent?	Standard Averaging Period	Permit Limit Averaging Period	Is Permit Limit Equal or More Stringent?	Streamlining Statement for Shielding Purposes
A13	63.6640 (ZZZZ)	100 hours/year for testing and maintenance; 50 hours per year for non-emergency situations	100 hours/year for testing and maintenance; 50 hours per year for non-emergency situations	100; 50	100; 50	Yes	hours/year	hours/year	Yes	The permit limits are equal to the standard based on hours/year. Compliance with the permit demonstrates compliance with the standard.
A13	63.6603, Table 2d (ZZZZ)	Change oil and filter every 500 hours of operation or annually, whichever comes first; Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and Inspect all hoses and belts every 500 hours of operation or annually, whichevre comes first, and replace as necessary. Sources have the option to utilize an oil analysis program as described in 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.	Change oil and filter every 500 hours of operation or annually, whichever comes first; Inspect air cleaners every 1,000 hours of operation or annually, whichever comes first; and Inspect all hoses and belts every 500 hours of operation or annually, whichevre comes first, and replace as necessary. The Permittee may utilize an oil analysis program as described in Subpart 63.6625(i) in order to extend the specified oil change requirement and can petition the Control Officer pursuant to the requriements of 40 CFR 63.6(g) for alternative work practices.	500 or annually; 1,000 or annually; 500 or annually	500 or annually; 1,000 or annually; 500 or annually	Yes	hours or annually	hours or annually	Yes	The permit limits are equal to the standard based on hours or annually. Compliance with the permit demonstrates compliance with the standard.
A05	60.42b (Db)	0.20 lb/MMBtu SO_2	0.13 lb/hr SO_2	43.6	0.13	Yes	Not specified	Not specified	N/A	The permit limit is more stringent than the standard. Compliance with the permit demonstrates compliance with the standard.
A05	60.44b (Db)	0.20 lb/MMBtu NOx	12 ppm NOx @3%O_2	170	12	Yes	30-day rolling average	4-hour rolling average	Yes	The permit limit is more stringent than the standard. Compliance with the permit demonstrates compliance with the standard.
A06	60.48c (Dc)	The owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.	30 ppmvd NOx @3%O_2 400 ppmvd CO @3%O_2 Records and logs shall contain, at minimum, the following information: monthly and rolling 12-month quantity of natural gas fuel used for the Nebraska boiler in MMBtu	N/A	30; 400	N/A - there is no corresponding standard	N/A	4-hour rolling average	N/A - there is no corresponding standard	The recordkeeping requirement in the permit is more stringent than the standard. Complinace with the permit demonstrates complinace with the standard's recordkeeping requirement.
A01/A02	60.332 (GG)	0.0075% by volume NOx at 15% O_2, dry basis	10 ppmvd NOx @15% O_2 (natural gas) 17 ppmvd NOx @15% O_2 (fuel oil)	75	10; 17	Yes	4-hour rolling average	4-hour rolling average	Yes	The permit limit is more stringent than the standard. Compliance with the permit demonstrates compliance with the standard.
A01/A02	60.333 (GG)	0.015% by volume SO_2 at 15% O_2, dry basis	0.27 lb/hr SO_2 (worst case combination of natural gas and diesel fuel combustion) 21.64 lb/hr SO_2 (combustion of diesel fuel only)	345	0.27; 21.64	Yes	4-hour	1-hour	Yes	The permit limit is more stringent than the standard. Compliance with the permit demonstrates compliance with the standard.

ATTACHMENT 1 – APPLICABLE REGULATIONS

REQUIREMENTS SPECIFICALLY IDENTIFIED AS APPLICABLE:

1. NRS, Chapter 445B.

2. Applicable AQR sections, as listed in Table A-1.

Table A-1. Requirements Specifically Identified As Applicable—Local

Citation	Title
AQR Section 00	Definitions
AQR Section 04	Control Officer
AQR Section 05	Interference with Control Officer
AQR Section 08	Persons Liable for Penalties – Punishment: Defense
AQR Section 09	Civil Penalties
AQR Section 12.4	ATC Application and Permit Requirements for Part 70 Sources
AQR Section 12.5	Part 70 OP Requirements
AQR Section 13.2(b)(82)	NESHAP - Stationary Reciprocating Internal Combustion Engines
AQR Section 14.1(b)(4)	NSPS – Standards of Performance for Industrial-Commercial-Instittutional Steam Generating Units
AQR Section 14.1(b)(40)	NSPS – Standards of Performance for Stationary Gas Turbines
AQR Section 18	Permit and Technical Service Fees
AQR Section 25	Upset/Breakdown, Malfunctions
AQR Section 26	Emissions of Visible Air Contaminants
AQR Section 28	Fuel Burning Equipment
AQR Section 40	Prohibition of Nuisance Conditions
AQR Section 41	Fugitive Dust
AQR Section 42	Open Burning
AQR Section 43	Odors in the Ambient Air
AQR Section 70	Emergency Procedures
AQR Section 80	Circumvention

3. CAAA (authority: 42 U.S.C. § 7401, et seq.)

4. Applicable 40 CFR subsections, as listed in Table A-2.

Table A-2. Requirements Specifically Identified As Applicable—Federal

Citation	Title
40 CFR Part 52.21	PSD
40 CFR Part 52.1470	SIP Rules
40 CFR Part 60, Subpart A	NSPS – General Provisions
40 CFR Part 60, Subpart Db	NSPS – Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60	Appendix A, Method 9 or equivalent (Opacity)
40 CFR Part 60, Subpart Dc	NSPS – Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR Part 60, Subpart GG	NSPS – Standards of Performance for Stationary Gas Turbines

Citation	Title
40 CFR Part 68	Chemical Accident Prevention Provisions
40 CFR Part 70	State Operating Permit Programs
40 CFR Part 82	Protection of Stratospheric Ozone
40 CFR Part 63, Subpart ZZZZ	NESHAP — Stationary Reciprocating Internal Combustion Engines

Appendix B

RACT Analysis - PG6541B Turbines, Emission Units A01 and A02

APPENDIX B

RACT Analysis

PG6541B Turbines, Emission Units A01 and A02

Appendix B
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Attachments

1.0 General

This appendix summarizes the Reasonably Available Control Technology (RACT) Analysis performed for the GE PG6541B turbines, Emission Units (EU) A01 and A02, located at Saguaro Power Company (Saguaro). The basic steps for this analysis are as follows:

- 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

Controls for oxides of nitrogen (NO_X) are evaluated in this appendix.

2.0 NO_X RACT Assessment

2.1 Equipment Description and Limitations

EUs A01 and A02 have nominal power rating of 35 MW. They burn natural gas but are permitted to allow combustion of #2 fuel oil in the event of natural gas curtailment. However, it is not feasible to run on #2 fuel oil as the fuel oil storage tanks were converted to water tanks and the engines are not configured to run on fuel oil. In practice, the facility would shut down in the event of natural gas curtailment. Accordingly, the worst-case fuel for these turbines is natural gas and the RACT analysis will be done for natural gas.

The GE PG6541B natural gas turbines are classified as combined cycle gas turbines as they are equipped with Heat Recovery Steam Generators (HRSGs) that power a conventional steam turbine. The HRSGs contain supplemental duct burners, but they are not used in practice and therefore will not be accounted for in this analysis.

2.2 Baseline Emissions

As noted in Section 3 of the report, baseline emissions can be set equivalent to actual emissions if actual emissions for the three previous consecutive years are 70% or less of the source's potential emissions. Saguaro meets this criterion on a facility-wide basis.

Table 1 summarizes the baseline NO_X emissions of the GE PB6541B natural gas combustion turbines, which are equipped with steam injection and Selective Catalytic Reduction (SCR) technologies as baseline controls.

Table 1 - Baseline Emissions

Emission Unit	NO_X Emissions[1] (tons)
A01	54.45
A02	55.17

Notes: [1] Maximum annual emissions for 2019 - 2021.

2.3 Identification and Technical Feasibility of NO_X Control Options

2.3.1. Identification of Available Controls

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 RACT determinations for combustion turbines of the same or comparable size. The database did not contain any such RACT determinations for this time period. In addition, locally permitted combustion turbines were researched and the combustion turbine manufacturer was queried to identify potential controls. Based on the information obtained, the proposed NO_X control technologies for EUs A01 and A02 are summarized in Table 2.

Table 2 - Available NO_X Control Technology Methods for EUs A01 and A02

Control Equipment	NO_X PPM Guarantee or Reduction Potential (%)	Range of Application	Commercial Availability/ R&D Status
Dry Low NO_X (DLN)	9 ppm NO_X	Primarily for new turbine installations	Available for new turbine packages
Steam/Water Injection	60	Usually combined with SCR	Available
Selective Non Catalytic Reduction (SNCR)	75-90	Primarily combustion engines	Available, but not widely used
Non-Selective Catalytic Reduction (NSCR)	Variable	Automobile industry	Available
Selective Catalytic Reduction (SCR)	75-90	Numerous combustion turbines at power plants throughout country	Available although long lead times for retrofits or new installations
Steam Injection with SCR	10 ppm NO_X	Baseline for this application	Available with certain turbine packages. Baseline for this application
DLN with SCR	4 ppm NO_X	Primarily for new turbine installations	Available

It should be noted that EMx© technology (formerly called $SCONO_X$) owned by Miratech Corporation has the potential for stringent NO_X and CO reduction, however, it is no longer being installed on units. Miratech indicated it is strictly being serviced on units already equipped with this technology. For this reason, EMx© was eliminated from consideration as it is not commercially available.

The technical feasibility of each available control option identified in this section will next be evaluated.

2.3.2. Dry Low NO_X (DLN)

DLN uses a lean mixture of gaseous fuel and compressed air to avoid formation of high temperature zones where high levels of NO_X are created. The lean mixture of gaseous fuel is produced by incorporating excess air to the mixture. This process enables cooling of the flame in the primary combustion zone, thus reducing formation of NO_X, and it requires a custom designed mixing chamber for each turbine. This would amount to a reconfiguration of each turbine by the manufacturer (GE), provided there is space available to accommodate the DLN equipment. At this time, it is unclear whether the DLN mixing chambers could physically be mounted on the Saguaro turbine packages. Significant engineering assessment and design work would need to be conducted before a final determination could be made. For purposes of this assessment, we will assume that the control technology can be physically installed. DLN can consistently maintain NO_X emission rates of 9 ppm NO_X @ 15% O_2. Upon review of the RACT/BACT/LAER clearinghouse and locally permitted turbines, DLN is typically combined with SCR to achieve NO_X outlet concentrations in the 2 to 6 ppm @ 15% O_2 range.

2.3.3. Steam/Water Injection

Steam/water injection increases the thermal mass by dilution and accordingly reduces peak temperatures in the flame zone. Water injection has the additional benefit of absorbing the latent heat of vaporization from the flame zone. The water-to-fuel weight ratio is typically less than one. This yields NO_X reductions of 60% or higher. However, water injection increases both CO and VOC emissions. This technology is technically feasible as steam injection is installed in the GE PG6541B turbines.

2.3.4. Selective Non-Catalytic Reduction (SNCR)

SNCR uses a nitrogen-based reagent (ammonia or urea) in a chemical reaction to reduce NO_X into molecular nitrogen and water vapor. The reagent is injected into the post combustion exhaust gas. SNCR system NO_X removal efficiency depends on the range of the processing temperatures; the most favorable temperature range is 1600ºF and 2100ºF. Urea is more advantageous as a reagent because it is not toxic, less volatile, and easier to handle and store. Urea also has higher efficiency in penetrating farther into the flue gas, hence enhancing the mixing with the flue gas. The SNCR system injects the reagent directly into the combustion chamber, where the flue gas is directly mixed with the reagent. SNCR injection and control system is capable of reducing NO_X emissions by 60% or greater.

As already mentioned, the efficiency of SNCR is determined by the exhaust gas temperature, and since the GE PG6541B exhaust temperature is significantly lower (600ºF - 900ºF), SNCR's efficiency will be compromised. Based on this limitation, SNCR is not a technically viable control option for NO_X emissions for these units.

2.3.5. Non Selective Catalytic Reduction (NSCR)

NSCR uses a catalyst for removing NO_X emissions from the exhaust gas. This technology is primarily used in the industries that utilize rich burning internal combustion engines, such as the automobile industry. The removal efficiency of the NSCR depends on high fuel concentrations with minimal oxygen present.

This type of environment (low oxygen concentration) does not occur in the combustion turbine exhaust, hence NSCR is not a technically feasible control technology for this application.

2.3.6. Selective Catalytic Reduction (SCR)

As discussed earlier, SCR along with steam injection is considered a baseline control for this application as these are installed on the GE PG6541B turbines for NO_X control. SCR reduces Nitrogen Oxides (NO_X) in the exhaust gas. The reduction process is activated by injecting a nitrogen-based agent (reagent), such as ammonia or urea, into the post combustion flue gas. With the help of a metal-based catalyst, the reagent reacts selectively with the flue gas NO_X within a specific temperature range to reduce the NO_X into molecular nitrogen (N_2) and water vapor (H_2O). The metal-based catalyst has activated sites and increases the rate of the reduction reaction. The catalyst is made of active metals or ceramics with a highly porous structure.

The SCR process starts with injecting a nitrogen-based reagent such as ammonia or urea into the ductwork, downstream of the combustion unit. The exhaust gas mixes with the reagent and enters a reactor module containing catalyst, where it diffuses through the catalyst. The main factors in determining the removal efficiency are: temperature, the amount of reducing agent, injection grid designs, and catalyst activity. Catalyst removal efficiency can be compromised by: poisoning of active sites by flue gas constituents, thermal sintering of active sites to high temperatures within reactor, blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and erosion due to high gas velocities.

Since natural gas fired units contain lower levels of NO_X, sulfur, and PM in the exhaust gas, less catalyst will be required, making natural gas fired units with SCR more cost effective. SCR systems can provide up to 90% NO_X removal efficiency. SCR will be considered as a feasible control technology in the top-down RACT analysis for NO_X emissions. The permitted emission limit for these GE PG6541B turbines is 10 ppmvd (4-hr average) @ 15% O_2 for natural gas combustion. Based on BACT/RACT/LAER permitted emission limits and local turbines permitted emission limits, Broadbent will also evaluate SCR at 6.0 ppmvd (4-hr average) NO_X. This limit is offset by a greater degree of Ammonia Slip, to be discussed later in this document.

2.3.7. Technical Feasibility Summary

Table 3 summarizes the results of the technological feasibility evaluations of the identified control options.

Table 3 - NO_X Control Technology Methods for EUs A01 and A02

Control Equipment	Technically Feasible?	Uncontrolled NO_X Emissions (tons/yr)	NO_X Controlled Emission Rate (tons/yr)	NO_X removed (tons/yr)
DLN	Yes	55.17	49.65	5.52
Steam/Water Injection	Yes	baseline	baseline	baseline
SNCR	No	n/a	n/a	n/a

NSCR	No	n/a	n/a	n/a
SCR	Yes	baseline	baseline	baseline
Steam Injection with SCR	Yes	55.17	baseline	baseline
DLN with SCR	Yes	55.17	22.07	33.10

Based on the information presented in Table 2, Saguaro will evaluate a turbine equipped with steam injection and SCR that yields 6 ppm NO_X @ 15% O_2, a turbine retrofitted with DLN combustors that yields 9 ppm NO_X @ 15% O_2, and a turbine retrofitted with DLN combustors and SCR that yields 4 ppm NO_X @ 15% O_2.

2.4 Cost of NO_X Control Options

For each technically feasible method of control, a total annualized equipment cost and an annual operating cost has been calculated. The calculation of the capital cost recovery factor used to estimate the annualized equipment cost assumes an interest rate of 6% and equipment life of 10 years. The individual cost calculations for each control alternative are included in Attachments B-1, B-2, and B-3. The capital cost is based on quotes or estimates from manufacturers. No quote was provided for Dry Low NO_x with SCR, however estimated cost for Dry Low NO_x with SCR was based on telephone conversations with multiple vendors. The calculated costs are summarized in Table 4.

Table 4 - Cost of NO_X Control Options for EUs A01 and A02

Method of Control	Annualized Cost ($/yr)	Estimated NO_X Removal (tons/yr)	Cost Effectiveness ($/ton removed)
Upgraded SCR system rated at 6 ppm NO_X with Steam Injection	$290,040	22.07	$13,143
DLN	$715,347	5.52	$129,662
DLN with SCR rated at 4 ppm NO_X	$790,781	33.10	$23,889

2.5 Environmental, Energy & Economic Considerations

2.5.1. 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 NO_X 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 NO_X control efficiency.

2.5.2. 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.

2.5.3. Economic Impacts

The economic impacts analysis is based on the cost effectiveness of each technology in terms of the cost per ton of removed pollutant as evaluated in Section 2.4. A maximum cost effectiveness threshold for NO_X RACT has not been established by DES. In 1994, the U.S. EPA recommended a maximum of $1,300 per ton to represent RACT at that time. Based on the increase in the Chemical Engineering Plant Cost Index (CEPCI) between then and now, this equates to approximately $3,000 per ton for the present. The U.S. EPA, in its approval of certain State Implementation Plan revisions for Pennsylvania (85 FR 65706) noted that Pennsylvania's proposed maximum of $2,800 per ton was low compared to other states but approved it. Maximum thresholds for other jurisdictions were presented in the notice as follows:

- Wisconsin, $2,500 per ton NO_X
- Illinois, $2,500—$3,000 per ton NO_X
- Maryland, $3,500—$5,000 per ton NO_X
- Ohio, $5,000 per ton NO_X
- New York, $5,000—$5,500 per ton NO_X

For the purpose of this analysis, even if the maximum value of $5,500 from above is deemed appropriate in Clark County, the cost of control for each individual combustion turbine exceeds this value. Table 4 presents the cost effectiveness of the viable control option upgrades.

3.0 NO_X RACT Determination

After eliminating technically infeasible options, evaluating the remaining technologies for environmental, energy, and economic impacts, and reviewing similar facilities for emission control technologies, Broadbent has determined that SCR and steam injection with a 10.0 ppmvd (4-hr average) NO_X limit at 15 percent oxygen while firing natural gas meets RACT for this application. This limit would not apply during startup, shutdown, or malfunction. Startup and shutdown would amount to the existing 65 lb/hr NO_X emission rate, to be used when CEMs data is not available. Malfunction would amount to use of good combustion practices, to the maximum extent possible during such an event. Monitoring would consist of the existing NO_X CEMs. Recordkeeping and reporting would consist of the following:

- 4-hr rolling averages of exhaust gas concentrations for NO_X and O_2;
- exhaust gas flowrate;
- fuel flowrate;
- hours of operation;
- hourly, daily, and quarterly accumulated mass emissions of NO_X; and

- hours of downtime of NO_X CEMs.

Startup and shutdown events are short in duration for the GE PG6541B turbines. Technically feasible emission controls require full load operation to be implemented, and therefore, cannot be used during startup or guaranteed effective during shutdown. Based on these factors, RACT for startup and shutdown of the GE PG6541B turbines will be work practice standards.

ATTACHMENT B – 1

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	A02
Emission Unit Description	Combined Cycle Turbine
Control Technology	Dry Low NOx Configuration
Emission Reduction[1] (%)	10%
Baseline Emission Rate[2] (tons/year)	55.17

Annualized Capital Costs

Initial Capital Investment[3]	$3,793,000
Direct & Indirect Costs[4]	$0
Total Capital Investment	$3,793,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$515,347

Annual Operating Costs

Remote Tuning	$200,000
Total Annual Operating Cost	$200,000
Total Annualized Cost	$715,347

Cost Effectiveness

Emissions Reduction (tons/year)	5.52
Cost Effectiveness of NOx Reduction (per	$129,662

Notes:

[1] NO_x emissions reduced from 10 ppm to 9 ppm.

[2] Actual emissions for 2021

[3] Cost based on vendor estimate

[4] Installation, startup and testing accounted for in capital investment.

Wendy Alexander

From: Rob May <rob.may@camsops.com>
Sent: Wednesday, September 21, 2022 1:31 PM
To: Scott McNulty; Wendy Alexander
Subject: FW: GT Controls Upgrade

The email chain below is from a consultant working on similar project and a controls engineer that work on these units DLN-1 is 3.2mil per unit and controls are 593K.

I am waiting for a quote form ethos energy for the same upgrade. (DLN with controls)

SAGUARO POWER COMPANY
Rob May
Plant Manager
702 558 1131
702 300 8181 Cell (NEW)
rob.may@camsops.com

** Note new cell number **

From: Rob May
Sent: Friday, September 9, 2022 6:11 AM
To: archie@arcon-services.com
Subject: RE: GT Controls Upgrade

SAGUARO POWER COMPANY
Rob May
Plant Manager
702 558 1131
702 300 8181 Cell (NEW)
rob.may@camsops.com

** Note new cell number **

From: Archie Conde <archie@arcon-services.com>
Sent: Thursday, September 8, 2022 4:00 PM
To: 'Ron Walker' <ron.walker@controlsystemtechnologies.com>; Rob May <rob.may@camsops.com>
Cc: gkrause@paragonassets.com
Subject: RE: GT Controls Upgrade

[EXTERNAL EMAIL] DO NOT CLICK links or attachments unless you recognize the sender and know the content is safe. If you believe you've received this email in error, or believe this is a phishing attempt contact Bluewire Help Desk

Thank Ron. Rob you can add 3.2 million per unit to upgrade to a DLN-1 unit. I base this off the project I am presently working on. Let me know if you need anything further.

From: Ron Walker [mailto:ron.walker@controlsystemtechnologies.com]
Sent: Thursday, September 08, 2022 6:21 PM
To: RobMay
Cc: Archie Conde(archie@arcon-services.com)
Subject: GT ControlsUpgrade

Rob,

I talked with Archie Conde who asked I email you regarding upgrading the GTs control system. We offer a full MkIV GT controls upgrade package to a new and modern system for Water, Steam and DLN-1 type NOx controls. The system hardware is based on a Honeywell C300 controller platform and fully warrantied by Honeywell. CST provides the software algorithms, logic conversions, installation, commissioning and follow-up customer support. Honeywell has it's call-in center for first response customer support where they can access the system and perform analysis on the hardware. If it is determined that the issue is not hardware then a call is made to CST for field engineering support services.

Ballpark for the hardware conversion, control system delivered to site, is approximately $593k. Depending on the existing system options this price could come down or go up, but typically, by not more than 10%.

I hope this helps you, if not, please feel free to reach out to me for any additional questions you or your team might have.

Sincerely,
Ron

Ronald Walker

Visit us at: www.cstfs.com

1969South Alafaya Trail, Suite 111
Orlando, FL32828

O: 321.418.8003
C:407.948.2183
F: 877.530.8717

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ATTACHMENT B – 2

Cost Effectiveness Calculation

Emission Unit/Control Technology	
Emission Unit	A02
Emission Unit Description	Combined Cycle Turbine
Control Technology	DLN with SCR
Emission Reduction[1] (%)	60%
Baseline Emission Rate[2] (tons/year)	55.17
Annualized Capital Costs	
Initial Capital Investment[3]	$4,293,000
Direct & Indirect Costs[4]	$0
Total Capital Investment	$4,293,000
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$583,281
Annual Operating Costs	
Ammonia Cost	$207,500
Total Annual Operating Cost	$207,500
Total Annualized Cost	$790,781
Cost Effectiveness	
Emissions Reduction (tons/year)	33.10
Cost Effectiveness of NOx Reduction (per	$23,889

Notes:

[1] NO_x emissions reduced from 10 ppm to 4 ppm.

[2] Actual emissions for 2021

[3] Cost based on vendor estimate for DLN and estimate for DLN-compatible SCR

[4] Installation, startup and testing accounted for in capital investment

ATTACHMENT B - 3

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	A02
Emission Unit Description	Combined Cycle Turbine
Control Technology	Upgraded SCR with steam injection
Emission Reduction[1] (%)	40%
Baseline Emission Rate[2] (tons/year)	55.17

Annualized Capital Costs

Initial Capital Investment[3]	$607,500
Direct & Indirect Costs[4]	$0
Total Capital Investment	$607,500
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$82,540

Annual Operating Costs

Ammonia Cost	$207,500
Total Annual Operating Cost	$207,500

Total Annualized Cost	$290,040

Cost Effectiveness

Emissions Reduction (tons/year)	22.07
Cost Effectiveness of NOx Reduction (per	$13,143

Notes:

[1] NO_x emissions reduced from 10 ppm to 6 ppm.

[2] Actual emissions for 2021

[3] Cost based on vendor estimate

[4] Installation, startup and testing accounted for in capital investment.

Wendy Alexander

From: Balasubramanian, Vignesh <vbala@vogtpower.com>
Sent: Friday, September 30, 2022 6:58 AM
To: Wendy Alexander
Cc: Stull, Michael; Scott McNulty
Subject: RE: SCR catalyst replacement for combined cycle turbine

Hi Wendy – Pleasure speaking with you yesterday.

Here is my preliminary estimate of the cost of the replacement catalyst:

1. Engineering, including thermal analysis to ensure catalyst temperatures are appropriate - $40,000 total
2. Quality / Project Management - $25,000 total
3. Catalyst - $300,000 per unit, $600,000 total
4. Installation - $550,000 total
5. Total price for 2 units - $1,215,000

This is a +-30% estimate with the information provided. During detailed execution, we can provide a firm price based on catalyst operating temperatures etc.

Thanks.

Sincerely,

Vignesh Bala
Director of Operations - HRSG Services

VOGT POWER INTERNATIONAL
A Babcock Power Inc. Company
13400 Eastpoint Centre Dr. Suite 200 | Louisville, KY 40223

office | (502) 271 0526
email | vbala@vogtpower.com
web | https://www.babcockpower.com/vogt

From: Wendy Alexander <walexander@broadbentinc.com>
Sent: Wednesday, September 28, 2022 6:00 PM
To: Balasubramanian, Vignesh <vbala@vogtpower.com>; Ryan Jeter <rjeter@miratechcorp.com>
Cc: Stull, Michael <mstull@vogtpower.com>; Scott McNulty <smcnulty@broadbentinc.com>
Subject: RE: SCR catalyst replacement for combined cycle turbine

Vignesh,

Appendix C

RACT Analysis - Volcano Boiler, Emission Unit A05

APPENDIX C

RACT Analysis

Volcano Boiler, Emission Unit A05

Appendix C
Table of Contents

1.0 General

This appendix summarizes the Reasonably Available Control Technology (RACT) Analysis performed for the Volcano Boiler, Emission Unit (EU) A05, located at Saguaro Power Company (Saguaro). The basic steps for this analysis are as follows:

- Identification of existing equipment and baseline emissions
- Identification of available control technologies.
- 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.

Controls for oxides of nitrogen (NO_X) are evaluated in this appendix.

2.0 NO_X RACT Assessment

2.1 Equipment Description and Limitations

EU A05 is a boiler with a maximum heat input rating of 218 MMBtu/hr which utilizes natural gas and/or hydrogen as the fuel supply. The emission unit is limited to 1,909,680 MMBtu annually. Further, NO_x emissions are limited to 12 ppmvd (4-hr average) @ 3% O_2. Finally, CO emissions are limited to 1.2 ppmvd (24-hr average) @3% O_2, as part of a Lowest Achievable Emission Rate (LAER) determination and thus cannot be increased as part of a NO_x control upgrade. It should be noted that NO_x and CO are inversely proportional in most combustion-based control upgrades meaning that decreasing NO_x emissions would result in increased CO emissions.

2.2 Baseline Emissions

As noted in Section 3 of the report, baseline emissions can be set equivalent to actual emissions if actual emissions for the three previous consecutive years are 70% or less of the source's potential emissions. Saguaro meets this criterion on a facility-wide basis.

Table 1 summarizes the baseline NO_x emissions for EU A05., which is equipped with a low NO_x burner and Flue Gas Recirculation (FGR) as NO_x controls.

Table 1 - Baseline Emissions

Emission Unit	NO_x Emissions[1] (tons)
A05	0.40

Notes: [1] Maximum annual emissions from 2019 - 2021

2.3 Identification and Technical Feasibility of NO_x Control Options

2.3.1. Identification of Available Controls

A review of RACT determinations for boilers over the last five years was conducted by reviewing the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC). The database did not contain any RACT determinations for this time period for comparably sized units. In addition, various U.S. EPA control technology reports were reviewed and the current contractor responsible for servicing Saguaro's boilers was consulted to identify potential controls. Based on the information obtained, the proposed NO_x control technologies for EU A05 are summarized in Table 2.

Table 2 - Available NO_x Control Technology Methods for EU A05

Control Equipment	NO_X PPM Guarantee or Reduction Potential (%)	Range of Application	Commercial Availability/ R&D Status
Low NO_x Burners	9 ppm NO_x	Wide range of application	Commercially available
Flue Gas Recirculation (FGR)	30-60	Wide range of application, Baseline for this application	Commercially available
Selective Catalytic Reduction (SCR)	75-90	Limited range of applications	Commercially available
Selective Non Catalytic Reduction (SNCR)	75 – 90	Limited range of applications	Commercially available, but not widely used
Low NO_x Burners with FGR	12 ppm NO_x	Baseline for this application	Commercially available with certain boilers. Baseline for this application

Since NO_X and CO emissions are inversely proportional and CO emissions are limited to 1.2 ppmvd (24-hr average) @3% O_2, as part of a Lowest Achievable Emission Rate (LAER) determination, CO emissions need to be considered when evaluating RACT for NO_x. NO_x controls that would result in CO emission increases would violate the LAER determination and thus will not be considered feasible.

The technical feasibility of each control option will next be evaluated.

2.3.2. Low NO_X burner rated at 9 ppm corrected to 3% oxygen

Burner modifications for NO_X control involve changing the design of a standard burner in order to create a larger flame. Enlarging the flame results in lower flame temperatures and lower thermal NO_X formation which, in turn, results in lower overall NO_X emissions.

Low NO_X burners reduce NO_X by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame, which suppresses thermal NO_X formation. The two most common types of low NO_X burners being applied to natural gas boilers are staged air burners and staged fuel burners, or a combination thereof.

The current burner assembly could be replaced with a model that is guaranteed to meet a 9 ppm NO_x emission rate, but with a 15 ppm CO emission rate. No suppliers contacted could reduce NO_x without a corresponding increase in CO emissions above the 1.2 ppm LAER limitation. Therefore, replacing the burner with a lower NO_x rated assembly is not considered technically feasible.

2.3.3. Flue Gas Recirculation (FGR)

FGR involves the recirculation of a portion of the flue gas to the burners. It reduces NO_x emissions by two mechanisms. First, the recirculated gas acts as a dilutant to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. Second, FGR lowers the oxygen concentration in the primary flame zone. The portion recycled is up to 25% to 30% and it can be implemented on most new design types. An FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. It may not be feasible on all existing boiler types or in places with spacing limitations. In this case, it is viable along with a 12 ppm NO_x burner.

2.3.4. Selective Catalytic Reduction (SCR)

SCR involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst. The catalyst allows the ammonia to reduce NO_X levels at lower exhaust temperatures than selective non-catalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400-1600°F, SCR can be utilized where exhaust gases are between 500° and 1200°F, depending on the catalyst used. SCR can result in NO_X reductions up to 75%. Since the EU A05 boiler generates exhaust temperatures of around 325 ° F, an SCR system is not a technically feasible option for this application.

2.3.5. Selective Non-Catalytic Reduction (SNCR)

SNCR involves the injection of a NO_X reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1400-1600°F. The ammonia or urea breaks down the NO_X in the exhaust gases into water and atmospheric nitrogen. SNCR reduces NO_X up to 50%. As was the case with SCR control, the boiler exhaust temperature is far too low to implement SNCR as a viable control technology. The 325° F boiler exhaust makes an SNCR system not technically feasible for this application.

2.3.6. Technological Feasibility Summary

Table 3 summarizes the technological feasibility evaluations of the identified control options.

Table 3 - NO_x Control Technology Methods for EU A05

Control Equipment	Technically Feasible?	Uncontrolled NO_X Emissions (tons/yr)	NO_X Controlled Emission Rate (tons/yr)	NO_X removed (tons/yr)
Low NO_X burner rated at 9 ppm	No	n/a	n/a	n/a
Low NO_x burner rated at 12 ppm with FGR	Yes	Baseline	Baseline	Baseline
SCR	No	n/a	n/a	n/a
SNCR	No	n/a	n/a	n/a

Based on the information presented in Table 3, the only technically viable option is the baseline case.

2.4 Cost of NO_X Control Options

For each technically feasible method of control alternative, a total equipment cost and an annual operating cost is typically calculated. In this case, the only technically feasible option is what is already installed so no costs are associated with it.

Table 4 - Cost ff NO_x Control Options for EU A05

Method of Control	Capital Cost	Annualized Cost ($/yr)	Estimated NO_X Removal (tons/yr)	Cost Effectiveness ($/ton removed)
NO_X burner rated to 12 ppm with FGR	$0	$0	0.00	n/a

2.5 Environmental, Energy & Economic Considerations

There are no environmental, energy, or economic impacts associated with this analysis.

3.0 NO_x RACT Determination

After eliminating technically infeasible options, it is evident that boiler EU A05 can be considered to comply with RACT with the existing 12 ppm burner with FGR as a lower NO_x burner is not technically feasible based on the CO LAER limit. Performance tests and CEMS data for the existing boiler emissions indicate the current NO_x emission limit is achieved.

The 12 ppm @3% O_2 (4-hr average) NO_x limit would not apply during periods of startup, shutdown, or malfunction. Instead, the boiler would be subject to good combustion practices, to the maximum extent possible during such events. Monitoring would consist of the existing NO_x CEMs. Recordkeeping and reporting would consist of the following:

- 4-hr rolling averages of exhaust gas concentrations for NO_x and O_2;

- exhaust gas flowrate;
- fuel flowrate;
- hours of operation;
- hourly, daily, and quarterly accumulated mass emissions of NO_x; and
- hours of downtime of NO_x CEMs

Appendix D

RACT Analysis - Nationwide/Nebraska Boiler, Emission Unit A06

APPENDIX D

RACT Analysis

Nationwide/Nebraska Boiler, Emission Unit A06

Appendix D
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Attachments

1.0 General

This appendix summarizes the Reasonably Available Control Technology (RACT) Analysis performed for the Nationwide/Nebraska Boiler, Emission Unit (EU) A06, located at Saguaro Power Company (Saguaro). The basic steps for this analysis are as follows:

- 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

Controls for oxides of nitrogen (NO_X) are evaluated in this appendix.

2.0 NO_X RACT Assessment

2.1 Equipment Description and Limitations

EU A06 is a Nebraska boiler with a maximum heat input rating of 86 MMBtu/hr that utilizes natural gas as the fuel supply. The emission unit is limited to 510,000 MMBtu annually. Further, NO_x emissions are limited to 30 ppmvd (4-hr average) @ 3% O_2.

2.2 Baseline Emissions

As noted in Section 3 of the report, baseline emissions can be set equivalent to actual emissions if actual emissions for the three previous consecutive years are 70% or less of the source's potential emissions. Saguaro meets this criterion on a facility-wide basis.

Table 1 summarizes the baseline NO_x emissions for EU A06, which is equipped with a low NO_x burner for NO_x control.

Table 1 - Baseline Emissions

Emission Unit	NO_x Emissions[1] (tons)
A06	0.72

Notes: [1] Maximum annual emissions from 2019 - 2021

2.3 Identification and Technical Feasibility of NO_x Control Options

2.3.1. Identification of Available Controls

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 RACT determinations for boilers of the same or comparable size. The database did not contain any RACT determinations for this time period. In addition, various U.S. EPA control technology reports were reviewed and the current contractor responsible for servicing Saguaro's boilers was consulted to identify potential controls. Based on the information obtained, the proposed NO_x control technologies for EU A06 are summarized in Table 2.

Table 2 - Available NO_x Control Technology Methods for EU A06

Control Equipment	NO_X PPM Guarantee or Reduction Potential (%)	Range of Application	Commercial Availability/ R&D Status
Low NO_x Burners with Flue Gas Recirculation (FGR)	30-70 (20 ppm NO_x or 9 ppm NO_x)	Burner changeout is normally an option for any boiler, FGR requires physical space around the boiler that is not always available	Commercially available with certain boilers
Flue Gas Recirculation (FGR)	30-60	Sometimes combined with Low NO_x Burners	Commercially available
Selective Catalytic Reduction (SCR)	75-90	Limited range of application and normally not with boiler exhaust profiles	Available
Selective Non-Catalytic Reduction (SNCR)	75-90	Limited range of application and normally not with boiler exhaust profiles	Commercially available, but not widely used

The technical feasibility of each control option will next be evaluated.

2.3.2. NO_X burner rated at 20 ppm or 9 ppm corrected to 3% oxygen with FGR

Burner modifications for NO_X control involve changing the design of a standard burner in order to create a larger flame. Enlarging the flame results in lower flame temperatures and lower thermal NO_X formation which, in turn, results in lower overall NO_X emissions.

Low NO_X burners reduce NO_X by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame, which suppresses thermal NO_X formation. The two most common types of low NO_X burners being applied to natural gas boilers are staged air burners and staged fuel burners, or a combination thereof. The existing burner associated with this boiler is a low NO_x burner designed to achieve 30 ppm NO_x corrected to 3% oxygen. It cannot be modified to achieve a lower NO_x concentration so it would be necessary to replace it with a lower NO_x burner. This is technically feasible and would be capable of reducing the NO_x concentration in the boiler exhaust to either 20 ppm or 9 ppm corrected to 3% oxygen depending on the burner design. Emissions of CO would necessarily increase; however, they should not exceed the current 400 ppm CO limit. To achieve these NO_x ppm ratings, the boilers would also need to be modified to include FGR. This technology is discussed separately below.

2.3.3. Flue Gas Recirculation (FGR)

FGR involves the recirculation of a portion of the flue gas to the burners. It reduces NO_x emissions by two mechanisms. First, the recirculated gas acts as a dilutant to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. Second, FGR lowers the oxygen concentration in the primary flame zone. The portion recycled is up to 25% to 30% and it can be implemented on most new design types. An FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. It may not be feasible on all existing boiler types or in places with spacing limitations. For the Nebraska boiler, it has been determined that FGR could be installed and coupled with burners to provide a 20 ppm or a 9 ppm NO_x guarantee.

2.3.4. SCR

SCR involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst. The catalyst allows the ammonia to reduce NO_X levels at lower exhaust temperatures than selective non-catalytic reduction (SNCR). Unlike SNCR, where the exhaust gases must be approximately 1400-1600°F, SCR can be utilized where exhaust gases are between 500° and 1200°F, depending on the catalyst used. SCR can result in NO_X reductions up to 75%. Since EU A06 generates exhaust temperatures around 325 ° F, an SCR system is not a technically feasible option for this application.

2.3.5. SNCR

SNCR involves the injection of a NO_X reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1400-1600°F. The ammonia or urea breaks down the NO_X in the exhaust gases into water and atmospheric nitrogen. SNCR reduces NO_X up to 50%. As was the case with SCR control, the boiler exhaust temperature is far too low to implement SNCR as a viable control technology. The 325 ° F boiler exhaust makes an SNCR system not technically feasible for this application.

2.3.6. Technical Feasibility Summary

Table 3 summarizes the technological feasibility evaluations of the identified control options.

Table 3 - NO_x Control Technology Methods for EU A06

Control Equipment	Technically Feasible?	Uncontrolled NO_X Emissions (tons/yr)	NO_X Controlled Emission Rate (tons/yr)	NO_X removed (tons/yr)
NO_X burner rated at 9 ppm with FGR	Yes	0.72	0.22	0.50

NO_x burner rated at 20 ppm with FGR	Yes	0.72	0.48	0.24
SCR	No	n/a	n/a	n/a
SNCR	No	n/a	n/a	n/a

Based on the information presented in Table 3, Saguaro will evaluate the cost of a NO_x burner rated at 20 ppm combined with FGR and a NO_X burner rated at 9 ppm combined with FGR. Since 30 ppm NO_x is baseline, cost is not evaluated for it.

2.4 Cost of NO_X Control Options

For each technically feasible method of control, a total annualized equipment cost and an annual operating cost has been calculated. The calculation of the capital cost recovery factor used to estimate the annualized equipment cost assumes an interest rate of 6% and equipment life of 10 years. The individual cost calculations for each control alternative are included in Attachments D-1 and D-2. The capital cost is based on quotes or estimates from manufacturers. In this case, quotes from R.F. MacDonald Company that services the Saguaro boilers. The calculated costs are summarized in Table 4.

Table 4 Cost Of NO_x Control Options for EU A06

Method of Control	Annualized Cost ($/yr)	Estimated NO_X Removal (tons/yr)	Cost Effectiveness ($/ton removed)
NO_X burner rated to 9 ppm with FGR	$89,351	0.50	$177,283
NO_x burner rated to 20 ppm with FGR	$75,764	0.24	$315,683

2.5 Environmental, Energy & Economic Considerations

2.5.1. Environmental Impacts

No additional environmental impacts were identified with implementation of the replacement burners and FGR. Actual emissions of CO would probably increase as part of this conversion; however, they should not increase above the permitted limits for CO on the boiler.

2.5.2. Energy Impacts

It is anticipated that only minimal adverse energy impacts would be associated with a lower NO_x burner or FGR technology since there would be minimal decrease in burner efficiency.

2.5.3. Economic Impacts

The economic impacts analysis is based on the cost effectiveness of each technology in terms of the cost per ton of removed pollutant as evaluated in Section 2.4. A maximum cost effectiveness threshold for NO_x RACT has not been established by DES. In 1994, the U.S. EPA recommended a maximum of $1,300 per ton to represent RACT at that time. Based on the increase in the Chemical Engineering Plant Cost Index (CEPCI) between then and now, this equates to approximately $3,000 per ton for the present. The U.S. EPA, in its approval of certain State Implementation Plan revisions for Pennsylvania (85 FR 65706) noted that Pennsylvania's proposed maximum of $2,800 per ton was low compared to other states but approved it. Maximum thresholds for other jurisdictions were presented in the notice as follows:

- Wisconsin, $2,500 per ton NO_X
- Illinois, $2,500—$3,000 per ton NO_x
- Maryland, $3,500—$5,000 per ton NO_X
- Ohio, $5,000 per ton NO_X
- New York, $5,000—$5,500 per ton NO_X

For the purpose of this analysis, even if the maximum value of $5,500 from above is deemed appropriate in Clark County, the cost of control for boiler EU A06 significantly exceeds this value. Table 4 presents the cost effectiveness of the viable control option upgrades and a 9-ppm burner with FGR would exceed $177,000 per ton to implement. It should be noted that although there are no plans to operate this boiler at or near it's permitted Potential to Emit (PTE), even if it were and that emissions savings was input in the analysis, the cost would still exceed $10,000 per ton of NO_x removed.

3.0 NO_x RACT Determination

After eliminating technically infeasible options, evaluating the remaining technologies for environmental, energy, and economic impacts, it is evident that boiler EU A06 can be considered to comply with RACT with the existing low NO_x burner with a 30.0 ppm (4-hr average) NO_x limit at 3 percent oxygen while firing natural gas. Performance tests indicate the current emission limit is achieved.

The 30 ppm @3% O_2 (4-hr average) NO_x limit would not apply during periods of startup, shutdown, or malfunction. Instead, the boiler would be subject to good combustion practices, to the maximum extent possible during such events. Monitoring would consist of the semiannual burner efficiency tests along with performance testing every 5 years. Recordkeeping and reporting would consist of the burner efficiency test results and the report for the performance testing.

ATTACHMENT D-1

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	A06
Emission Unit Description	Nationwide/Nebraska Boiler
Control Technology	Low NO_x Burner with FGR
Emission Reduction[1] (%)	70%
Baseline Emission Rate[2] (tons/year)	0.72

Annualized Capital Costs

Initial Capital Investment[3]	$657,629
Direct & Indirect Costs[4]	$0
Total Capital Investment	$657,629
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$89,351

Annual Operating Costs

Total Annual Operating Cost	$0
Total Annualized Cost	$89,351

Cost Effectiveness

Emissions Reduction (tons/year)	0.50
Cost Effectiveness of NOx Reduction (per	$177,283

Notes:

[1] NO_x emissions reduced from 30 ppm to 9 ppm.

[2] Actual emissions for 2020 (max of 2019 - 2021).

[3] Cost based on vendor estimate.

[4] Installation, startup and testing (accounted for in vendor estimate).

CleaverBrooks®

Budget Proposal

Saguaro Power Burner Retrofit

To: Scott Mcnulty
Principal Geologist
Broadbent Air Quality Division
8 W Pacific Ave,
Henderson, NV 89015 United States
(702) 563-0600
Smcnulty@broadbentinc.com

From: Ryland Whitaker
R.F. MacDonald Company
6651 Schuster Street

Las Vegas, NV 89118 United States
(725)229-3368
ryland.whitaker@rfmacdonald.com

September 28, 2022

Dear Scott,

Through a steadfast commitment to research, development, strategic acquisitions, and a focus on providing boiler room solutions for more than 80 years, Cleaver-Brooks is the sole provider of integrated boiler, burner, and controls solutions. With the #1 market share in North America, Cleaver-Brooks is the global leader in designing and manufacturing integrated boiler room systems, and the Cleaver-Brooks brand is globally synonymous with the highest quality, best reliability, and creative innovation in boiler room solutions. Industry-leading proprietary burners, controls, components, and accessories engineered by Cleaver-Brooks perform together seamlessly at peak energy and emissions efficiency.

Cleaver-Brooks offers the broadest range of integrated boiler room systems, subsystems, components and accessories in the market, giving it a distinct competitive advantage as a complete solutions provider across commercial, industrial, and institutional markets. A principal component of the Cleaver-Brooks strategy is to offer the most advanced and completely integrated boiler room systems that satisfy diverse energy demands, high-efficiency performance, ultra-low emissions, safety, reliability, and convenience from utilizing a single-source manufacturer.

From the Power of Total Integration, Cleaver-Brooks offers boiler room systems including mission-critical subsystems performing water treatment, heat recovery, integrated system controls, and maintained by a worldwide dedicated sales and service representative network. All sales and service representatives employ trained technicians to provide first-class routine maintenance and repair services in accordance with national, state/provincial, and local codes and standards.

As a Cleaver-Brooks Representative Association (CBRA) member near you, R.F. MacDonald Company has produced this proposal from your system requirements and equipment specifications. At your convenience, please review this proposal, and contact me regarding any questions or comments.

Sincerely,

Ryland Whitaker
R.F. MacDonald Company
6651 Schuster Street
Las Vegas, NV 89118 United States
(725)229-3368
ryland.whitaker@rfmacdonald.com

CleaverBrooks®

System Requirements

Proposal Number: 29850248 / Proposal Date: 09/16/22

Job Name: Saguaro Power Burner Retrofit / Project Name: Saguaro Power Burner Retrofit

Configurable Burner




NCB Burner System

- For new boilers or retrofit applications/hr
- Natural Gas and light oil firing/hr
- Millions of configurations possible to satisfy your specific needs
- Available to < 30 ppm NOx, < 50 ppm CO
- 12 to 360 MMBTU/hr

The NCB burner is a unique packaged burner system for new boilers and retrofit markets. These burners use advanced CFD modeling, and are equipped with advanced Natcom® design features, including externally adjustable gas injectors, Class-III igniters, atomizers with coupling block valves, which you can complement with your choice among a variety of industrial-grade controls, valves, switches, and gauges.

Natcom® burners feature emissions reductions of 50% compared to flaring and can achieve emissions goals of 9 ppm NOx. The high-efficiency burner design is engineered for multi-fuel firing, including renewables.

NCB-085 Burner

Technical Data Sheet

For indoor applications, uncontrolled or 30 ppm NOx emissions

85 MM BTU/H NG; 81 MM BTU/H #2 OIL

Designed for furnace dimensions of at least:	Physical arrangement:	Combustion Control System (CCS) compatibility options:	Fuel Options:	Choice of NFPA or CSA compliance for U.S. or Canadian units, respectively (contact us for TSSA compliance).
H=8.97' W=6.69' Lturn=15.33' Ltot=18.00'	FD fan, fuel train and control panel are windbox mounted. Right- or left-hand drum arrangements available.	Fully Metered (FM), Parallel Positioning (PP) and Single Point Positioning (SP). All systems use 4-20mA and pneumatic actuators.	Main Fuel: Natural gas and/or #2 oil. Igniter fuel: Natural gas and/or propane.	

Performance guarantees

	NG, no FGR	#2 Oil, no FGR	NG, 12% FGR	#2 Oil, 12% FGR
Excess Air %*	15	15	15	15
NOx emissions ppmvd @3%O_2	70	110	30	75
CO emissions ppmvd @3%O_2	50	75	50	75
VOC lb/MM BTU (HHV)	0.004	0.004	0.004	0.004
Total PM lb/MM BTU (HHV)	0.01	0.05	0.01	0.05
Turndown	10	8	10	8

Performance guarantees are based on normal operating conditions and valid from 25% to 100% MCR, boiler with gas tight furnace division wall and to nominal operating pressure and temperature. Igniter emissions are not guaranteed. For application where CB does not provide the controls, emissions are guaranteed in manual mode only. SOx emissions are not burner dependent and depend solely on the sulfur content of the fuel. Burner/boiler systems are not intended for automatic recycling use. Fan motors of 100 HP and above are only offered with manual start/stop control. Please contact your local representative for more details.

*Excess air given for MCR only.

CleaverBrooks

Budget Quote Summary

Proposal Number: 29850248 / Proposal Date: 09/16/22

Job Name: Saguaro Power Burner Retrofit / Project Name: Saguaro Power Burner Retrofit

Product Model: NATCOM		
Item	**Qty.**	**Description**
#1	1	**Reference: 1** Configured in the Custom NATCOM program.
#2	1	Burner Model: NCB-230
#3	1	Fuels Included: Gas
#4	1	Burner Heat Input (MMBTU/hr): 85
#5	1	Guaranteed NOx Emissions, Gas (PPM @3% O2): 30
#6	1	Type of Control: Full Metering
#7	1	Burner Fan Motor HP: 150
#8	1	Burner Fan Location: Windbox Mounted
#9	1	Available Gas Pressure at Regulator Inlet: 25 - 40 psig
#10	1	Oil Pressure Required @ Train Inlet: 150 psig
#11	1	Turndown on Natural Gas: 10:1
#12	1	Turndown Firing Oil: 8:1
#13	1	Variable Frequency Drive Included: Y
#14	1	O2 Trims: Yes
#15	1	Boiler Control Model: HAWK 4500
#16	1	Ambient Temperature Range: 50 - 100 °F
#17	1	Site Elevation: < 2500 ft ASL
		Product Price to Customer (USD): $

CleaverBrooks®

Budget Quote Summary

Proposal Number: 29850248 / Proposal Date: 09/16/22

Job Name: Saguaro Power Burner Retrofit / Project Name: Saguaro Power Burner Retrofit

Item	Qty.	Product Model	PTC (USD)
#1	1	NATCOM	$507.629.00
		Subtotal Price to Customer (USD):	**$507,629.00**
		Cost Adder for 9ppm(USD):	**$150,000.00**
		Freight (EXW - Ex Works Factory) Cost (USD):	**NA**
		Total Price to Customer (USD):	**$657,629.00**

CLEAVER-BROOKS OFFERING

Cleaver-Brooks offers to furnish the Equipment described herein for the purchase price noted, exclusive of all taxes. Prices quoted are firm for 30 days from the date of the Cleaver-Brooks Proposal subject to adjustment as noted. Standard Cleaver-Brooks **payment terms** are *unconditional net 30 from the date of readiness for shipment or unless otherwise specified in this Proposal*. Cleaver-Brooks will review your order prior to acceptance (and acknowledgment) and order entry. Until acceptance and order entry, the Equipment is **subject to prior sale**. Incorporation of technical specifications or requirements different from or additional to the Cleaver-Brooks Proposal and not previously reviewed by Cleaver-Brooks will extend the order review process and may postpone or prevent acceptance of your order and order entry. Cleaver-Brooks does not agree and will not agree to **INCIDENTAL, CONSEQUENTIAL AND LIQUIDATED DAMAGES OR IMPLIED WARRANTIES**. Cleaver-Brooks does not agree and will not agree to, unless specifically set forth in an agreement in writing having an authorized Cleaver-Brooks signature: (1) **terms and conditions** in your order that are different from or additional to those of the Cleaver-Brooks Proposal; (2) **technical specifications**, technical requirements or descriptions of the goods and services ordered that are different from or additional to those of the Cleaver-Brooks Proposal; or (3) **generalized expressions** such as "per plans and specifications."

CLEAVER-BROOKS PRICE ADJUSTMENT POLICY

The price quoted in the Cleaver-Brooks Proposal is firm for thirty (30) days from the Proposal date if shipment of the Equipment is made within six (6) months from the date of the Cleaver-Brooks Proposal or contract document if no Proposal was issued. If the Equipment is not shipped within such six (6) months, the contract price shall be increased by one percent (1%) for each thirty (30) days or fraction thereof that shipment is deferred beyond six (6) months from the date of the Cleaver-Brooks Proposal or contract document.

PROPOSED PAYMENT TERMS

Amount At or Exceeds $250,000: Yes
Payment Terms: Progress Payments
Terms Description:

Note: May require Cleaver-Brooks review if other than 20%/30%/50% referenced in ¶ 1(a).

PROPOSED SHIPPING TERMS

[x] EXW – Ex Works Factory
[ ] CIP – Carriage and Insurance Paid to
[ ] OTHER:______________________________
Freight Allowed To Location:________________________

Note: Freight unloading by others.

BUYER OF CLEAVER-BROOKS EQUIPMENT

Buyer Representative - Printed First and Last Name

Buyer Representative - Company Name

,

Buyer Representative - Company Address, State/Province, Area Code, and Country

Buyer Representative - Phone Number

Buyer Representative - Email Address

Buyer Representative - Signature

/ /

Buyer Representative - Date Accepted (MM/DD/YYYY)

CLEAVER-BROOKS SALES REPRESENTATIVE

Ryland Whitaker

Sales Representative - Printed First and Last Name

R.F. MacDonald Company

Sales Representative - Company Name

10261 MATERN PLACE
SANTA FE SPRINGS, CA 90670
United States

Sales Representative - Company Address, State/Province, Area Code, and Country

(725)229-3368

Sales Representative - Phone Number

ryland.whitaker@rfmacdonald.com

Sales Representative - Email Address

Sales Representative - Signature

09/16/22

Sales Representative - Date Offered

CLEAVER-BROOKS TERMS AND CONDITIONS OF SALE ON NEXT PAGE

CleaverBrooks

Terms and Conditions of Sale

Date Revised: July 23, 2021

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE

1. OFFER AND CONTRACT

(a) Through its proposal (the "Proposal") The Cleaver-Brooks Company, Inc. (the "Company") offers to sell its products, systems or parts (the "Equipment") for the purchase price (the "Purchase Price") on these terms and conditions of sale.

(b) UPON WRITTEN ACCEPTANCE OF THE PROPOSAL BY THE BUYER, THE PROPOSAL AND THESE TERMS CONSTITUTE THE COMPLETE AGREEMENT BETWEEN THE COMPANY AND THE BUYER ("THIS AGREEMENT"). ANY ADDITIONAL OR DIFFERENT TERMS ARE REJECTED UNLESS AGREED TO BY THE COMPANY IN A SIGNED AMENDMENT AFTER REVIEW AT THE PRODUCT GROUP HOME OFFICE.

(c) Except as indicated below, this **Proposal is valid for thirty (30) days** subject to written withdrawal by the Company at any time prior to receipt of written acceptance by the Buyer.

(d) The Purchase Price and any delivery dates of this Proposal are **subject to prior sales that occur before written acceptance by the Buyer and increased material costs**.

(e) Orders received are scheduled for production as proposals are accepted in writing by the Buyer.

(f) If at the time the Product Group home office receives a written acceptance of a proposal, and the then available production lead time at the Product Group manufacturing location does not allow for shipment within the number of weeks offered in the Proposal, then the Purchase Price and any delivery dates shall be adjusted based upon the next available production and delivery dates.

2. TERMS AND PRICES

(a) Standard terms of payment are thirty (30) days net from the date of invoice for completion of performance milestones for payment, including readiness of the Equipment for shipment. Partial shipments of units under multiple unit orders shall be invoiced and paid separately. The Company will waive lien rights and release payment claims to the extent of payments received. The Company may require a letter of credit from the Buyer.

(b) Any excise, sales, privilege, use or any other local, state, or federal taxes which the Company may be required to pay, arising from the sale, delivery, or use of the Equipment and any applicable prepaid freight, will be added to the Purchase Price and invoiced separately.

(c) If the Buyer requests changes in scope or schedule, or if the Buyer delays production or shipment of the Equipment, the Purchase Price and any delivery dates shall be equitably adjusted to reflect changes caused thereby.

(d) Availability and costs of any proposed surety bonding (or other financial securities) are determined by providers thereof at the time of award and the costs of such surety bonding shall be added to the Purchase Price. The Company does not commit to provide a particular financial security. All financial securities issued will be subject to agreed expiration dates, and reduce in amount as performance milestones are accomplished.

(e) The Buyer shall pay **interest on all late payments** at the lesser rate of 1.5% per month or the highest rate permissible under applicable law, calculated daily and compounded monthly.

(f) The Buyer shall reimburse the Company for all costs incurred in collecting any late payments, including, without limitation, attorney's fees.

(g) The Buyer shall not withhold payment of any amounts due and payable by reason of any set-off of any claim or dispute with the Company, whether relating to the Company's breach, bankruptcy, or otherwise. The Company shall not be liable for any claim by the Buyer unless and until such claim is finally adjudicated through the dispute resolution process.

(h) The Purchase Price is subject to increase before written acceptance of the Proposal by the Buyer based upon an increase of the CRU USA Midwest FOB Mill index.

(i) In addition to all other remedies available under this Agreement or at law (which the Company does not waive by the exercise of any rights hereunder), the Company shall be entitled to suspend the manufacture and/or delivery of any Equipment if the Buyer fails to pay any Company invoice within thirty (30) days of the date of the invoice.

3. DELIVERY

(a) Unless otherwise offered in this Proposal, delivery is Ex Works (INCOTERMS® (most recent version)), at the Product Group manufacturing location ("the Delivery Point").

(b) The estimated shipment date is based upon timely receipt by the Company of **Buyer's applicable information**, and of **Buyer's written approval**, or detailed exceptions to, the Company's general arrangement drawings within ten (10) business days of receipt.

(c) If the **Buyer requests to defer delivery** dates by a written request adequate to support GAAP requirements for revenue recognition by the Company, or if the Buyer fails to promptly accept the Equipment tendered for delivery, or shipment of the Equipment is otherwise delayed by causes beyond the Company's reasonable control, the following conditions shall apply: (i) payments due upon shipment (or "delivery") shall be invoiced, due and payable upon "readiness to ship;" (ii) all financial securities required of the Company shall be released based upon "readiness to ship", (iii) the Buyer shall pay reasonable storage and handling charges incurred by the Company on the Buyer's behalf in the circumstances; (iv) risk of loss shall transfer to the Buyer upon "readiness to ship," (v) the Buyer shall be responsible for insuring the Equipment, and (vi) the Buyer shall inspect at delivery and give notice as soon as practical of any loss, damage or shortage evident by visual inspection and quantity count.

4. TITLE AND RISK OF LOSS

(a) Title and risk of loss passes to the Buyer upon the Company's delivery of the Equipment to the Delivery Point. If for any reason the Buyer (or the Buyer's transporting carrier) fails to accept delivery of the Equipment on the date on which the Equipment has been delivered to the Delivery Point or if the Company is unable to ship the Equipment because the Buyer (or the Buyer's transporting carrier) has not provided appropriate instructions, documents, licenses or authorizations: (i) risk of loss to the Equipment shall pass to the Buyer; (ii) the Equipment shall be deemed to have been delivered.

(b) As collateral security for the payment of the Purchase Price of the Equipment, the Buyer hereby grants to the Company a lien on and security interest in and to all of the right, title and interest of the Buyer in, to and under the Equipment, wherever located, and whether now existing or hereafter arising or acquired from time to time, and in all accessions thereto and replacements or modifications thereof, as well as all proceeds (including insurance proceeds) of the foregoing. The security interest granted under this provision constitutes a purchase money security interest under the Georgia Uniform Commercial Code.

5. LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER

(a) THE COMPANY SHALL NOT BE LIABLE FOR ANY SPECIAL, INCIDENTAL, INDIRECT, EXEMPLARY, PUNITIVE, OR CONSEQUENTIAL DAMAGES (INCLUDING WITHOUT LIMIT LOST PROFITS, PRODUCTIVITY LOSSES, ECONOMIC LOSSES, OR BUSINESS DOWNTIME) OR FOR ANY SUCH LOSS, DAMAGE, EXPENSE, DIRECTLY OR INDIRECTLY ARISING FROM THE USE OF THE EQUIPMENT, SERVICES, SPARE OR REPLACEMENT PARTS, OR FROM ANY OTHER CAUSE WHETHER BASED IN WARRANTY, NEGLIGENCE, TORT, CONTRACT OR OTHERWISE, AND REGARDLESS OF ANY ADVICE OR RECOMMENDATION THAT MAY HAVE BEEN RENDERED CONCERNING THE PURCHASE, INSTALLATION OR USE OF THE EQUIPMENT, SERVICES, SPARE OR REPLACEMENT PARTS WHETHER OR NOT HAVING BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

(b) THE BUYER HEREBY RELEASES THE COMPANY OF ANY SUCH LIABILITY AND COVENANTS NOT TO SUE THE COMPANY FOR ANY SUCH DAMAGES.

(c) IN NO EVENT SHALL THE COMPANY'S AGGREGATE LIABILITY UNDER ANY CIRCUMSTANCES EXCEED AN AMOUNT EQUAL TO THE PURCHASE PRICE OF THE EQUIPMENT.

(d) The Company warrants that at the time of delivery the Equipment will conform to the Company's applicable specifications and to such contract specifications as are agreed to by the Company.

(e) The warranty runs for a period of twelve (12) months from the **date of initial operation** but no more than eighteen (18) months from **date of shipment** for any part or parts of the Equipment, or within one (1) year of shipment for any spare parts shipped under an Equipment order.

(f) The **Buyer must make any warranty claim by written notice** to the Product Group home office within thirty (30) days of the discovery of any defect or the claim is deemed waived.

(g) The Company reserves the right to analyze claimed defects (including return to the manufacturing location, transportation prepaid, for inspection, if required by the Company). The Company, at its option, shall repair or replace defective parts which the Company deems to be defective, Ex Works (INCOTERMS® (most recent version)) at the Product Group manufacturing location, **but shall not install or be liable for the installation of such parts**.

(h) Expenses incurred by the Buyer in replacement, repair or return of the Equipment, or of any parts, will only be reimbursed if preauthorized by the Company.

(i) This warranty is the **Buyer's exclusive remedy** and the extent of the Company's liability for breach of warranties, representations, instructions, or for defects in connection with the sale or use of the Equipment.

(j) **Warranty adjustments or replacements shall not extend the initial warranty period**.

(k) THE WARRANTY IS IN LIEU OF ALL OTHER WARRANTIES OR REPRESENTATIONS, ORAL, EXPRESS, OR IMPLIED, INCLUDING WITHOUT LIMIT WARRANTIES THAT EXTEND BEYOND THE DESCRIPTION OF THE EQUIPMENT. THERE ARE NO EXPRESS WARRANTIES OTHER THAN THOSE CONTAINED IN PARAGRAPH 5 ("LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER") AND TO THE EXTENT PERMITTED BY LAW THERE ARE NO IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

(l) **The warranty does not apply to**: expendable items; ordinary wear and tear; altered units; units repaired by persons not expressly approved by the Company; or, to damage caused by accident, the elements, abuse, misuse, temporary heat, overloading, erosive or corrosive substances, or the alien presence of oil, grease, scale, deposits or other contaminants.

(m) The warranty is conditioned upon the Equipment being properly installed, maintained and operated within its capacity, under normal load and service conditions, with competent, supervised operators and, if the Equipment uses water, with proper water conditioning.

(n) **Excluded from warranty** is damage resulting from any of: foaming caused by chemical conditions of the water; corrosion or caustic embrittlement; or improper or inadequate treatment of feedwater or conditioning of boiler water or the supply of improper or inadequate fuel. Preauthorized freight and/or labor for defective items will be reimbursed (exclusive of tasks normally performed as manufacturing location maintenance).

(o) **Warranty may be voided** by the Buyer's modifications or repairs if the Buyer proceeds without receiving the Company's technical advice. **Refractory** is inherently vulnerable to conditions of service and is warranted only to be installed as specified and the refractory is specifically excluded from any other warranty.

(p) The Equipment, accessories and other parts and components not manufactured by the Company are warranted only to the extent of and by the original manufacturer's warranty to the Company; in no event shall such other manufacturer's warranty create any more extensive warranty obligations of the Company to the Buyer than the Company's warranty covering the Equipment manufactured by the Company.

6. TERMINATION

(a) **Orders are not cancelable**.

(b) In the event of termination prior to completion, the Buyer shall pay the Company's direct and indirect costs, expenses, overhead and reasonable profit for work performed and materials purchased. Materials paid for will be available "As Is" to the Buyer without warranty; however, partially completed products are not available for completion by others.

(c) If performance by the Company of this Agreement is prohibited or significantly restricted by any governmental agencies, or by laws, rules or regulations of any government, the Company, at its option, may cancel this Agreement without liability.

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (continued)

7. EXCUSED DELAY ("FORCE MAJEURE")

(a) The Company shall not be liable for loss, damage, or failure to perform resulting from causes beyond the Company's reasonable control, or from strikes, labor difficulties, lockouts, acts or omissions of any governmental authority or the Buyer, insurrection, riot, war, fires, floods, Acts of God, breakdown of essential machinery, accidents, priorities or embargoes, tariffs, car and material shortages, delays in transportation or inability to obtain labor, materials or parts from usual sources. Any such delay shall be excused for the time reasonably necessary to compensate for the delay.

(b) If performance by the Company of this Agreement is prohibited or significantly restricted by any governmental agencies, or by laws, rules or regulations of any government, the Company, at its option, may cancel this Agreement without liability.

8. INSURANCE

(a) The Company provides certificates of insurance as required for work performed at the Product Group manufacturing location (workers compensation, commercial general liability, property). After the risk of loss of and damage to the Equipment passes to the Buyer and the Owner, until the Equipment is finally accepted and the Purchase Price is paid in full, and all obligations of the Company are concluded, the Buyer shall provide and maintain property, boiler and machinery and builders risk insurance in the names of the Buyer, the Owner and the Company, as their interests may appear, for the total value of the Equipment and for all work performed in the erection thereof, against risk of fire, lightning, windstorm, aircraft and explosion, including inherent dangers and boiler explosion. The proceeds of such insurance shall be applied first to the cost of repairing and replacing the Equipment and work destroyed or damaged.

9. BACKCHARGES

(a) Items delivered by the Company may require work or revision after shipment, whether for repair of damage (transit, unloading, handling, or damage by other contractors), adaptation to site interface conditions with existing facilities or work of other contractors, or otherwise. If the Buyer notifies and informs the Company, the Company shall promptly advise the Buyer of the applicable standards or technical guidelines for such work, and the extent of the Company's other obligations, if any, with respect to such work. The Company will use its best efforts in the circumstances to assist the Buyer to obtain resources suitable for such work. Any work the Buyer intends to be done at the Company's expense requires the Company's prior approval as to: scope; identification of who will perform such work; applicable quality standards; arrangements for the time, place and urgency of such work; an agreed price or estimate of cost; and, the opportunity for the Company to have a representative in attendance. Costs claimed for work done without prior approval shall not be accepted as backcharges.

10. TECHNICAL SUPPORT

(a) Start-up technical support, if provided by the Company, is technical advice only, and excludes on-site labor. Care, custody, control, and compliance on-site during installation and start up are the responsibility of the Buyer. Representatives of the Company are authorized only to advise and consult with the Buyer. No representative of the Company is authorized or licensed to operate the Equipment. All **preliminary operations** and demonstration of capacity and performance guarantees, if required, prior to final acceptance, shall be performed by the Buyer.

11. WORK BY OTHERS: ACCESSORY AND SAFETY DEVICES; USE BEFORE START UP

(a) The Company is a supplier of the Equipment, and shall have no responsibility for labor or work of any nature relating to the installation or operation or use of the Equipment, all of which shall be performed by the Buyer or others. The Buyer shall furnish accessory and safety devices desired by it and/or required by law or OSHA standards for the Buyer's use of the Equipment. The Buyer shall install and operate the Equipment in accordance with all code requirements and other applicable laws, rules, regulations, ordinances, and Company's specifications, operating instructions, and manuals. If damage to the Equipment or other property or injury to persons is caused by use or operation of the Equipment prior to its being placed in normal operation ("Start up"), then the Buyer shall indemnify, defend, and hold the Company harmless from all resulting claims, damages, liability, costs and expenses.

12. COMPLIANCE WITH THE LAW

(a) The Buyer shall comply with all applicable laws, regulations and ordinances.

(b) The Buyer shall maintain in effect all the licenses, permissions, authorizations, consents and permits that it needs to carry out its obligations under this Agreement.

(c) The Buyer shall comply with all export and import laws of all countries involved in the sale of the Equipment under this Agreement or any resale of the Equipment by the Buyer.

(d) The Buyer assumes all responsibility for shipments of the Equipment requiring any government import clearance.

(e) The Company may cancel this Agreement if any governmental authority imposes antidumping or countervailing duties or any other penalties on the Equipment.

(f) If any changes are required in the Equipment to meet the approval of applicable authorities, the Buyer shall inform the Company of such changes and shall reimburse it for changes made to comply.

13. LIMITED LICENSE

(a) The Buyer agrees that the Company has spent considerable time and money developing proprietary hardware and software components that are incorporated into the Equipment. Nothing in this Agreement is intended to grant or create any right or license to the Buyer to copy, reverse engineer, disclose, publish, distribute or alter any pre-existing software, patent rights, copyrights, trademarks or other intellectual property rights owned or controlled by the Company, except as necessary for the Buyer to use the Equipment in accordance with this Agreement.

14. CONFIDENTIAL INFORMATION

(a) All non-public, confidential or proprietary information of the Company, including, but not limited to, specifications, samples, patterns, software, designs, patented and unpatented intellectual property, plans, drawings, documents, data, business operations, customer lists, pricing, discounts or rebates, disclosed by the Company to the Buyer, whether disclosed orally or disclosed or accessed in written, electronic or other form or media, and whether or not marked, designated or otherwise identified as "confidential," in connection with this Agreement is confidential, solely for the use of performing under this Agreement and may not be disclosed or copied unless authorized in advance by the Company in writing.

(b) Upon the Company's request, the Buyer shall promptly return all documents and other materials received from the Company.

(c) This Paragraph ("CONFIDENTIAL INFORMATION") does not apply to information that is: (i) in the public domain; (ii) known to the Buyer at the time of disclosure; or (iii) rightfully obtained by the Buyer on a non-confidential basis from a third party.

(d) The Company shall be entitled to injunctive relief for any violation of this Paragraph ("CONFIDENTIAL INFORMATION").

15. INTELLECTUAL PROPERTY

(a) The Company shall defend the Buyer in any suits instituted against the Buyer for infringement of any claim of any United States Patent covering solely the structure of the Equipment as originally manufactured by the Company per the Company's specifications, exclusive of combination or modification by the Buyer. This obligation applies, provided that the Buyer (i) gives the Company immediate notice in writing of any such claim or institution or threat of such suit; (ii) authorizes the Company to control settlement of the same, and (iii) gives all needed information, assistance and authority to enable the Company to do so. If the Company elects to defend any such suit and the structure of the said Equipment is held to infringe any such United States Patent, and if the Buyer's use thereof is enjoined, the Company shall, at its expense and at its option: (i) obtain for the Buyer the right to continue using the Equipment, (ii) supply non-infringing Equipment for installation by the Buyer, (iii) modify the Equipment so that it becomes non-infringing, or (iv) refund the then market value of the Equipment.

(b) To the extent arising from the Company incorporating a design or modification requested by the Buyer, the Buyer shall defend and indemnify the Company against all expenses, costs, and loss by reason of any real or alleged infringement.

(c) The Company's proposal, the resultant contract, and all **proprietary or confidential information** exchanged between the Company and the Buyer in connection therewith, shall be treated as confidential and be used only for performance of the contract.

16. RELATIONSHIP OF THE PARTIES

(a) The relationship between the parties is that of independent contractors. Nothing contained in this Agreement shall be construed as creating any agency, partnership, joint venture or other form of joint enterprise, employment or fiduciary relationship between the parties and neither party shall have authority to contract for or bind the other party in any manner whatsoever. This Agreement is for the sole benefit of the parties hereto and their respective successors and permitted assigns and nothing herein, express or implied, is intended to or shall confer upon any other person or entity any legal or equitable right, benefit or remedy of any nature whatsoever under or by reason of this Agreement.

17. RESOLUTION OF DISPUTES

(a) Any waiver by a party of any right shall not be considered a continuing waiver in any other instance.

(b) Any controversy or claim arising out of or relating to this contract, or the breach thereof, and not amicably resolved within thirty (30) days from referral to senior executives of each party, or to non-binding mediation, shall be settled by arbitration administered by the **American Arbitration Association** ("AAA") under its **Commercial Arbitration Rules** (with **Expedited Procedures**), with proceedings to be held by one (1) arbitrator at a locale to be determined by an AAA Case Management Center, unless otherwise agreed, and judgement on the award rendered by the arbitrator may be entered in any court having jurisdiction thereof.

(c) This Agreement shall be construed under the internal laws of the State in which is located the Product Group home office, without regard to conflict of law principles. Except as otherwise provided in Paragraph 5 ("LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER"), any claim arising under or in connection with this Agreement shall be asserted under this provision within two (2) years after the claim arises or be forever waived and barred. Invalidity or unenforceability of one (1) or more provisions of this Agreement shall not affect any other provision of this Agreement.

18. RECOVERY OF FEES AND EXPENSES

(a) In the event arbitration or suit is brought or an attorney is retained by the Company to enforce these Terms and Conditions or to collect any money hereunder, or to collect any money damages for breach thereof, the Company shall be entitled to recover, in addition to other remedy, reimbursement for reasonable attorney's fee, court costs, costs of investigation and other related expenses incurred in connection therewith.

19. BUY AMERICAN

(a) If this purchase is subject to a mandatory "Buy American" clause, the applicable clause must be provided for review by the company before compliance may be affirmed.

(b) Products of the Company may originate in the USA, Canada, or Liechtenstein.

20. INTERNATIONAL CONVENTION

(a) The United Nations Convention on Contracts for the International Sale of Goods (1980) shall not apply to international, cross border sales of the Company.

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (continued)

21. MISCELLANEOUS

(a) THIS AGREEMENT IS THE COMPLETE AGREEMENT BETWEEN THE COMPANY AND THE BUYER AND NO ADDITIONAL OR DIFFERENT TERM OR CONDITION STATED BY THE BUYER SHALL BE BINDING UNLESS AGREED BY THE COMPANY IN WRITING.
(b) No course of prior dealings and no usage of the trade shall be relevant to supplement or explain any terms used herein.
(c) This Agreement may be modified only by a writing signed by both the Company and the Buyer and shall be governed by and construed in accordance with the internal laws of the State of Georgia without giving effect to any choice or conflict of law provision or rule (whether of the State of Georgia or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than those of the State of Georgia.
(d) The failure of the Company to insist upon strict performance of any of the terms and conditions stated herein shall not be considered a continuing waiver of any such term or condition or any of the Company's rights. If any term or provision of this Agreement is invalid, illegal or unenforceable in any jurisdiction, such invalidity, illegality or unenforceability shall not affect any other term or provision of this Agreement or invalidate or render unenforceable such term or provision in any other jurisdiction.

22. PRODUCT GROUP CONDITIONS

(a) Supplemental conditions (below) also apply for The Cleaver-Brooks Company, Inc. Product Groups.

SUPPLEMENTAL CONDITIONS for the PACKAGED BOILER SYSTEMS PRODUCT GROUP

These provisions amend the indicated articles of THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (above)

[Add to **2. TERMS AND PRICES**]

[Add to 2.a] The **performance milestones for payment** for projects valued at or above $250,000 are as follows unless otherwise indicated in the Proposal to which these conditions are attached:
(i) Upon Issuance of Submittals:........ **20%** of the Contract Price (Net 30 Days)
(ii) Upon Release for Production: .... **30%** of the Contract Price (Net 30 Days)
(iii) Upon Readiness for Shipment: .... **50%** of the Contract Price (Net 30 Days)

[Add to **6. TERMINATION**]

(d) If the Buyer's circumstances change after an order is accepted, and the Buyer is unable to use ordered items or similar items, then subject to the Company's express written consent, the buyer may **return for credit** such unneeded items as have been delivered under the order, which will be accepted as returns if they are unused, undamaged, and current inventory, subject to the normal restocking charge.

23. CANCELLATION SCHEDULE

(a) The cancellation schedule for projects is as follows unless otherwise indicated in the Proposal to which these conditions are attached:
(i) After Receipt of Purchase Order: .... Up to **25%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
(ii) 1-30 Days After Drawing Approval: .... Up to **50%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
(iii) Over 30 Days After Drawing Approval: .... Up to **75%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
(iv) After Final Assembly: .... Up to **100%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)

SUPPLEMENTAL CONDITIONS for the ENGINEERED BOILER SYSTEMS PRODUCT GROUP

These provisions amend the indicated articles of THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (above)

[Add to **2. TERMS AND PRICES**]

[Add to 2.a] The **performance milestones for payment** for projects valued at or above $250,000 are as follows unless otherwise indicated in the Proposal to which these conditions are attached:
(i) Upon Receipt of Purchase Order: .... **10%** of the Contract Price (Net 30 Days)
(ii) Upon Issuance of Drawing Submittals (Mechanical GA and P&ID Drawings):........ **30%** of the Contract Price (Net 30 Days)
(iii) Upon Completion of Hydrostatic Test:........ **35%** of the Contract Price (Net 30 Days)
(iv) Upon Readiness for Shipment: .... **25%** of the Contract Price (Net 30 Days)

[Add to 2.b] If the price includes **allowed transportation or other shipping charges**, then increases in transportation rates, demurrage, special detention, or other shipping charges, occurring after the date of quotation shall be added to the Purchase Price.

[Add to 2.c] The Company may, but shall not be obligated to, incorporate into the Equipment any **upgrades or applicable changes in the Company's standard specifications**, design, construction, arrangement or components.

[Add to **3. DELIVERY**]

[Add to 2.b] The Company will endeavor to make shipment of orders as scheduled; however, all shipment dates are approximate only, and the Company reserves the right to readjust shipment schedules.

24. CANCELLATION SCHEDULE

(a) The cancellation schedule for projects is as follows unless otherwise indicated in the Proposal to which these conditions are attached:
(i) Up to 14 Days After Receipt of Purchase Order:........ **0%** of the Contract Price (Net 30 Days)
(ii) Over 14 Days After Receipt of Purchase Order: .... **25%** of the Contract Price (Net 30 Days)
(iii) Up to 30 Days After Drawing Approval:........ **45%** of the Contract Price (Net 30 Days)
(iv) 31-60 Days After Drawing Approval: .... **55%** of the Contract Price (Net 30 Days)
(v) 61-90 Days After Drawing Approval: .... **75%** of the Contract Price (Net 30 Days)
(vi) Over 90 Days After Drawing Approval: .... **100%** of the Contract Price (Net 30 Days)

25. FOUNDATIONS

(a) The Company shall provide the Buyer with General Arrangement drawings showing the Equipment with reference to foundations, including loading diagrams.
(b) The Company shall not be responsible for the depth of the footings, size or accuracy of the foundations or anchor bolts, or the character of the materials selected for their construction.
(c) Adequate foundations, having plan measurements in accordance with such drawings including foundation bolts and plates, concrete work, all grouting, and excavation, shall be furnished in place in due time by the Buyer.
(d) The Company shall not be responsible for any damages, or repairs necessary to the Equipment furnished by it, caused by or resulting from defects in or settlement of the foundations.

26. SUPPORTING STEEL

(a) Unless otherwise stated, any supporting steel to be furnished by the Company as specified in this Proposal will be designed to support the Equipment which the Company proposes to furnish and will be designed in accordance with the latest Rules of the American Institute of Steel Construction.
(b) If the Company is required to increase the size or weight of its supporting structures to conform to other than the Rules of the American Institute of Steel Construction or because of additional loadings imposed by the Buyer, the Buyer shall reimburse the Company for the additional steel and work required.

ATTACHMENT D-2

Cost Effectiveness Calculation

Emission Unit/Control Technology

Emission Unit	A06
Emission Unit Description	Nationwide/Nebraska Boiler
Control Technology	Low NO_x Burner with FGR
Emission Reduction[1] (%)	33%
Baseline Emission Rate[2] (tons/year)	0.72

Annualized Capital Costs

Initial Capital Investment[3]	$557,629
Direct & Indirect Costs[4]	$0
Total Capital Investment	$557,629
Estimated Equipment Life (years)	10
Interest Rate (%)	6.0%
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$75,764

Annual Operating Costs

Total Annual Operating Cost	$0
Total Annualized Cost	$75,764

Cost Effectiveness

Emissions Reduction (tons/year)	0.24
Cost Effectiveness of NOx Reduction (per	$315,683

Notes:
[1] NO_x emissions reduced from 30 ppm to 20 ppm.
[2] Actual emissions for 2020 (max of 2019 - 2021).
[3] Cost based on vendor estimate.
[4] Installation, startup and testing (accounted for in vendor estimate).

CleaverBrooks®

Budget Proposal

Saguaro Power Burner Retrofit

To: Scott Mcnulty
Principal Geologist
Broadbent Air Quality Division
8 W Pacific Ave,
Henderson, NV 89015 United States
(702) 563-0600
Smcnulty@broadbentinc.com

From: Ryland Whitaker
R.F. MacDonald Company
6651 Schuster Street

Las Vegas, NV 89118 United States
(725)229-3368
ryland.whitaker@rfmacdonald.com

September 28, 2022

Dear Scott,

Through a steadfast commitment to research, development, strategic acquisitions, and a focus on providing boiler room solutions for more than 80 years, Cleaver-Brooks is the sole provider of integrated boiler, burner, and controls solutions. With the #1 market share in North America, Cleaver-Brooks is the global leader in designing and manufacturing integrated boiler room systems, and the Cleaver-Brooks brand is globally synonymous with the highest quality, best reliability, and creative innovation in boiler room solutions. Industry-leading proprietary burners, controls, components, and accessories engineered by Cleaver-Brooks perform together seamlessly at peak energy and emissions efficiency.

Cleaver-Brooks offers the broadest range of integrated boiler room systems, subsystems, components and accessories in the market, giving it a distinct competitive advantage as a complete solutions provider across commercial, industrial, and institutional markets. A principal component of the Cleaver-Brooks strategy is to offer the most advanced and completely integrated boiler room systems that satisfy diverse energy demands, high-efficiency performance, ultra-low emissions, safety, reliability, and convenience from utilizing a single-source manufacturer.

From the Power of Total Integration, Cleaver-Brooks offers boiler room systems including mission-critical subsystems performing water treatment, heat recovery, integrated system controls, and maintained by a worldwide dedicated sales and service representative network. All sales and service representatives employ trained technicians to provide first-class routine maintenance and repair services in accordance with national, state/provincial, and local codes and standards.

As a Cleaver-Brooks Representative Association (CBRA) member near you, R.F. MacDonald Company has produced this proposal from your system requirements and equipment specifications. At your convenience, please review this proposal, and contact me regarding any questions or comments.

Sincerely,

Ryland Whitaker
R.F. MacDonald Company
6651 Schuster Street
Las Vegas, NV 89118 United States
(725)229-3368
ryland.whitaker@rfmacdonald.com

CleaverBrooks®

System Requirements

Proposal Number: 29850248 / Proposal Date: 09/16/22

Job Name: Saguaro Power Burner Retrofit / Project Name: Saguaro Power Burner Retrofit

Configurable Burner

NCB Burner System

- For new boilers or retrofit applications/hr
- Natural Gas and light oil firing/hr
- Millions of configurations possible to satisfy your specific needs
- Available to < 30 ppm NOx, < 50 ppm CO
- 12 to 360 MMBTU/hr

The NCB burner is a unique packaged burner system for new boilers and retrofit markets. These burners use advanced CFD modeling, and are equipped with advanced Natcom® design features, including externally adjustable gas injectors, Class-III igniters, atomizers with coupling block valves, which you can complement with your choice among a variety of industrial-grade controls, valves, switches, and gauges.

Natcom® burners feature emissions reductions of 50% compared to flaring and can achieve emissions goals of 9 ppm NOx. The high-efficiency burner design is engineered for multi-fuel firing, including renewables.

NCB-085 Burner

Technical Data Sheet

For indoor applications, uncontrolled or 30 ppm NOx emissions

85 MM BTU/H NG; 81 MM BTU/H #2 OIL

Designed for furnace dimensions of at least:	Physical arrangement:	Combustion Control System (CCS) compatibility options:	Fuel Options:	Choice of NFPA or CSA compliance for U.S. or Canadian units, respectively (contact us for TSSA compliance).
H=8.97' W=6.69' Lturn=15.33' Ltot=18.00'	FD fan, fuel train and control panel are windbox mounted. Right- or left-hand drum arrangements available.	Fully Metered (FM), Parallel Positioning (PP) and Single Point Positioning (SP). All systems use 4-20mA and pneumatic actuators.	Main Fuel: Natural gas and/or #2 oil. Igniter fuel: Natural gas and/or propane.	

Performance guarantees

	NG, no FGR	#2 Oil, no FGR	NG, 12% FGR	#2 Oil, 12% FGR
Excess Air %*	15	15	15	15
NOx emissions ppmvd @3%O_2	70	110	30	75
CO emissions ppmvd @3%O_2	50	75	50	75
VOC lb/MM BTU (HHV)	0.004	0.004	0.004	0.004
Total PM lb/MM BTU (HHV)	0.01	0.05	0.01	0.05
Turndown	10	8	10	8

Performance guarantees are based on normal operating conditions and valid from 25% to 100% MCR, boiler with gas tight furnace division wall and to nominal operating pressure and temperature. Igniter emissions are not guaranteed. For application where CB does not provide the controls, emissions are guaranteed in manual mode only. SOx emissions are not burner dependent and depend solely on the sulfur content of the fuel. Burner/boiler systems are not intended for automatic recycling use. Fan motors of 100 HP and above are only offered with manual start/stop control. Please contact your local representative for more details.

*Excess air given for MCR only.

CleaverBrooks

Budget Quote Summary

Proposal Number: 29850248 / Proposal Date: 09/16/22

Job Name: Saguaro Power Burner Retrofit / Project Name: Saguaro Power Burner Retrofit

Product Model: NATCOM		
Item	**Qty.**	**Description**
#1	1	**Reference: 1** Configured in the Custom NATCOM program.
#2	1	Burner Model: NCB-230
#3	1	Fuels Included: Gas
#4	1	Burner Heat Input (MMBTU/hr): 85
#5	1	Guaranteed NOx Emissions, Gas (PPM @3% O2): 30
#6	1	Type of Control: Full Metering
#7	1	Burner Fan Motor HP: 150
#8	1	Burner Fan Location: Windbox Mounted
#9	1	Available Gas Pressure at Regulator Inlet: 25 - 40 psig
#10	1	Oil Pressure Required @ Train Inlet: 150 psig
#11	1	Turndown on Natural Gas: 10:1
#12	1	Turndown Firing Oil: 8:1
#13	1	Variable Frequency Drive Included: Y
#14	1	O2 Trims: Yes
#15	1	Boiler Control Model: HAWK 4500
#16	1	Ambient Temperature Range: 50 - 100 °F
#17	1	Site Elevation: < 2500 ft ASL
		Product Price to Customer (USD): $

Budget Quote Summary

Proposal Number: 29850248 / Proposal Date: 09/16/22

Job Name: Saguaro Power Burner Retrofit / Project Name: Saguaro Power Burner Retrofit

Item	Qty.	Product Model	PTC (USD)
#1	1	NATCOM	$507.629.00
		Subtotal Price to Customer (USD):	$507,629.00
		Cost Adder for 20ppm(USD):	$50,000.00
		Freight (EXW - Ex Works Factory) Cost (USD):	NA
		Total Price to Customer (USD):	$557,629.00

CLEAVER-BROOKS OFFERING

Cleaver-Brooks offers to furnish the Equipment described herein for the purchase price noted, exclusive of all taxes. Prices quoted are firm for 30 days from the date of the Cleaver-Brooks Proposal subject to adjustment as noted. Standard Cleaver-Brooks **payment terms** are *unconditional net 30 from the date of readiness for shipment or unless otherwise specified in this Proposal*. Cleaver-Brooks will review your order prior to acceptance (and acknowledgment) and order entry. Until acceptance and order entry, the Equipment is **subject to prior sale**. Incorporation of technical specifications or requirements different from or additional to the Cleaver-Brooks Proposal and not previously reviewed by Cleaver-Brooks will extend the order review process and may postpone or prevent acceptance of your order and order entry. Cleaver-Brooks does not agree and will not agree to **INCIDENTAL, CONSEQUENTIAL AND LIQUIDATED DAMAGES OR IMPLIED WARRANTIES**. Cleaver-Brooks does not agree and will not agree to, unless specifically set forth in an agreement in writing having an authorized Cleaver-Brooks signature: (1) **terms and conditions** in your order that are different from or additional to those of the Cleaver-Brooks Proposal; (2) **technical specifications**, technical requirements or descriptions of the goods and services ordered that are different from or additional to those of the Cleaver-Brooks Proposal; or (3) **generalized expressions** such as "per plans and specifications."

CLEAVER-BROOKS PRICE ADJUSTMENT POLICY

The price quoted in the Cleaver-Brooks Proposal is firm for thirty (30) days from the Proposal date if shipment of the Equipment is made within six (6) months from the date of the Cleaver-Brooks Proposal or contract document if no Proposal was issued. If the Equipment is not shipped within such six (6) months, the contract price shall be increased by one percent (1%) for each thirty (30) days or fraction thereof that shipment is deferred beyond six (6) months from the date of the Cleaver-Brooks Proposal or contract document.

PROPOSED PAYMENT TERMS

Amount At or Exceeds $250,000: Yes
Payment Terms: Progress Payments
Terms Description:

Note: May require Cleaver-Brooks review if other than 20%/30%/50% referenced in ¶ 1(a).

PROPOSED SHIPPING TERMS

[x] EXW – Ex Works Factory
[ ] CIP – Carriage and Insurance Paid to
[ ] OTHER:______________________________
Freight Allowed To Location:______________________________

Note: Freight unloading by others.

BUYER OF CLEAVER-BROOKS EQUIPMENT

____
Buyer Representative - Printed First and Last Name

____
Buyer Representative - Company Name

,
____
Buyer Representative - Company Address, State/Province, Area Code, and Country

____
Buyer Representative - Phone Number

____
Buyer Representative - Email Address

____
Buyer Representative - Signature

/ /
Buyer Representative - Date Accepted (MM/DD/YYYY)

CLEAVER-BROOKS SALES REPRESENTATIVE

Ryland Whitaker
Sales Representative - Printed First and Last Name

R.F. MacDonald Company
Sales Representative - Company Name

10261 MATERN PLACE
SANTA FE SPRINGS, CA 90670
United States
Sales Representative - Company Address, State/Province, Area Code, and Country

(725)229-3368
Sales Representative - Phone Number

ryland.whitaker@rfmacdonald.com
Sales Representative - Email Address

____
Sales Representative - Signature

09/16/22
Sales Representative - Date Offered

CLEAVER-BROOKS TERMS AND CONDITIONS OF SALE ON NEXT PAGE

Terms and Conditions of Sale

Date Revised: July 23, 2021

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE

1. OFFER AND CONTRACT

(a) Through its proposal (the "Proposal") The Cleaver-Brooks Company, Inc. (the "Company") offers to sell its products, systems or parts (the "Equipment") for the purchase price (the "Purchase Price") on these terms and conditions of sale.

(b) UPON WRITTEN ACCEPTANCE OF THE PROPOSAL BY THE BUYER, THE PROPOSAL AND THESE TERMS CONSTITUTE THE COMPLETE AGREEMENT BETWEEN THE COMPANY AND THE BUYER ("THIS AGREEMENT"). ANY ADDITIONAL OR DIFFERENT TERMS ARE REJECTED UNLESS AGREED TO BY THE COMPANY IN A SIGNED AMENDMENT AFTER REVIEW AT THE PRODUCT GROUP HOME OFFICE.

(c) Except as indicated below, this **Proposal is valid for thirty (30) days** subject to written withdrawal by the Company at any time prior to receipt of written acceptance by the Buyer.

(d) The Purchase Price and any delivery dates of this Proposal are **subject to prior sales that occur before written acceptance by the Buyer and increased material costs**.

(e) Orders received are scheduled for production as proposals are accepted in writing by the Buyer.

(f) If at the time the Product Group home office receives a written acceptance of a proposal, and the then available production lead time at the Product Group manufacturing location does not allow for shipment within the number of weeks offered in the Proposal, then the Purchase Price and any delivery dates shall be adjusted based upon the next available production and delivery dates.

2. TERMS AND PRICES

(a) Standard terms of payment are thirty (30) days net from the date of invoice for completion of performance milestones for payment, including readiness of the Equipment for shipment. Partial shipments of units under multiple unit orders shall be invoiced and paid separately. The Company will waive lien rights and release payment claims to the extent of payments received. The Company may require a letter of credit from the Buyer.

(b) Any excise, sales, privilege, use or any other local, state, or federal taxes which the Company may be required to pay, arising from the sale, delivery, or use of the Equipment and any applicable prepaid freight, will be added to the Purchase Price and invoiced separately.

(c) If the Buyer requests changes in scope or schedule, or if the Buyer delays production or shipment of the Equipment, the Purchase Price and any delivery dates shall be equitably adjusted to reflect changes caused thereby.

(d) Availability and costs of any proposed surety bonding (or other financial securities) are determined by providers thereof at the time of award and the costs of such surety bonding shall be added to the Purchase Price. The Company does not commit to provide a particular financial security. All financial securities issued will be subject to agreed expiration dates, and reduce in amount as performance milestones are accomplished.

(e) The Buyer shall pay **interest on all late payments** at the lesser rate of 1.5% per month or the highest rate permissible under applicable law, calculated daily and compounded monthly.

(f) The Buyer shall reimburse the Company for all costs incurred in collecting any late payments, including, without limitation, attorney's fees.

(g) The Buyer shall not withhold payment of any amounts due and payable by reason of any set-off of any claim or dispute with the Company, whether relating to the Company's breach, bankruptcy, or otherwise. The Company shall not be liable for any claim by the Buyer unless and until such claim is finally adjudicated through the dispute resolution process.

(h) The Purchase Price is subject to increase before written acceptance of the Proposal by the Buyer based upon an increase of the CRU USA Midwest FOB Mill index.

(i) In addition to all other remedies available under this Agreement or at law (which the Company does not waive by the exercise of any rights hereunder), the Company shall be entitled to suspend the manufacture and/or delivery of any Equipment if the Buyer fails to pay any Company invoice within thirty (30) days of the date of the invoice.

3. DELIVERY

(a) Unless otherwise offered in this Proposal, delivery is Ex Works (INCOTERMS® (most recent version)), at the Product Group manufacturing location ("the Delivery Point").

(b) The estimated shipment date is based upon timely receipt by the Company of **Buyer's applicable information**, and of **Buyer's written approval**, or detailed exceptions to, the Company's general arrangement drawings within ten (10) business days of receipt.

(c) If the **Buyer requests to defer delivery** dates by a written request adequate to support GAAP requirements for revenue recognition by the Company, or if the Buyer fails to promptly accept the Equipment tendered for delivery, or shipment of the Equipment is otherwise delayed by causes beyond the Company's reasonable control, the following conditions shall apply: (i) payments due upon shipment (or "delivery") shall be invoiced, due and payable upon "readiness to ship;" (ii) all financial securities required of the Company shall be released based upon "readiness to ship", (iii) the Buyer shall pay reasonable storage and handling charges incurred by the Company on the Buyer's behalf in the circumstances; (iv) risk of loss shall transfer to the Buyer upon "readiness to ship," (v) the Buyer shall be responsible for insuring the Equipment, and (vi) the Buyer shall inspect at delivery and give notice as soon as practical of any loss, damage or shortage evident by visual inspection and quantity count.

4. TITLE AND RISK OF LOSS

(a) Title and risk of loss passes to the Buyer upon the Company's delivery of the Equipment to the Delivery Point. If for any reason the Buyer (or the Buyer's transporting carrier) fails to accept delivery of the Equipment on the date on which the Equipment has been delivered to the Delivery Point or if the Company is unable to ship the Equipment because the Buyer (or the Buyer's transporting carrier) has not provided appropriate instructions, documents, licenses or authorizations: (i) risk of loss to the Equipment shall pass to the Buyer; (ii) the Equipment shall be deemed to have been delivered.

(b) As collateral security for the payment of the Purchase Price of the Equipment, the Buyer hereby grants to the Company a lien on and security interest in and to all of the right, title and interest of the Buyer in, to and under the Equipment, wherever located, and whether now existing or hereafter arising or acquired from time to time, and in all accessions thereto and replacements or modifications thereof, as well as all proceeds (including insurance proceeds) of the foregoing. The security interest granted under this provision constitutes a purchase money security interest under the Georgia Uniform Commercial Code.

5. LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER

(a) THE COMPANY SHALL NOT BE LIABLE FOR ANY SPECIAL, INCIDENTAL, INDIRECT, EXEMPLARY, PUNITIVE, OR CONSEQUENTIAL DAMAGES (INCLUDING WITHOUT LIMIT LOST PROFITS, PRODUCTIVITY LOSSES, ECONOMIC LOSSES, OR BUSINESS DOWNTIME) OR FOR ANY SUCH LOSS, DAMAGE, EXPENSE, DIRECTLY OR INDIRECTLY ARISING FROM THE USE OF THE EQUIPMENT, SERVICES, SPARE OR REPLACEMENT PARTS, OR FROM ANY OTHER CAUSE WHETHER BASED IN WARRANTY, NEGLIGENCE, TORT, CONTRACT OR OTHERWISE, AND REGARDLESS OF ANY ADVICE OR RECOMMENDATION THAT MAY HAVE BEEN RENDERED CONCERNING THE PURCHASE, INSTALLATION OR USE OF THE EQUIPMENT, SERVICES, SPARE OR REPLACEMENT PARTS WHETHER OR NOT HAVING BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

(b) THE BUYER HEREBY RELEASES THE COMPANY OF ANY SUCH LIABILITY AND COVENANTS NOT TO SUE THE COMPANY FOR ANY SUCH DAMAGES.

(c) IN NO EVENT SHALL THE COMPANY'S AGGREGATE LIABILITY UNDER ANY CIRCUMSTANCES EXCEED AN AMOUNT EQUAL TO THE PURCHASE PRICE OF THE EQUIPMENT.

(d) The Company warrants that at the time of delivery the Equipment will conform to the Company's applicable specifications and to such contract specifications as are agreed to by the Company.

(e) The warranty runs for a period of twelve (12) months from the **date of initial operation** but no more than eighteen (18) months from **date of shipment** for any part or parts of the Equipment, or within one (1) year of shipment for any spare parts shipped under an Equipment order.

(f) The **Buyer must make any warranty claim by written notice** to the Product Group home office within thirty (30) days of the discovery of any defect or the claim is deemed waived.

(g) The Company reserves the right to analyze claimed defects (including return to the manufacturing location, transportation prepaid, for inspection, if required by the Company). The Company, at its option, shall repair or replace defective parts which the Company deems to be defective, Ex Works (INCOTERMS® (most recent version)) at the Product Group manufacturing location, **but shall not install or be liable for the installation of such parts**.

(h) Expenses incurred by the Buyer in replacement, repair or return of the Equipment, or of any parts, will only be reimbursed if preauthorized by the Company.

(i) This warranty is the **Buyer's exclusive remedy** and the extent of the Company's liability for breach of warranties, representations, instructions, or for defects in connection with the sale or use of the Equipment.

(j) **Warranty adjustments or replacements shall not extend the initial warranty period**.

(k) THE WARRANTY IS IN LIEU OF ALL OTHER WARRANTIES OR REPRESENTATIONS, ORAL, EXPRESS, OR IMPLIED, INCLUDING WITHOUT LIMIT WARRANTIES THAT EXTEND BEYOND THE DESCRIPTION OF THE EQUIPMENT. THERE ARE NO EXPRESS WARRANTIES OTHER THAN THOSE CONTAINED IN PARAGRAPH 5 ("LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER") AND TO THE EXTENT PERMITTED BY LAW THERE ARE NO IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

(l) **The warranty does not apply to**: expendable items; ordinary wear and tear; altered units; units repaired by persons not expressly approved by the Company; or, to damage caused by accident, the elements, abuse, misuse, temporary heat, overloading, erosive or corrosive substances, or the alien presence of oil, grease, scale, deposits or other contaminants.

(m) The warranty is conditioned upon the Equipment being properly installed, maintained and operated within its capacity, under normal load and service conditions, with competent, supervised operators and, if the Equipment uses water, with proper water conditioning.

(n) **Excluded from warranty** is damage resulting from any of: foaming caused by chemical conditions of the water; corrosion or caustic embrittlement; or improper or inadequate treatment of feedwater or conditioning of boiler water or the supply of improper or inadequate fuel. Preauthorized freight and/or labor for defective items will be reimbursed (exclusive of tasks normally performed as manufacturing location maintenance).

(o) **Warranty may be voided** by the Buyer's modifications or repairs if the Buyer proceeds without receiving the Company's technical advice. **Refractory** is inherently vulnerable to conditions of service and is warranted only to be installed as specified and the refractory is specifically excluded from any other warranty.

(p) The Equipment, accessories and other parts and components not manufactured by the Company are warranted only to the extent of and by the original manufacturer's warranty to the Company; in no event shall such other manufacturer's warranty create any more extensive warranty obligations of the Company to the Buyer than the Company's warranty covering the Equipment manufactured by the Company.

6. TERMINATION

(a) **Orders are not cancelable**.

(b) In the event of termination prior to completion, the Buyer shall pay the Company's direct and indirect costs, expenses, overhead and reasonable profit for work performed and materials purchased. Materials paid for will be available "As Is" to the Buyer without warranty; however, partially completed products are not available for completion by others.

(c) If performance by the Company of this Agreement is prohibited or significantly restricted by any governmental agencies, or by laws, rules or regulations of any government, the Company, at its option, may cancel this Agreement without liability.

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (continued)

7. EXCUSED DELAY ("FORCE MAJEURE")

(a) The Company shall not be liable for loss, damage, or failure to perform resulting from causes beyond the Company's reasonable control, or from strikes, labor difficulties, lockouts, acts or omissions of any governmental authority or the Buyer, insurrection, riot, war, fires, floods, Acts of God, breakdown of essential machinery, accidents, priorities or embargoes, tariffs, car and material shortages, delays in transportation or inability to obtain labor, materials or parts from usual sources. Any such delay shall be excused for the time reasonably necessary to compensate for the delay.

(b) If performance by the Company of this Agreement is prohibited or significantly restricted by any governmental agencies, or by laws, rules or regulations of any government, the Company, at its option, may cancel this Agreement without liability.

8. INSURANCE

(a) The Company provides certificates of insurance as required for work performed at the Product Group manufacturing location (workers compensation, commercial general liability, property). After the risk of loss of and damage to the Equipment passes to the Buyer and the Owner, until the Equipment is finally accepted and the Purchase Price is paid in full, and all obligations of the Company are concluded, the Buyer shall provide and maintain property, boiler and machinery and builders risk insurance in the names of the Buyer, the Owner and the Company, as their interests may appear, for the total value of the Equipment and for all work performed in the erection thereof, against risk of fire, lightning, windstorm, aircraft and explosion, including inherent dangers and boiler explosion. The proceeds of such insurance shall be applied first to the cost of repairing and replacing the Equipment and work destroyed or damaged.

9. BACKCHARGES

(a) Items delivered by the Company may require work or revision after shipment, whether for repair of damage (transit, unloading, handling, or damage by other contractors), adaptation to site interface conditions with existing facilities or work of other contractors, or otherwise. If the Buyer notifies and informs the Company, the Company shall promptly advise the Buyer of the applicable standards or technical guidelines for such work, and the extent of the Company's other obligations, if any, with respect to such work. The Company will use its best efforts in the circumstances to assist the Buyer to obtain resources suitable for such work. Any work the Buyer intends to be done at the Company's expense requires the Company's prior approval as to: scope; identification of who will perform such work; applicable quality standards; arrangements for the time, place and urgency of such work; an agreed price or estimate of cost; and, the opportunity for the Company to have a representative in attendance. Costs claimed for work done without prior approval shall not be accepted as backcharges.

10. TECHNICAL SUPPORT

(a) Start-up technical support, if provided by the Company, is technical advice only, and excludes on-site labor. Care, custody, control, and compliance on-site during installation and start up are the responsibility of the Buyer. Representatives of the Company are authorized only to advise and consult with the Buyer. No representative of the Company is authorized or licensed to operate the Equipment. All **preliminary operations** and demonstration of capacity and performance guarantees, if required, prior to final acceptance, shall be performed by the Buyer.

11. WORK BY OTHERS: ACCESSORY AND SAFETY DEVICES; USE BEFORE START UP

(a) The Company is a supplier of the Equipment, and shall have no responsibility for labor or work of any nature relating to the installation or operation or use of the Equipment, all of which shall be performed by the Buyer or others. The Buyer shall furnish accessory and safety devices desired by it and/or required by law or OSHA standards for the Buyer's use of the Equipment. The Buyer shall install and operate the Equipment in accordance with all code requirements and other applicable laws, rules, regulations, ordinances, and Company's specifications, operating instructions, and manuals. If damage to the Equipment or other property or injury to persons is caused by use or operation of the Equipment prior to its being placed in normal operation ("Start up"), then the Buyer shall indemnify, defend, and hold the Company harmless from all resulting claims, damages, liability, costs and expenses.

12. COMPLIANCE WITH THE LAW

(a) The Buyer shall comply with all applicable laws, regulations and ordinances.

(b) The Buyer shall maintain in effect all the licenses, permissions, authorizations, consents and permits that it needs to carry out its obligations under this Agreement.

(c) The Buyer shall comply with all export and import laws of all countries involved in the sale of the Equipment under this Agreement or any resale of the Equipment by the Buyer.

(d) The Buyer assumes all responsibility for shipments of the Equipment requiring any government import clearance.

(e) The Company may cancel this Agreement if any governmental authority imposes antidumping or countervailing duties or any other penalties on the Equipment.

(f) If any changes are required in the Equipment to meet the approval of applicable authorities, the Buyer shall inform the Company of such changes and shall reimburse it for changes made to comply.

13. LIMITED LICENSE

(a) The Buyer agrees that the Company has spent considerable time and money developing proprietary hardware and software components that are incorporated into the Equipment. Nothing in this Agreement is intended to grant or create any right or license to the Buyer to copy, reverse engineer, disclose, publish, distribute or alter any pre-existing software, patent rights, copyrights, trademarks or other intellectual property rights owned or controlled by the Company, except as necessary for the Buyer to use the Equipment in accordance with this Agreement.

14. CONFIDENTIAL INFORMATION

(a) All non-public, confidential or proprietary information of the Company, including, but not limited to, specifications, samples, patterns, software, designs, patented and unpatented intellectual property, plans, drawings, documents, data, business operations, customer lists, pricing, discounts or rebates, disclosed by the Company to the Buyer, whether disclosed orally or disclosed or accessed in written, electronic or other form or media, and whether or not marked, designated or otherwise identified as "confidential," in connection with this Agreement is confidential, solely for the use of performing under this Agreement and may not be disclosed or copied unless authorized in advance by the Company in writing.

(b) Upon the Company's request, the Buyer shall promptly return all documents and other materials received from the Company.

(c) This Paragraph ("CONFIDENTIAL INFORMATION") does not apply to information that is: (i) in the public domain; (ii) known to the Buyer at the time of disclosure; or (iii) rightfully obtained by the Buyer on a non-confidential basis from a third party.

(d) The Company shall be entitled to injunctive relief for any violation of this Paragraph ("CONFIDENTIAL INFORMATION").

15. INTELLECTUAL PROPERTY

(a) The Company shall defend the Buyer in any suits instituted against the Buyer for infringement of any claim of any United States Patent covering solely the structure of the Equipment as originally manufactured by the Company per the Company's specifications, exclusive of combination or modification by the Buyer. This obligation applies, provided that the Buyer (i) gives the Company immediate notice in writing of any such claim or institution or threat of such suit; (ii) authorizes the Company to control settlement of the same, and (iii) gives all needed information, assistance and authority to enable the Company to do so. If the Company elects to defend any such suit and the structure of the said Equipment is held to infringe any such United States Patent, and if the Buyer's use thereof is enjoined, the Company shall, at its expense and at its option: (i) obtain for the Buyer the right to continue using the Equipment, (ii) supply non-infringing Equipment for installation by the Buyer, (iii) modify the Equipment so that it becomes non-infringing, or (iv) refund the then market value of the Equipment.

(b) To the extent arising from the Company incorporating a design or modification requested by the Buyer, the Buyer shall defend and indemnify the Company against all expenses, costs, and loss by reason of any real or alleged infringement.

(c) The Company's proposal, the resultant contract, and all **proprietary or confidential information** exchanged between the Company and the Buyer in connection therewith, shall be treated as confidential and be used only for performance of the contract.

16. RELATIONSHIP OF THE PARTIES

(a) The relationship between the parties is that of independent contractors. Nothing contained in this Agreement shall be construed as creating any agency, partnership, joint venture or other form of joint enterprise, employment or fiduciary relationship between the parties and neither party shall have authority to contract for or bind the other party in any manner whatsoever. This Agreement is for the sole benefit of the parties hereto and their respective successors and permitted assigns and nothing herein, express or implied, is intended to or shall confer upon any other person or entity any legal or equitable right, benefit or remedy of any nature whatsoever under or by reason of this Agreement.

17. RESOLUTION OF DISPUTES

(a) Any waiver by a party of any right shall not be considered a continuing waiver in any other instance.

(b) Any controversy or claim arising out of or relating to this contract, or the breach thereof, and not amicably resolved within thirty (30) days from referral to senior executives of each party, or to non-binding mediation, shall be settled by arbitration administered by the **American Arbitration Association** ("AAA") under its **Commercial Arbitration Rules** (with **Expedited Procedures**), with proceedings to be held by one (1) arbitrator at a locale to be determined by an AAA Case Management Center, unless otherwise agreed, and judgement on the award rendered by the arbitrator may be entered in any court having jurisdiction thereof.

(c) This Agreement shall be construed under the internal laws of the State in which is located the Product Group home office, without regard to conflict of law principles. Except as otherwise provided in Paragraph 5 ("LIMITATION OF LIABILITY; LIMITED WARRANTY; WARRANTY DISCLAIMER"), any claim arising under or in connection with this Agreement shall be asserted under this provision within two (2) years after the claim arises or be forever waived and barred. Invalidity or unenforceability of one (1) or more provisions of this Agreement shall not affect any other provision of this Agreement.

18. RECOVERY OF FEES AND EXPENSES

(a) In the event arbitration or suit is brought or an attorney is retained by the Company to enforce these Terms and Conditions or to collect any money hereunder, or to collect any money damages for breach thereof, the Company shall be entitled to recover, in addition to other remedy, reimbursement for reasonable attorney's fee, court costs, costs of investigation and other related expenses incurred in connection therewith.

19. BUY AMERICAN

(a) If this purchase is subject to a mandatory "Buy American" clause, the applicable clause must be provided for review by the company before compliance may be affirmed.

(b) Products of the Company may originate in the USA, Canada, or Liechtenstein.

20. INTERNATIONAL CONVENTION

(a) The United Nations Convention on Contracts for the International Sale of Goods (1980) shall not apply to international, cross border sales of the Company.

THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (continued)

21. MISCELLANEOUS

(a) THIS AGREEMENT IS THE COMPLETE AGREEMENT BETWEEN THE COMPANY AND THE BUYER AND NO ADDITIONAL OR DIFFERENT TERM OR CONDITION STATED BY THE BUYER SHALL BE BINDING UNLESS AGREED BY THE COMPANY IN WRITING.

(b) No course of prior dealings and no usage of the trade shall be relevant to supplement or explain any terms used herein.

(c) This Agreement may be modified only by a writing signed by both the Company and the Buyer and shall be governed by and construed in accordance with the internal laws of the State of Georgia without giving effect to any choice or conflict of law provision or rule (whether of the State of Georgia or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than those of the State of Georgia.

(d) The failure of the Company to insist upon strict performance of any of the terms and conditions stated herein shall not be considered a continuing waiver of any such term or condition or any of the Company's rights. If any term or provision of this Agreement is invalid, illegal or unenforceable in any jurisdiction, such invalidity, illegality or unenforceability shall not affect any other term or provision of this Agreement or invalidate or render unenforceable such term or provision in any other jurisdiction.

22. PRODUCT GROUP CONDITIONS

(a) Supplemental conditions (below) also apply for The Cleaver-Brooks Company, Inc. Product Groups.

SUPPLEMENTAL CONDITIONS for the PACKAGED BOILER SYSTEMS PRODUCT GROUP

These provisions amend the indicated articles of THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (above)

[Add to **2. TERMS AND PRICES**]

[Add to 2.a] The **performance milestones for payment** for projects valued at or above $250,000 are as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) Upon Issuance of Submittals: .... **20%** of the Contract Price (Net 30 Days)
- (ii) Upon Release for Production: .... **30%** of the Contract Price (Net 30 Days)
- (iii) Upon Readiness for Shipment: .... **50%** of the Contract Price (Net 30 Days)

[Add to **6. TERMINATION**]

(d) If the Buyer's circumstances change after an order is accepted, and the Buyer is unable to use ordered items or similar items, then subject to the Company's express written consent, the buyer may **return for credit** such unneeded items as have been delivered under the order, which will be accepted as returns if they are unused, undamaged, and current inventory, subject to the normal restocking charge.

23. CANCELLATION SCHEDULE

(a) The cancellation schedule for projects is as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) After Receipt of Purchase Order: .... Up to **25%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
- (ii) 1-30 Days After Drawing Approval: .... Up to **50%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
- (iii) Over 30 Days After Drawing Approval: .... Up to **75%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)
- (iv) After Final Assembly: .... Up to **100%** of the Contract Price based on Costs and Conditions of Sale (Net 30 Days)

SUPPLEMENTAL CONDITIONS for the ENGINEERED BOILER SYSTEMS PRODUCT GROUP

These provisions amend the indicated articles of THE CLEAVER-BROOKS COMPANY, INC. GENERAL TERMS AND CONDITIONS OF SALE (above)

[Add to **2. TERMS AND PRICES**]

[Add to 2.a] The **performance milestones for payment** for projects valued at or above $250,000 are as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) Upon Receipt of Purchase Order: .... **10%** of the Contract Price (Net 30 Days)
- (ii) Upon Issuance of Drawing Submittals (Mechanical GA and P&ID Drawings): .... **30%** of the Contract Price (Net 30 Days)
- (iii) Upon Completion of Hydrostatic Test: .... **35%** of the Contract Price (Net 30 Days)
- (iv) Upon Readiness for Shipment: .... **25%** of the Contract Price (Net 30 Days)

[Add to 2.b] If the price includes **allowed transportation or other shipping charges**, then increases in transportation rates, demurrage, special detention, or other shipping charges, occurring after the date of quotation shall be added to the Purchase Price.

[Add to 2.c] The Company may, but shall not be obligated to, incorporate into the Equipment any **upgrades or applicable changes in the Company's standard specifications**, design, construction, arrangement or components.

[Add to **3. DELIVERY**]

[Add to 2.b] The Company will endeavor to make shipment of orders as scheduled; however, all shipment dates are approximate only, and the Company reserves the right to readjust shipment schedules.

24. CANCELLATION SCHEDULE

(a) The cancellation schedule for projects is as follows unless otherwise indicated in the Proposal to which these conditions are attached:

- (i) Up to 14 Days After Receipt of Purchase Order: .... **0%** of the Contract Price (Net 30 Days)
- (ii) Over 14 Days After Receipt of Purchase Order: .... **25%** of the Contract Price (Net 30 Days)
- (iii) Up to 30 Days After Drawing Approval: .... **45%** of the Contract Price (Net 30 Days)
- (iv) 31-60 Days After Drawing Approval: .... **55%** of the Contract Price (Net 30 Days)
- (v) 61-90 Days After Drawing Approval: .... **75%** of the Contract Price (Net 30 Days)
- (vi) Over 90 Days After Drawing Approval: .... **100%** of the Contract Price (Net 30 Days)

25. FOUNDATIONS

(a) The Company shall provide the Buyer with General Arrangement drawings showing the Equipment with reference to foundations, including loading diagrams.

(b) The Company shall not be responsible for the depth of the footings, size or accuracy of the foundations or anchor bolts, or the character of the materials selected for their construction.

(c) Adequate foundations, having plan measurements in accordance with such drawings including foundation bolts and plates, concrete work, all grouting, and excavation, shall be furnished in place in due time by the Buyer.

(d) The Company shall not be responsible for any damages, or repairs necessary to the Equipment furnished by it, caused by or resulting from defects in or settlement of the foundations.

26. SUPPORTING STEEL

(a) Unless otherwise stated, any supporting steel to be furnished by the Company as specified in this Proposal will be designed to support the Equipment which the Company proposes to furnish and will be designed in accordance with the latest Rules of the American Institute of Steel Construction.

(b) If the Company is required to increase the size or weight of its supporting structures to conform to other than the Rules of the American Institute of Steel Construction or because of additional loadings imposed by the Buyer, the Buyer shall reimburse the Company for the additional steel and work required.

Appendix 8a

Saguaro RACT Analysis:
DAQ Supporting Documentation

Rob Barton

From: Justin Legg <jlegg@alzeta.com>
Sent: Thursday, September 28, 2023 4:07 PM
To: Rob Barton
Subject: RE: ceramic burners for Caesars

Rob,

It's important to distinguish the difference between "5 PPM NOx corrected to 3% O2" and operation of the burner at 3% O2.

- ALZETA's CSB burner will operate at approximately 9.0% O2 (dry) with no FGR to maintain 5 PPM NOx.
  - **Uncorrected** emissions will be approximately 3.3 PPM NOx, as measured at 9.0% O2
  - **Corrected** emissions at 3% O2 will be 5 PPM NOx, in accordance with typical air quality rules in California and beyond
- With FGR, ALZETA's burners are capable of operating at approximately 6.0% O2 (dry), while maintaining NOx emissions of 5 PPM **corrected to** 3% O2
- For reference, ALZETA's CSB burners cannot operate at 3% O2 – this condition is too rich to maintain the integrity of the burner surface.

We can guarantee 5 PPM NOx **Corrected to** 3% O2, when operating at approximately 9% O2 without FGR. Let me know if you have any other questions.

Regards,

Justin Legg
Product Development Engineer
ALZETA Corporation
408-727-8282 x355
jlegg@alzeta.com

Office # 919-845-1422 ext. 24
Cell # 919-308-7701

From: Rob Barton
Sent: Monday, September 25, 2023 4:48 PM
To: Justin Legg <jlegg@alzeta.com>
Cc: Gary McCutchen <g.mccutchen@rtpenv.com>
Subject: RE: ceramic burners for Caesars

Hi Justin,

Thanks again for providing this information. One quick follow-up question:

Gary mentions the Cleaver-Brooks CBLE is able to be ordered in 60, 30, 9, or 5 ppm NOx configurations. The CSB is capable of meeting all of those emissions limits, depending on how much excess air is used.

Does this mean you can provide a performance guarantee for a CSB100 in a 5 ppm configuration at 3% O2? If not, what is the lowest NOx level the burner is capable of with and without FGR at 3% O2?

Rob

Rob Barton
RTP Environmental Associates, Inc.
304-A West Millbrook Road
Raleigh, NC 27609
Office # 919-845-1422 ext. 24
Cell # 919-308-7701

From: Justin Legg <jlegg@alzeta.com>
Sent: Wednesday, August 30, 2023 2:17 PM
To: Rob Barton <barton@rtpenv.com>
Cc: Gary McCutchen <g.mccutchen@rtpenv.com>
Subject: RE: ceramic burners for Caesars

Hi Rob,

I wanted to respond regarding an 86 MMBTU/hr burner for the Nebraska watertube Boiler, and also address some of Gary's earlier questions:

- Yes, the CSB1000 is very feasible for a water-tube boiler retrofit (note also that ALZETA's commercial agreements *do allow* us to supply CSB burners directly for water-tube boiler applications)
  - For background, ALZETA has been supplying CSB metal-mesh type burners since the early 2000s. Our first commercial installation was for a 126 MMBTU/hr O-Type boiler, and we have dozens of installations watertube installations, primarily throughout California.
- Regarding performance:
  - For a surface-stabilized metal mesh burner, NOx is primarily a function of excess air. The surface stabilization, combined with premixing, allows for the burner to operate at leaner conditions than other commercial burners. This lowers the flame temperature, reducing thermal NOx.
  - As such, the CSB can be tuned for different NOx requirements. Gary mentions the Cleaver-Brooks CBLE is able to be ordered in 60, 30, 9, or 5 ppm NOx configurations. The CSB is capable of meeting *all* of those emissions limits, depending on how much excess air is used. The CSB also a low emitter of CO (typically single-digit for the above NOx requirements)

  - For longevity of the burner element, an excess air amount of 50% or more is ideal. This would result in approximately 15 PPM NOx (dry, corrected to 3% O2)
  - Where efficiency is a concern, FGR can be used to lower the flame temperature; by substituting excess air with FGR and maintaining a constant amount of "dilution," NOx performance can be attained at *lower* amounts of excess air (i.e. 25% instead of 50%). **However,** FGR results in additional capital costs in order to accommodate the higher temperatures
- Regarding costs:
  - For an 86 MMBTU/hr CSB *without* FGR, budgetary cost for the equipment is roughly $360,000
  - Lifespan of a burner element is dependent on maintenance/operating conditions. Assuming proper maintenance of the unit, I'd estimate a 10-15 year lifespan; a full replacement element would be roughly $60,000.
  - Maintenance costs would only be related to air filtration. ALZETA uses large polyester industrial panel filters. The panels themselves are cleanable/washable up to 3 times, and there are also washable pre-filters available. Costs related to tuning would be minimal, as tuning is again related to maintaining proper excess air.

Regards,

Justin Legg
Product Development Engineer
ALZETA Corporation
408-727-8282 x355
jlegg@alzeta.com

From: Rob Barton [mailto:barton@rtpenv.com]
Sent: Friday, August 11, 2023 8:48 PM
To: jlegg@alzeta.com
Cc: Gary McCutchen
Subject: RE: ceramic burners for Caesars

Justin,

One more question… what is the lifespan of these burners? Based on our previous conversation, the estimated life of the ceramic fiber burners was about 10 years. I was wondering if the novel design was also associated with a similar lifespan.

Thanks!
Rob

Rob Barton
RTP Environmental Associates, Inc.
304-A West Millbrook Road
Raleigh, NC 27609
Office # 919-845-1422 ext. 24
Cell # 919-308-7701

From: Rob Barton
Sent: Friday, August 11, 2023 11:40 PM
To: jlegg@alzeta.com
Cc: Gary McCutchen <g.mccutchen@rtpenv.com>
Subject: RE: ceramic burners for Caesars

Justin,

Gary McCutchen (see thread below) mentioned the possibility of a metal mesh burner retrofit for existing watertube boilers. I had a similar question regarding feasibility and cost for a Nebraska watertube package boiler (Model NOX 2A/S-55) with a rated heat input of 86 MMBtu/hr. Can you confirm whether the CSB1000 might be a suitable replacement for the existing burner? If so, can you please provide a budgetary cost estimate for this burner and estimated level of performance with and without FGR?

Thank you!
Rob

Rob Barton
RTP Environmental Associates, Inc.
304-A West Millbrook Road
Raleigh, NC 27609
Office # 919-845-1422 ext. 24
Cell # 919-308-7701

From: Gary McCutchen <g.mccutchen@rtpenv.com>
Sent: Thursday, August 10, 2023 8:06 AM
To: Justin Legg <jlegg@alzeta.com>
Subject: FW: ceramic burners for Caesars

Justin, this is really interesting and useful. I didn't find (or notice) this type of burner as an option when I was doing the Reasonably Available Control Technology (RACT) determinations. The agency (Clark County, NV) where Caesars is located has to apply RACT to major sources per the Clean Air Act, so is looking into the costs (a technology can be rejected, as you probably know, if the cost-effectiveness is too high) of retrofitting natural gas fired boilers, like those at Caesars, to reduce NOx emissions.

This leads me to a couple of additional questions, which I hope you will be able to answer:

- Can this CSB burner be retrofit on existing boilers, especially those at Caesars and MGMRI? The Caesars and MGMRI boilers are summarized in these excerpts from the RACT report:
  - 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.[1] According to the Caesars RACT analysis, the Hurst and Burnham boilers are 3-pass fire-tube, 800-bhp boilers; the existing Riello burners associated with all five boilers include LNB designs and cannot be modified to increase NO_x reduction to the level of ULNB capability. Caesars uses these boilers more than emergency generators or boilers at other Caesars properties, although they still are small emitters, with actual emissions of less than 3 tpy. All the boilers fire natural gas and have NO_x emissions limits of 29–30 ppm at 3% O_2. There are no limits on fuel use or operating hours
  - For MGMRI: The process equipment consists of two natural gas-fired boilers, each with a capacity of 32.66 MMBtu/hr, and 46 diesel-fired emergency generators that range from 1,100–3,700 hp. The boilers are classified as Commercial/Institutional (< 100 MMBtu/hr) and the engines as Large Internal Combustion Engines (> 500 hp). The two Cleaver Brooks boilers (MG13 and 14), which are Model CBLE series, are permitted to use only natural gas. According to the manufacturer's website, the CBLE are high-efficiency fire-tube boilers that can be ordered to achieve less than 60, 30, 9, or 5 ppm NO_x.[2] The permitted limit of 40 ppm at 3% O_2 is higher than the more common 30 ppm limit for LNB boilers.
- If retrofits are possible for one or more of these boilers, could you estimate the cost of retrofitting and operating them? In terms of operating costs, we're looking at whether there would be increased or decreased

maintenance, fuel use, etc., compared to the current burners. (When I thought ceramic burners were feasible, they had a fuel savings, which was important to their being considered affordable.) The most important cost figure is the retrofit cost. The costs don't have to be exact—even a general estimate would help, since I don't think I'm going to be able to find much cost information online.

Justin, I really appreciate the information you've provided and would very much appreciate any information you can provide on the above questions. The County was quite interested in this technology when I discussed it with them.

Gary McCutchen

Principal, RTP Environmental Associates, Inc.
g.mccutchen@rtpenv.com
(919) 395-9596 (mobile)
(775) 969-3616 (office)
18900 Fetlock Drive, Reno, NV 89508

From: Justin Legg <jlegg@alzeta.com>
Sent: Tuesday, August 8, 2023 11:35 AM
To: Gary McCutchen <g.mccutchen@rtpenv.com>
Subject: RE: ceramic burners for Caesars

Hi Gary,

Yes, we develop and manufacture surface-stabilized metal mesh burners. NOx emissions are 15 PPMV Dry, corrected to 3% O2 and lower. This is a technology that is well established in boiler applications, particularly in California's air quality districts (including South Coast Air Quality Management District). They are commercially available between 2 MMBTU/hr and 130 MMBTU/hr (I've attached a brochure for our commercial product, the CSB). For Firetube boilers specifically, they are manufactured by our partner company, Powerflame, as their "NVC" product.

Regards,

Justin Legg
Product Development Engineer
ALZETA Corporation
408-727-8282 x355
jlegg@alzeta.com

From: Gary McCutchen [mailto:g.mccutchen@rtpenv.com]
Sent: Monday, August 07, 2023 6:57 PM
To: Justin Legg
Subject: RE: ceramic burners for Caesars

Thanks very much for the confirmation and information. If I could bother you one more time, your statement about surface-stabilized metal mesh-type burners intrigued me. Do you make them and/or do you know what size they go up to and what the NOx emissions rate is? Can they get down to 10-15 MM Btu/hr NOx.

Gary McCutchen

Principal, RTP Environmental Associates, Inc.
g.mccutchen@rtpenv.com

(919) 395-9596 (mobile)
(775) 969-3616 (office)
18900 Fetlock Drive, Reno, NV 89508

From: Justin Legg <jlegg@alzeta.com>
Sent: Monday, August 7, 2023 5:08 PM
To: Gary McCutchen <g.mccutchen@rtpenv.com>
Subject: RE: ceramic burners for Caesars

Hi Gary,

- Yes, I can confirm that the e-mail to Russell Harns at Broadbent was sent by me.
- We are not aware of any applications larger than 16 MMBTU/hr for ceramic fiber burners.
- We are not aware of any research regarding ceramic burners on boilers or other large combustion devices.
- The problem with Caesars is size. We no longer build large radiant ceramic fiber burners as large as 16 MMBTU/hr; our current largest burner is in the 3 MMBTU/hr range, and these types of burners are typically applied to small hydronic/hot water boilers.
    - Please also note that large ceramic fiber burners have been replaced by surface-stabilized metal mesh-type burners, which are capable of 16 MMBTU/hr and larger.

Regards,

Justin Legg
Product Development Engineer
ALZETA Corporation
408-727-8282 x355
jlegg@alzeta.com

From: Gary McCutchen [mailto:g.mccutchen@rtpenv.com]
Sent: Saturday, August 05, 2023 2:15 PM
To: jlegg@alzeta.com
Subject: ceramic burners for Caesars
Importance: High

Hi Justin,

I'm assisting the Clark County air agency in determining appropriate retrofit control technologies for major sources of air pollution in the area. Caesars has forwarded to the County an email from you indicating that their firetube boilers are too large (30+ MM Btu/hr) for such burners. Based on that information, we conducted an online search for size limits and found information indicating that the largest commercial applications for such burners is about 16 MM Btu/hr, which of course agrees with your statement.

We're still pretty impressed with this technology and are interested in the types of sources that could apply it. If you wouldn't mind, I'd appreciate if you could take a few minutes to clarify the following:

- That the following email to Caesars was indeed from you:

    "Hi Russell,
    Based on the information you've provided, we believe that "ceramic burners" are not the appropriate technology for a firetube boiler application. They are only intended for low heat-flux applications, and a ceramic fiber burner for a 30 MMBTU/hr boiler application would be too large to be practical." Let me know if you have any other questions.

Regards,
Justin Legg
Product Development Engineer
ALZETA Corporation”

- Whether you are aware of any applications on boilers or other sources greater than 16 MM Btu/hr.
- Whether you’re aware of any research regarding ceramic burner applications on larger boilers or other combustion devices.
- Whether the problem for the Caesars boilers is only the size; in other words, are ceramic burners workable for smaller firetube boilers or can the design of firetube boilers also be a problem (especially for retrofit situations)?

Thank you very much for any assistance you can provide.

Gary McCutchen

Principal, RTP Environmental Associates, Inc.
g.mccutchen@rtpenv.com
(919) 395-9596 (mobile)
(775) 969-3616 (office)
18900 Fetlock Drive, Reno, NV 89508

[1] EPA-453/R-94-022, Alternative Control Techniques Document—NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers, March 1994, p. 1-1.

[2] MGMRI’s OP limits the two boilers to 40 ppm NOx at 3% O2: “The permittee shall operate and maintain each of the boilers with burners that have a manufacturer’s maximum emission concentration of 40 ppmv NOx, corrected to 3% oxygen (EUs: MG01, MG02, MG05, MG06, MG13, MG14, and MG16).” Condition III.A.5.c.

Appendix 9

DAQ Detailed Cost Calculations

COST EFFECTIVENESS CALCULATION 1	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	0.39
Emissions Reduction (%)	90
Controlled Emissions (tpy)	0.039
Annualized Capital Costs	
Initial Capital Investment+A15	$100,000
Direct & Indirect Costs	$15,340
Total Capital Investment	$115,340
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,379
Annual Operating Costs	
Urea	$595
Catalyst	$1,013
Maintenance	$3,000
Total Annualized Cost	$12,987
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.351
Cost Effectiveness ($/ton)	$37,001

Note:
Highest rate in most recent 5 years

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Based on quotes from WW Williams in Caesars RACT of $119,571, then adjusted down for smaller unit

Note:
From Caesars based on quote from WW Williams

Note:
All costs from Caesars, except maintenance cut to $3K from $6K assuming lower due to # of generators at site.

COST EFFECTIVENESS CALCULATION 2	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
DUAL FUEL	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	Dual Fuel
Baseline Emissions Rate (tpy)	0.39
Emissions Reduction (%)	30
Controlled Emissions (tpy)	0.273
Annualized Capital Costs	
Initial Capital Investment	$8,000
Direct & Indirect Costs	$2,000
Total Capital Investment	$10,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$727
Annual Operating Costs	
Maintenance	
Total Annualized Cost	$727
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.117
Cost Effectiveness ($/ton)	$6,209

Note:
Highest rate in most recent 5 years

Note:
20-30% from lab tests on direct-injection motor. West Virginia thesis.

Note:
Based on ranges for engines with and without turbocharging. See: https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/

Note:
Assumed cost for hooking up to natural gas

Note:
Using natural gas could save money, depending on relative fuel prices and maintenace is expected to be less than with diesel due to less wear, but slightly higher due to dual system, so likely no change.

COST EFFECTIVENESS CALCULATION 3	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
MANIFOLD AIR TEMPERATURE (MAT) REDUCTION	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	MAT
Baseline Emissions Rate (tpy)	0.39
Emissions Reduction (%)	70
Controlled Emissions (tpy)	0.117
Annualized Capital Costs	
Initial Capital Investment	$10,000
Direct & Indirect Costs	$5,000
Total Capital Investment	$15,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,090
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$4,090
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.273
Cost Effectiveness ($/ton)	$14,981

Note:
Highest rate in most recent 5 years

Note:
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

Note:
Based on internet search indicating an aftercooler costing $5000-7000, but that's just the unit and does not include the piping and other hardware, so selected $10,000.

Note:
Assumed cost to install system.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 4	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
DIRECT WATER INJECTION (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	0.39
Emissions Reduction (%)	60
Controlled Emissions (tpy)	0.156
Annualized Capital Costs	
Initial Capital Investment	$8,370
Direct & Indirect Costs	
Total Capital Investment	$8,370
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$608
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$3,608
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.234
Cost Effectiveness ($/ton)	$15,419

Note:
Highest rate in most recent 5 years

Based on Issa article

Note:
Based on Issa article, which gave costs in $/kW for 6000 to 64,000 HP. Includes cost to adapt injection to existing engines.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 5	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
EMULSIFIED DIESEL	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	EMULSIFIED DIESEL
Baseline Emissions Rate (tpy)	0.39
Emissions Reduction (%)	20
Controlled Emissions (tpy)	0.312
Annualized Capital Costs	
Initial Capital Investment	$4,650
Direct & Indirect Costs	
Total Capital Investment	$4,650
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$338
Annual Operating Costs	
Fuel cost difference ($0.22/gallon, 6724 gal/year at 500 hr/yr	$1,479
Maintenance	$3,000
Total Annualized Cost	$4,817
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.078
Cost Effectiveness ($/ton)	$61,754

Note:
Highest rate in most recent 5 years

Based only 10% water in emulsion. Can go higher in water and reduce NOx more, but stability of emulsion decreased rapidly with additonal water.

Note:
Based on $25/kW capital costs.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 6	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	Unit G041
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	90
Controlled Emissions (tpy)	0.1861
Annualized Capital Costs	
Initial Capital Investment	$100,000
Direct & Indirect Costs	$15,340
Total Capital Investment	$115,340
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,379
Annual Operating Costs	
Urea	$595
Catalyst	$1,013
Maintenance	$3,000
Total Annualized Cost	$12,987
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.6749
Cost Effectiveness ($/ton)	$7,754

Note:
Highest rate in most recent 5 years

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Based on quotes from WW Williams in Caesars RACT of $119,571, then adjusted down for smaller unit

Note:
From Caesars based on quote from WW Williams

Note:
All costs from Caesars, except maintenance cut to $3K from $6K assuming lower due to # of generators at site.

COST EFFECTIVENESS CALCULATION 7	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
INJECTION TIMING RETARD (ITR)	
Emissions Unit/Control Technology	
Emissions Unit	Unit G041
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	ITR
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	30
Controlled Emissions (tpy)	1.3027
Annualized Capital Costs	
Initial Capital Investment	$16,000
Direct & Indirect Costs	
Total Capital Investment	$16,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,162
Annual Operating Costs	
Other	$16,000
Maintenance	
Total Annualized Cost	$17,162
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.5583
Cost Effectiveness ($/ton)	$30,740

Note:
Highest rate in most recent 5 years

Note:
20-30% estimated in EPA ACT, p. 2-18, for CI diesels. Used 30%.

Note:
NAFB used 10 years but no justification, so defaulted to 30 years

Note:
Based on ACT costs, p. 2-42, for a 2000 HP engine. Range is $16-24K for capital cost, $16-32K annual cost.

COST EFFECTIVENESS CALCULATION 8	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
MANIFOLD AIR TEMPERATURE (MAT) REDUCTION	
Emissions Unit/Control Technology	
Emissions Unit	Unit G041
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	MAT
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	70
Controlled Emissions (tpy)	0.5583
Annualized Capital Costs	
Initial Capital Investment	$10,000
Direct & Indirect Costs	$5,000
Total Capital Investment	$15,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,090
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$4,090
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.3027
Cost Effectiveness ($/ton)	$3,139

Note:
Highest rate in most recent 5 years

Note:
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

Note:
Based on internet search indicating an aftercooler costing $5000-7000, but that's just the unit and does not include the piping and other hardware, so selected $10,000.

Note:
Assumed cost to install system.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 9	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	35
Controlled Emissions (tpy)	1.20965
Annualized Capital Costs	
Initial Capital Investment	$37,510
Direct & Indirect Costs	
Total Capital Investment	$37,510
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$2,725
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$5,725
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.65135
Cost Effectiveness ($/ton)	$8,790

Note:
Highest rate in most recent 5 years

Based on Issa article

Note:
Based on Issa article, which gave costs in $/kW for 6000 to 64,000 HP. Includes cost to adapt injection to existing engines.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 10	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	50
Controlled Emissions (tpy)	0.9305
Annualized Capital Costs	
Initial Capital Investment	$21,840
Direct & Indirect Costs	
Total Capital Investment	$21,840
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,587
Annual Operating Costs	
Fuel cost difference ($0.22/gallon, 6724 gal/year at 500 hr/yr	$7,810
Maintenance	$3,000
Total Annualized Cost	$12,397
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.9305
Cost Effectiveness ($/ton)	$13,323

Note:
Highest rate in most recent 5 years

Based only 10% water in emulsion. Can go higher in water and reduce NOx more, but stability of emulsion decreased rapidly with additonal water.

Note:
Based on $24/kW capital costs.

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 11	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Dual Fuel	
Emissions Unit/Control Technology	
Emissions Unit	Unit A032
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	Dual Fuel
Baseline Emissions Rate (tpy)	1.861
Emissions Reduction (%)	30
Controlled Emissions (tpy)	1.3027
Annualized Capital Costs	
Initial Capital Investment	$21,840
Direct & Indirect Costs	$2,000
Total Capital Investment	$23,840
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,732
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$4,732
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.5583
Cost Effectiveness ($/ton)	$8,476

Note:
Highest rate in most recent 5 years

Note:
Assumes 30% control

Note:
Based on ranges for engines with and without turbocharging. See: https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/

Note:
Assumed cost for hooking up to natural gas

Note:
Using natural gas could save money, depending on relative fuel prices and maintenace is expected to be less than with diesel due to less wear, but slightly higher due to dual system, so likely no change.

COST EFFECTIVENESS CALCULATION 12	
NELLIS AIR FORCE BASE (NAFB)	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	Hush House
Emission Unit Description	Hush House
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	12.9
Emissions Reduction (%)	90
Controlled Emissions (tpy)	1.29
Annualized Capital Costs	
Initial Capital Investment	$1,410,811
Direct & Indirect Costs	$153,400
Total Capital Investment	$1,564,211
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$113,640
Annual Operating Costs	
Urea	$595
Catalyst	$1,013
Maintenance	$6,000
Total Annualized Cost	$121,248
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	11.61
Cost Effectiveness ($/ton)	$10,443

Note:
Highest rate in most recent 5 years

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Extrapolated from WW Wiliiams cost of $145K and ratio of 3700 HP diesel to 36,000 HP turbofan in afterburner mode.

Note:
From Caesars based on quote from WW Williams, scaled up by factor of 10

Note:
All costs from Caesars without scaleup.

COST EFFECTIVENESS CALCULATION 13	
CAESARS	
BOILERS	
ULTRA-LOW NOx BURNERS (LNB)	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	ULNB
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	70
Controlled Emissions (tpy)	0.822
Annualized Capital Costs	
Initial Capital Investment	$235,000
Direct & Indirect Costs	$3,000
Total Capital Investment	$238,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$17,291
Annual Operating Costs	
Total Annualized Cost	$17,291
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.918
Cost Effectiveness ($/ton)	$9,015

Note:
From Caesars RACT analysis for CP02

Note:
From Caesars

Note:
Based on quotes from Caesars RACT

Note:
From Caesars

Note:
None estimated

COST EFFECTIVENESS CALCULATION 14	
CAESARS	
BOILERS	
FGR	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FGR
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	42
Controlled Emissions (tpy)	1.5892
Annualized Capital Costs	
Initial Capital Investment	$116,318
Direct & Indirect Costs	$3,000
Total Capital Investment	$119,318
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,668
Annual Operating Costs	
Total Annualized Cost	$8,668
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.1508
Cost Effectiveness ($/ton)	$7,533

Note:
From Caesars RACT analysis for CP02

Note:
From Caesars

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted for inflation with inflation index to 2023 (2023/1975 = $16196/$2924)

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 15	
CAESARS	
BOILERS	
FGR	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FGR
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	42
Controlled Emissions (tpy)	1.5892
Annualized Capital Costs	
Initial Capital Investment	$94,920
Direct & Indirect Costs	$3,000
Total Capital Investment	$97,920
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$7,114
Annual Operating Costs	
Total Annualized Cost	$7,114
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.1508
Cost Effectiveness ($/ton)	$6,182

Note:
From Caesars RACT analysis for CP02

Note:
From Caesars

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted with Chem Engr Cost Index (ratio = 824.5 (2022) / 182.4 (1975) = 4.52). 4.52x21,000 = $94,920

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 16	
CAESARS	
BOILERS	
ULNB/FGR	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	ULNB/FGR
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	75
Controlled Emissions (tpy)	0.685
Annualized Capital Costs	
Initial Capital Investment	$77,200
Direct & Indirect Costs	
Total Capital Investment	$77,200
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$5,609
Annual Operating Costs	
General	$39,520
Total Annualized Cost	$45,129
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	2.055
Cost Effectiveness ($/ton)	$21,960

Note:
From Caesars RACT analysis for CP02

Note:
From MGM

Note:
Based on 1975 cost for retrofit from 1978 EPA From MGMRI RACT analysis

Note:
From MGMRI RACT analysis

COST EFFECTIVENESS CALCULATION 17	
CAESARS	
BOILERS	
Overfire Air (OFA)	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	OFA
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	50
Controlled Emissions (tpy)	1.37
Annualized Capital Costs	
Initial Capital Investment	$116,318
Direct & Indirect Costs	$3,000
Total Capital Investment	$119,318
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,668
Annual Operating Costs	
Total Annualized Cost	$8,668
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.37
Cost Effectiveness ($/ton)	$6,327

Note:
From Caesars 2017 Emissions Inventor--
Highest actual emissions--Unit A11.

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted for inflation with Chem Engr index to 2022 (2022/1975 = $824.5/182.4 = 4.52

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 18	
CAESARS	
BOILERS	
Fuel-Induced Recirculation (FIR2)	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FIR2
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	43
Controlled Emissions (tpy)	1.5618
Annualized Capital Costs	
Initial Capital Investment	$94,920
Direct & Indirect Costs	$3,000
Total Capital Investment	$97,920
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$7,114
Annual Operating Costs	
Total Annualized Cost	$7,114
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.1782
Cost Effectiveness ($/ton)	$6,038

Note:
From Caesars RACT analysis for CP02

Note:
From Caesars

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted with Chem Engr Cost Index (ratio = 824.5 (2022)/182.4 (1975) = 4.52). 4.52x21,000 = $94,920

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 19	
CAESARS	
BOILERS	
Ceramic Fiber Burners (CFB)	
Emissions Unit/Control Technology	
Emissions Unit	CP04
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	CFB
Baseline Emissions Rate (tpy)	1.08
Emissions Reduction (%)	50
Controlled Emissions (tpy)	0.54
Annualized Capital Costs	
Initial Capital Investment	$36,235
Direct & Indirect Costs	$3,000
Total Capital Investment	$39,235
Estimated Equipment Life, years	10
Interest Rate, %	6
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$5,336
Annual Operating Costs	
5% fuel savings assuming 446.6 hr/year	
Total Annualized Cost	$5,336
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.54
Cost Effectiveness ($/ton)	$9,881

Note:
From Caesars RACT analysis for CP04

Note:
From Cost 2011

Note:
Based on cost of $0.78/M Btu (per 1000 Btu), 33 Mm Btu/hr burner, CEPCI = $824.5/585.7

Note: general estimate from Caesars analyses

Note:
CP02 emissions of 2.74 would give a CE of $3895/ton because of the additional tons of NOx captured

COST EFFECTIVENESS CALCULATION 20	
CAESARS	
BOILERS	
Ceramic Fiber Burners (CFB)	
Emissions Unit/Control Technology	
Emissions Unit	CP04
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	CFB
Baseline Emissions Rate (tpy)	1.08
Emissions Reduction (%)	50
Controlled Emissions (tpy)	0.54
Annualized Capital Costs	
Initial Capital Investment	$36,235
Direct & Indirect Costs	$3,000
Total Capital Investment	$39,235
Estimated Equipment Life, years	10
Interest Rate, %	6
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$5,336
Annual Operating Costs	
5% fuel savings assuming 446.6 hr/year	-$6,815
Total Annualized Cost	-$1,479
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.54
Cost Effectiveness ($/ton)	-$2,739

Note:
From Caesars RACT analysis for CP04

Note:
From Cost 2011

Note:
Based on cost of $0.78/M Btu (per 1000 Btu), 33 Mm Btu/hr burner, CEPCI = $824.5/585.7

Note: general estimate from Caesars analyses

Note:
Assumes natural gas at $9.25/1000 cubic feet and operation of the burner at full capacity (33 MM Btu/hr)

Note:
CP02 emissions of 2.74 would give a CE of (-$1080/ton captured)

COST EFFECTIVENESS CALCULATION 21	
CAESARS	
BOILERS	
Oxygen Trim (OT)	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	OT
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	15
Controlled Emissions (tpy)	2.329
Annualized Capital Costs	
Initial Capital Investment	$7,596
Direct & Indirect Costs	$7,596
Total Capital Investment	$15,192
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,104
Annual Operating Costs	
	$2,000
Total Annualized Cost	$3,104
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.411
Cost Effectiveness ($/ton)	$7,552

Note:
From Caesars 2017 Emissions Inventor-- Highest boiler emissions

Note:
From Guide, p. 5-5

Note:
Based on 1994 ACT cost in 1992 $ of $100/MM Btu/hr. This is $3300 for a 33 MM Btu/hr burner. Adjusted for inflation withChem Engr index to 2022 (2022/1992 = $824.5/$358.2 = 2.3, so $7596.

Note: Assumes same as capital cost

Note:
General estimate

COST EFFECTIVENESS CALCULATION 22	
CAESARS	
BOILERS	
Gas Fuel Flow Modifiers (GFFM)	
Emissions Unit/Control Technology	
Emissions Unit	CP02
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	GFFM
Baseline Emissions Rate (tpy)	2.74
Emissions Reduction (%)	15
Controlled Emissions (tpy)	2.329
Annualized Capital Costs	
Initial Capital Investment	$117,500
Direct & Indirect Costs	$3,000
Total Capital Investment	$120,500
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,754
Annual Operating Costs	
Total Annualized Cost	$8,754
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.411
Cost Effectiveness ($/ton)	$21,300

Note:
From Caesars RACT analysis for CP02

Note:
From ACT, mid-range value

Note:
Based on quotes from Caesars RACT for ULNB but reduced to half the ULNB cost since less equipment involved

Note:
From Caesars

Note:
None estimated

COST EFFECTIVENESS CALCULATION 23	
CAESARS	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	CP13 Group
Emission Unit Description	Emergency Generator
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	1.04
Emissions Reduction (%)	90
Controlled Emissions (tpy)	0.104
Annualized Capital Costs	
Initial Capital Investment	$145,519
Direct & Indirect Costs	$15,340
Total Capital Investment	$160,859
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$11,686
Annual Operating Costs	
Urea	$1,666
Catalyst	$2,702
Maintenance	$6,000
Total Annualized Cost	$22,054
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.936
Cost Effectiveness ($/ton)	$23,562

Note:
From Caesars RACT analysis for the group of generators beginning with CP13.

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Based on quotes from WW Williams in Caesars RACT

Note:
From Caesars based on quote from WW Williams

Note:
All costs from Caesars, except maintenance cut to $3K from $6K assuming lower due to # of generators at site.

COST EFFECTIVENESS CALCULATION 24	
CAESARS	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
INJECTION TIMING RETARD (ITR)	
Emissions Unit/Control Technology	
Emissions Unit	CP13 GROUP
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	ITR
Baseline Emissions Rate (tpy)	1.04
Emissions Reduction (%)	30
Controlled Emissions (tpy)	0.728
Annualized Capital Costs	
Initial Capital Investment	$16,000
Direct & Indirect Costs	
Total Capital Investment	$16,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,162
Annual Operating Costs	
Other	$920
Maintenance	
Total Annualized Cost	$2,082
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.312
Cost Effectiveness ($/ton)	$6,674

Note:
From Caesars RACT analysis for the group of generators beginning with CP13.

Note:
20-30% estimated in EPA ACT, p. 2-18, for CI diesels. Used 30%.

Note:
Based on ACT costs, p. 2-42, for a 2501-4000 HP engine. Range is $24K for capital cost, $32-46K annual cost in 1993 $; this value is adjusted per the CEPCI to 2022 $. Annualized cost from the ACT seems high but likely reflects the 0-5% fuel penalty, so the 8000 hour adjusted cost of $73,600 is adjusted down to 100 hr/year operation allowed, which is $920/year.

COST EFFECTIVENESS CALCULATION 25	
CAESARS	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	CP13 GROUP
Emission Unit Description	Emergency Generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	1.04
Emissions Reduction (%)	60
Controlled Emissions (tpy)	0.416
Annualized Capital Costs	
Initial Capital Investment	$94,533
Direct & Indirect Costs	
Total Capital Investment	$94,533
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$6,868
Annual Operating Costs	
2-3% Fuel Penalty	
Other	
Maintenance	
Total Annualized Cost	$6,868
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.624
Cost Effectiveness ($/ton)	$11,006

Note:
Highest rate in most recent 5 years

Based on Issa article

Note:
Based on Issa article, which gave costs in $/kW for 6000 to 64,000 HP. Includes cost to adapt injection to existing engines. Extrapolated cost to smaller 2100 kW engine to get $45/kW.

Note:
Did not calculate cost of fuel penalty or increased maiintenance.

COST EFFECTIVENESS CALCULATION 26	
CAESARS	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	CP13 Group
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	1.04
Emissions Reduction (%)	50
Controlled Emissions (tpy)	0.52
Annualized Capital Costs	
Initial Capital Investment	$46,200
Direct & Indirect Costs	
Total Capital Investment	$46,200
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$3,356
Annual Operating Costs	
Fuel cost difference ($0.22/gallon, 6724 gal/year at 500 hr/yr	$3,122
Maintenance	
Total Annualized Cost	$6,478
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.52
Cost Effectiveness ($/ton)	$12,459

Note:
From Caesars RACT analysis

Based only 10% water in emulsion. Can go higher in water and reduce NOx more, but stability of emulsion decreased rapidly with additonal water.

Note:
Based on $22d/kW capital costs.

COST EFFECTIVENESS CALCULATION 27	
CAESARS	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Dual Fuel	
Emissions Unit/Control Technology	
Emissions Unit	CP13 GROUP
Emission Unit Description	Non-emergency generator
Pollutant	NOx
Control Technology	Dual Fuel
Baseline Emissions Rate (tpy)	1.04
Emissions Reduction (%)	26.5
Controlled Emissions (tpy)	0.7644
Annualized Capital Costs	
Initial Capital Investment	$24,000
Direct & Indirect Costs	$2,000
Total Capital Investment	$26,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,889
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$4,889
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.2756
Cost Effectiveness ($/ton)	$17,739

Note:
From Caesars report

Note:
From 1993 ACT, p. 2-3, Table 2-1. For 2001-4000 HP, diesel = 830 ppmv, dual = 610 ppmv, so 26.5% reduction.

Note:
Based on ranges for engines with and without turbocharging. See: https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/ Note that this is for small truck engines and, with turbochargers, assumes $8-12K conversioin charge, so assume double the $12K for the large engine.

Note:
Assumed cost for hooking up to natural gas

Note:
Using natural gas could save money, depending on relative fuel prices and maintenace is expected to be less than with diesel due to less wear, but slightly higher due to dual system, so likely no change.

COST EFFECTIVENESS CALCULATION 28	
SWITCH	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	NA
Emission Unit Description	emergency generator
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	1.16
Emissions Reduction (%)	90
Controlled Emissions (tpy)	0.116
Annualized Capital Costs	
Initial Capital Investment	$145,519
Direct & Indirect Costs	$15,340
Total Capital Investment	$160,859
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$11,686
Annual Operating Costs	
Urea	$1,666
Catalyst	$2,702
Maintenance	$6,000
Total Annualized Cost	$22,054
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.044
Cost Effectiveness ($/ton)	$21,125

Note:
This is total emissions from the entire source, per the RACT Guidance, p. 7), but there are around 100 generators.

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Based on quotes from WW Williams in Caesars RACT

Note:
From Caesars based on quote from WW Williams

Note:
All costs from Caesars.

COST EFFECTIVENESS CALCULATION 29	
MGMRI	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Dual Fuel	
Emissions Unit/Control Technology	
Emissions Unit	MG17
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	Dual Fuel
Baseline Emissions Rate (tpy)	3.49
Emissions Reduction (%)	26.5
Controlled Emissions (tpy)	2.56515
Annualized Capital Costs	
Initial Capital Investment	$24,000
Direct & Indirect Costs	$2,000
Total Capital Investment	$26,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$1,889
Annual Operating Costs	
Maintenance	$3,000
Total Annualized Cost	$4,889
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.92485
Cost Effectiveness ($/ton)	$5,286

Note:
Nelllis AFB actual emissions % of NAFB PTE (Unit 41) PTE = 8.07 tpy, actual max= 1.861, so 23.1% of 15.12 = 3.49

Note:
From 1993 ACT, p. 2-3, Table 2-1. For 2001-4000 HP, diesel = 830 ppmv, dual = 610 ppmv, so 26.5% reduction.

Note:
Based on ranges for engines with and without turbocharging. See: https://finddiffer.com/how-much-does-it-cost-to-convert-a-diesel-engine-to-gas/ Note that this is for small truck engines and, with turbochargers, assumes $8-12K conversioin charge, so assume double the $12K for the large engine.

Note:
Assumed cost for hooking up to natural gas

Note:
Using natural gas could save money, depending on relative fuel prices and maintenace may even be less than with diesel due to less wear, so assume general additional maintenance of $3K

COST EFFECTIVENESS CALCULATION 30	
MGMRI	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	Unit MG17
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	3.49
Emissions Reduction (%)	50
Controlled Emissions (tpy)	1.745
Annualized Capital Costs	
Initial Capital Investment	$55,440
Direct & Indirect Costs	
Total Capital Investment	$55,440
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$4,028
Annual Operating Costs	
Fuel cost difference ($0.22/gallon, 16,389 gal/year at 115.1 hr/yr	$7,810
Maintenance	$3,000
Total Annualized Cost	$14,838
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.745
Cost Effectiveness ($/ton)	$8,503

Note:
Nelllis AFB actual emissions % of NAFB PTE (Unit 41) PTE = 8.07 tpy, actual max= 1.861, so 23.1% of 15.12 = 3.49

Based only 10% water in emulsion. Can go higher in water and reduce NOx more, but stability of emulsion decreased rapidly with additonal water.

Note:
Based on $24/kW capital costs.

Note:
Based on operation 23.1% of allowed 500 hours and use of 141.9 gal/hr at full load

Note:
Assumes this is the additional cost of maintenance.

COST EFFECTIVENESS CALCULATION 31	
MGMRI	
BOILERS	
ULTRA-LOW NOx BURNERS (LNB)	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	ULNB
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	77
Controlled Emissions (tpy)	0.3818
Annualized Capital Costs	
Initial Capital Investment	$235,000
Direct & Indirect Costs	
Total Capital Investment	$235,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$17,073
Annual Operating Costs	
Total Annualized Cost	$17,073
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.2782
Cost Effectiveness ($/ton)	$13,357

Note:
From MGMRI RACT analysis TAble 2-1.

Note:
MGMRI has 40 ppm LNB already on. ULNB burner quoted can get to 9 ppm, so about 77% reduction.

Note:
Based on quotes from Pyro Combustion Controls for a ULNB burner for Caesars boilers (in the Caesars RACT analysis).

Note:
None estimated

COST EFFECTIVENESS CALCULATION 32	
MGMRI	
BOILERS	
FGR	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FGR
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	35.69
Controlled Emissions (tpy)	1.067546
Annualized Capital Costs	
Initial Capital Investment	$77,200
Direct & Indirect Costs	
Total Capital Investment	$77,200
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$5,609
Annual Operating Costs	
Total Annualized Cost	$5,609
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.592454
Cost Effectiveness ($/ton)	$9,467

Note:
From MGMRI RACT analysis Table 2-1

Note:
From MGMRI Table 2-1

Note:
From MGMRI RACT analysis, Table 2-2.

Note:
If add corrected annual operating cost of $9439, CE becomes $25,399

COST EFFECTIVENESS CALCULATION 33	
MGMRI	
BOILERS	
Fuel-Induced Recirculation (FIR2)	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FIR2
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	35.69
Controlled Emissions (tpy)	1.067546
Annualized Capital Costs	
Initial Capital Investment	$94,920
Direct & Indirect Costs	$3,000
Total Capital Investment	$97,920
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$7,114
Annual Operating Costs	
Total Annualized Cost	$7,114
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.592454
Cost Effectiveness ($/ton)	$12,007

Note:
From MGMRI RACT analysis Table 2-1

Note:
From MGMRI RACT analysis, Table 2-1

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted with Chem Engr Cost Index (ratio = 824.5 (2022)/182.4 (1975) = 4.52). 4.52x21,000 = $94,920

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 34	
MGMRI	
BOILERS	
Ceramic Fiber Burners (CFB)	
Emissions Unit/Control Technology	
Emissions Unit	MG13 & MG14
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	CFB
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	62.5
Controlled Emissions (tpy)	0.6225
Annualized Capital Costs	
Initial Capital Investment	$36,235
Direct & Indirect Costs	$3,000
Total Capital Investment	$39,235
Estimated Equipment Life, years	10
Interest Rate, %	6
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$5,336
Annual Operating Costs	
5% fuel savings	
Total Annualized Cost	$5,336
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.0375
Cost Effectiveness ($/ton)	$5,143

Note:
From MGMRI RACT analysis -actual average annual emissions per boiler

Note:
Based on current 40 ppm v. ceramic 15 ppm: (40-15)/40 = 0.625 = 62.5%

Note:
Based on cost of $0.78/M Btu (per 1000 Btu), 33 MM Btu/hr burner, CEPCI = $824.5/585.7

Note: general estimate

COST EFFECTIVENESS CALCULATION 35	
MGMRI	
BOILERS	
Ceramic Fiber Burners (CFB)	
Emissions Unit/Control Technology	
Emissions Unit	MG13 & MG14
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	CFB
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	62.5
Controlled Emissions (tpy)	0.6225
Annualized Capital Costs	
Initial Capital Investment	$36,235
Direct & Indirect Costs	$3,000
Total Capital Investment	$39,235
Estimated Equipment Life, years	10
Interest Rate, %	6
Capital Recovery Factor	0.136
Annualized Total Capital Investment	$5,336
Annual Operating Costs	
5% fuel savings assuming 2094 hr/year	$31,959
Total Annualized Cost	-$26,623
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.0375
Cost Effectiveness ($/ton)	-$25,661

Note:
From MGMRI RACT analysis -actual average annual emissions per boiler

Note
Based on current 40 ppm v. ceramic 15 ppm: (40-15)/40 = 0.625 = 62.5%

Note:
Based on cost of $0.78/M Btu (per 1000 Btu), 33 Mm Btu/hr burner, CEPCI = $824.5/585.7

Note: general estimate

Note:
Assumes natural gas at $9.25/1000 cubic feet and operation of the burner at full capacity (33 MM Btu/hr). Operating hours estimated based on actual v. PTE: (1.66/6.95)x8760 = 2094 hr/yr. 2094x(33 mm Btu/hr)x (1 cu ft/1000 Btu)x ($9.25/1000 cu ft) x 0.05) = $31,959/yr

COST EFFECTIVENESS CALCULATION 36	
MGMRI	
BOILERS	
ULNB/FGR	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	ULNB/FGR
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	75
Controlled Emissions (tpy)	0.415
Annualized Capital Costs	
Initial Capital Investment	$77,200
Direct & Indirect Costs	$22,211
Total Capital Investment	$99,411
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$7,222
Annual Operating Costs	
General	$9,439
Total Annualized Cost	$16,661
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.245
Cost Effectiveness ($/ton)	$13,382

Note:
From MGMRI Table 2-1

Note:
From MGM RACT, Table 2-1

Note:
From MGMRI RACT analysis, Table 2-2

Note:
From the MGMRI RACT analysis, this annual cost is $22,211. If this is included in the costs but the annual operating cost is left out, CE =

Note:
From MGMRI RACT analysis. Leaving this and direct/indiirect costs out would result in a CE = $4505/ton, but this is unrealistic

COST EFFECTIVENESS CALCULATION 37	
MGMRI	
BOILERS	
Fuel-Induced Recirculation (FIR2)	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	FIR2
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	57
Controlled Emissions (tpy)	0.7138
Annualized Capital Costs	
Initial Capital Investment	$94,920
Direct & Indirect Costs	$3,000
Total Capital Investment	$97,920
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$7,114
Annual Operating Costs	
Total Annualized Cost	$7,114
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.9462
Cost Effectiveness ($/ton)	$7,518

Note:
From MGMRI RACT Table 2-1

Note:
From estimated reduction from 40 ppm to 17 ppm = 57%

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted with Chem Engr Cost Index (ratio = 824.5 (2022)/182.4 (1975) = 4.52). 4.52x21,000 = $94,920

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 38	
MGMRI	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
SELECTIVE CATALYTIC REDUCTION (SCR)	
Emissions Unit/Control Technology	
Emissions Unit	EX007
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	SCR
Baseline Emissions Rate (tpy)	3.49
Emissions Reduction (%)	90
Controlled Emissions (tpy)	0.349
Annualized Capital Costs	
Initial Capital Investment	$145,519
Direct & Indirect Costs	$15,340
Total Capital Investment	$160,859
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$11,686
Annual Operating Costs	
Urea	$1,666
Catalyst	$2,702
Maintenance	$6,000
Total Annualized Cost	$22,054
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	3.141
Cost Effectiveness ($/ton)	$7,021

Note:
MGMRI provided no actual emissions for individual units, so used highest PTE of 15.12 times the highest Nelllis AFB actual emissions % of NAFB PTE (Unit 41) PTE = 8.07 tpy, actual max= 1.861, so 23.1% of 15.12 = 3.49

Note:
90% reduction with SCR indicated in literature and WW Williams quote for Caesars

Note:
Based on quotes from WW Williams in Caesars RACT

Note:
From Caesars based on quote from WW Williams

Note:
All costs from Caesars

COST EFFECTIVENESS CALCULATION 39	
MGMRI	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
MANIFOLD AIR TEMPERATURE (MAT) REDUCTION	
Emissions Unit/Control Technology	
Emissions Unit	EX007
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	MAT
Baseline Emissions Rate (tpy)	3.49
Emissions Reduction (%)	70
Controlled Emissions (tpy)	1.047
Annualized Capital Costs	
Initial Capital Investment	$400,000
Direct & Indirect Costs	
Total Capital Investment	$400,000
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$29,060
Annual Operating Costs	
General	$60,000
Maintenance	
Total Annualized Cost	$89,060
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	2.443
Cost Effectiveness ($/ton)	$36,455

Note:
Nelllis AFB actual emissions % of NAFB PTE (Unit 41) PTE = 8.07 tpy, actual max= 1.861, so 23.1% of 15.12 = 3.49

Note:
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

Note:
1993 ACT, Fig. 6-10

Note:
1993 ACT, Figure 6-10

COST EFFECTIVENESS CALCULATION 40	
MGMRI	
INTERNAL COMBUSTION ENGINE (ICE) DIESEL GENERATORS	
Direct Water Injection (DWI)	
Emissions Unit/Control Technology	
Emissions Unit	MG17
Emission Unit Description	Emergency generator
Pollutant	NOx
Control Technology	DWI
Baseline Emissions Rate (tpy)	3.49
Emissions Reduction (%)	60
Controlled Emissions (tpy)	1.396
Annualized Capital Costs	
Initial Capital Investment	$84,627
Direct & Indirect Costs	
Total Capital Investment	$84,627
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$6,148
Annual Operating Costs	
2-3% Fuel Penalty	
Other	
Maintenance	$6,000
Total Annualized Cost	$12,148
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	2.094
Cost Effectiveness ($/ton)	$5,801

Note:
Nelllis AFB actual emissions % of NAFB PTE (Unit 41) PTE = 8.07 tpy, actual max= 1.861, so 23.1% of 15.12 = 3.49

Based on Issa article

Note:
Based on Issa article, which gave costs in $/kW for 6000 to 64,000 HP. Includes cost to adapt injection to existing engines. Extrapolated cost to smaller 1880 kW (2520 HP) engine to get $45/kW.

Note:
Double the general maintenance allowance of $3000 diue to potential effect of water injection into the cylinders.

Note:
$11,603/ton if use EPA's control levels of 25-35% (taking 30% midrange)

COST EFFECTIVENESS CALCULATION 41	
MGMRI	
BOILERS	
Overfire Air (OFA)	
Emissions Unit/Control Technology	
Emissions Unit	MG13
Emission Unit Description	NATURAL GAS BOILER
Pollutant	NOx
Control Technology	OFA
Baseline Emissions Rate (tpy)	1.66
Emissions Reduction (%)	50
Controlled Emissions (tpy)	0.83
Annualized Capital Costs	
Initial Capital Investment	$116,318
Direct & Indirect Costs	$3,000
Total Capital Investment	$119,318
Estimated Equipment Life, years	30
Interest Rate, %	6
Capital Recovery Factor	0.07265
Annualized Total Capital Investment	$8,668
Annual Operating Costs	
Total Annualized Cost	$8,668
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.83
Cost Effectiveness ($/ton)	$10,444

Note:
From MGMRI RACT analysis, Table 2-1

Note:
Based on 1975 cost for retrofit from 1978 EPA Control Tech doc of $21K (p. 4-55), adjusted for inflation withChem Engr index to 2022 (2022/1975 = $824.5/182.4 = 4.52

Note: general estimate

Note:
None estimated

COST EFFECTIVENESS CALCULATION 42	
CLARK COUNTY GENERATING STATION (CCGS)	
UNIT 4 (COMBUSTION TURBINE)	
Emissions Unit	4
Pollutant	NOx
Control Technology	SCR
Baseline Emissions (ppm@15% O2)	120
Controlled Emissions (ppm@15% O2)	4
Baseline Emissions Rate (tpy)	37.65
Controlled Emissions (tpy)	1.255
Emissions Reduction (%)	97%
Annualized Capital Costs	
Initial Capital Investment	10,100,000
Direct & Indirect Costs	7,000,000
Total Capital Investment	17,100,000
Estimated Equipment Life, years	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	1,894,124
Annual Operating Costs	
Catalyst	156,100
Total Annualized Cost	**2,050,224**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	36.4
Cost Effectiveness ($/ton)	**56,333**

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
Pollutant	NOx
Control Technology	Water Injection
Baseline Emissions (ppm@15% O2)	120
Controlled Emissions (ppm@15% O2)	25
Baseline Emissions Rate (tpy)	37.65
Controlled Emissions (tpy)	7.84
Emissions Reduction (%)	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**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	29.8
Cost Effectiveness ($/ton)	**114,188**

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 (CCGS)	
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 Emissions Rate (tpy)	2.05
Controlled Emissions (tpy)	0.41
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	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	391,009
Annual Operating Costs	
Catalyst	130,100
Total Annualized Cost	**521,109**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.6
Cost Effectiveness ($/ton)	**317,750**

Notes:

1. 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"

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 (see Attachment 7)

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 (CCGS)	
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 Emissions Rate (tpy)	14.3
Controlled Emissions (tpy)	5.72
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	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	2,334,366
Annual Operating Costs	
Catalyst	192,382
Total Annualized Cost	**2,526,748**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	8.6
Cost Effectiveness ($/ton)	**294,493**

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 (CCGS)	
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 Emissions Rate (tpy)	4.57
Controlled Emissions (tpy)	0.57
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	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	443,070
Annual Operating Costs	
Catalyst	130,100
Total Annualized Cost	**573,170**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	4.0
Cost Effectiveness ($/ton)	**143,337**

Notes:

according to generating capacity using 'six-tenths factor' methodology (see Attachment 9):

$Cost_1 / Cost_2 = (MW_1 / MW_2)^{0.6}$

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. 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)

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 (CCGS)	
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 Emissions Rate (tpy)	4.37
Controlled Emissions (tpy)	1.748
Emissions Reduction (%)	60%
Annualized Capital Costs	
Initial Capital Investment	
Direct & Indirect Costs	
Total Capital Investment	19,000,000
Estimated Equipment Life, years	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	2,104,582
Annual Operating Costs	
Total Annualized Cost	**2,104,582**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	2.6
Cost Effectiveness ($/ton)	**802,663**

Notes:

1. LNB total installed cost is based on CCGS Unit 4 vendor estimate (see Attachment 7a - RACT Analysis Request for Supporting Documentation (1/30/2023))

2. SCR upgrade costs are based on Saguaro Power Company vendor estimate for 35 MW CCU and scaled using 'six-tenths factor' methodology:

$Cost_2 = Cost_1 (MW_2 / MW_1)^{0.6}$

3. Achievable emissions for SCR/LNB is based the lowest RBLC determination for a similarly equipped unit (see RBLC Determinations - Attachment 10)

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 NV Energy RACT Analysis - Attachment 7)

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 Emissions Rate (tpy)	32.19
Controlled Emissions (tpy)	1.74
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	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	2,326,117
Annual Operating Costs	
Catalyst	192,382
Total Annualized Cost	**2,518,499**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	30.5
Cost Effectiveness ($/ton)	**82,709**

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 CCGS 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 Emissions Rate (tpy)	32.19
Controlled Emissions (tpy)	7.83
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	15
Interest Rate, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	1,163,059
Annual Operating Costs	
Total Annualized Cost	**1,163,059**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	24.4
Cost Effectiveness ($/ton)	**47,745**

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.*

COST EFFECTIVENESS CALCULATION 50	
SAGUARO POWER COMPANY	
UNIT 1 AND 2 (COMBINED CYCLE UNITS)	
Emissions Unit	2
Pollutant	NOx
Control Technology	SCR/LNB
Baseline Emissions (ppm@15% O2)	10
Controlled Emissions (ppm@15% O2)	2
Baseline Emissions Rate (tpy)	54.40
Controlled Emissions (tpy)	10.88
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, %	7.14
Capital Recovery Factor	0.111
Annualized Total Capital Investment	420,141
Annual Operating Costs	
Total Annualized Cost	**420,141**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	43.5
Cost Effectiveness ($/ton)	**9,654**

Notes:

1. *LNB total installed cost is based on CCGS Unit 4 vendor estimate (see Attachment 8 - SPC RACT Analysis)*
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 as per DAQ RACT guidelines.*
4. *Estimated equipment life is based on EPA CoST Model (version 4.1)*
5. *Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see SPC RACT Analysis - Attachment 8)*
6. *Unit 2 was selected as representative of both units for the cost effectiveness evaluation because it has the highest baseline emissions.*

COST EFFECTIVENESS CALCULATION 51	
SAGUARO POWER COMPANY	
UNIT 1 AND 2 (COMBINED CYCLE UNITS)	
Emissions Unit	2
Pollutant	NOx
Control Technology	Replace Catalyst on Existing SCR
Baseline Emissions (ppm@15% O2)	10
Controlled Emissions (ppm@15% O2)	3
Baseline Emissions Rate (tpy)	54.40
Controlled Emissions (tpy)	16.32
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, %	7.14
Capital Recovery Factor	0.245
Annualized Total Capital Investment	148,719
Annual Operating Costs	
Ammonia	207,500
Total Annualized Cost	**356,219**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	38.1
Cost Effectiveness ($/ton)	**9,355**

Notes:

1. *SCR catalyst replacement costs are based on Saguaro Power Company vendor estimate. DAQ assumes the additional ammonia is based on a catalyst replacement project that accommodates higher ammonia injection rates.*
2. *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)*
3. *The highest value was selected due to the uncertainty in the scope of the SCR catalyst replacement project.*
4. *Capital interest rate based on interest rate as per DAQ RACT guidelines.*
5. *Estimated equipment life assumes a five-year catalyst replacement cycle*
6. *Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see SPC RACT Analysis - Attachment 8)*
7. *Unit 2 was selected as representative of both units for the cost effectiveness evaluation because it has the highest baseline emissions.*

COST EFFECTIVENESS CALCULATION 52	
SAGUARO POWER COMPANY	
UNIT 5 (Indeck/Volcano Auxiliary Boiler)	
Emissions Unit	5
Pollutant	NOx
Control Technology	N/A
Baseline Emissions (ppm@3% O2)	12
Controlled Emissions (ppm@3% O2)	8.2
Baseline Emissions Rate (tpy)	0.39
Controlled Emissions (tpy)	0.27
Emissions Reduction (%)	32%
Annualized Capital Costs	
Initial Capital Investment	6,500
Direct & Indirect Costs	
Total Capital Investment	6,500
Estimated Equipment Life, years	15
Interest Rate, %	6.0
Capital Recovery Factor	0.103
Annualized Total Capital Investment	669
Annual Operating Costs	
Total Annualized Cost	**669**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.1
Cost Effectiveness ($/ton)	**5,419**

Notes:

1. Capital interest rate based on interest rate as per DAQ RACT guidelines.

2. Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1)

3.Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)

DAQ did not have sufficient information at the time of this evaluation to determine the technical feasibility of the combustion-related NOx controls. All/some of these options would be eliminated if the existing oxidation catalyst system is unable to offset additional CO formation by modifying the existing burner. DAQ also notes that any post-combustion controls (SCR) are not feasible due to relatively low boiler exit temperature. While technical feasibility of the combustion-NOx controls cannot be established, DAQ evaluated potential costs to determine whether there may be any cost-effective combustion controls even if they were deemed to be technically feasible. The data suggests that TCI would need to be less than $6,500 to achieve a RACT level reduction of 0.01 lb/MMBtu (~8.2 PPM @ 3% O2), which is the lowest RBLC determination for any combustion-related control option. DAQ is not aware of any potential upgrade that can be purchased for this cost.

COST EFFECTIVENESS CALCULATION 53	
SAGUARO POWER COMPANY	
UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	LNB Replacement with FGR
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	9
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.42
Emissions Reduction (%)	70%
Annualized Capital Costs	
Initial Capital Investment	657,629
Direct & Indirect Costs	
Total Capital Investment	657,629
Estimated Equipment Life, years	15
Interest Rate, %	6.0
Capital Recovery Factor	0.103
Annualized Total Capital Investment	67,711
Annual Operating Costs	
Total Annualized Cost	**67,711**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.0
Cost Effectiveness ($/ton)	**69,590**

Notes:

1. LNB/FGR cost is based on SPC vendor estimate (see Attachment 8 - SPC RACT Analysis). The estimate does not appear to include direct installation cost.

2. Achievable emissions are based on SPC vendor guarantee (see Attachment 8 - SPC RACT Analysis).

3. Capital interest rate based on DAQ RACT Guidelines document

4. Estimated equipment life for all control options based on EPA CoST Model (version 4.1)

5. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)

COST EFFECTIVENESS CALCULATION 53a	
SAGUARO POWER COMPANY	
UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	LNB Replacement with Metal Mesh LNB+FGR
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	5
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.23
Emissions Reduction (%)	83%
Annualized Capital Costs	
Initial Capital Investment	385,870
Direct & Indirect Costs	
Total Capital Investment	385,870
Estimated Equipment Life, years	15
Interest Rate, %	6.0
Capital Recovery Factor	0.103
Annualized Total Capital Investment	39,730
Annual Operating Costs	
Total Annualized Cost	**39,730**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.2
Cost Effectiveness ($/ton)	**34,299**

Notes:

1. The capital cost is based on a budgetary estimate provided to RTP (8/14/2023 email from Jason Howard to Note:) from Alzeta for a 35 MMBtu/hr firetube boiler ($225K) and scaled using 'six-tenths factor' methodology:

$$Cost_2 = Cost_1 (MW_2/MW_1)^{0.6}$$

$Cost_1$ (2023$)	$	*225,000*
HI_1 (MMBtu/hr)		35
HI_2 (MMBtu/hr)		86
Cost2 (2023$)	$	385,870

2. Estimate does not include direct installation cost

3. Achievable emissions of 5 ppm @ 3% O_2 based on a vendor literature. Literature suggests burners are capable of < 9 ppm but does not specify. DAQ assumes 5 ppm for conservatism using FGR option.

4. Capital interest rate based on interest rate as per DAQ RACT guidelines.

5. Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1) for LNB. Did not receive any information from vendor on equipment life.

6. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)

This LNB option (surface stabilized combustion burner), marketed by Alzeta (CSB product line), was identified by RTP during the preparation of the final report. Although budgetary costs were not provided in time for the final report by the vendor for this specific boiler, cost information was obtained for a similar burner design. Because cost effectiveness is >> DAQ cost threshold ($5,500/ton), this option was also eliminated from consideration. The cost and performance estimates used in the final report for the 'LNB+FGR' option are based on the assumptions below (8/15/2023).

COST EFFECTIVENESS CALCULATION 54	
SAGUARO POWER COMPANY	
UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	LNB Replacement with FGR
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	15
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.70
Emissions Reduction (%)	50%
Annualized Capital Costs	
Initial Capital Investment	94,430
Direct & Indirect Costs	
Total Capital Investment	94,430
Estimated Equipment Life, years	10
Interest Rate, %	6.0
Capital Recovery Factor	0.136
Annualized Total Capital Investment	12,830
Annual Operating Costs	
Total Annualized Cost	**12,830**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.7
Cost Effectiveness ($/ton)	**18,460**

Notes:

1. The capital cost of the ceramic fiber burner ($0.78/1000 Btu (2011$)) based on a whitepaper (Characterizing Costs, Savings, and Benefits of a Selection of Energy Efficient Emerging Technologies in the

Burner Rating (MMBtu/hr)		*86*	
Burner Equipment Cost	*$*	*67,080*	*2011$*
	$	*94,430*	*2022$*

2. Present value cost adjustment (2022$) = Cost x CEPCI (2022) / CEPCI (YYYY)

CEPCI (8/2022)	*824.5*
CEPCI (2011)	*585.7*

3. Estimate does not include direct installation cost

4. Achievable emissions of 15 ppm @ 3% O_2 based on a vendor whitepaper (Radiant Fiber Burners for Gas-Fired Appliances and Equipment, John P. Kesselring, Robert M. Kendall, and Richard J. Schreiber, Alzeta

5. Capital interest rate based on interest rate as per DAQ RACT guidelines.

6. Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1)

7. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 10 - SPC RACT Analysis)

COST EFFECTIVENESS CALCULATION 55	
SAGUARO POWER COMPANY	
UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	FIR
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	9
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.42
Emissions Reduction (%)	70%
Annualized Capital Costs	
Initial Capital Investment	507,629
Direct & Indirect Costs	
Total Capital Investment	507,629
Estimated Equipment Life, years	15
Interest Rate, %	6.0
Capital Recovery Factor	0.103
Annualized Total Capital Investment	52,267
Annual Operating Costs	
Total Annualized Cost	**52,267**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	1.0
Cost Effectiveness ($/ton)	**53,717**

Notes:

1. *Achievable emissions are assumed to be similar to LNB upgrade+FGR (9 ppm @ 3% O2). LNB+FGR performance is based on vendor guarantee (see Attachment 8 - SPC RACT Analysis)*
2. *FIR costs are assumed to be the same as LNB upgrade without FGR. This cost is based on a vendor estimate for LNB+FGR (see Attachment 8 - SPC RACT Analysis)*
3. *DAQ did not include the 'cost adder for 9 ppm' ($150K) because this represents the additional cost of FGR in the LNB+FGR cost estimate.*
4. *Capital interest rate based on interest rate as per DAQ RACT guidelines.*
5. *Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1)*
6. *Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)*

COST EFFECTIVENESS CALCULATION 56	
SAGUARO POWER COMPANY	
UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	FIR2
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	13
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.58
Emissions Reduction (%)	58%
Annualized Capital Costs	
Initial Capital Investment	150,000
Direct & Indirect Costs	
Total Capital Investment	150,000
Estimated Equipment Life, years	15
Interest Rate, %	6
Capital Recovery Factor	0.103
Annualized Total Capital Investment	15,444
Annual Operating Costs	
Total Annualized Cost	**15,444**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.8
Cost Effectiveness ($/ton)	**19,157**

Notes:

1. Achievable emissions assume an incremental reduction of 58% based on the average removal efficiency demonstrated in a utility boiler study (Demonstration of Fuel Injection Recirculation (FIR) for NOx Emissions Control, Reese, James L., et al., 1994).

2. FIR2 costs are assumed to be the same as the installation of FGR without burner replacement. This cost is based on a vendor estimate for LNB+FGR (see Attachment 8 - SPC RACT Analysis)

3. DAQ assumes that the 'cost adder for 9 ppm' ($150K) represents the additional cost for adding FGR in the LNB+FGR cost estimate. This may understate actual cost associated with FGR retrofit w/o burner replacement.

4. Capital interest rate based on interest rate as per DAQ RACT guidelines.

5. Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1)

6. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)

COST EFFECTIVENESS CALCULATION 57	
SAGUARO POWER COMPANY	
UNIT 6 (NEBRASKA BOILER)	
Emissions Unit	6
Pollutant	NOx
Control Technology	FGR
Baseline Emissions (ppm@3% O2)	30
Controlled Emissions (ppm@3% O2)	15
Baseline Emissions Rate (tpy)	1.39
Controlled Emissions (tpy)	0.70
Emissions Reduction (%)	50%
Annualized Capital Costs	
Initial Capital Investment	150,000
Direct & Indirect Costs	
Total Capital Investment	150,000
Estimated Equipment Life, years	15
Interest Rate, %	6
Capital Recovery Factor	0.103
Annualized Total Capital Investment	15,444
Annual Operating Costs	
Total Annualized Cost	**15,444**
Cost Effectiveness (CE)	
Emissions Reduction (tpy)	0.7
Cost Effectiveness ($/ton)	**22,222**

Notes:

1. Achievable emissions assumes an incremental reduction of 50% based on the upper range of expected performance from other installations (40-50% using 20-30% FGR).

2. FIR costs are assumed to be the same as the installation of FGR without burner replacement. This cost is based on a vendor estimate for LNB+FGR (see Attachment 8 - SPC RACT Analysis)

3. DAQ assumes that the 'cost adder for 9 ppm' ($150K) represents the additional cost for adding FGR in the LNB+FGR cost estimate. This may understate actual cost associated with FGR retrofit w/o burner replacement.

4. Capital interest rate based on interest rate as per DAQ RACT guidelines.

5. Estimated equipment life for combustion-related upgrades are 15 years based on EPA CoST Model (version 4.1)

6. Baseline NOx emissions (tpy) based on maximum two-year annual average for the period 2017-2021 (see Attachment 8 - SPC RACT Analysis)

Appendix 10

DAQ RBLC Determinations

Case-by-Case Major Source RACT Analyses for Clark County, NV: Appendices

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
AL-0307	ALLOYS PLANT	AL	10/9/2015	PACKAGE BOILER	17.5	MMBTU/H	LOW NOX BURNER FLUE GAS RECIRCULATION GCP	30	PPMVD	3% O2	0.64	LB/H		0		
AL-0307	ALLOYS PLANT	AL	10/9/2015	2 CALP LINE BOILERS	24.59	MMBTU/H	LOW NOX BURNER FLUE GAS RECIRCULATION (FGR) GOOD COMBUSTION PRACTICES (GCP)	30	PPMVD	3% O2	0.9	LB/H		0		
FL-0335	SUWANNEE MILL	FL	9/5/2012	Four(4) Natural Gas Boilers - 46 MMBtu/hour	46	MMBTU/H	Low NOx Burner and Flue Gas Recirculation	0.036	LB/MMBTU		0			0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	80	MMBTU/H	LOW NOX BURNER WITH FLUE GAS RECIRCULATION	0.032	LB/MMBTU	3 HOURS	2.56	LB/H	3 HOURS	0		
MD-0041	CPV ST. CHARLES	MD	4/23/2014	AUXILLARY BOILER	93	MMBTU/H	EXCLUSIVE USE OF NATURAL GAS, ULTRA LOW-NOX BURNERS, AND FLUE GAS RECIRCULATION (FGR)	0.011	LB/MMBTU	3-HOUR AVERAGE	0			0		
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FGAUXBOILERS: Two auxiliary boilers < 100 MMBTU/H heat input each	100	MMBTU/H heat input each	Low NOx burners and flue gas recirculation.	0.05	LB/MMBTU	TEST PROTOCOL	0			0		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB)	95	MMBTU/H	Dry low NOx burners, flue gas recirculation and good combustion practices.	0.05	LB/MMBTU	TEST PROTOCOL	0			0		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUAUXBOILER (Auxiliary boiler)	83.5	MMBTU/H	Low NOx burners/Internal flue gas recirculation and good combustion practices.	0.05	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUAUXBOILER (North Plant): Auxiliary Boilder	61.5	MMBTU/H	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	6/29/2018	EUAUXBOILER (South Plant): Auxiliary Boiler	61.5	MMBTU/h	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	7/16/2018	EUAUXBOILER: Auxiliary Boiler	99.9	MMBTU/H	Low NOx burners/Flue gas recirculation.	0.036	LB/MMBTU	HOURLY	3.6	LB/H	HOURLY	0		
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Boiler less than 100 MMBtu/hr	51.9	mmcubic ft/year	Low NOx burners and flue gas recirculation	0.01	LB/MMBTU	AVERAGE OF THREE TESTS	0.66	LB/H	AVERAGE OF THREE TESTS	0		
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Auxiliary boiler	60	MMBTU/H	flue gas recirculation with low NOx burners	0.0085	LB/MMBTU	1 H	0			0		
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Auxiliary boiler	0		Flue gas recirculation with low NOx burners.	0.045	LB/MMBTU	1 H	0			0		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Auxillary Boiler	99	MMBtu/H	low NOx burners and flue gas recirculation	1.98	LB/H		1.98	T/YR	PER ROLLING 12-MONTHS	0.02	LB/MMBTU	
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Auxiliary Boiler (B001)	99	MMBtu/H	low NOx burners and flue gas recirculation	1.98	LB/H		4.46	T/YR		0.02	LB/MMBTU	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Auxiliary Boiler (B001)	34	MMBTU/H	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	
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	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	9/27/2017	Auxiliary Boiler (B001)	37.8	MMBTU/H	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-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Auxiliary Boiler (B001)	26.8	MMBTU/H	Flue gas recirculation and low NOX burner	0.29	LB/H		0.74	T/YR	PER ROLLING 12 MONTH PERIOD	0.011	LB/MMBTU	
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	Auxiliary boiler	39.8	MMBTU/H	Utilize Low-NOx burners and FGR.	0.035	LB/MMBTU	3-HR BLOCK AVERAGE	0			0		
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	PA	6/15/2015	Auxilary Boiler	62.04	MCF/hr	Good combustion practices, Ultra-Low NOx burners, FGR	0.0086	LB/MMBTU		2.3	TPY	ANY CONSECUTIVE 12-MONTH PERIOD	0		
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Auxilary boiler	92.4	MMBtu/hr	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-0319	RENAISSANCE ENERGY CENTER	PA	8/27/2018	NATURAL GAS FIRED AUXILIARY BOILER	88	MMBtu/hr	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	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	95.7	MMBTU/H	Low NOx burners and flue gas recirculation	0.011	LB/MMBTU		0			0		
WI-0283	AFE, INC. â€“LCM PLANT	WI	4/24/2018	B01-B12, Boilers	28	mmBTU/hr	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	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	28	mmBTU	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices.	0.0105	LB/MMBTU	1-HOUR AVERAGE	0			0		
*WV-0029	HARRISON COUNTY POWER PLANT	WV	3/27/2018	Auxiliary Boiler	77.8	mmBtu/hr	LNB, FGR, Good Combustion Practices	0.86	LB/HR		1.96	TONS/YEAR		0.0011	LB/MMBTU	
WY-0075	CHEYENNE PRAIRIE GENERATING STATION	WY	7/16/2014	Auxiliary Boiler	25.06	MMBtu/h	Ultra low NOx burners and flue gas recirculation	0.0175	LB/MMBTU	3 HOUR AVERAGE	0.4	LB/H	3 HOUR AVERAGE	0		

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
IN-0261	VERMILLION GENERATING STATION	IN	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES	250	LB/H	EACH TURBINE	25	TON/12 CONSEC. MONTH	COMPLIANCE DETERMINED END OF EACH MONTH	0		
LA-0343	SABINE PASS LNG TERMINAL	LA	9/6/2019	gas turbines during startups, shutdowns, and maintenance	0		good combustion practices	96	PPMV	@ 15% O2	0			0		

RBLC Query Results - NOx (Water Injection) (15.110 - Gas Fired Simple Cycle Turbines)

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
IN-0264	MONTPELIER GENERATING STATION	IN	1/6/2017	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	WATER INJECTION	25	PPMV	AT 15% O2 FOR NATURAL GAS	42	PPMV	AT 15% O2 FOR FUEL OIL	0		

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MM BTU/h	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	25	PPMV	30 DAY ROLLING AVERAGE	0			0		
ND-0030	LONESOME CREEK GENERATING STATION	ND	9/16/2013	Natural Gas Fired Simple Cycle Turbines	412	MMBTU/H	SCR	5	PPMVD	4 HOUR ROLLING AVERAGE EXCEPT STARTUP	18.5	LB	TOTAL FOR 30 MINUTES DURING STARTUP	0		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP03)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR	7.7	LB/H	30-DAY ROLLING AVERAGE	36	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Trubine (EP04)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR AVERAGE	7.7	LB/H	30-DAY ROLLING AVERAGE	36	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP05)	40	MW	SCR	5	PPMV AT 15% O2	1-HOUR	7.7	LB/H	30-DAY ROLLING AVERAGE	36	T/YR	

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Six Simle Cycle Gas-Fired Turbines	1113	MMBtu/hr	SCR, DLN combustors, and good combustion practices	2	PPMV @ 15% O2	3-HOURS	0			0		
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LA	9/3/2020	Turbines (EQT0020 - EQT0031)			LNB + SCR	3.1	PPMVD @15%O2	3-HOUR AVERAGE	0			0		
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	2 COMBUSTION TURBINES	130	MW	USE OF DRY LOW-NOX COMBUSTOR TURBINE DESIGN (DLN1), USE OF FACILITY PROCESS FUEL GAS AND PIPELINE NATURAL GAS DURING NORMAL OPERATION AND SCR SYSTEM	2.5	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	1304.5	LB/EVENT	FOR ALL STARTUPS	0		

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
CA-1223	PIO PICO ENERGY CENTER	CA	11/19/2012	COMBUSTION TURBINES (NORMAL OPERATION)	300	MW	WATER INJECTION, SCR	2.5	PPMVD	@15% O2, 1-HR AVG	8.18	LB/H	1-HR AVG	0		
CA-1223	PIO PICO ENERGY CENTER	CA	11/19/2012	(STARTUP & SHUTDOWN PERIODS)	300	MW	water injection and SCR system	22.5	LB/H	STARTUP EVENTS	6	LB/H	SHUTDOWN EVENTS	0		
ND-0029	PIONEER GENERATING STATION	ND	5/14/2013	Natural gas-fired turbines	451	MMBTU/H	Water injection plus SCR	5	PPPMVD	AVERAGE EXCEPT FOR	19	LB/H	DURING STARTUP	0		
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	turbines, simple cycle with water injection	1690	MMBTU/H	combusting natural gas or ULSD;	2.5	PPMDV AT 15% O2	AVERAGE ON NG	3.8	PPMDV AT 15% O2	AVERAGE ON ULSD	0		

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
AK-0085	GAS TREATMENT PLANT	AK	8/13/2020	Six (6) Simple Cycle Gas-Turbines (Power Generation)	386	MMBtu/hr	Good Combustion Practices and burning clean fuels (NG)	0.0022	LB/MMBTU	3-HOUR AVERAGE	0			0		
FL-0346	LAUDERDALE PLANT	FL	4/22/2014	Five 200-MW combustion turbines	2000	MMBtu/hr (approx)	Good combustion practice	3.77	LB/H	THREE ONE-HR RUNS (NATURAL GAS)	8	LB/H	THREE ONE-HR RUNS (OIL)	0		
IN-0261	VERMILLION GENERATING STATION	IN	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES	17.6	LB/H	EACH TURBINE	1.76	TON/12 CONSEC. MONTH	DETERMINED END OF EACH MONTH	0		
LA-0307	MAGNOLIA LNG FACILITY	LA	3/21/2016	Gas Turbines (8 units)	333	mm btu/hr	good combustion practices and fueled by natural gas	0			0			0		
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	Gas turbines (9 units)	1069	mm btu/hr	good combustion practices and fueled by natural gas	1.6	PPMVD	@15%O2	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	0			0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	0			0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runb	2201	MM BTU/hR	Good combustion practices & use of pipeline quality natural gas	0			0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runb	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	0			0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	0			0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	0			0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MM BTU/h	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.5	PPMV	3 HOUR AVERAGE	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	927	MM BTU/h	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.4	PPMV	3 HOUR AVERAGE	0			0		
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LA	9/3/2020	Turbines (EQT0020 - EQT0031)	0		Good combustion practices	0			0			0		
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	rated 667 MMBTU/hr natural gas-fired simple cycle CTG	667	MMBTU/H	Good combustion practices.	5	LB/H	DURING STARTUP/SHUT DOWN	0			0		
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGSC1-natural gas fired simple cycle CTG	667	MMBTU/H	Good combustion practices	5	LB/H	EXCEPT DURING STARTUP/SHUT DOWN	0			0		
TX-0696	ROANâ€™S PRAIRIE GENERATING STATION	TX	9/22/2014	(2) simple cycle turbines	600	MW	good combustion	1.4	PPMVD	@15% O2 GE OPTION	1	PPMVD	@15% O2 SIEMENS OPTION	0		
TX-0733	ANTELOPE ELK ENERGY CENTER	TX	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Good combustion practices	2	PPMVD @ 15% O2		0			0		
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	TX	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	2	PPMVD @ 15% O2		0			0		
TX-0768	SHAWNEE ENERGY CENTER	TX	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	Pipeline quality natural gas; limited hours; good combustion practices.	1.4	PPMV		0			0		
TX-0788	NECHES STATION	TX	3/24/2016	Large Combustion Turbines > 25 MW	232	MW	good combustion practices	2	PPM		0			0		
TX-0819	GAINES COUNTY POWER PLANT	TX	4/28/2017	Simple Cycle Turbine	227.5	MW	Pipeline quality natural gas; limited hours; good combustion practices	2	PPMVD	145% O2	0			0		
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines	920	MW	Good combustion practices	2	PPMVD		0			0		

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Six Simle Cycle Gas-Fired Turbines	1113	MMBtu/hr	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS	0			0		
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	2 COMBUSTION TURBINES	130	MW	AND PIPELINE NATURAL GAS, GOOD COMBUSTION	0.7	PPMVD @ 15% O2	AVERAGE, EXCLUDING	101.1	LB/EVENT	FOR ALL STARTUPS	0		
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	Oxidation Catalyst, and use of natural gas as fuel for pollution	2	PPMVD@15%O 2	BASED ON ONE H BLOCK AV	1.65	LB/H	ONE H STACK TESTS EVERY 5	0		
OR-0050	TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	turbines, simple cycle with water injection	1690	MMBTU/H	Limit the time in startup or shutdown.	0			0			0		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP03)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE	3	LB/H	3-HOUR AVERAGE	14	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Trubine (EP04)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE	3	LB/H	3-HOUR AVERAGE	14	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Simple Cycle Turbine (EP05)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE	3	LB/H	3-HOUR AVERAGE	14	T/YR	

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AL-0328	PLANT BARRY	AL	11/9/2020	Two 744 MW Combined Cycle Units	744	MW	SCR	2	PPM	3 HOUR AVG / @15% O2	39.1	LB/HR	3 HOUR AVG	0		
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	0			0		
CT-0158	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	SCR	2	PPMVD @15% O2	1 HR BLOCK	2	PPMVD @15% O2	1 HR BLOCK	0		
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	Combustion Turbine with SCR/HRSG	607.1	MMBTU/hr	Selective Catalytic Reduction (SCR) and Water/Steam Injection	11.89	LB/H	HOURLY MAXIMUM	52.07	T/YR	ANNUAL MAXIMUM	5	PPM@15% O2	12 MONTH AVERAGE
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Selelctive catalytic reduction (SCR) system	2	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK	16.5	LB/H	AVERAGE OF THREE TESTS	0		
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Selective Catalytic Reduction (SCR) System and use of natural gas a clean burning fuel	0.75	LB/H	AVERAGE OF THREE TESTS	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK AVE	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Selective Catalytic Reduction System (SCR)	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK AVE	19.5	LB/H	AVERAGE OF THREE ONE HOUR TESTS	0		
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Selective Catalytic Reduction System (SCR) and use of natural gas a clean burning fuel	2	PPMVD@15%O2	3-HR ROLLING AVE BASED ON 1-HR BLOCK	17.33	LB/H	3-HR ROLLING AVE BASED ON 1-HR BLOCK	0		
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Selective Catalytic reduction (SCR) and use of natural gas a clean burning fuel	23	LB/H	3-HR ROLLING AVE BASED ON 1-HR BLOCK	2	PPMVD@15%O2	3-HR ROLLING AVE BASED ON 1-HR BLOCK	0		
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Combined Cycle Power Blocks 472 MW - (2)	0		SCR	2	PPMDV		111.2	T/YR	EACH UNIT	0		
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H	SCR	2	PPM	CORRECTED TO 15% OXYGEN	17.4	LB/H	DUCT BURNERS NOT OPERATING	18.4	LB/H	DUCT BURNERS OPERATING
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR	SCR	2	PPMVD @ 15% O2	WITH OR WITHOUT DUCT BURNER	17.25	TPY 12 MONTH ROLLING	INCLUDING START UP AND SHUR DOWN	0		
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046	MMBTU/H	SCR	131.6	TPY	12-MONTH ROLLING TOTAL	0			0		
*PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267	MMBTU/H	SCR	2	PPMVD	@ 15% OXYGEN	19.6	LB/H	WITH DUCT BURNER	79.9	TPY	BASED ON A 12-MONTH ROLLING TOTAL
TX-0709	SAND HILL ENERGY CENTER	TX	9/13/2013	Natural gas-fired combined cycle turbines	173.9	MW	SCR	2	PPM	24HR ROLLING AVG.	0			0		
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	0			0		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	SCR	3	PPMV AT 15% O2	1-HOUR	4.6	LB/H	30-DAY ROLLING AVERAGE	25.5	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	SCR	3	PPMV AT 15% O2	1-HOUR	4.6	LB/H	30-DAY ROLLING AVERAGE	25.5	T/YR	

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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	0			0		
CO-0076	PUEBLO AIRPORT GENERATING STATION	CO	12/11/2014	Four combined cycle combustion turbines	373	MMBTU/H each	SCR and dry low NOx burners	8	LB/H	4-HR ROLLING AVE / STARTUP AND SHUTDOWN	0			0		
FL-0337	POLK POWER STATION	FL	10/14/2012	Combine cycle power block (4 on 1)	1160	MW	SCR/DLN	2	PPMVD @15% O2	24-HR BLOCK (GAS) CEMS	8	PPMVD @15% O2	24-HR BLOCK (OIL) CEMS	0		
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)	15	PPMVD AT 15% O2	30-OPERATING-DAY ROLLING AVG. (NSPS)	0		
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)	15	PPMVD AT 15% O2	30-OPERATING-DAY ROLLING AVG. (NSPS)	0		
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258	mmBtu/hr	Low-NOx burners and SCR	2	PPM	30-DAY ROLLING AVG. @15% O2	114.5	TON/YR	12-MONTH ROLLING TOTAL	0		
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	Combustion turbine #2 - combined cycle	2258	mmBtu/hr	SCR, Low-NOx burner	2	PPM	30-DAY ROLLING AVERAGE	114.5	TON/YR	12-MONTH ROLLING TOTAL	0		
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	5	PPMV @ 15% O2	3-UNIT OPERATING HOURS	0		
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	2	PPMV	1-UNIT OPERATING HOUR @ 15% O2	0		
IL-0133	LINCOLN LAND ENERGY CENTER	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	SEE NOTES	0		SEE NOTES	0		
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	0			0		
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	0			0		
*LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	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-HR AVG	0			0		
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	123	LB/EVENT	CEM	0		
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	USE OF DRY LOW-NOX COMBUSTOR TURBINE DESIGN , USE OF PIPELINE QUALITY NATURAL GAS DURING NORMAL OPERATION AND SCR SYSTEM	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	870	LB/EVENT	FOR ALL STARTUPS	0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	153	LB/EVENT	COLD STARTUP	0			0		
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)	42	PPM @ 15% O2	3-HOUR BLOCK AVERAGE	0		

MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	132	LB/EVENT	WARM STARTUP	0			0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	286	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	105	LB/EVENT	HOT STARTUP	0			0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	286	MW	DRY LOW-NOX COMBUSTOR DESIGN, GOOD COMBUSTION PRACTICES AND SELECTIVE CATALYTIC REDUCTION (SCR)	23	LB/EVENT	SHUT DOWN	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	235	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	245.2	LB/EVENT	COLD STARTUP	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	235	MW	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	82.9	LB/EVENT	WARM STARTUP	0			0		
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Dry low NOx (DLN) burner and selective catalytic reduction (SCR) system.	2	PPM	EACH CTG; 24-H ROLLING AVG.	16.2	LB/H	EACH CTG; 24-H ROLLING AVG.	0		
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Dry low NOx (DLN) burners and selective catalytic reduction (SCR) system.	2	PPM	24-H ROLLING AVG	18	LB/H	24-H ROLLING AVG	0		
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG--Startup/Shutdown	2237	MMBTU/H each	Dry low NOx (DLN) burner and selective catalytic reduction (SCR)	185.7	LB/H	HOURLY DURING STARTUP	134	LB/H	HOURLY DURING SHUTDOWN	0		
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Dry Low NOx burners (DLN) and Selective Catalytic Reduction (SCR) system.	2	PPMVOL	3-H ROLL AVG., EXCEPT STARTUP/SHUT DOWN	18.6	PPH	24-H ROLL AVG., EXCEPT STARTUP/SHUT DOWN	0		
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Dry low NOx burner (DLN) and selective catalytic reduction system (SCR).	2	PPMVOL	3-H ROLL AVG., EXCEPT STARTUP/SHUT DOWN	23.7	PPH	24-H ROLL AVG., EXCEPT STARTUP/SHUT DOWN	0		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each CTGHRSG	SCR with DLNB (selective catalytic reduction with dry low NOx burners).	3	PPM	24-H ROLL.AVG. NOT STARTUP/SHUT DOWN	8.18	LB/H	24-H ROLL.AVG. NOT STARTUP/SHUT DOWN	0		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: Startup & Shutdown	647	MMBTU/H for each CTGHRSG	SCR with DLNB (selective catalytic reduction with dry low NOx burners).	43.7	LB/H	OPERATING HOUR DURING STARTUP	43.1	LB/H	OPERATING HOUR DURING SHUTDOWN	0		
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)	38.1	LB/H	24-H ROLLING AVERAGE	286	LB/H	OPERATING HR DURING STARTUP OR SHUTDOWN	0		
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	8.18	LB/H	24-H ROLLING AVG; EACH EU	0		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	FGCTGHRSG--Startup/Shutdown (2 combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	554	MMBTU/H; EACH	Selective catalytic reduction with dry low NOx burners (SCR with DLNB).	43.7	LB/H	OPERATING HOUR DURING STARTUP; EACH EU	43.1	LB/H	OPERATING HOUR DURING SHUTDOWN; EACH EU	0		

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/SHUT DOWN	21.4	LB/H	24-H ROLL.AVG., EXCEPT STARTUP/SHUT DOWN	0		
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	38.1	LB/H	24-HR ROLL AVG.	0		
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	22.4	LB/H	EACH INDIV. CT/HRSG TRAIN; 24-H ROLL AVG	0		
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.	29.7	LB/H	24-H ROLL AVG NOT S.S.	0		
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.	29.7	LB/H	24-H ROLL AVG; NOT STARTUP/SHUT DOWN (SS)	0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)	0		SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	2	PPMVD	AT 15%O2; 24-H ROLL AVG; EACH UNIT;	28.9	LB/H	24-H ROLL AVG; EACH UNIT; NOT S.S.	0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)--Startup & Shutdown	0		SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	262.4	LB/H	EACH UNIT; OPERATING HOUR DURING S.S.	0			0		
*MI-0451	MEC NORTH, LLC	MI	6/23/2022	EUCTGHRSG (North Plant): A combined cycle natural gas fired combustion turbine generator with heat recovery steam generator	3064	MMBTU/H	SCR with DLNB (Selective catalytic reduction with Dry low NOx burners)	2.5	PPM	24-HR ROLLING AVG	29.2	LB/H	24-HR ROLLING AVG	0		
*MI-0452	MEC SOUTH, LLC	MI	6/23/2022	EUCTGHRSG (South Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	3064	MMBTU/H	SCR with DLNB [Selective Catalytic Reduction with Dry Low NOx Burners]	2	PPM	24-HR ROLLING AVG	29.2	LB/H	24-HR ROLLING AVG EXCEPT SU/SD	0		
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	DLN combustion system with SCR on each of the two combustion turbines and use of only natural gas as fuel.	2	PPMVD	3-HR ROLLING AVE BASED ON 1-HR BLOCK	16.8	LB/H	AVERAGE OF THREE TESTS	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Selective Catalytic Reduction Systems(SCR) and Dry Low NOx	2	PPMVD@15%O2	3-HR BLOCK AVERAGE BASED ON 1-HR BLOCK	18.1	LB/H	AVERAGE OF THREE ONE HOUR TESTS	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Selective Catalytic Reduction System (SCR) and Dry Low NOx	2	PPMVD@15%O2	3-HR ROLLING AVERAE BASED ON 1-HR BLOCK	16.8	LB/H	AVERAGE OF THREE ONE-HOUR TESTS	0		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600	MMSCF/rolling 12-months	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	22	LB/H		92	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-MO	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	21	LB/H		92	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-MO	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	22.6	LB/H		94.8	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2

OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines- Mitsubishi, with duct burners	47917	MMSCF/rolling 12-MO	selective catalytic reduction (SCR); dry low NOx combustors; lean fuel technology	20.8	LB/H		94.8	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2045	MMBTU/H	selective catalytic reduction (SCR) and dry low NOx combustors	20.5	LB/H	WITH DUCT BURNER. SEE NOTES.	103.2	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME AT 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)	23.5	LB/H	WITH DUCT BURNER. SEE NOTES.	107.2	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
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.	30.51	LB/H	WITH DUCT BURNER. SEE NOTES.	151.3	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	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)	25.3	LB/H	WITH DUCT BURNER. SEE NOTES.	117.6	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	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)	25.3	LB/H	WITH DUCT BURNER. SEE NOTES.	118.02	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	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	33.85	LB/H	WITH DUCT BURNER. SEE NOTES.	26.37	LB/H	WITHOUT DUCT BURNERS. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Dry low-NOx (DLN) combustor and selective catalytic reduction (SCR)	2	PPMVD		0			0		
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		358.9	TONS	ANY 12-MONTH PERIOD	0		
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		100.3	TONS	YEAR	0		
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		233.3	TONS	12-MONTH ROLLING BASIS	0		
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		25.7	LB/HR		0		
TX-0689	CEDAR BAYOU ELECTRIC GENERATION STATION	TX	8/29/2014	Combined cycle natural gas turbines	225	MW	DLN, SCR	2	PPM	24HR ROLLING AVG.	0			0		
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	0			0		
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	0			0		
*VA-0335	PANDA STONEWALL LLC	VA	12/18/2020	Combustion Turbines, Two (2) and HRSG Duct Burners	2.55	MMBTU/H	Selective Catalytic Reduction (SCR), with ammonia injection and dry low NOx combustion.	2	PPMVD @ 15% O2	W & W/O DUCT BURNING	0			0		
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	6	PPM AT 15% O2	24-HR ROLLING AVG., DIESEL	0		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	SCR & Dry Low-NOx Burners	15.2	LB/H		0			2	PPM	@ 15% O2
*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	32.09	LB/HR	3-HOUR ROLLING AVERAGE	0.43	LB/MWH GROSS	30 OPERATING DAY ROLLING AVG.
*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	34.09	LB/HR	3-HOUR ROLLING AVERAGE	0.43	LB/MWH GROSS	30 OPERATING DAY ROLLING AVG.

Case-by-Case Major Source RACT Analyses for Clark County, NV: Appendices

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
*LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	LA	6/3/2022	Combined Cycle Gas Turbine Startup and Shutdown	5081	mm BTU/h	Good combustion practices.	520	LB/HR		0			0		
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG	2237	MMBTU/H	Good combustion practices	0.0018	LB/MMBTU	EACH CTG; TEST PROTOCOL	0			0		
MI-0405	MIDLAND COGENERATION VENTURE	MI	4/23/2013	Natural gas fueled combined cycle combustion turbine generators (CTG) with HRSG and duct burner (DB)	2486	MMBTU/H	Good combustion practices	0.004	LB/MMBTU	TEST PROTOCOL	0			0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Combined Cycle Combustion Turbine - Siemens turbine without Duct Burner	33691	MMCF/YR	Good Combustion Practices and use of Natural gas as a clean burning fuel	1	PPMVD@ 15%O2	AVERAGE OF THREE TESTS	6.4	LB/H	AVERAGE OF THREE TESTS	0		
TX-0618	CHANNEL ENERGY CENTER LLC	TX	10/15/2012	Combined Cycle Turbine	180	MW	Good combustion	2	PPMVD	@15% O2	0			0		
TX-0619	DEER PARK ENERGY CENTER	TX	9/26/2012	Combined Cycle Turbine	180	MW	good combustion, use of natural gas	2	PPMVD	@15% O2	0			0		
TX-0620	ES JOSLIN POWER PLANT	TX	9/12/2012	Combined cycle gas turbine	195	MW	good combustion and natural gas as fuel	2	PPMVD	@15% O2	0			0		

RBLCID	FACILITY NAME	STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	UNITS	CONTROL METHOD	EMISSION LIMIT 1	UNITS	AVERAGING TIME	EMISSION LIMIT 2	UNITS	AVERAGING TIME	STANDARD EMISSION LIMIT	UNITS	AVERAGING TIME
AK-0088	LIQUEFACTION PLANT	AK	7/7/2022	Four Combined Cycle Gas-Fired Turbines	384	MMBtu/hr	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS	0			0		
AL-0328	PLANT BARRY	AL	11/9/2020	Two 744 MW Combined Cycle Units	744	MW	Oxidation Catalyst	13.6	LB/HR	3 HOUR AVG	0.003	LB/MMBTU	3 HOUR AVG	0		
CT-0157	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/12 months	Oxidation Catalyst	1	PPMVD @15% O2		2	PPMVD @15% O2		0		
CT-0158	CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000	MMBtu/yr	Oxidation Catalyst	1	PPMVD @15% O2		2	PPMVD @15% O2		0		
IL-0133	LINCOLN LAND ENERGY CENTER	IL	7/29/2022	Combined-Cycle Combustion Turbines	3647	mmBtu/hour	Oxidation catalyst and good combustion practices.	1	PPMV, ADJ. TO 15% O2	ROLLING 3-OPERATING HOUR	1.1	PPMV, ADJ. TO 15% O2	ROLLING 3-OPERATING HOUR	0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	2300	MMBTU/H	OXIDIZED CATALYST	1	PPMVD	3 HOURS	2	PPMVD	3 HOURS	0		
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	921	MM BTU/h	Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices.	1.1	PPMV	3 HOUR AVERAGE	0			0		
LA-0364	FG LA COMPLEX	LA	1/6/2020	Cogeneration Units	2222	mm btu/h	Good combustion practices and catalytic oxidation	4	PPMVD		0			0		
*LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	LA	6/3/2022	Combined Cycle Gas Turbine w/ Duct Burners and HRSG	5081	mm BTU/h	Catalytic oxidation and good combustion practices.	1	PPMVD	3 1-HR TEST AVERAGE	2	PPMVD	3 1-HR TEST AVERAGE	0		
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Combustion Turbine with Duct Burner	2449	MMBTU/H	Oxidation catalyst	1	PPMVD@15% O2	1 HR AVG EXCLUDING SS/NO DUCT FIRING	1.7	PPMVD@15% O2	1 HR AVG EXCLUDING SS/DUCT FIRING	0		
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	725	MEGAWATT	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	0		
MD-0041	CPV ST. CHARLES	MD	4/23/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	725	MW	EXCLUSIVE USE OF NATURAL GAS, AND AN OXIDATION CATALYST	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	7.6	LB/H	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	0		
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	1000	MW	USE OF PIPELINE NATURAL GAS, GOOD COMBUSTION PRACTICES, AND USE OF AN OXIDATION CATALYST	1.6	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	6720	LB/EVENT	COLD STARTUP	0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	301	LB/EVENT	COLD STARTUP	0			0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	3-HR BLOCK AVG. W/OUT DUCT FIRING	1.9	PPMVD @ 15% O2	3-HR BLOCK AVG. WITH DUCT FIRING	0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	258	LB/EVENT	WARM STARTUP	0			0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	286	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	207	LB/EVENT	HOT STARTUP	0			0		
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	286	MW	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST	63	LB/EVENT	SHUTDOWN	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1	PPMVD @ 15% O2	W/OUT DUCT FIRING, 3-HR BLOCK AVG	2	PPMVD @ 15% O2	WITH DUCT FIRING, 3-HR BLOCK AVG	0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	164	LB/EVENT	COLD STARTUP	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	63	LB/EVENT	WARM STARTUP	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	52.6	LB/EVENT	HOT STARTUP	0			0		
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	235	MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	12	LB/EVENT	SHUTDOWN	0			0		

MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	2147	MMBTU/H	Catalytic oxidation system (COS)	2	PPMVOL	DRY AT 15% OXYGEN	0			0		
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	2807	MMBTU/H	Catalytic oxidation system (COS)	2	PPMVOL	DRY AT 15% OXYGEN	0			0		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 Combined cycle CTGs with HRSGs with duct burners	647	MMBTU/H for each CTGHRSG	Oxidation catalyst technology and good combustion practices.	4	PPM	TEST PROTOCOL	0			0		
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: Startup & Shutdown	647	MMBTU/H for each CTGHRSG	Oxidation catalyst technology and good combustion practices.	198.9	LB/H	EACH, DURING STARTUP	419.7	LB/H	EACH, DURING SHUTDOWN	0		
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	8322	MMBTU/H	Oxidation Catalyst Technology and Good Combustion Practices	4	PPM	TEST PROTOCOL WILL SPECIFY	0			0		
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	Oxidation catalyst technology and good combustion practices.	4	PPM AT 15% O2	TEST PROTOCOL WILL SPECIFY AVG TIME	0			0		
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	An oxidation catalyst and good combustion practices.	1	PPMVD	HOURLY; EACH CT/HRSG TRAIN	48	T/YR	EACH CT/HRSG TRAIN; 12-MO ROLL TIME PER.	0		
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	Oxidation catalyst technology and good combustion practices.	4	PPMVD	AT 15%O2; NOT INCL. STARTUP/SHUT DOWN	0			0		
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	Oxidation catalyst technology and good combustion practices.	4	PPMVD	AT 15%O2; HOURLY	0			0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)	0		Oxidation catalyst technology and good combustion practices.	0.0026	LB/MMBTU	EACH UNIT; HOURLY EXCEPT S.S.	0.0013	LB/MMBTU	EACH UNIT W/O DUCT BURNER FIRING; NOT SS	0		
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	667	MMBTU/H	An oxidation catalyst for VOC control and good combustion practices.	3	PPM	PPMVD@15%O2; HOURLY; SEE NOTES	5	LB/H	HOURLY EXCEPT STARTUP/SHUT DOWN; SEE NOTE	0		
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	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/SHUT DOWN; SEE NOTE	0		
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUCTGHRSG1	667	MMBTU/H	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	1/7/2021	EUCTGHRSG2	667	MMBTU/H	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY; EXCEPT DURING STARTUP/SHUT DOWN	5	LB/H	HOURLY EXCEPT DURING STARTUP/SHUT DOWN	0		
*MI-0451	MEC NORTH, LLC	MI	6/23/2022	EUCTGHRSG (North Plant): A combined cycle natural gas fired combustion turbine generator with heat recovery steam generator	3064	MMBTU/H	Oxidation catalyst technology and good combustion practices.	2	PPM	HOURLY	0			0		

*MI-0452	MEC SOUTH, LLC	MI	6/23/2022	EUCTGHRSG (South Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	3064	MMBTU/H	Oxidation Catalyst Technology and Good Combustion Practices	2	PPM	HOURLY	0			0		
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine with Duct Burner	40297.6	mmcubic ft/year	oxidation Catalyst and Good Combustion Practices and use of Clean fuel (Natural gas)	2	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLK	6.9	LB/H	AVERAGE OF THREE TESTS.	0		
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o duct burner	40297.6	mmcubic ft/year	Oxidation catalyst and good combustion practices, use of natural gas a clean burning fuel	2.9	LB/H	AVERAGE OF THREE TESTS	1	PPMVD	3H ROLLING AVE BASED ON 1H BLOCKS	0		
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined cylce turbine with duct burner	39463	mmcubic ft/year*	Oxidation catalyst	1	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK	5.7	LB/H	AVERAGE OF THREE TESTS	0		
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/1/2012	Combined Cycle Combustion Turbine	39463	MMCubic ft/yr	Oxidation Catalyst and Good combustion Practices and use of natural gas a clean burning fuel	2.9	LB/H	AVERAGE OF THREE TESTS	1	PPMVD	3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	33691	MMCF/YR	Oxidation catalyst and pollution prevention (use of natural gas a clean burning fuel)	2	PPMVD	AVERAGE OF THREE ONE HOUR TESTS	6.6	LB/H	AVERAGE OF THREE ONE HOUR TESTS	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	CO Oxidation Catalyst and good combustion practices and use natural gas only as a clean burning fuel	2	PPMVD@15%O2	AVERAGE OF THREE ONE HOUR TESTS	7.2	LB/H	AVERAGE OF THREE ONE HOUR TESTS	0		
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	33691	MMCF/YR	Oxidation Catalyst and use of natural gas a clean burning fuel	1	PPMVD@15%O2	AVERAGE OF THREE ONE-HOUR TESTS	2.9	LB/H	AVERAGE OF THREE ONE-HOUR TESTS	0		
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine without Duct Burner	20282	MMCF/YR	Oxidation catalysts and use of Natural gas a clean burning fuel	0.7	PPMVD215%O2	AVERAGE OF THREE ONE HOUR STACK TESTS	2.11	LB/H	AVERAGE OF THREE ONE HOUR STACK TESTS	0		
NJ-0082	WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burner	20282	MMCF/YR	Oxidation catalyst and use of natural gas a clean burning fuel	1	PPMVD@15%O2	AVERAGE OF THREE STACK TEST RUNS	4	LB/H	AVERAGE OF THREE STACK TEST RUNS	0		
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	4000	h/yr	Oxidation Catalyst and good combustion practices	2	PPMVD@15%O2	AV OF THREE ONE H STACK TESTS EVERY 5 YR	10.3	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	0		
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	8040	H/YR	Oxidation catalyst and good combustion practices	1	PPMVD@15%O2	AV OF THREE ONE H STACK TESTS EVERY 5 YR	4.37	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	0		
NJ-0088	COGEN TECH LINDEN VENTURE LP	NJ	7/30/2019	250 MW COMBINED CYCLE COMBUSTION TURBINE FIRING NATURAL GAS	21042	MMCubic ft/yr	Add on Oxidation Catalyst and use of Natural Gas as primary fuel for pollution prevention	3.2	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	1	PPMVD@15% O2	3 H ROLLING AV BASED ON ONE H BLOCK	0		
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Turbines and duct burners - NG	0		Good combustion practice and oxidation catalyst.	0.7	PPMVD @ 15% O2	1 H	0			0		
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	515600	MMSCF/rolling 12-months	oxidation catalyst	3.9	LB/H		28.6	T/YR	PER ROLLING 12 MONTHS	1	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	51560	MMSCF/rolling 12-MO	oxidation catalyst	5.9	LB/H		28.6	T/YR	PER ROLLING 12-MONTHS	1.9	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	47917	MMSCF/rolling 12-MO	oxidation catalyst	7.9	LB/H		56	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	47917	MMSCF/rolling 12-MO	oxidation catalyst	7.3	LB/H		56	T/YR	PER ROLLING 12-MONTHS	2	PPM	PPMVD AT 15% O2

OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2045	MMBTU/H	oxidation catalyst	7.1	LB/H	WITH DUCT BURNER. SEE NOTES.	40.2	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	0		SEE NOTES
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	2725	MMBTU/H	Good combustion controls and oxidation catalyst	8.2	LB/H	WITH DUCT BURNER. SEE NOTES.	47.1	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	3131	MMBTU/H	Good combustion controls and oxidation catalyst	10.64	LB/H	WITH DUCT BURNER. SEE NOTES.	50.6	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	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	Good combustion controls and oxidation catalyst	8.8	LB/H	WITH DUCT BURNER. SEE NOTES.	50.3	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	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	oxidation catalyst and good combustion control	8.8	LB/H	WITH DUCT BURNER. SEE NOTES.	50.28	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	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	oxidation catalyst and good combustion practices as recommended by the manufacturer	11.73	LB/H	WITH DUCT BURNER. SEE NOTES.	4.92	LB/H	WITHOUT DUCT BURNERS. SEE NOTES.	2	PPM	BY VOLUME, DRY AT 15% O2. SEE NOTES.
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	Combined-cycle Turbines (2) - Natural gas fired	3277	MMBTU/H	Oxidation Catalyst	1	PPMVD	WITHOUT DUCT BURNER	1.5	PPMVD	WITH DUCT BURNER	0		
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	Combined Cycle Combustion Turbine AND DUCT BURNER (3)	2538000	MMBTU/H	Oxidation Catalyst	1	PPM	3 LB/HR, DUCT BURN NOT OPERATING, 15% O2	3.9	PPM	10.8 LB/HR, DUCT BURN OPERATING, 15% O2	0		
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3.4	MMCF/HR	Oxidation Catalyst	1.5	PPMVD @ 15% OXYGEN	WITH OR WITHOUT DUCT BURNER	93.44	TPY 12-MONTH ROLLING	INCLUDING STARTUP AND SHUTDOWN	0		
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	Oxidation catalyst, good combustion practices and low sulfur fuels	1.9	PPMDV @ 15% O2		256.4	TONS	ANY 12-MONTH PERIOD	0		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Combustion turbine with duct burner	3304.3	MMBtu/hr	Oxidation catalyst, combustion controls, exclusive natural gas	1.5	PPMDV @ 15% O2		24.6	TONS	YEAR	0		
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Combustion turbine and HRSG with duct burner NG only	3338	MMBtu/hr	Oxidation catalyst and good combustion practices	1.5	PPMDV @ 15% O2		64.2	TONS	12-MONTH ROLLING BASIS	0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Combustion Turbine With Duct Burner	3727	MMBtu/hr	Oxidation catalyst and good engineering practice	1.5	PPMDV @ 15% O2		8.93	LB/HR		0		
TX-0641	PINECREST ENERGY CENTER	TX	11/12/2013	combined cycle turbine	700	MW	oxidation catalyst	2	PPMVD	INITIAL STACK TEST, 15% OXYGEN	0			0		
TX-0708	LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) combined cycle turbines	650	MW	oxidation catalyst	2	PPMVD	@15% O2, 3-HR ROLLING	0			0		
TX-0710	VICTORIA POWER STATION	TX	12/1/2014	combined cycle turbine	197	MW	oxidation catalyst	4	PPMVD	@15% O2, 3-HR ROLLING AVERAGE	0			0		
TX-0712	TRINIDAD GENERATING FACILITY	TX	11/20/2014	combined cycle turbine	497	MW	oxidation catalyst	4	PPMVD	@15% O2 1-HR	0			0		
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) combined cycle turbines	274	MW	oxidation catalyst	2	PPMVD	@15% O2, 3-HR AVERAGE	0			0		
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) combined cycle turbines	240	MW	oxidation catalyst	1	PPMVD	@15% O2	0			0		
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	Combined Cycle Turbines (>25 MW) â€" natural gas	210	MW	Oxidation catalyst	2	PPM		0			0		
TX-0767	LON C. HILL POWER STATION	TX	10/2/2015	Combined Cycle Turbines (>25 MW)	195	MW	oxidation catalyst	2	PPM		0			0		
TX-0773	FGE EAGLE PINES PROJECT	TX	11/4/2015	Combined Cycle Turbines (>25 MW)	321	MW	Oxidation Catalyst	2	PPM		0			0		
TX-0788	NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	2	PPM		0			0		
TX-0789	DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231	MW	OXIDATION CATALYST	2	PPM		0			0		
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	Oxidation catalyst and good combustion practices	3.5	PPMVD	15% O2	0			0		

TX-0834	MONTGOMERY COUNTY POWER STATIOIN	TX	3/30/2018	Combined Cycle Turbine	2635	MMBTU/HR/UNIT	Oxidation catalyst	2	PPMVD	15% O2 3 HOUR AVERAGE	0			0		
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	3227	MMBTU/HR	Oxidation Catalyst and good combustion practices	1.4	PPMVD		214.8	T/YR	PER TURBINE-12 MO ROLLING TOTAL	0		
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural-Gas-Fired Combined-Cycle Turbine (P01)	4671	MMBTU/H	Oxidation Catalyst, good combustion control	2.7	PPM AT 15% O2	168-HR AVG., NAT. GAS, DUCT FIRING	0.6	PPM AT 15% O2	168-HR AVG., NAT. GAS, W/O DUCT FIRING	0		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Combined Cycle Turbine/Duct Burner	2419.61	mmBtu/Hr	Oxidation Catalyst & Good Combustion Practices	5.3	LB/H		0.0022	LB/MMBTU		2	PPM	@ 15% O2
*WV-0033	MAIDSVILLE	WV	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W/O DUCT FIRING	2	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W DUCT FIRING	11.19	LB/HR	AVG OF 3 1-HR TEST RUNS
*WV-0033	MAIDSVILLE	WV	1/5/2022	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	1275	mw	good combustion practices and oxidation catalyst	1	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W/O DUCT FIRING	2	PPMDV @ 15% O2	AVG OF 3 1-HR TEST RUNS (W DUCT FIRING	11.89	LB/HR	AVG OF 3 1-HR TEST RUNS
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP01)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	1-HOUR	3	LB/H	3-HOUR AVERAGE	14.7	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	Combined Cycle Turbine (EP02)	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE	3	LB/H	3-HOUR AVERAGE	14.7	T/YR	