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PART 70 OPERATING PERMIT
TECHNICAL SUPPORT DOCUMENT
(STATEMENT of BASIS)

APPLICATION FOR:
Part 70 Renewal

SUBMITTED BY:
Nevada Power Company

FOR:
Clark Generating Station
Source: 00007

LOCATION:
5640 Stephanie St.
Las Vegas, Nevada 89122

SIC code 4911, "Electric Services"
NAICS code 221112, "Fossil Fuel Electric Power Generation"

Application Received: December 12, 2024

TSD Date: October 28, 2026

EXECUTIVE SUMMARY

NV Energy – Clark Generating Station is an electrical power generating station located in the Las Vegas Valley, Hydrographic Area 212 (HA 212), which is currently designated as attainment for all pollutants except ozone. HA 212 was designated a moderate nonattainment area for ozone on January 5, 2023. The designation did not impose any new requirements at that time. HA 212 was designated a serious nonattainment area for ozone on January 21, 2025. Clark County has drafted or imposed new requirements to address this designation, which include, but are not limited to, lowering the NO_x and VOC major source thresholds to 50 tons per year.

The source consists of seventeen natural gas-fired turbines (one 60 MW simple cycle unit, four 85 MW combined cycle units which provide heat for four heat recovery steam generator (HRSG) turbines with no supplemental duct firing, and 12 simple cycle paired units rated at 57.9 MW per pair), two 54,000 gpm cooling towers, one 474 hp diesel-fired emergency generator, one 460 hp diesel-fired emergency fire pump, and one 250 gallon above ground gasoline storage tank. The source also has three ammonia storage tanks (sealed), diesel storage tanks, maintenance shop activities (i.e., sand blasters, etc.), steam cleaning operations, and lube oil sumps and vents that are designated as insignificant activities.

This source is a categorical source, as defined by AQR 12.2.2(j)(1). Therefore, fugitive emissions are included in the source status determination.

This source is a Major Source of PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC for the purposes of the Title V program and a Minor Source for SO_2 and HAP. Because the source is a Major Source for a criteria pollutant, it is classified as an Anyway Source for Greenhouse Gases (GHGs).

This source is subject to 40 CFR Part 60, Subparts: GG, KKKK, and IIII, and 40 CFR Part 63, Subparts: ZZZZ and CCCCCC. By meeting the requirements of 40 CFR Part 60, Subpart IIII (for the applicable engines), the source meets the requirements of 40 CFR Part 63, Subpart ZZZZ. Additionally, this source is regulated by 40 CFR Part 72, Acid Rain Permits Regulation.

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 (OP) Renewal:

Table 1: Emission Units PTE Summary (tons per year)

Pollutant	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAPs[1]	GHG[2]
Source PTE	715.84	715.84	1,026.62	1,851.70	48.44	216.66	8.10	4,529,427

[1]Ten tons for any individual hazardous air pollutant, or 25 tons for the combination of all hazardous air pollutants.
[2]DAQ requires the source to estimate its GHG potential to emit (PTE) for each individual pollutant (e.g., CO_2, CH_4, N_2O, SF_6, etc.). These values are included in the TSD for informational purposes and are measured in metric tons per year of CO2e.

DAQ has received delegated authority from the U.S. Environmental Protection Agency to implement the requirements of the Part 70 OP. Based on the information submitted by the applicant, supplemental information provided to the application, and a technical review performed by DAQ staff, the draft Part 70 OP renewal to Clark Generating Station is proposed.

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I. ACRONYMS AND ABBREVIATIONS

These terms may be seen in the technical support document:

AQR	Clark County Air Quality Regulation
AST	aboveground storage tank
ATC	Authority to Construct
BACT	Best Available Control Technology
BLM	Bureau of Land Management
bhp	brake horsepower
CAA	Clean Air Act
CD	control device
CE	control efficiency
CEMS	Continuous Emissions Monitoring System
CF	control factor
CFR	Code of Federal Regulations
CO	carbon monoxide
CPI	Urban Consumer Price Index
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
DAQ	Division of Air Quality
DES	Clark County Department of Environment and Sustainability
DOM	date of manufacture
EF	emissions factor
EPA	U.S. Environmental Protection Agency
EU	emission unit
FR	Federal Register
GHG	greenhouse gas
g/kW-hr	grams per kilowatt hour
gpm	gallons per minute
HA	Hydrographic Area
HAP	hazardous air pollutant
hp	horsepower
HSRG	Heat Recovery Steam Generator
kW	kilowatts
LAER	Lowest Achievable Emission Rate
LVH	lower heating value
MMBtu/hr	Million British Thermal Units per Hour
NAAQS	National Ambient Air Quality Standard
NAICS	North American Industry Classification System
NEI	net emission increase
NO_x	nitrogen oxide(s)
NSR	New Source Review
O&M	operations and maintenance
OP	operating permit
Pb	lead
$PM_{2.5}$	particulate matter less than 2.5 microns in aerodynamic diameter
PM_{10}	particulate matter less than 10 microns in aerodynamic diameter

ppm	parts per million
PSD	prevention of significant deterioration
PTE	potential to emit
RACT	Reasonably Achievable Control Technology
RATA	Relative Accuracy Test Audit
RICE	reciprocating internal combustion engine
RMP	Risk Management Plan
SCC	Source Classification Code
SDE	Status Determination Evaluation
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SM	synthetic minor
SO_2	sulfur dioxide
SOP	standard operating procedure
TBD	to be determined
TDS	total dissolved solids
TPH	tons per hour
TSD	Technical Support Document
ULNB	Ultra Low NO_x Burner
VAEL	Voluntarily Accepted Emission Limit
VMT	vehicle miles traveled
VOC	volatile organic compound

II. SOURCE DESCRIPTION

A. PROCESS DESCRIPTION

Turbines

Turbine Unit 4 (EU: A00704D) is a simple cycle combustion turbine combusting natural gas only. Units 5 and 6 (EUs: A00701A and A00702B) are operated as a combined cycle pair, where the exhaust gas is collected in the heat recovery steam generator (HRSG) and used to turn steam-turbine Unit 10. Supplemental duct-firing is not used in the HRSG. No additional emissions result from the operation of Unit 10. Turbine Units 7 and 8 (EUs: A00705 and A00708) are also a combined cycle pair associated with steam-turbine Unit 9. All turbine units operated by the source are permitted to combust only natural gas. CEMS for NO_X and CO are installed on Turbine Units 5, 6, 7 and 8. There are also twelve natural gas-fired peaking units (EUs: A27-A38) that are operated generally during periods of peak demand.

Cooling Towers

Two 54,000 gpm cooling towers (EUs: A00712 and A00713) operate as part of the combined cycle process.

Gasoline Dispensing Facility

The source operates a GDF (EU: A46) consisting of one 250-gallon aboveground storage tank (AST).

Diesel Engines

The source operates one 474 hp diesel-fired emergency generator (EU: A21) and one 460 hp diesel-fired emergency fire pump (EU: A45).

B. PERMITTING HISTORY

This is a Part 70 OP renewal permitting action submitted on December 12, 2024. The initial Part 70 operating permit was issued on November 3, 2003, with renewals issued on November 2, 2009, December 24, 2014, and October 5, 2020.

The following represents permitting activities prior to this permitting action since the last renewal:

Table II-B-1: Permit History

Date	Description
June 17, 2021	A minor revision to the Part 70 OP to replace the 1,200-gallon AST with a 250-gallon AST. Phase I control requirements were removed as a result because AQR Section 52 does not apply to existing storage tanks less than 251 gallons.
November 30, 2021	A reopen for cause to the Part 70 OP to add an Annual Emissions Statement requirement.

Multiple notifications, which did not require a permit change, were submitted to DAQ after the previous renewal application to the OP was submitted. These include:

- Notification of agreed plan with DAQ for when a turbine exchange takes place on one of the Clark Peaker fleet turbine engines. The permittee would perform the required preconstruction emission increase analysis and provide subsequent notification to DAQ pursuant to AQR 12.2.1.6(b) and 12.3.1.6(b) in combination with the notification required by 12.5.2.12(a) to DAQ and EPA Region IX. (February 27, 2019)
- Notification of SCR Outlet Diverter Damper Control System programming change, due to failures of SCR outlet diverter dampers because of the existing programming. (April 17, 2019)
- Notification of installation of a spare gas generator in Turbine Unit 21 (EU: A37), due to a mechanical failure. (September 18, 2019)
- Notification of installation of a spare gas generator in Turbine Unit 18 (EU: A34), due to a mechanical failure. (November 4, 2020)
- Notification of installation of a spare gas generator in Turbine Unit 21 (EU: A37), due to a mechanical failure. (March 15, 2021)

Multiple notifications, which did not require a permit change, were submitted to DAQ after the previous minor revision to the OP was issued (June 17, 2021). These include:

- Notification of installation of a spare gas generator in Turbine Unit 17 (EU: A33), due to a mechanical failure. (June 30, 2021)
- Notification of installation of a spare gas generator in Turbine Unit 20 (EU: A36), due to a mechanical failure. (July 12, 2021)
- Notification of installation of one turbine in Unit 11 (EU: A27) with a unit equipped with a wet compression system. (September 23, 2021)
- Notification of installation of a spare gas generator in Turbine Unit 15 (EU: A31), due to a mechanical failure. (November 1, 2021)
- Notification of installation of SCR tempering air damper positioners for Turbine Units 11-22 (EUs: A27-38) to improve unit reliability and availability. (November 17, 2021)
- Notification of installation of a spare gas generator in Turbine Unit 22 (EU: A38), due to a mechanical failure. (January 4, 2022)
- Notification of installation of wet compression on the air inlet of twenty-three (23) natural gas-fired turbines associated with EUs A27-A38. Project conclusion like notification dated September 23, 2021. (March 7, 2022)
- Notification of installation of a spare gas generator in Turbine Unit 21 (EU: A37), due to a mechanical failure. (March 8, 2022)
- Notification of installation of a spare gas generator in Turbine Unit 20 (EU: A36) and Turbine Unit 18 (EU: A34), due to a failed borescope inspection on one of the gas generators in each of the units. (March 21, 2022)
- Notification of approximately one week forced outage of Turbine Unit 19 (EU: A35) until the rotatable spare engine can be installed, due to failure of seals in the existing engine. (July 18, 2022)
- Notification of installation of two spare gas generators in Turbine Unit 12 (EU: A28), due to a failed borescope inspection of both of the gas generators in the unit. (October 6, 2022)
- Notification of removal of wet compression-equipped turbine from Turbine Unit 11 (EU: A27). See notification dated September 23,2021, for initial installation of turbine. Additionally, the gas generators associated with this unit were reconfigured. The gas generator in the "B" side was moved to the "A" side, and a facility-owned spare gas generator was installed in the "B" side. (October 24, 2022)

- Notification of installation of a spare gas generator in Turbine Unit 20 (EU: A36), due to a failed annual borescope inspection on one of the gas generators. (November 7, 2022)
- Notification of Automatic Voltage Regulator (AVR) and Power System Stabilizer (PSS) Commissioning Testing on Turbine Units 4-8 (EUs: A00704D, A00701A, A00702B, A00705, and A00708). (March 7, 2023)
- Notification of installation of a spare gas generator in Turbine Unit 20 (EU: A36), due to an internal failure. (May 16, 2023)
- Notification of installation of a spare gas generator in Turbine Unit 19 (EU: A35), due to a failed annual borescope inspection on one of the gas generators. (November 21, 2023)
- Notification of installation of a spare gas generator in Turbine Unit 20 (EU: A36), due to high lube oil consumption on the existing gas generator. (March 6, 2024)
- Notification of installation of a spare gas generator in Turbine Unit 15 (EU: A31), due to an identified cracked row 1 blades in the high-pressure turbine (HPT) section of unit B. (December 11, 2024)

The installation of the spare generators discussed above were approved as the permittee performed the required preconstruction emission increase analysis, provided notification to DES pursuant to AQR 12.2.1.6(b) and 12.3.1.6(b), and provided notification to DAQ and EPA Region IX pursuant to AQR 12.5.2.12(a).

C. CURRENT PERMITTING ACTION

1. This is a renewal to the Part 70 OP that was submitted to DAQ on December 12, 2024. The permittee proposed no changes to the permit conditions. After discussing with the permittee, they requested the silos onsite be removed from the permit. As a water conservation measure, the source was permitted to use gray water (water treated with lime and soda ash) in the cooling towers. One lime silo (EU: A00709) and two soda ash silos (EUs: A00710 and A00711) were installed for this purpose. However, these silos have been sitting idle for nearly 30 years. To avoid having to install parametric monitoring on the silos, the permittee proposed removing the silos from the permit (EUs: A00709-A00711). Per the permittee, the silos will remain onsite but inoperable by the following methods: the piping from the silo units to the rest of the plant has been mostly disconnected; the pumps and motors have either been removed, disconnected, or are damaged beyond repair from not operating in nearly 30 years; and the brine concentrator vessel has numerous cracks, rendering the silos inoperable. As such, DAQ has agreed to remove the silos from the permit and make note of the onsite inoperable silos. Associated silo conditions in the permit were removed.

2. As part of the renewal, a prior notification form (PNF) submitted on March 11, 2024, was incorporated. As explained by the permittee, the wooden structures of the cooling towers (EUs: A00712 and A00713) were replaced with fiberglass-reinforced plastic; this structural change is a maintenance activity that does not impact emissions and is not subject to specific air quality permitting requirements. Additionally, the permittee replaced the existing drift eliminators (rated at 0.002%) with new ones rated at 0.001%. Replacing the drift eliminators with newer more efficient ones does not result in an increase in PTE or of actual emissions, so this change was approved as a PNF by DAQ. Because drift eliminators are factored into $PM_{10}/PM_{2.5}$ emissions calculations, associated permit conditions were updated.

3. In addition to the drift eliminators update discussed above, DAQ made the following updates to the permit:

   a. Updated the structure of the permit to align with current DAQ format.

   b. Updated the EU list structure to better ease reading.

   c. Added the 354-kW rating to the description of the existing emergency generator (EU: A21). The kW rating was obtained from the previous renewal application (00007_20191220_APP) page 59/180.

   d. References for Gasoline Dispensing Operation (GDO) were updated to Gasoline Dispensing Facility (GDF). DAQ is implementing this change across all permits to align terminology with 40 CFR Part 63, Subpart CCCCCC.

   e. GDF language was updated to include AQR 102 citations and applicable requirements from AQR 102.

   f. Nonroad engine language was updated to DAQ's current language. See Section 1.3 in the permit.

   g. Updated the exceptions language for when emergency generator engines can be used to supply power as part of a financial arrangement with another entity. DAQ has revised the language to be better aligned with what is stated in the CFR. See the operational limits section of the permit.

   h. Reviewed the applicability of new AQRs 101-105. During this discussion with the permittee, it was discovered that the insignificant parts washer operation at the maintenance shop is no longer there. Therefore, parts washer was removed from the insignificant table.

   i. A new applicability and status determination calculation to identify which pollutants are major, synthetic minor, or minor. This was promulgated due to the updated drift eliminator ratings installed and removal of silos.

   j. Incorporated requirements from AQR 122: *Reasonably Available Control Technology for Major Sources in HA 212*. This source is listed in the regulation, which became effective June 17, 2026. After discussing with the permittee, the permittee elected to limit NO_x emissions to 292 tpy or less in any consecutive 12-month period for Unit 4 (EU: A00704D) instead of installing NO_x CEMS for Unit 4. The permittee also elected to conduct subsequent performance tests on Unit 4 (EU: A00704D), Units 5-8 (EUs: A00701A, A00702B, A00705, and A00708), and Units 11-22 (EUs: A27-A38) to demonstrate compliance with the applicable NO_x and/or VOC limitations specified in AQR 122.5.1 in lieu of continuous emissions monitoring for the specific pollutants in question. As such, the permit has been updated to reflect the permittee's decision.

   k. Addressed a Pending Change Referral form submitted by compliance staff. Monitoring and recordkeeping requirements were added for Unit 4's heat input limit. The other Units have a CEMS, which should capture that data.

l. Reviewed EPA's correcting amendments published on July 16, 2026 (91 FR 43561, FR Doc. 2026-14371) regarding 40 CFR Part 60, Subparts GG and KKKK. The administrative and typographical revisions do not impact the applicable requirements for the units at this source; therefore, no revisions to the permit conditions are necessary due to the amendments.

m. Added monitoring and recordkeeping requirements for the hourly heat input rate for each EU with a heat input limit. The operational limit was listed in the previous permit. After discussing with the compliance staff, it was determined that associated monitoring and recordkeeping requirements were missing.

D. EMISSION UNITS LIST

Table II-D-1 lists the emission units covered by this Part 70 OP.

Table II-D-1: Summary of Emission Units

EU	Description	Rating	Manufacturer	Model No.	Serial No.	SCC
Natural Gas-Fired Turbines						
A00704D	Natural Gas-Fired Turbine (Unit 4); Simple Cycle	60 MW	General Electric	7B (7000)		20100201
A00701A	Natural Gas-Fired Turbine (Unit 5); Combined Cycle	85 MW	Westinghouse	501B6		20100201
A00702B	Natural Gas-Fired Turbine (Unit 6); Combined Cycle	85 MW	Westinghouse	501B6		20100201
A00705	Natural Gas-Fired Turbine (Unit 7); Combined Cycle	85 MW	Westinghouse	501B6		20100201
A00708	Natural Gas-Fired Turbine (Unit 8); Combined Cycle	85 MW	Westinghouse	501B6		20100201
Cooling Towers[1]						
A00712	Cooling Tower **(four cells)** For Unit 9 Steam Turbine Generator **(associated with Turbines 7 and 8)**	54,000 gpm				38500110
A00713	Cooling Tower **(four cells)** For Unit 10 Steam Turbine Generator **(associated with Turbines 5 and 6)**	54,000 gpm				38500110
Emergency Diesel-Fired Engines						
A21	Genset - Emergency	**354 kW**	Kohler	300R0ZD71	302650	20200102
	Engine – Diesel DOM: pre-1993	474 hp	Detroit Diesel	8063-7416	6V-92TA	
A45	Emergency Fire Pump	460 hp	Aurora	10-481-18D	20-2596555	20200102
	Engine – Diesel DOM: 2009		Cummins	CFP15E-F10	79347925	
Natural Gas-Fired Peaking Turbines[2]						
A27	Two (2) Natural Gas-Fired Turbines (Unit 11); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201
A28	Two (2) Natural Gas-Fired Turbines (Unit 12); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201

EU	Description	Rating	Manufacturer	Model No.	Serial No.	SCC
A29	Two (2) Natural Gas-Fired Turbines (Unit 13); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201
A30	Two (2) Natural Gas-Fired Turbines (Unit 14); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201
A31	Two (2) Natural Gas-Fired Turbines (Unit 15); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201
A32	Two (2) Natural Gas-Fired Turbines (Unit 16); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201
A33	Two (2) Natural Gas-Fired Turbines (Unit 17); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201
A34	Two (2) Natural Gas-Fired Turbines (Unit 18); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201
A35	Two (2) Natural Gas-Fired Turbines (Unit 19); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201
A36	Two (2) Natural Gas-Fired Turbines (Unit 20); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201
A37	Two (2) Natural Gas-Fired Turbines (Unit 21); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201
A38	Two (2) Natural Gas-Fired Turbines (Unit 22); Simple Cycle	57.9 MW (Combined)	Pratt and Whitney	FT8-3 Swift Pac		20100201
Gasoline Dispensing Facility						
A46	**Aboveground Storage Tank: Regular Unleaded Gasoline**	250 gallons				**40600131**

Note: ft^3 = cubic feet; gpm = gallons per minute; hp = horsepower; kw = kilowatt; MW = megawatt. Bolded text indicates updated emission unit information.
[1]Each cooling tower has four cells rated at 13,500 gpm each (54,000 gpm total per cooling tower).
[2]Operated generally during periods of peak demand.

The following units or activities listed in Table II-D-2 are present at this source, but are deemed insignificant.

Table II-D-2: Insignificant Activities

Rating	Description
19,900 gallons each	Three Ammonia Storage Tanks (Sealed)
	Diesel Storage Tanks
	Maintenance Shop Activities (e.g. sand blasters, etc.)
	Steam Cleaning Operations
	Lube Oil Sumps and Vents

III. EMISSIONS INFORMATION

A. APPLICABILITY

Unlike in previous permitting actions, status determination evaluation (SDE) is no longer used. DAQ has changed its methodology as indicated below:

Permitting applicability is determined by calculating the emissions for all proposed emission units using 8,760 hours of operation (except for emergency generators or fire pumps, which use 500

hours), any inherent controls, any inherent throughput limitations, and the emission factors provided by the manufacturer, by source test results, by EPA AP-42, or by other approved methods.

Applicability emissions include emissions from insignificant emission units and activities, but do not include fugitive emissions (except for categorical sources listed in AQR 12.2.2(j) or any other stationary source category that, as of August 7, 1980, is being regulated under Sections 111 or 112 of the Act). Since this is a categorical source, fugitive emissions should be included if present.

The permittee submitted an uncontrolled emissions summary table with their application. The table correctly removed the control efficiencies provided by the Selective Catalytic Reduction (SCR) and Oxidative Catalyst. However, it did not back calculate the 3,500 hours per year limit applied to EUs A27-A38. Calculations were redone at 8,760 hours per year as is consistent with current DAQ methodology. No new requirements were triggered.

Applicability calculations are included in the attachments. Table III-A-1 shows the source-wide applicability emissions associated with this source.

Table III-A-1: Source-wide Applicability Emissions (tons per year)

Pollutants	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAPs
Source Applicability Emissions	**880.00**	**880.00**	**11,394.26**	**5,182.06**	**66.68**	**1,041.30**	**12.14[1]**
Major Source Thresholds (Title V)	100	100	50	100	100	50	10/25[2]
Major Source Thresholds (Serious Ozone Nonattainment)	100	100	50	100	100	50	10/25[2]

[1]Combination of multiple hazardous air pollutants.
[2]Ten tons for any individual hazardous air pollutant, or 25 tons for the combination of all hazardous air pollutants.

As shown in Table III-A-1, applicability emissions exceed the Major Source Title V threshold for PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC. The source is below the Major Source thresholds for SO_2 and HAPs (no single HAP pollutant is equal to or over 10 tons). Because applicability confirms the facility's status as a Major Source, a subsequent evaluation of the PTE (Section III.B of this TSD) is needed to determine the final source classification (i.e., Major or Synthetic Minor) for PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC.

B. SOURCE-WIDE PTE

PTE is calculated to include any controls or limits, whether voluntarily proposed by the source or required. PTE does not include insignificant emission units and activities but does include fugitive emissions.

Table III-B-1 shows the PTE associated with this source; PTE calculations are included in the attachments.

Table III-B-1: Source-wide PTE

PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAPs	GHGs[1]
715.84	715.84	1,026.62	1,851.70	48.44	216.66	8.10	4,529,427

[1]Metric tons per year of carbon dioxide equivalent. GHG = greenhouse gas pollutants.

As shown in Table III-B-1, PTE emissions exceed the Major Source Title V threshold for PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC even after controls or limits are factored in. Therefore, this source is a Major Source for PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC, and a Minor Source for SO_2 and HAPs. Because the source is a Major Source for a criteria pollutant, it is classified as an Anyway Source for Greenhouse Gases (GHGs).

C. EMISSIONS INCREASE

Table III-C-1 shows the emission changes associated with updating the drift eliminator rating of the cooling towers (EUs: A00712 and A00713), the removal of the three silos (EUs: A00709-A00711), and the RACT NO_x emission cap limit of 292 tpy imposed on EU A00704D due to the promulgation of AQR 122. As there is no emissions increase for any regulated pollutant exceeding the Minor New Source Review (NSR) significant thresholds defined under AQR 12.5.1(d), this permitting action does not trigger Minor NSR.

GHG emissions are included for informational purposes only; as there is no Minor NSR significance threshold for GHGs.

Table III-C-1: Emissions Increase

	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	H_2S	Pb	GHG
Minor NSR Significance 12.5.1(d)	7.5	5.0	12.5	50	20	12.5	5	0.6	-
Existing Permit	755.00	755.00	2,467.22	1,851.70	48.44	216.66	0	0	4,529,427
New Permit	715.84	715.84	1,026.62	1,851.70	48.44	216.66	0	0	4,529,427
Total Δ PTE	-39.16	-39.16	-1,440.60	0	0	0	0	0	0
Triggers	No	No	No	No	No	No	No	No	N/A

D. OPERATIONAL LIMITS

The operational limits were retained except for the throughput of each silo limit (removed), and the language used for the emergency generator (EU: A21), which was updated to be better aligned with what is stated in the CFR. Below is the updated operational limit language for the emergency generator (EU: A21):

- The permittee shall limit the operation of the emergency generator (EU: A21) for testing and maintenance purposes to 100 hours/year. The permittee may operate the emergency generator up to 50 hours/year for nonemergency situations, but those hours count towards the 100 hours provided for testing and maintenance. Except as provided below, the 50 hours per year for nonemergency use cannot be used for peak shavings or nonemergency demand response, or to generate income for a facility by supplying power to an electric grid or to otherwise supply power as part of a financial arrangement with another entity: *[40 CFR Part 63.6640]*

    - The 50 hours per year for nonemergency use can be used to supply power as part of a financial arrangement with another entity if all the following conditions are met:

- The engine is dispatched by the local balancing authority and/or local transmission and distribution operator.
- The dispatch is intended to mitigate local transmission and/or distribution limitations to avert potential voltage collapse or line overloads that could lead to interruption of power supply in a local area or region.
- The dispatch follows reliability, emergency operation, or similar protocols that follow specific NERC, regional, state, public utility commission, or local standards or guidelines.
- The power is provided only to the facility itself or to support the local transmission and distribution system.
- The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission, or local standards or guidelines that are being followed for the dispatching engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

The operational limits retained are summarized below:

- The permittee shall limit the maximum water flow in each cooling tower to 54,000 gallons per minute (EUs: A00712 and A00713).
- The permittee shall limit the operation of each Turbine, Unit 11 through 22 (EUs: A27 through A38), to 3,500 hours per year.
- The permittee shall limit the number of startups and shutdowns of each Turbine, Units 11 through 22 (EUs: A27 through A38), to 350 startups and 350 shutdowns per year.
- The permittee shall limit the operation of the emergency fire pump (EU: A45) for testing and maintenance purposes to 100 hours per year. The permittee may operate the emergency 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 permittee shall limit the gasoline throughput (EUs: A46) to 1,000 gallons per month.
- The permittee shall limit operation of each natural gas turbine unit to the heat input limits listed in table III-D-1 based on the LHV:

Table III-D-1: Natural Gas Turbine Units Heat Input Limits

Emission Unit	Clark Station Designation	Natural Gas
A00704D	Turbine Unit 4	899 MMBtu/hr
A00701A	Turbine Unit 5	1,081 MMBtu/hr
A00702B	Turbine Unit 6	1,081 MMBtu/hr
A00705	Turbine Unit 7	1,081 MMBtu/hr
A00708	Turbine Unit 8	1,081 MMBtu/hr
A27	Turbine Unit 11	541 MMBtu/hr
A28	Turbine Unit 12	541 MMBtu/hr
A29	Turbine Unit 13	541 MMBtu/hr

Emission Unit	Clark Station Designation	Natural Gas
A30	Turbine Unit 14	541 MMBtu/hr
A31	Turbine Unit 15	541 MMBtu/hr
A32	Turbine Unit 16	541 MMBtu/hr
A33	Turbine Unit 17	541 MMBtu/hr
A34	Turbine Unit 18	541 MMBtu/hr
A35	Turbine Unit 19	541 MMBtu/hr
A36	Turbine Unit 20	541 MMBtu/hr
A37	Turbine Unit 21	541 MMBtu/hr
A38	Turbine Unit 22	541 MMBtu/hr

E. CONTROL TECHNOLOGY

As part of the renewal, the following add-on control devices table was added. During this permitting action, the permittee provided manufacturer information for the add-on controls. However, model numbers were not available.

Table III-E-1: Summary of Add-On Control Devices

EU	Device Type	Control Device Number	Manufacturer	Model No.	Pollutant
A27	Water Injection Skid	CD1a	Becon Inc.	N/A	NO_x
	SCR	CD1b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD1c	BASF	N/A	CO/VOC
A28	Water Injection Skid	CD2a	Becon Inc.	N/A	NO_x
	SCR	CD2b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD2c	BASF	N/A	CO/VOC
A29	Water Injection Skid	CD3a	Becon Inc.	N/A	NO_x
	SCR	CD3b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD3c	BASF	N/A	CO/VOC
A30	Water Injection Skid	CD4a	Becon Inc.	N/A	NO_x
	SCR	CD4b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD4c	BASF	N/A	CO/VOC
A31	Water Injection Skid	CD5a	Becon Inc.	N/A	NO_x
	SCR	CD5b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD5c	BASF	N/A	CO/VOC
A32	Water Injection Skid	CD6a	Becon Inc.	N/A	NO_x
	SCR	CD6b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD6c	BASF	N/A	CO/VOC
A33	Water Injection Skid	CD7a	Becon Inc.	N/A	NO_x
	SCR	CD7b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD7c	BASF	N/A	CO/VOC

EU	Device Type	Control Device Number	Manufacturer	Model No.	Pollutant
A34	Water Injection Skid	CD8a	Becon Inc.	N/A	NO_x
	SCR	CD8b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD8c	BASF	N/A	CO/VOC
A35	Water Injection Skid	CD9a	Becon Inc.	N/A	NO_x
	SCR	CD9b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD9c	BASF	N/A	CO/VOC
A36	Water Injection Skid	CD10a	Becon Inc.	N/A	NO_x
	SCR	CD10b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD10c	BASF	N/A	CO/VOC
A37	Water Injection Skid	CD11a	Becon Inc.	N/A	NO_x
	SCR	CD11b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD11c	BASF	N/A	CO/VOC
A38	Water Injection Skid	CD12a	Becon Inc.	N/A	NO_x
	SCR	CD12b	Peerless Mfg. Co.	N/A	NO_x
	Oxidation Catalyst	CD12c	BASF	N/A	CO/VOC

Note: Each EU consists of two gas turbines that converge into a common stack housing the CO catalyst, SCR catalyst, and ammonia injection system.

Turbine Units 5 through 8

Control requirements for Turbine Units 5 through 8 (EUs: A00701A, A00702B, A00705, and A00708) remain consistent with the previous permit. These units continue to be subject to all applicable requirements and limits listed in 40 CFR Part 60, Subpart A and Subpart GG.

The permittee continues to meet the startup/shutdown definitions indicated in the permit pursuant to ATC Modification 5, Condition IV-E-8 (10/1/08).

Compliance with the referenced CFRs above is met through the use of only natural gas in the combustion turbine units per Consent Decree Condition IV-B-33 (08/13/07), ensuring the sulfur content of the natural gas fuel does not exceed 0.5 grains per 100 dscf as determined by annual verification (consistent with the pipeline natural gas definition in 40 CFR Part 75, Appendix D), and meeting the NO_x limitation under Subpart GG that is based on the formula provided in 40 CFR Part 60.332(a)(1).

Additionally, PM_{10} exhaust emissions from each simple cycle system continue to be controlled via proper maintenance and periodic replacement of inlet air filters for each turbine.

Turbine Units 11 through 22 (Peaker Units)

Control requirements for Turbine Units 11 through 22 (EUs: A27 – A38) remain consistent with the previous permit. These units continue to be subject to a cumulative total testing/tuning limit of 600 minutes per calendar year per turbine. Also, the permittee continues to meet the startup/shutdown definitions indicated in the permit pursuant to ATC Modification 4, Revision 1, Condition III-B-5 (03/20/07).

The permittee for each turbine must continue to maintain and operate (per the manufacturer's specifications), a Selective Catalytic Reduction (SCR), water injection, and good combustion practices to control NO_x exhaust emissions and meet the NO_x emissions limits. Additionally, the permittee for each turbine must continue to maintain and operate (per the manufacturer's specifications), oxidation catalysts to control CO and VOC emissions and meet their respective emissions limits.

Cooling Towers (EUs: A00712 and A00713)

Control requirements for the cooling towers have been updated to reflect the installation of the new drift eliminators with a maximum drift rate of 0.001 percent. The cooling towers total dissolved solids (TDS) concentration remains limited to 12,000 ppm on a 30-day rolling average. The updated maximum drift rate condition is below:

- The permittee shall operate the cooling towers with drift eliminators that have a maximum drift rate of 0.001 percent, based on manufacturer's specifications. *[NSR ATC/OP 00007, Modification 4 Revision 1, Condition III-B-7 (03/20/07), revised in Part 70 OP Renewal Application (12/12/24)]*

Diesel Engines

The following control condition language was updated to align with the current CFR, which was updated in 89 FR 70518, August 30, 2024. These revisions provide additional flexibility. The language was updated to replace each instance of the use of the term "annually" with "within 1 year + 30 days of the previous change" (and, in the case of items such as spark plug, air cleaner, and hose and belt inspections, "within 1 year + 30 days of the previous inspection"):

- The permittee shall inspect and maintain the diesel emergency generator (EU: A21) to comply with the following requirements in accordance with the provisions of 40 CFR Part 63, Subpart ZZZZ *[40 CFR Part 63.6602]*:
    - Change the oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;
    - Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and
    - Inspect all hoses and belts every 500 hours or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

The following control conditions were added to align with the current CFR language. These conditions were missing from the permit:

- The permittee may use an oil analysis program (described in 40 CFR Part 63.6625(i)) to extend the specified oil change requirement and can petition the Control Officer pursuant to the requirements of 40 CFR Part 63.6(g) for alternative work practices. (EU: A21) *[40 CFR Part 63.6602]*

- During startup periods, the permittee shall minimize the diesel-fired generator engine's (EU: A21) time spent at idle and minimize its startup time to a period needed for appropriate and safe loading of the engine (not to exceed 30 minutes), after which non-startup emission limitations will apply. *[40 CFR Part 63.6602]*

The control requirement to operate and maintain the diesel emergency generator in accordance with the manufacturer's specification was updated to the following to align with current DAQ standard language and include the emergency fire pump:

- The permittee shall operate and maintain the diesel-fired emergency generator set and fire pump in accordance with the manufacturer's O&M manual for emissions-related components (EUs: A21 and A45). *[AQR 12.5.2.6(a)]*

Aside from the updated/new conditions above, the diesel-fired emergency generator and fire pump are still subject to diesel fuel requirements pursuant to 40 CFR 1090.305. Also, the permittee must continue to operate the fire pump (EU: A45) with turbocharger and aftercooler pursuant to NSR ATC 00007, Modification 6, Conditions IV-D-1, (04/27/09).

Gasoline Dispensing

The gasoline dispensing control conditions were updated to include AQR 102 citations and control conditions from AQR 102 as they are more stringent requirements than 40 CFR Part 63, Subpart CCCCCC. See below:

- The permittee shall implement control technology requirements on gasoline dispensing equipment. *[40 CFR Part 63, Subpart CCCCCC, AQR 12.5.2.6(a) & AQR 102]*

- The permittee shall install, operate, and maintain in good working condition at all times the GDF, including any associated air pollution control and monitoring equipment, in a manner consistent with good air pollution control practices for minimizing emissions. *[AQR 102.5(b)]*

- 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% oxygen content by weight. *[AQRs 53.1.1 & 53.2.1]*

- 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% 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]*

- 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 AQRs 102.5(c) & 102.6(b)]*

- Minimize gasoline spills;
- Clean up spills as expeditiously as practicable;
- Cover all open gasoline containers and all gasoline storage tank fill pipes with a gasketed seal when not in use; and
- 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.

- An owner or operator shall not allow degassing of gasoline vapors from any gasoline storage tank at the GDF unless VOC emissions are controlled by a device that has been approved in advance by the Control Officer to be at least 90% efficient by weight. *[AQR 102.5 (d)]*

Other

The existing control conditions were retained, including the requirement to maintain and operate equipment consistent with good air pollution control practices to minimize emissions pursuant to 40 CFR Part 60.11(d) and meeting the most stringent standard or requirement if there are inconsistencies between standards or requirements.

Additionally, DAQ is adding the following standard condition to all applicable permits to address air contaminants and odors. This condition prohibits the discharge of air contaminants (or other materials) in quantities that cause a nuisance, ensuring compliance with AQRs 40 and 43.

- 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. *[Part 70 OP Renewal Application (12/12/24), AQR 40; and AQR 43]*

F. MONITORING

The monitoring requirements listed in the previous permit were retained, which include complying with the applicable monitoring requirements of 40 CFR Part 60, Subparts A, GG, and KKKK, and 40 CFR Part 63, Subpart CCCCCC. Summary of the monitoring conditions retained per emission unit type is below:

Turbine Units 5 through 8

Calibrate, maintain, and operate a CEMS on the turbine units to monitor and record the following parameters for each individual turbine unit: hours of operation; fuel consumption, hours of downtime of the CEMS; exhaust gas flow rate (by direct or indirect methods); exhaust gas concentration of NO_x, CO, and O_2; one hour average NO_x concentration, and the hourly and 12-month rolling accumulated mass emissions of NO_x and CO.

Maintain a Quality Assurance Plan (QAP) for the CEMS which has already been submitted to and approved by the Control Officer that is binding and consistent with the applicable regulations.

Determine NO_x emission concentrations on a one-hour average for the turbine units as specified in the permit condition and monitor the monthly occurrences and duration of startup/shutdown cycles for the turbine units.

Turbine Units 11 through 22

Using a CEMS on the turbine units, monitor and record the following parameters for each individual turbine unit: exhaust gas concentration of NO_x, CO, and diluent O_2; exhaust gas flow rate (by direct or indirect methods); fuel flow rate; hours of operation; one-hour clock averages for NO_x and CO concentrations; hourly mass emissions of NO_x and CO; and hours of downtime of the CEMS.

Maintain a Quality Assurance Plan (QAP) for the CEMS which has already been submitted to and approved by the Control Officer that is binding and consistent with the applicable regulations.

Monitor the monthly occurrences and duration of startup/shutdown cycles, and the duration of testing/tuning events for each turbine unit.

Cooling Towers

Monitor the Total Dissolved Solids (TDS) of the cooling tower recirculation water daily when operating using a conductivity meter (or other device the Control Officer has approved in advance) (EUs: A00712 and A00713).

Diesel Engines

Retain a copy of the vendor fuel specifications to monitor the sulfur content and cetane index or aromatic content of the diesel fuel burned in the emergency generator (EU: A21) and fire pump (EU: A45).

Maintain a non-resettable hour meter on the emergency generator (EU: A21) and fire pump (EU: A45), which monitors the hours of operation during testing, maintenance, nonemergency operation, and emergency use for each unit.

Gasoline Dispensing

Monitor and record the throughput of gasoline and shall calculate the total of the last 365 days of gasoline throughput and divide the result by 12. Also, monitor the fuel storage and dispensing system to ensure compliance with the control requirements specified in 40 CFR Part 63, Subpart CCCCCC (63.11116). During this permitting action, the language was updated to current wording in the permit.

The following monitoring conditions were added:

Visible Emissions

Standard DES visible emission language, which includes but is not limited to requiring quarterly visible emission checks on each emergency generator and fire pump. This is new standard language also includes having the permittee sign and adhere to the department's *Visible Emissions Check Guidebook*. A copy of the signed guide must be on-site at all times. This visible emissions language replaces and enhances condition III.D.20 in the previous permit. Note that condition

III.D.20 required a plant-wide visual emission observation each calendar quarter. However, visible emissions monitoring is needed only for EUs that have a potential for opacity. Natural gas fired equipment, cooling towers, strictly VOC emitters (i.e., GDF) do not have a potential for opacity. As such, only visible emissions monitoring is required for the emergency engines.

Turbine Unit 4

At the end of each month, calculate a 12-month total NOx emissions (in tpy) for the preceding 12-month period. Also, monitor the hourly heat input rate (in MMBtu/hr) for Turbine Unit 4 using the hourly volume of natural gas combusted and the monthly natural gas LHV.

Per Compliance's request, the permittee shall also monitor the total hours of operation for the unit. This will be done as a way for Compliance to spot check compliance with the NOx emissions cap. Per the permittee, they will track and demonstrate compliance with the 292 tpy annual cap by multiplying the hours of operation by the emission factor and dividing by 2000. The NO_x emission factor is derived by taking the NO_x PTE of 1,732.6 tpy (NO_x PTE at 8,760 hr/yr before the 292 tpy emissions cap was taken due to AQR 122) and multiplying it by 2000 lb/ton and dividing it by 8,760 hr/yr. By following this methodology presented, the permittee will be using 395.57 lb/hr as the EF, which is about 1,476 hours of operation. It is possible that the permittee elects to use an EF derived from the performance test at a later date, which could result in a lower EF. As such, the hours of operation could vary before the 292 tpy cap is exceeded. For now, a footnote was added per Compliance's request in Table 3-2 of the permit to point out the 1,476 hours of operation review threshold. However, as discussed and indicated in the footnote, 1,476 hours of operation is not an enforceable limit.

Turbine Unit 5-8 and Units 11-22

Applicable requirements from AQR 122 were added. This includes monitoring VOC emissions using the parameters and the appropriate parameter range identified in the performance test protocol submitted to the Control Officer to demonstrate compliance with the applicable concentration and mass emission limitations specified in AQR 122.5.1(b)(4) and (c)(3). Additionally, edits were made in the monitoring conditions to incorporate language and citations from AQR 122.

G. PERFORMANCE TESTING

With the removal of the silos (EUs: A00709-A00711), the associated baghouse controls have also been removed, so the baghouse performance testing requirements listed in the previous permit have been removed during this permitting action.

New performance testing requirements were triggered with this permitting action due to the promulgation of AQR 122. Testing requirements as outlined in AQR 122.5.2 were added to the permit.

H. CONTINUOUS EMISSIONS MONITORING

The purpose of CEMS is to ensure equipment and/or processes are operated so as not to exceed the permitted emission limits. CEMS is a compliance tool for both the agency and the permittee. For this source, CEMS measures NO_x, CO, and O_2 emissions from the exhaust stacks of Turbine Units 5 through 8 and 11 through 22. Annual RATA for each CEMS unit is required to ensure the

monitoring system is operating properly, with some exemptions – See Appendix F, Section 5.1.4. To demonstrate continuous, direct compliance with the emission limitations for NO_x and CO specified for each turbine, except Turbine 4 (EU: A00704D), the permittee continues to calibrate, maintain, operate and certify the CEMS for each turbine as required by applicable regulations of 40 CFR Part 60 and 40 CFR Part 75.

The Turbine Units combust only pipeline quality natural gas. The NO_x emissions were controlled by water injection in Turbine Units 5 through 8, prior to installation of the ULNBs. The natural gas flow, turbine load, and water injection rate were continuously monitored as the indicators of NO_x emissions. After installation of ULNBs, water injection was no longer required on Turbine Units 5 through 8.

IV. REGULATORY REVIEW

A. LOCAL REGULATORY REQUIREMENTS

DAQ has determined that the following public laws, statutes, and associated regulations are applicable:

1. Nevada Revised Statute (NRS) Chapter 445B – Air Pollution
2. Air Quality Regulations as shown in the table below:

Table IV-A-1: Local Air Quality Regulations

Citation	Title	SIP[1]	Affected Emission Unit
AQR 0	"Definitions"	Yes	Entire source
AQR 1	"Definitions"	Yes	Entire source
AQR 04	"Control Officer"	Yes	Entire source
AQR 05	"Interference with Control Officer"	Yes	Entire source
AQR 06	"Injunctive Relief"	Yes	Entire source
AQR 07	"Hearing Board and Hearing Officer"	No	Entire source
AQR 08	"Persons Liable for Penalties – Punishment: Defense"	Yes	Entire source
AQR 09	"Civil Penalties"	No	Entire source
AQR 12.0	"Applicability and General Requirements"	Yes	Entire source
AQR 12.2	"Permit Requirements for Major Sources in Attainment Areas"	Yes	Entire source
AQR 12.3	"Permit Requirements for Major Sources in Nonattainment Areas"	Yes	Entire source
AQR 12.4	"Authority to Construct Application and Permit Requirements for Part 70 Sources"	Yes	Entire source
AQR 12.5	"Part 70 Operating Permit Requirements"	No	Entire source
AQR12.6	"Confidentiality"	No	Entire source
AQR 12.7	"Emission Reduction Credits"	Yes	Entire source
AQR 12.9	"Annual Emissions Inventory Requirement"	Partial	Entire source

Citation	Title	SIP[1]	Affected Emission Unit
AQR 12.10	"Continuous Monitoring Requirements for Stationary Sources"	No	Applicable emission units
AQR 12.12	"Transfer of Permit"	No	Entire source
AQR 12.13	"Posting of Permit"	No	Entire source
AQR 12.14	"Regional Haze Requirements"	No	Entire source
AQR 13.2(b)(1)	Delegated Program: "Subpart A - General Provisions"	No	Diesel Engines
AQR 13.2(b)(82)	Delegated Program: "Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines"	No	Applicable emission units
AQR 13.2(b)(106)	Delegated Program: "Subpart CCCCCC - National Emissions Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities"	No	Applicable emission units
AQR 14.1(b)(1)	Delegated Program: "Subpart A – General Provisions"	No	Applicable emission units
AQR 14.1(b)(40)	Delegated Program: "Subpart GG – Standards of Performance for Stationary Gas Turbines"	No	Applicable emission units
AQR 14.1(b)(82)	Delegated Program: "Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines"	No	Applicable emission units
AQR 14.1(b)(84)	Delegated Program: "Subpart KKKK – Standards of Performance for Stationary Combustion Turbines"	No	Applicable emission units
AQR 18	"Permit and Technical Service Fees"	Partial	Entire source
AQR 21	"Acid Rain Permits"	No	Applicable emission units
AQR 22	"Acid Rain Continuous Emission Monitoring"	No	Applicable emission units
AQR 25	"Affirmative Defense for Excess Emissions due to Malfunctions, Startup, and Shutdown"	Partial	Entire source
AQR 26	"Emission of Visible Air Contaminants"	Yes	Entire source
AQR 28	"Fuel Burning Equipment"	Yes	Entire source
AQR 40	"Prohibitions of Nuisance Conditions"	No	Entire source
AQR 41	"Fugitive Dust"	Yes	Entire source
AQR 42	"Open Burning"	Yes	Entire source
AQR 43	"Odors in the Ambient Air"	No	Entire source
AQR 53	"Oxygenated Gasoline Program"	Yes	Applicable emission units
AQR 70	"Emergency Procedures"	Yes	Entire source
AQR 80	"Circumvention"	Yes	Entire source
AQR 81	"Provisions of Regulation Severable"	Yes	Entire source
AQR 102	"Gasoline Dispensing Facilities"	No	Applicable emission units
AQR 122	"Reasonably Available Control Technology for Major Sources in HA 212"	No	Applicable emission units

[1]Refer to 40 CFR Part 52, Subpart DD, § 52.1470(c), Table 3 for EPA-approved Clark County Regulations

DAQ is providing a regulatory analysis as to the following Air Quality Regulations that do/don't apply:

AQR 101

The source has an industrial adhesive operation located in hydrographic area 212 (the Las Vegas Valley); however, it is not subject to AQR 101: *VOC Emissions Control for Industrial Adhesive Operations.* Per the permittee, they use approximately five 24oz cans of adhesive aerosol annually. When converted to gallons, that is approximately 1 gallon. Per AQR 101.2(c)(1), a source is exempt from AQR 101 if it uses less than 500 gallons (1,892 L) of industrial adhesive materials per calendar year in industrial adhesive operations.

AQR 102

The source has a gasoline dispensing facility (GDF) located in hydrographic area 212 (the Las Vegas Valley); therefore, it is subject to AQR 102: *Gasoline Dispensing Facilities.* Because the gasoline throughput is less than 120,000 gallons in any consecutive 12-month period, the source does not need to meet all the requirements of AQR 102 (i.e., vapor balance system). Instead, the source will be subject to the applicable requirements under AQRs 102.5, 102.6, and 102.11 (on work practices, gasoline storage tank filling standards, and recordkeeping requirements). Notably, AQR 102.6 adds submerged filling control standards that the permittee was not subject to before. This is because AQR 102 has stricter requirements compared to 40 CFR Part 63, Subpart CCCCCC.

AQR 103

The source does not have a miscellaneous metal or plastic parts coating operation; therefore, it is not subject to AQR 103: *VOC Emissions Control for Miscellaneous Metal or Plastic Parts Coating Operations.* For future reference, even if a miscellaneous metal or plastic parts coating operation were introduced at this source, it would still not be subject to AQR 103 because per the definition of "miscellaneous metal or plastic coating operations," this kind of operation is found at facilities whose operations fall under SIC codes 33-41. This source's SIC code starts with 49.

AQR 104

The source has an industrial cleaning solvent operation located in hydrographic area 212 (the Las Vegas Valley); however, it is not subject to AQR 104: *VOC Emissions Control for Industrial Cleaning Solvent Operations.* Per the permittee, they use between 50 and 200 16oz to 24 oz cans of aerosol cleaning solvent annually. When converted to gallons, that is approximately 19 gallons (worst case). Per AQR 104.2(c)(1), a source is exempt from AQR 104 if it uses less than 500 gallons (1,892 L) of industrial cleaning solvent per calendar year in industrial cleaning solvent operations.

AQR 105

The source does not have a metal solvent degreaser operation located in hydrographic area 212 (the Las Vegas Valley); therefore, it is not subject to AQR 105: *VOC Emissions Control for Metal Solvent Degreaser Operations.* Per the permittee, they removed their parts washer. Also, parts are typically replaced or if cleaning is an option, they use approximately two to five gallons of Simple Green annually. Simple Green is applied manually using a spray bottle and a wire brush or rag. Per AQR 105, "metal solvent degreaser" means a tank, drum, or other container in which metal

objects are exposed to a solvent or solvent vapors to remove contaminants. For the purpose of AQR 105, it includes only cold cleaners, open top vapor degreasers, and conveyorized degreases. Manual application of solvent degreaser does not meet the definition of a metal solvent degreaser.

AQR 122

AQR 122 establishes and implements Reasonably Available Control Technology (RACT) requirements for existing major stationary sources of nitrogen oxide (NOx) and/or volatile organic compounds (VOCs) as required by Section 182(b)(2) of the Clean Air Act (Act) under Title 42, Section 7511a of the U.S. Code (42 USC 7511a). The source is a listed source under AQR 122; therefore, it is subject to the regulation. Applicable requirements were added during this permitting action.

B. FEDERALLY APPLICABLE REGULATIONS

1. Clean Air Act, as amended (CAAA), Authority: 42 U.S.C. § 7401, et seq

2. Applicable 40 CFR sections are listed in Table IV-B-1.

Table IV-B-1: Federal Standard

Citation	Title
40 CFR Part 60, Subpart A	"General Provisions"
40 CFR Part 60, Subpart GG	"Standards of Performance for Stationary Gas Turbines"
40 CFR Part 60, Subpart IIII	"Standards of Performance for Stationary Compression Ignition Internal Combustion Engines"
40 CFR Part 60, Subpart KKKK	"Standards of Performance for Stationary Combustion Turbines"
40 CFR Part 63, Subpart A	"General Provisions"
40 CFR Part 63, Subpart CCCCCC	"National Emissions Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities"
40 CFR Part 63, Subpart ZZZZ	"National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines"
40 CFR Part 64	"Compliance Assurance Monitoring"
40 CFR Part 70	"State Operating Permit Programs"
40 CFR Part 72	"Permits Regulation" – Acid Rain Program
40 CFR Part 73	"Sulfur Dioxide Allowance System" – Acid Rain Program
40 CFR Part 75	"Continuous Emission Monitoring" – Acid Rain Program
40 CFR Part 82	"Protection of Stratospheric Ozone"

Below is a summary of the applicable federal requirements. No new federal requirements were triggered during this permitting action.

40 CFR Part 60 – Standards of Performance for New Stationary Sources

40 CFR Part 60, Subpart GG—Standards of Performance for Stationary Gas Turbines

Discussion: The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired. Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of 40 CFR Part 60.332.

Units 5-8 (EUs: A00701A, A00702B, A00705, and A00708) underwent modification in 1988-1991. All four turbine units are subject to Subpart GG in its entirety.

Unit 4 (EU: A00704D) is not subject to 40 CFR Part 60 Subpart GG, as it was permitted prior to the October 1977 applicability date.

Units 11-22 (EUs: A27-A38) are not subject to 40 CFR Part 60 Subpart GG per 40 CFR 60.4305(b) as they are applicable to 40 CFR Part 60, Subpart KKKK, which exempts these units from this subpart.

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Discussion: Subpart IIII applies to the diesel fire pump (EU: A45) at this source because construction commenced after July 11, 2005. The requirements are found in the Part 70 OP. The diesel emergency generator (EU: A21) was constructed prior to the applicability and is not subject to the requirements of this subpart.

The emergency fire pump diesel engine has demonstrated compliance with the emission standards set forth in Table 4 to Subpart IIII of Part 60 for the same model year and maximum engine power, which are provided in Table IV-B-2.

Table IV-B-2: Emission Standards for IC Engines

EU	Year	Power	NMHC + NO_x	NO_x	NMHC	CO	PM
A45	2009[1]	225≤kW<450 (300≤HP<600)	4.0 (3.0)	-	-	3.5 (2.6)	0.20 (0.15)

[1]In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Discussion: Subpart KKKK does not apply to Turbines Units 4-8 at this source because the turbines did not commence construction, modification, or reconstruction after February 18, 2005. Subpart KKKK does apply to Turbine Units 11-22, as construction commenced after the applicability date.

Subpart KKKKa—Standards of Performance for Stationary Combustion Turbines

Discussion: Subpart KKKKa does not apply to any turbine at this source because the turbines did not commence construction, modification, or reconstruction after December 13, 2024.

40 CFR Part 63 – National Emission Standards for Hazardous Air Pollutants

Subpart YYYY—National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Discussion: Subpart YYYY applies to the combustion turbines at major sources of HAP emissions. As Clark Generating Station is not a major source of HAP emissions, the source is not subject to this subpart.

Subpart ZZZZ—National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Discussion: Subpart ZZZZ applies to the diesel emergency generator (EU: A21) and to the diesel fire pump (EU: A45) at this source. Applicable Subpart ZZZZ requirements were added for EU A21. The diesel fire pump (EU: A45) is also subject to Subpart IIII and therefore, will meet the requirements of Subpart ZZZZ by meeting the requirements of Subpart IIII.

Subpart CCCCCC—National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities

Discussion: The provisions of this subpart are applicable to any GDF that is located at an area source. The affected source includes each gasoline cargo tank during the delivery of product to a GDF and also includes each storage tank. The GDF at this source (EU: A43) has a monthly throughput of less than 10,000 gallons of gasoline, and therefore, must comply with the requirements in 40 CFR Part 63.11116.

40 CFR Part 64 – Compliance Assurance Monitoring

Discussion: The CAM Rule is not applicable to Turbine Unit 4 (EU: A00704D), the diesel-powered emergency generator (EU: A21), The diesel-powered fire pump (EU: A45), the cooling towers (EUs: A00712 and A00713), and the gasoline dispensing operation (EU: A0043) based on the applicability statement outlined in 40 CFR 64.2(a)(2), i.e., a control device is not used on these units (other than inherent process equipment) to achieve compliance with any emission limitation or standard for a regulated air pollutant.

The NO_x and CO CEMS, which are operated and required by the Part 70 OP on Turbine Units 5 through 8 and 11 through 22, meet the CAM 40 CFR 64.2(b)(1)(vi) exemption requirements of a continuous compliance determination method.

For Turbine Units 5 through 8 and 11 through 22, the CAM Rule is not applicable for PM_{10}, SO_2, VOC, or HAP because no control device is used to achieve compliance for any of these pollutants.

40 CFR 72-Acid Rain Permits Regulation

Discussion: Turbine Units 4 through 8 were operating as simple cycle natural gas-fired turbines prior to November 15, 1990, and have not added auxiliary firing. Therefore, according to 72.6(b)(1) the provisions of this regulation do not apply to these units. Turbine

Units 11 through 22 are new units according to 40 CFR 72.6 and the provisions of this regulation apply.

40 CFR 73 – Acid Rain Sulfur Dioxide Allowance System

Discussion: Turbine Units 11 through 22 are applicable units and therefore the provisions of this regulation apply.

40 CFR 75 – Continuous Emission Monitoring

Discussion: Clark Generating Station is an affected facility subject to the Acid Rain emission limitations of 40 CFR 40 CFR 72; therefore, the source is subject to monitoring, recordkeeping, and reporting requirements of this regulation.

V. COMPLIANCE

A. COMPLIANCE HISTORY

Compliance Issue	How Resolved/Proposed	Date/Status
Partial visible emission observations conducted.	Permittee to document action taken to come into compliance and keep this documentation with their Air Quality record keeping logs. No enforcement action taken by DAQ.	March 3, 2016

B. COMPLIANCE CERTIFICATION

Records shall be kept for all limitations specified in the permit.

Requirements for reporting remain the same as prior Part 70 OP. This includes adhering to the reporting schedule below:

Table V-B-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 Emissions Inventory Report	Calendar year	March 31 each year[1]
Annual Emissions Statement[2]	Calendar year	March 31 each year[1]
Notification of Malfunctions, Startup, Shutdowns, or Deviations with Excess Emission	As required	Within 24 hours of the permittee learns of the event
Excess Emissions that Pose a Potential Imminent and Substantial Danger	As required	Within 12 hours of when permittee learns of event

Required Report	Applicable Period	Due Date
Report of Malfunctions, Startup, Shutdowns, or Deviations with Excess Emission	As required	Within 72 hours of the notification[1]
Deviation Report without Excess Emissions	As required	Along with semiannual reports[1]
Performance Testing Protocol	As required	No less than 45 days, but no more than 90 days, before the anticipated test date[1]
Performance Testing Results	As required	Within 60 days of end of test[1]
RATA Protocol	As required	No less than 21 days, but no more than 90 days, before the anticipated test date[1]
RATA Results	As required	Within 45 days of end of test for Part 75 sources or within 60 days for all others[1]

[1]If the due date falls on a federal or Nevada holiday, or on any day the office is not normally open for business, 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.

C. SUMMARY OF MONITORING FOR COMPLIANCE

Table V-C-1: Compliance Monitoring

EU	Process Description	Monitored Pollutants	Applicable Subsection Title	Requirements	Compliance Monitoring
A00704D	Combustion Turbine	CO, NO_x, SO_2, PM_{10}, VOC, HAP	AQR Section 12	Annual emission limits	Record keeping hours of operation, fuel use.
A00701A, A00702B, A00705, and A00708	Combustion turbines Units 5 through 8	CO, NO_x SO_2, PM_{10}, VOC, and HAP	AQR Section 12, 40 CFR 60 Subpart GG	Annual and short-term emission limits. Fuel consumption recordkeeping and reporting	CEMS for NO, and CO. Compliance for HAPs and non-CEMS monitored emissions shall be based on fuel consumption and emission factors. Recording is required for compliance demonstration. SO_2 will be monitored through sulfur content in the fuels and recordkeeping of hours of operation.
A00701A, A00702B, A00705, and A00708	Combustion turbines Units 5 through 8	SO_2	Subpart GG	Natural gas sulfur content limited by 0.50 grains per 100 standard cubic feet.	Annual sulfur content results to be submitted with annual reports. Recordkeeping of sulfur content quarterly. Excess emissions report if sulfur exceeds 0.05 percent by weight.

EU	Process Description	Monitored Pollutants	Applicable Subsection Title	Requirements	Compliance Monitoring
A00701A, A00702B, A00705, and A00708	Combustion turbines Units 5 through 8		AQR Section 26	Opacity 20%	Regular, periodic visual survey of opacity shall be made while burning gas. Immediate logging of any opacity noted, and correction of opacity exceedance. Reporting of upset/breakdown to EPA and DAQ.
A00712 and A00713	Cooling tower	PM_{10}	AQR Section 12	Emission limits based upon hours of operation and TDS	Control technology of drift eliminators. Recordkeeping of hours of operation. Monitoring of total dissolved solids and recordkeeping
A27-A38	Combustion turbines Units 11 through 22	CO, NO_x, SO_2, PM_{10}, VOC, and HAPs	AQR Section 12, 40 CFR 60 Subpart KKKK	Annual and short-term emission limits. Fuel consumption recordkeeping and reporting	CEMS for NO and CO. Compliance for HAPs and non-CEMS monitored emissions shall be based on fuel consumption and emission factors. Recording is required for compliance demonstration. SO_2 will be monitored through sulfur content in the fuels and recordkeeping of hours of operation.
A27-A38	Combustion turbines Units 11 through 22	SO_2	Subpart KKKK	Natural gas sulfur content limited to 0.060 lbs SO_2/MMBtu.	Annual sulfur content results, as determined per 40 CFR Part 75, Appendix D, to be submitted with annual reports. Recordkeeping of sulfur content quarterly. Excess emissions report if sulfur exceeds 0.05 percent by weight.
A27-A38	Combustion turbines Units 11 through 22		AQR Section 26	Opacity 20%	Regular, periodic visual survey of opacity shall be made while burning gas. Immediate logging of any opacity noted, and correction of opacity exceedances. Reporting of upset/breakdown to EPA and DAQ.
A45	Emergency Fire Pump	NO_x, CO, VOC, PM_{10}, HAP, and SO_2	AQR Sections 12	Emission limitations based upon fuel throughput and hours of operation for testing and maintenance. Sulfur limited to 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume.	Recordkeeping of fuel use and hours of operation. Calculated emissions based upon manufacturer's emission factors, AP-42 and fuel. Fuel certification by supplier.

VI. EMISSION REDUCTION CREDITS (OFFSETS)

This source is subject to offset requirements in accordance with AQR 12.7. Offset requirements and associated mitigation are pollutant specific.

VII. MODELING

A. INCREMENT ANALYSIS

Facility Location: 675550, 3995450 (Universal Transverse Mercator (UTM) NAD83)

Clark Generating Station is a major source in Hydrographic Area 212 (the Las Vegas Valley). Permitted emission units include 17 turbines, two generators and two cooling towers. 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. Stack data submitted by the applicant was 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 VII-A-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 VII-A-1: PSD Increment Consumption

Pollutant	Averaging Period	Source's PSD Increment Consumption (µg/m³)	Location of Maximum Impact	
			UTM X (m)	UTM Y (m)
SO_2	3-hour	2.50[1]	675900	3995800
SO_2	24-hour	1.15[1]	675900	3996000
SO_2	Annual	0.13	675700	3996000
NO_X	Annual	2.24	675700	3995800

[1] Highest Second High Concentration.

VIII. ENVIRONMENTAL JUSTICE

This permitting action is a renewal for an existing Title V OP. The cooling towers drift eliminators replacements and the removal of the silos from the permit resulted in a decrease in $PM_{10}/PM_{2.5}$ emissions. As there is no increase in the source's potential impact on the surrounding community, an Environmental Justice (EJ) analysis is not required for this permitting action. The source continues to be subject to the applicable requirements to protect the NAAQS, which are set at levels protective of public health, including sensitive populations. Public involvement requirements for this renewal will be satisfied through the standard procedures outlined in AQR 12.5.2.17.

IX. PERMIT SHIELD

The permittee did not request any changes during this permitting action. The existing permit shield remains in effect. However, the Subpart GG citation was updated to align with current AQR 14. AQR 14 was amended effective 10/7/2025. Also, as stated in the streamlining table (Table X-1), Subpart KKKK should be shielded. Added Subpart KKKK citation to Table IX-1. See below:

Table IX-1: Applicable Requirements Related to Permit Shield

Citation	Title
AQR 14.1(b)(40), Subpart GG	"Standards of Performance for Stationary Gas Turbines"
AQR 14.1(b)(84), Subpart KKKK	"Standards of Performance for Stationary Combustion Turbines"

X. STREAMLINING

Table X-1: Streamlining

Regulation (40 CFR)	Pollutant	Regulatory Standard	Permit Limit	Value Comparison			Averaging Comparison			Shield Statement
				Standard Value, in Units of Permit Limit[1]	Permit Limit Value	Is Permit Limit Equal or More Stringent	Standard Averaging Period	Permit Limit Averaging Period	Is Permit Limit Equal or More Stringent	
Turbines 5 through 8										
60.332 (GG)	NOx	75[1] ppmvd @ 15% O_2	5.0 ppmvd @ 15% O_2	75[1]	5.0	Yes	4 hour	1 hour	Yes	The permit limit is more stringent than the standard, based on both concentration and averaging time, therefore the facility should be shielded from the standard.
60.333 (GG)	SO_2	0.15% by volume @15% O_2	1.62 lbs/hr	830[2]	1.62	Yes	4 hour	1 hour	Yes	The permit limit is more stringent than the standard, based on both concentration and averaging time, therefore the facility should be shielded from the standard.

Regulation (40 CFR)	Pollutant	Regulatory Standard	Permit Limit	Value Comparison			Averaging Comparison			Shield Statement
				Standard Value, in Units of Permit Limit[1]	Permit Limit Value	Is Permit Limit Equal or More Stringent	Standard Averaging Period	Permit Limit Averaging Period	Is Permit Limit Equal or More Stringent	
Turbines 11 through 22										
60.4330 (KKKK)	SO_2	0.06 lb/MMBtu	0.00066 lb/MMBtu	0.06	6.6 E-04	Yes	N/A	N/A	Yes	The permit limit is more stringent than the standard, based on both concentration and averaging time, therefore the facility should be shielded from the standard.

[1]The 60.332 NOx standard is a formula; the value used here (75 ppmvd) is the minimum possible value of the standard for any emission unit.
[2]Heat input used to calculate SO_2 standard value (in units of the permit limit) is the permit limit of 1081 MMBtu/hr.

XI. PUBLIC PARTICIPATION

Under AQR 12.5.2.17, the public participation requirement is triggered for OP renewals.

XII. ATTACHMENTS

See the following attachments for calculations.

XII-1. Source Permit Applicability Calculations (tons per year)

EU	Condition	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC
A00704D	8,760 hr/yr	165.40	165.40	1,732.60	433.10	7.90	94.50
A00701A	8,760 hr/yr	106.90	106.90	360	319.70	7.10	21.90
A00702B	8,760 hr/yr	106.90	106.90		319.70	7.10	21.90
A00705	8,760 hr/yr	106.90	106.90		319.70	7.10	21.90
A00708	8,760 hr/yr	106.90	106.90		319.70	7.10	21.90
A00712	8,760 hr/yr	6.68	6.68	0	0	0	0
A00713	8,760 hr/yr	6.68	6.68	0	0	0	0
A21	500 hr/yr	0.26	0.26	2.48	1.03	0.01	0.02
A45	500 hr/yr	0.02	0.02	0.62	0.17	0.01	0.11
A27	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A28	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A29	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A30	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A31	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A32	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A33	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58

EU	Condition	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC
A34	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A35	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A36	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A37	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A38	8,760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A46	1,000 gal/month	0	0	0	0	0	0.11
Applicability		**880.00**	**880.00**	**11,394.26**	**5,182.06**	**66.68**	**1,041.30**

Note: There is a flow rate operational limit on the cooling towers (EUs: A00712 and A00713). For reporting purposes, 8,760 hours per year was used for the cooling towers, which is consistent with how the permittee currently reports their emissions.

XII-2. Source Permit PTE Calculations (tons per year)

EU	Condition	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC
A00704D	8,760 hr/yr	165.40	165.40	292.00	433.10	7.90	94.50
A00701A	8,760 hr/yr	106.90	106.90	360	319.70	7.10	21.90
A00702B	8,760 hr/yr	106.90	106.90		319.70	7.10	21.90
A00705	8,760 hr/yr	106.90	106.90		319.70	7.10	21.90
A00708	8,760 hr/yr	106.90	106.90		319.70	7.10	21.90
A00712	8,760 hr/yr	6.68	6.68	0	0	0	0
A00713	8,760 hr/yr	6.68	6.68	0	0	0	0
A21	500 hr/yr	0.26	0.26	2.48	1.03	0.01	0.02
A45	500 hr/yr	0.02	0.02	0.62	0.17	0.01	0.11
A27	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A28	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A29	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A30	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A31	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A32	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A33	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A34	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A35	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A36	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A37	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A38	3,500 hr/yr	9.10	9.10	30.96	11.55	1.01	2.86
A46	1,000 gal/month	0	0	0	0	0	0.11
PTE		**715.84**	**715.84**	**1026.62**	**1,851.70**	**48.44**	**216.66**

Note: There is a flow rate operational limit on the cooling towers (EUs: A00712 and A00713). For reporting purposes, 8,760 hours per year was used for the cooling towers, which is consistent with how the permittee currently reports their emissions

Uncontrolled - Turbine Calculations Including Startup, Shutdowns, and Testing/Tuning

EU	Hours	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC
A00704D	8760 hr/yr	165.4	165.4	1,732.60	433.1	7.9	94.5
A00701A	8760 hr/yr	106.9	106.9	360	319.7	7.1	21.9
A00702B	8760 hr/yr	106.9	106.9		319.7	7.1	21.9
A00705	8760 hr/yr	106.9	106.9		319.7	7.1	21.9
A00708	8760 hr/yr	106.9	106.9		319.7	7.1	21.9
A27[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A28[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A29[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A30[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A31[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A32[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A33[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A34[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A35[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A36[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A37[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
A38[1]	8760 hr/yr	22.78	22.78	774.88	289.08	2.53	71.58
[1]Calculated at 8,760 hrs/yr without SCR and Oxidative Catalyst controls							

Controlled - Turbine Calculations Including Startup, Shutdowns, and Testing/Tuning

EU	Hours	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC
A00704D	8760 hr/yr	165.4	165.4	292.00	433.1	7.9	94.5
A00701A	8760 hr/yr	106.9	106.9	360	319.7	7.1	21.9
A00702B	8760 hr/yr	106.9	106.9		319.7	7.1	21.9
A00705	8760 hr/yr	106.9	106.9		319.7	7.1	21.9
A00708	8760 hr/yr	106.9	106.9		319.7	7.1	21.9
A27[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86
A28[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86
A29[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86
A30[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86
A31[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86
A32[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86
A33[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86
A34[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86
A35[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86
A36[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86
A37[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86
A38[1,2]	3500 hr/yr	9.1	9.1	30.96	11.55	1.01	2.86

[1]Controlled by Selectrice Catalytic Reduction (SCR) with an efficiency of 90% NOx per EPA Air Pollution Control Technology Factor Sheet on Selective Catalytic Reduction, published 2003

[2]Controlled by Oxidative Catalyst with an efficiency of 90% CO/VOC per EPA Memorandum "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines", published 2001

Uncontrolled/Controlled – Emergency Engines

						Emission Factor	Control	Potential Emissions		
EU#	A21		**Horsepower:**	474		(lb/hp-hr)	Efficiency	lb/hr	lb/day	ton/yr
Make:	Detroit Diesel		**Hours/Day:**	24.0						
Model:	8063-7416		**Hours/Year**	500	**PM10**	2.20E-03	0.00%	1.04	25.03	0.26
S/N:	6V-92TA				**NOx**	2.10E-02	0.00%	9.94	238.51	2.48
					CO	8.71E-03	0.00%	4.13	99.07	1.03
Manufacturer Guarantees					**SO_2**	1.21E-05	0.00%	0.01	0.14	0.01
PM10	0.998	g/hp-hr			**VOC**	1.54E-04	0.00%	0.07	1.76	0.02
NOx	9.51	g/hp-hr			**HAP**	2.71E-05	0.00%	0.01	0.31	0.01
CO	3.95	g/hp-hr								
SO_2		g/hp-hr								
VOC	0.07	g/hp-hr								
Engine Type:	Diesel				Diesel Fuel Sulfur Content is 15 ppm (0.0015%)					

EU#	A45		Horsepower:	460		Emission Factor (lb/hp-hr)	Control Efficiency	Potential Emissions		
Make:	Cummins		Hours/Day:	24.0				lb/hr	lb/day	ton/yr
Model:	CFP15E-F10		Hours/Year	500	PM10	1.98E-04	0.00%	0.09	2.19	0.02
S/N:	79347925				NOx	5.42E-03	0.00%	2.49	59.87	0.62
					CO	1.48E-03	0.00%	0.68	16.31	0.17
Manufacturer Guarantees					SO_2	1.21E-05	0.00%	0.01	0.13	0.01
PM10	0.09	g/hp-hr			VOC	9.48E-04	0.00%	0.44	10.47	0.11
NOx	2.46	g/hp-hr			HAP	2.71E-05	0.00%	0.01	0.30	0.01
CO	0.67	g/hp-hr								
SO_2		g/hp-hr								
VOC	0.43	g/hp-hr								
Engine Type:	Diesel				Diesel Fuel Sulfur Content is 15 ppm (0.0015%)					

Uncontrolled/Controlled – Cooling Towers

EU	Description	Drift Loss % (1)	Flow Rate	TDS (mg/l)	Hours of Operation		PM10 Emissions		PM2.5 Emissions	
					hr/day	hr/yr	lb/hr	ton/yr	lb/hr	ton/yr
A00712	Cooling Tower	0.001%	54000	12000	24	8760	1.52	6.68	1.52	6.68
A00713	Cooling Tower	0.001%	54000	12000	24	8760	1.52	6.68	1.52	6.68
							0.00	0.00	0.00	0.00
							3.04	**13.36**	**3.04**	**13.36**

Operational limit on the flow rate on the permit but for reporting purposes, 8,760 hours/year used.

Uncontrolled/Controlled – GDF

Value	Input	Description
219.71	**Lt**	Total routine losses, lb/yr
119.37	Ls	Standing Losses, lb/yr
100.33	Lw	Working losses, lb/yr
		Net Standing Loss
119.37	**Ls**	Standing Losses, lb/yr
43.86	Vv	Vapor Space volume, ft3
0.06	Wv	stock vapor density, lb/ft3
0.19	Ke	vapor space explansion factor, per day
0.63	Ks	Vented vapor saturation factor, dimensionless
	365	constant days/yr
43.86	**Vv**	ft3
5.08	D	tank diameter, ft see Equation 1-14 for horizontal tanks
2.17	Hvo	vapor space outage, ft use HE/2 from Equation 1-15 for horizontal tanks
0.19	**Ke**	vapor space explansion factor, per day
30.62	ΔTv	average daily vapor temp range, degrees R
1.28	ΔPv	average daily vapor pressure range, psi
0.06	ΔPb	breather vent pressure setting range, psi
14.6	Pa	atmospheric pressure, psia (converted from 29.7 inHg current conditions)
5.2	Pva	vapor pressure at average daily liquid surface temperature, psia
507.76	Tla	average daily liquid surface temperature, °R
30.62	**ΔTv**	average daily vapor temp range, degrees R
2.54	Hs	tank shell height, ft
5.08	D	Tank Diameter, ft
31.1	ΔTa	average daily ambient temperature range, °R
0.25	αR	tank roof surface solar absorptance, dimensionless (Table 7.1-6

0.25	αS	tank shell surface solar absorptance, dimensionless
1769	I	average daily total insolation factor, Btu/ft2 d (Table 7.1-7
0.25	α	average tank surface solar absorptance, dimensionless
1.28	**ΔPv**	average daily vapor pressure range, psi
4.77	Pvx	vapor pressure at the average daily maximum liquid surface temperature, psia
3.5	Pvn	vapor pressure at the average daily minimum liquid surface temperature, psia
0.06	**ΔPb**	breather vent pressure setting range, psi
0.03	Pbp	breather vent pressure setting, psig
-0.03	Pbv	breather vent vacuum setting, psig
31.1	**ΔTa**	average daily ambient temperature range, °R
520.3	Tax	average daily maximum ambient temperature, °R
489.2	Tan	average daily minimum ambient temperature, °R
5.08	**De**	effective tank diameter, ft
4.42	L	length of the horizontal tank, ft (for tanks with rounded ends, use the overall length)
4.58	D	diameter of a vertical cross-section of the horizontal tank, ft
4.33	**He**	effective height, ft
2.17	**Hvo**	vapor space outage, ft; use HE/2 from Equation 1-15 for horizontal tanks
2.54	Hs	tank shell height, ft
1.27	Hl	liquid height, ft; typically assumed to be at the half-full level, unless known to be maintained at some other level
0	Hro	roof outage, ft; (or shell height equivalent to the volume contained under the roof)
0.63	**Ks**	Vented vapor saturation factor, dimensionless
5.2	Pva	vapor pressure at average daily liquid surface temperature, psia; see Notes 1 and 2 to Equation 1-22
2.17	Hvo	
	0.053	constant, psia-ft
0.06	**Wv**	stock vapor density, lb/ft3
66	Mv	vapor molecular weight, lb/lb-mole, Table 7.1-2 & 7.1-3
10.73	R	the ideal gas constant, 10.731 psia ft3 /lb-mole °R
5.2	Pva	vapor pressure at average daily liquid surface temperature, psia; see Notes 1 and 2 to Equation 1-22
509.13	Tv	average vapor temperature, °R;
4.77	**Pvx**	vapor molecular weight, lb/lb-mole, Table 7.1-2 & 7.1-3
3.5	**Pvn**	
	exp	exponential function
11.72	A	constant in the vapor pressure equation, dimensionless
5237.3	B	constant in the vapor pressure equation, °R
515.41	Tlx	average daily maximum liquid surface temperature, °R
500.1	Tln	average daily minimum liquid surface temperature, °R
507.76	**Tla**	average daily liquid surface temperature, °R
2.54	Hs	tank shell height, ft
5.08	D	tank diameter, ft,
504.75	Taa	average daily ambient temperature, °R; see Note 4
506.08	Tb	liquid bulk temperature, °R; see Note 5
0.25	αR	tank roof surface solar absorptance, dimensionless (Table 7.1-6
0.25	αS	tank shell surface solar absorptance, dimensionless
1769	I	average daily total insolation factor, Btu/ft2 d (Table 7.1-7
504.75	**Taa**	average daily ambient temperature, °R
520.3	Tax	average daily maximum ambient temperature, °R
489.2	Tan	average daily minimum ambient temperature, °R

506.08	**Tb**	liquid bulk temperature, °R; see Note 5
504.75	Taa	average daily ambient temperature, °R; see Note 4
0.25	αS	tank shell surface solar absorptance, dimensionless
1769	I	average daily total insolation factor, Btu/ft2 d (Table 7.1-7
509.13	**Tv**	average vapor temperature, °R;
2.54	Hs	tank shell height, ft
4.58	D	tank diameter, ft,
506.08	Tb	liquid bulk temperature, °R; see Note 5
504.75	Taa	average daily ambient temperature, °R; see Note 4
0.25	αS	tank shell surface solar absorptance, dimensionless
1769	I	average daily total insolation factor, Btu/ft2 d (Table 7.1-7

Net Working Loss		
100.33	**Lw**	Working losses, lb/yr
1604.17	Vq	net working loss throughput, ft3 /yr, see Note 1
1	Kn	working loss turnover (saturation) factor, dimensionless
48	N	number of turnovers per year, dimensionless

1604.17	**Vq**	net working loss throughput, ft3 /yr, see Note 1
	5.614	conversion of barrels to cubic feet, ft3/bbl
285.74	Q	net throughput, bbl/yr
	0.13368056	conversion of cubic feet per gallon
	250	gallon tank
	12,000	gallons per year (calculated annual based on 1,000 gallon/month permit throughput limit)

1.002	**Kn**	working loss turnover (saturation) factor (dimensionless), see Equation 1-35 PVA = vapor pressure at the average daily liquid surface temperature, psia; see Notes 1 and 2 to Equation 1-22
0.99	**Kb**	vent setting correction factor, dimensionless
0	Pi	pressure of the vapor space at normal operating conditions, psig PI is an actual pressure reading (the gauge pressure). If the tank is held at atmospheric pressure (not held under a vacuum or at a steady
14.6	Pa	atmospheric pressure, psia
0.03	Pbp	breather vent pressure setting, psig
5.2	Pva	vapor pressure at average daily liquid surface temperature, psia
1	**Kp**	working loss product factor, dimensionless for crude oils, KP = 0.75; adjustment of KP may be appropriate in the case of splash loading into a tank for all other organic liquids, KP = 1
0.06	Wv	vapor density, lb/ft3 , see Equation 1-22

VOC Total Potential to Emit (Standing Loss + Working Loss)		
0.11	**PTE**	**tons/yr**

Hazardous Air Pollutant Emissions form Gasoline Dispensing Facility (GDF)		
Emisisons Unit	A46: 250 gallon GDF	
Gasoline throughput	12,000	gallons/yr
Annual Operating Hours	8760	hr/year
Gasoline emission factor - No Controls[1]	19.5	lbs/1000 gallons

HAP	**Percent in liquid[2]**	**Emissions (tons/yr)**
Benzene	1.00%	1.17E-03
Toluene	1.60%	1.87E-03
Ethylbenzene	8.00%	9.36E-03
Xylene	2.40%	2.81E-03
Total	**--**	**1.52E-02**

[1]Emission Factors from CAPCOA, Gasoline Service Station Industry Wide Risk Assessment Guidelines, Appendix A, Scenario 1.

[2]CAPCOA, Gasoline Service Station Industry Wide Risk Assessment Guidelines, Section II.C, summary of assumptions of content of gasoline.

Uncontrolled – Source-Wide HAP Emissions

HAP	Unit 4 (EU: A00704D)	Total of Turbine Units 5-8 (EUs: A00701A, A00702B, A00705 A00708)	474 hp Generator	Total of 12 Peakers (EUs: A27 through A38)[1]	460 hp Fire Pump (EU: A45)	Total for Gasoline Storage Tank (EU: A46)	
1,3-Butadiene	1.88E-03	9.04E-03	1.71E-06	1.36E-02	2.48E-06	--	**0.02**
Acetaldehyde	1.75E-01	8.40E-01	3.35E-05	1.26E+00	4.87E-05	--	**2.28**
Acrolein	2.80E-02	1.34E-01	4.04E-06	2.02E-01	5.88E-06	--	**0.36**
Arsenic	--	--	--	--	--	--	**0.00**
Cadmium	--	--	--	--	--	--	**0.00**
Beryllium	--	--	--	--	--	--	**0.00**
Chromium	--	--	--	--	--	--	**0.00**
Lead	--	--	--	--	--	--	**0.00**
Manganese	--	--	--	--	--	--	**0.00**
Formaldehyde	6.69E-02	3.22E-01	5.15E-05	4.83E-01	7.50E-05	--	**0.87**
Mercury	--	--		--	--	--	**0.00**
Nickel	--	--		--	--	--	**0.00**
Benzene	5.68E-03	2.73E-02	4.08E-05	4.10E-02	5.93E-05	1.17E-03	**0.08**
Ethyl Benzene	1.40E-01	6.72E-01	--	1.01E+00	--	9.36E-03	**1.83**
Selenium	--	--	--	--	--	--	**0.00**
Naphthalene	5.68E-03	2.73E-02	--	4.10E-02	5.39E-05	--	**0.07**
Toluene	9.18E-02	4.40E-01	1.79E-05	6.63E-01	2.60E-05	1.87E-03	**1.20**
Propylene Oxide	1.27E-01	6.08E-01	--	9.16E-01	--	--	**1.65**
Xylenes	2.80E-01	1.34E+00	1.24E-05	2.02E+00	1.81E-05	2.81E-03	**3.65**
PAHs	9.62E-03	4.64E-02	7.34E-06	6.96E-02	1.07E-05	--	**0.13**
Totals	**9.32E-01**	**4.47E+00**	**1.69E-04**	**6.73E+00**	**3.00E-04**	**1.52E-02**	**12.14**

[1]HAP emissions for EUS A27-A38 retroactively calculated at 8,760 hrs/yr

Controlled – Source-Wide HAP Emissions

HAP	Unit 4 (EU: A00704D)	Total of Turbine Units 5-8 (EUs: A00701A, A00702B, A00705 A00708)	474 hp Generator	Total of 12 Peakers (EUs: A27 through A38)	460 hp Fire Pump (EU: A45)	Total for Gasoline Storage Tank (EU: A46)	
1,3-Butadiene	1.88E-03	9.04E-03	1.71E-06	5.43E-03	2.48E-06	--	**0.02**
Acetaldehyde	1.75E-01	8.40E-01	3.35E-05	5.05E-01	4.87E-05	--	**1.52**
Acrolein	2.80E-02	1.34E-01	4.04E-06	8.08E-02	5.88E-06	--	**0.24**
Arsenic	--	--	--	--	--	--	**0.00**
Cadmium	--	--	--	--	--	--	**0.00**
Beryllium	--	--	--	--	--	--	**0.00**
Chromium	--	--	--	--	--	--	**0.00**
Lead	--	--	--	--	--	--	**0.00**
Manganese	--	--	--	--	--	--	**0.00**
Formaldehyde	6.69E-02	3.22E-01	5.15E-05	1.93E-01	7.50E-05	--	**0.58**
Mercury	--	--		--	--	--	**0.00**
Nickel	--	--		--	--	--	**0.00**
Benzene	5.68E-03	2.73E-02	4.08E-05	1.64E-02	5.93E-05	1.17E-03	**0.05**
Ethyl Benzene	1.40E-01	6.72E-01	--	4.04E-01	--	9.36E-03	**1.23**
Selenium	--	--	--	--	--	--	**0.00**
Naphthalene	5.68E-03	2.73E-02	--	1.64E-02	5.39E-05	--	**0.05**
Toluene	9.18E-02	4.40E-01	1.79E-05	2.65E-01	2.60E-05	1.87E-03	**0.80**
Propylene Oxide	1.27E-01	6.08E-01	--	3.66E-01	--	--	**1.10**
Xylenes	2.80E-01	1.34E+00	1.24E-05	8.08E-01	1.81E-05	2.81E-03	**2.43**
PAHs	9.62E-03	4.64E-02	7.34E-06	2.78E-02	1.07E-05	--	**0.08**
Totals	**9.32E-01**	**4.47E+00**	**1.69E-04**	**2.69E+00**	**3.00E-04**	**1.52E-02**	**8.10**