

Construction Permit Source Analysis & Technical Review

Company	CPV Basin Ranch Holdings, LLC	Permit Numbers	175063, PSDTX1634, GHGPSDTX237, and HAP85
City	Barstow	Project Number	368773
County	Ward	Regulated Entity Number	RN111876330
Project Type	Initial	Customer Reference Number	CN606219053
Project Reviewer	Christopher Loughran, P.E.	Received Date	January 12, 2024
Site Name	CPV Basin Ranch Energy Center		

Project Overview

CPV Basin Ranch Holdings, LLC (CPV) submitted an expedited initial air permit application to authorize the construction and operation of CPV Basin Ranch Energy Center, a combined-cycle electric generating facility with a nominal 1,320-megawatt (MW) net generating capacity on an approximately 327-acre site to be located in the town of Barstow, Ward County. The Generating Facility will utilize combined-cycle gas turbine (CCGT) technology in a 2x2x2 configuration, using General Electric (GE) 7HA.03 technology. Major generating facility equipment will include: two H-class combustion turbine generators (CTGs); two heat recovery steam generators (HRSGs) with supplemental duct burners (DBs) and exhaust stacks; two steam turbine generators (STGs); two air-cooled condensers (ACCs); an auxiliary boiler; a fuel gas heater; and other associated auxiliary equipment and systems (e.g., tanks, ponds, emergency equipment). Use of the DBs is proposed for 8,760 hours for operational flexibility. The CTGs, DBs, auxiliary boiler, and fuel gas heater will fire natural gas only. The project is being proposed with the potential to include a carbon capture system (CCS). The project triggers Prevention of Significant Deterioration (PSD) review for CO, NO_x, PM, PM₁₀, PM_{2.5}, SO₂, VOC, H₂SO₄, and Greenhouse Gases (GHGs as CO₂e).

Additionally, the applicant submitted a case-by-case MACT initial permit application for HAP emissions pursuant to Section 112(g) of the Federal Clean Air Act (CAA), 40 CFR 63 Subpart B, and 30 TAC 116.400. The Project will be a major source of HAPs due to emissions from the Generating Facility and the CCS. The CCS will not operate without the CCGTs. The applicant stated that the CCS system is considered control equipment for the Generating Facility and is therefore exempt from requirements under 40 CFR 63 Subpart YYYY. As such, the applicant stated that it is exempt from case-by-case MACT requirements. However, in an effort to be comprehensive, a case-by-case MACT initial permit action was requested for the proposed project.

Maintenance, startup, and shutdown (MSS) activities are being authorized in this permit.

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Emission Summary

Air Contaminant	Current Allowable Emission Rates (tpy)	Proposed Allowable Emission Rates (tpy)	Change in Allowable Emission Rates (tpy)
PM	0	230.23	230.23
PM ₁₀	0	217.31	217.31
PM _{2.5}	0	215.60	215.60
VOC	0	405.35	405.35
NO _x	0	366.88	366.88
CO	0	406.90	406.90
SO ₂	0	74.29	74.29
Lead (Pb)	0	0.01	0.01
H ₂ SO ₄	0	54.19	54.19
NH ₃	0	300.00	300.00
HAPs	0	237.99	237.99
Formaldehyde	0	11.65	11.65
Acetone	0	11.59	11.59
CH ₄ ^a	0	162.39	162.39
CO ₂ ^a	0	5,269,205.64	5,269,205.64
N ₂ O ^a	0	9.60	9.60
SF ₆ ^a	0	0.0040	0.0040
CO ₂ e ^b	0	5,276,217.05	5,276,217.05
CO ₂ e ^c	0	5,276,390.27	5,276,390.27

^a Emission rate is given for informational purposes only and does not constitute enforceable limit.

^b Carbon dioxide equivalent (CO₂e) emissions are based on the following global warming potentials taken from Table A-1 of 40 CFR 98 effective January 1, 2015 through December 31, 2024 (79 FR 73779, December 11, 2014): 1 for CO₂, 25 for CH₄, 298 for N₂O, and 22,800 for SF₆.

^c CO₂e emissions are based on the following global warming potentials taken from Table A-1 of 40 CFR 98 effective January 1, 2025 and later (89 FR 31894, April 25, 2024): 1 for CO₂, 28 for CH₄, 265 for N₂O, and 23,500 for SF₆.

Compliance History Evaluation – 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:

January 19, 2024

Site rating & classification:

Unclassified (new greenfield site, confirmed site rating by permit reviewer with BOE compliance history report run on 9/18/2024)

Company rating & classification:

Unclassified (confirmed by permit reviewer with BOE compliance history report run on 9/18/2024)

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Has the permit changed on the basis of the compliance history or rating? No

Did the Regional Office have any comments? If so, explain. No

Public Notice Information

Requirement	Date
Legislator letters mailed	1/24/2024
Date 1 st notice published	2/1/2024
Publication Name: The Monahans News	
Pollutants: Carbon monoxide, hazardous air pollutants, nitrogen oxides, organic compounds, lead, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, sulfuric acid, sulfur dioxide, and greenhouse gases	
Date 1 st notice Alternate Language published	N/A – Spanish notice is required, but the applicant's public notice verification form stated that no alternative language newspaper/publication could be located in the municipality and county in which the site is located
Publication Name (Alternate Language): N/A	
1 st public notice tearsheet(s) received	2/7/2024
1 st public notice affidavit(s) received	2/7/2024
1 st public notice certification of sign posting/application availability received	3/12/2024
SB709 Notification mailed	7/3/2024
Date 2 nd notice published	10/10/2024
Publication Name: The Monahans News	
Pollutants: In a significant amount: carbon monoxide, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, sulfur dioxide, sulfuric acid mist, and greenhouse gases. The proposed facility will emit the following air contaminants which are significant for the FCAA §112(g) action: hazardous air pollutants. In addition, the facility will emit the following air contaminants: exempt solvents and lead.	
Date 2 nd notice published (Alternate Language)	N/A – Spanish notice is required, but the applicant's public notice verification form stated that no alternative language newspaper/publication could be located in the municipality and county in which the site is located
Publication Name (Alternate Language): N/A	

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2 nd public notice tearsheet(s) received	10/15/2024
2 nd public notice affidavit(s) received	10/15/2024
2 nd public notice certification of sign posting/application availability received	11/13/2024

Public Interest

Number of comments received	4*
Number of meeting requests received	0
Number of hearing requests received	0
Date meeting held	N/A
Date response to comments filed with OCC	N/A*
Date of SOAH hearing	N/A

*All 4 of the public comments received for the project were positive supporting comments. Since the comments were all supportive, a formal response to comment document is not required to be filed with the Office of the Chief Clerk, consistent with agency precedent. The Environmental Law Division of the TCEQ Office of Legal Services sent a response letter to each commenter acknowledging their supporting comments on November 22, 2024.

Federal Rules Applicability

Requirement	
Subject to NSPS?	Yes
Subparts	A, Db, Dc, IIII, KKKK, & TTTTa
Subject to NESHAP?	No
Subparts	N/A
Subject to NESHAP (MACT) for source categories?	Yes
Subparts	A, B, YYYY, ZZZZ, & DDDDD
Nonattainment review applicability:	

The site is located in Ward County, which is currently designated as either attainment or unclassifiable for all pollutants. Therefore, nonattainment new source review does not apply.

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PSD review applicability:

As a new “greenfield” site with no existing emissions, the site is an existing PSD minor source. The project emission increases are summarized in the table below. As a named source (“Fossil fuel-fired steam electric plants > 250 million BTUs per hour heat input”), the “step 1” project emission increase for each pollutant is compared to the PSD named source new major source threshold of 100 tpy for each pollutant. As shown in the table, CO, NOx, PM, PM₁₀, PM_{2.5}, and VOC each exceed the 100-tpy new major source threshold, and therefore PSD applies to each of these pollutants. Note that contemporaneous netting does not apply to new greenfield sites. Since at least one pollutant exceeds the new major source threshold, the remaining pollutants that did not exceed the new major source threshold are compared to their respective significant emission rate threshold. As shown in the table, SO₂ and H₂SO₄ each exceed their respective significant emission rates of 40 tpy and 7 tpy, respectively, and therefore are also subject to PSD review.

As a PSD “anyway” source, meaning PSD is triggered for a non-GHG pollutant, GHGs as CO₂e must be evaluated for PSD applicability. As shown in the table, the GHG annual emission rate as CO₂e is greater than its respective PSD significant emission rate threshold of 75,000 tpy. Therefore, PSD review is also triggered for GHGs. Note that since the global warming potentials are changing effective January 1, 2025, the CO₂e emission rates are shown in the table using both the global warming potentials effective before January 1, 2025 and effective for January 1, 2025 and later.

In summary, the project triggers PSD review for CO, NOx, PM, PM₁₀, PM_{2.5}, SO₂, VOC, H₂SO₄, and GHGs as CO₂e.

Pollutant	“Step 1” Project Emissions Increase (tpy)	New Major Source Threshold (tpy)	New Major Source Threshold Exceeded?	Significant Emission Rate (tpy)	Significant Emission Rate Exceeded?	PSD Triggered?
CO	406.90	100	Yes	100 ^a	N/A ^a	Yes
NOx	366.88	100	Yes	40 ^a	N/A ^a	Yes
PM	230.23	100	Yes	25 ^a	N/A ^a	Yes
PM ₁₀	217.31	100	Yes	15 ^a	N/A ^a	Yes
PM _{2.5}	215.60	100	Yes	10 ^a	N/A ^a	Yes
SO ₂	74.29	100	No	40	Yes ^b	Yes
VOC	405.35	100	Yes	40 ^a	N/A ^a	Yes
Pb	0.01	100	No	0.6	No	No
H ₂ SO ₄	54.19	100	No	7	Yes	Yes
GHGs, CO ₂ e	5,276,217.05 ^c 5,276,390.27 ^d	N/A	N/A	75,000	Yes	Yes

^a Since the “step 1” project emission increase exceeds the PSD new major threshold of 100 tpy for a named source, the project emission increase is not compared to the significant emission rate since PSD is triggered for the pollutant due to exceeding the new major source threshold and therefore it is not compared to its respective PSD significant emission rate threshold.

^b Contemporaneous netting does not apply to new greenfield sites, and the rules do not allow contemporaneous netting at existing minor sources.

^c CO₂e emissions are based on the following global warming potentials taken from Table A-1 of 40 CFR 98 effective January 1, 2015 through December 31, 2024 (79 FR 73779, December 11, 2014): 1 for CO₂, 25 for CH₄, 298 for N₂O, and 22,800 for SF₆.

^d CO₂e emissions are based on the following global warming potentials taken from Table A-1 of 40 CFR 98 effective January 1, 2025 and later (89 FR 31894, April 25, 2024): 1 for CO₂, 28 for CH₄, 265 for N₂O, and 23,500 for SF₆.

Title V Applicability – 30 TAC Chapter 122 Rules

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Requirement

Title V applicability:

As a new greenfield site, the site does not currently have a Title V permit. However, since the project emissions exceeds the Title V major source threshold as defined in §122.10, a Title V permit will be required.

Periodic Monitoring (PM) applicability:

This site will be major source and is subject to PM under 30 TAC Chapter 122. The permit requires PM as follows:

Emission Source	SC No.	PM Condition Summary
Combined Cycle Turbine Generator 1 and Duct Burner (EPN CTG1_HRSG1 and EPN CCS1) Combined Cycle Turbine Generator 2 and Duct Burner (EPN CTG2_HRSG2 and EPN CCS1)	6.A, 51.C	Records of dates and times for startups, including type of startup (cold, warm, or hot startup), and shutdowns of the CTGs specified in Special Condition (SC) No. 6.A.
Combined Cycle Turbine Generator 1 and Duct Burner (EPN CTG1_HRSG1 and EPN CCS1) Combined Cycle Turbine Generator 2 and Duct Burner (EPN CTG2_HRSG2 and EPN CCS1)	7, 51.D	Totalizing fuel flow meter to measure and record the natural gas fuel usage for each turbine and duct burner. This condition also specifies QA/QC including the fuel flow meter calibrations.
Combined Cycle Turbine Generator 1 and Duct Burner (EPN CTG1_HRSG1 and EPN CCS1) Combined Cycle Turbine Generator 2 and Duct Burner (EPN CTG2_HRSG2 and EPN CCS1)	8, 51.X	Monthly and rolling 12-month average output specific CO ₂ emission rate tracking and records. (lb CO ₂ /MWh-gross).
Emergency Diesel Generators (EPNs CTGEG and CCSEG) Fire pump (EPN FPUMP)	10, 51.E	Non-resettable run time meter to measure and record the engine operational hours and diesel fuel delivery records indicating the date and quantity of fuel delivered.
CCS1 Boiler 1 (FIN CCS1BLR1) CCS1 Boiler 2 (FIN CCS1BLR2) CCS2 Boiler 1 (FIN CCS2BLR1)	12, 13, 51.H	Totalizing fuel flow meter to measure and record the natural gas fuel usage for each unit listed in the special condition. This condition also specifies QA/QC including the fuel flow meter calibrations.

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CCS2 Boiler 2 (FIN CCS2BLR2)		
CTG Boiler (FIN / EPN CTGBLR / CTGBLR)		
Fuel Heater (FIN / EPN FHEAT / FHEAT)		
CCS1 Boiler 1 (FIN/EPN CCS1BLR1)	14, 15, 51.I	Planned startup events records including the number of startup events and hours of operation which may be demonstrated by using recorded operating parameters including the natural gas fuel feed rates and steam generation records. Emissions records for planned MSS activities which include the emission rates in pounds per hour and tons per rolling 12-month period, which are required to be updated on a monthly basis.
CCS1 Boiler 2 (FIN/EPN CCS1BLR2)		
CCS2 Boiler 1 (EPN FIN/EPN CCS2BLR1)		
CCS2 Boiler 2 (FIN/EPN CCS2BLR2)		
Combustion turbine generators and duct burners (EPNs CTG1_HRSG1 and CTG2_HRSG2, CCS1, CCS2)	16, 17, 51.J	Natural gas fuel specification (no more than 0.5 grains total sulfur per 100 dscf on an hourly and annual basis) and sampling every 6 months to determine total sulfur and net heating value (test results from the fuel supplier may be used to satisfy this requirement).
CCS1 Boiler 1 (EPN CCS1)		
CCS1 Boiler 2 (EPN CCS1)		
CCS2 Boiler 1 (EPN CCS2)		
CCS2 Boiler 2 (EPN CCS2)		
CTG Boiler (EPN CTGBLR)		
Fuel Heater (EPN FHEAT)		
Emergency Diesel Generators (EPNs CTGEG and CCSEG)	18, 52.K	Diesel fuel specification of no more than 15 ppmw sulfur, which may be satisfied by ultra-low sulfur diesel (ULSD) designated on the fuel delivery receipt.
Fire pump (EPN FPUMP)		
All combustion sources authorized in the permit	19, 51.L	Opacity of emissions from the combustion sources authorized by the permit limited to 5 percent averaged over a six-minute period and 15 percent averaged over a six-minute period during periods of MSS operation. Quarterly visible emission observations and records during each calendar quarter while the facilities are in operation, unless the emission unit is not operating for the entire calendar quarter.
Storage Tanks (EPNs TK-1 through TK-17)	20-22, 51.M	Monthly tank service and liquid throughput records according to SC No. 22.B for comparison to the specifications provided in SC No. 20.
Cooling tower (EPN CTWR)	24, 51.N	Annual drift eliminator inspections and records. Total dissolved solids (TDS) concentration or conductivity monitoring and monthly PM/PM ₁₀ /PM _{2.5} emission records. Cooling tower water VOC monthly

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		monitoring and recordkeeping to ensure that no leaks of VOC into the cooling tower water occurs, which may be reduced to once every six months if there is no VOC detected for 12 consecutive months.
Water Evaporators (EPN WE)	25, 51.O	Annual water evaporator inspections and records. Total dissolved solids (TDS) concentration or conductivity monitoring and monthly PM/PM ₁₀ /PM _{2.5} emission records.
CCS1 TEG Dehydrator (EPN CCS1-CO2VT)	26, 51.P	Monitoring of the temperature of the dehydration vents with a high-temperature alarms to help prevent excessive TEG carry-over.
CCS2 TEG Dehydrator (EPN CCS2-CO2VT)		Monitoring the TEG make-up rates.
CCS1 Absorber (EPN CCS1)	29, 51.Q	Quarterly assessments and records of the relevant physical and chemical properties of the recirculating amine solvent to ensure the quality and appropriate CO ₂ removal characteristics to minimize degradation of the amine solution.
CCS2 Absorber (EPN CCS2)		
Solvent Leaks (EPN SOLVFUG)	31, 51.R	28VHP leak detection and repair (LDAR) program for equipment leak fugitives.
Methane Leaks (EPN NGFUG)		
Ammonia Leaks (EPN NH3FUG)	32, 51.S	28AVO leak detection and repair (LDAR) program for equipment leak fugitives in ammonia service.
Combustion Turbine Generators/Duct Burners (FINs CTG1_HRSG1 and CTG2_HRSG2)	33, 50.C, 50.D	Initial stack testing and recurring stack testing when requested by the TCEQ.
CCS Boilers (FINs CCS1BLR1, CCS1BLR2, CCS2BLR1, CCS2BLR2)		
CTG Boiler (EPN CTGBLR)		
CCS Absorbers (EPNs CCS1 and CCS2)		
Sulfur Hexafluoride Leaks (EPN SF6FUG)	37, 38, 51.U	Sulfur hexafluoride (SF ₆) circuit breakers with a low pressure alarm to indicate leaks. Annual (calendar year) SF ₆ emission calculations and records in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting Rule for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD.
Carbon Capture System 1 (EPN CCS1)	39, 51.V	Continuous temperature monitoring of the liquid supply to the first water wash section of each carbon capture system absorber as parametric monitoring to promote continuous compliance with the VOC and HAP MAERT limits.
Carbon Capture System 2 (EPN CCS2).	40, 51.V	Daily monitoring (at least once every 24 hours) of the amine solvent mixture concentration (wt.%) in the lean CO ₂ -absorbing solution supplied to the CO ₂ recovery section of each carbon capture system absorber as parametric monitoring to promote continuous compliance with the VOC and HAP MAERT limits.
Equipment Maintenance (EPN MSS-MAINT))	43, 51.B, 51.W	Annual revalidation of the inherently low emitting (ILE) MSS activities listed in Attachment A of the permit special conditions.

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Various (EPNs CTG1_HRSG1, CTG2_HRSG2, CCS1BLR1, CCS1BLR2, CCS2BLR1, CCS2BLR2, CCS1-CO2VT, CCS2-CO2VT, and NGPURGE)	44, 51.W	Monthly emission records for the non-ILE maintenance listed in Attachment B.
Various	45	This conditions states that associated Permit No. HAP85 implements the requirements of Section 112(g) of the Federal Clean Air Act, 40 CFR 63 Subpart B, and 30 TAC 116.400 for case-by-case MACT permitting. Special Condition Nos. 26, 29, 30, 33.B, 39, and 40 have been developed to demonstrate compliance with the case-by-case MACT permit
Various	46-49, 51.X	Greenhouse gas (GHG) monitoring, quality assurance/quality control requirements, emission calculation methodologies, recordkeeping, and reporting requirements.

Compliance Assurance Monitoring (CAM) applicability:

The site will be subject to 30 TAC Chapter 122 requirements. The permit covers the following control devices which will be used to comply with applicable requirements of the permit, and which control source of emissions with a pre-control emission rate in excess of the major source threshold as specified in 30 TAC 122.604(b)(3) and 30 TAC 122.10(13).

The units potentially subject to CAM are the Combustion Turbine Generators/Duct Burners, Units 1 and 2, since they each use selective catalytic reduction (SCR) to reduce NO_x emissions and an oxidation catalyst to reduce CO emissions, and these emissions have a pre-control emission rate that each exceed the 100-tpy Title V major source threshold specified in 30 TAC 122.604(b) and 30 TAC 122.10(13) (CAM may also apply to VOC, but it is not clear since the applicant did not quantify the pre-control VOC emission rate prior to the oxidation catalyst). Note that 30 TAC 122.604(c)(6) states that CAM does not apply if an applicable requirement specifies a continuous compliance determination method, which one could consider as applying in the case of the CEMS. Regardless of whether CAM applies or if the exemption in 30 TAC 122.604(c)(6) applies, NO_x and CO CEMS will nevertheless ensure compliance assurance for the SCR and oxidation catalyst control systems used to control NO_x and CO, respectively. CEMS for CO is assumed to be a surrogate indicator of compliance assurance for VOC since proper control of CO by the oxidation catalyst systems should ensure proper control of VOC since proper control of CO indicates that proper combustion of VOC to CO₂ is occurring.

Emission Source	SC No.	CAM Condition Summary
Combined Cycle Turbine Generator 1 (EPN CTG1_HRSG1 when not directed to the carbon capture system and EPN CCS1 when directed to the carbon capture system)	34, 35, 51.A, 51.B, 51.T	SC No. 34 includes the Continuous Emissions Monitoring Systems (CEMS) that will measure and record the in-stack and exhaust concentrations of NO _x , CO, and O ₂ from Combustion Turbine Generators/Duct Burners, Units 1 and 2, and require calculation of the mass emission rates which therefore assures compliance with the concentration limits and emission rate limits in the permit special conditions and MAERT. Note that CEMS for CO is considered to be a surrogate for CAM for VOC, and therefore CEMS for VOC is not included in the permit. SC No. 35 includes the following options to continuous monitor ammonia (NH ₃): continuous compliance with NH ₃ CEMS, 2) a second NO _x CEMS probe located between the duct burners and the SCR, upstream of the stack NO _x CEMS, which may be used in association with the SCR efficiency and NH ₃ injection rate to estimate NH ₃ slip, 3) a dual stream system of NO _x CEMS at the exit of the SCR to calculate the NH ₃ slip concentrations, or 4) other NH ₃ slip measurement methods with approval by the TCEQ Midland Regional Office.
Combined Cycle Turbine Generator 2		

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(EPN CTG1_HRSG2 when not directed to the carbon capture system and EPN CCS2 when directed to the carbon capture system)		
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Process Description

The Generating Facility will utilize combined-cycle gas turbine (CCGT) technology in a 2x2x2 configuration, using GE 7HA.03 technology. Major Generating Facility equipment will include: two H-class CTGs; two heat recovery steam generators (HRSGs) with duct burner (DBs) and exhaust stacks, including selective catalytic reduction (SCR) and oxidation catalyst emissions control equipment; two steam turbine generators (STGs); two air-cooled condensers (ACCs); an auxiliary boiler; a fuel gas heater (used for both the CCGT and the CCS); and other associated auxiliary equipment and systems (e.g., tanks, ponds, and emergency equipment).

Natural gas will be the only fuel fired in the two CCGTs. The CTGs will exhaust to the HRSGs, which will feed steam to two STGs. Each HRSG will be equipped with SCR to reduce emissions of NO_x and an oxidation catalyst to reduce emissions of CO and VOC. The HRSGs will also be equipped with natural gas supplementary firing in the DBs.

The proposed generating facility is intended to operate as a base load facility and is proposed to be available to operate up to 8,760 hours per year by incorporating a range of load and operating conditions. The applicant seeks the flexibility for the generating facility and project to operate in a manner that will enable it to meet changing power demands of the region.

The carbon capture system (CCS) will consist of two separate trains, one associated with each CCGT, consisting of an amine-based absorption process to which the generating facility will be capable of ducting its exhaust gas to the associated CCS versus using the HRSG exhaust stacks. Two 182-MMBtu/hr natural gas-fired CCS boilers equipped with low-NO_x burners will be used for supplemental steam production associated with each CCS (for a total of four CCS boilers).

When the CCS is in use, emissions will typically exhaust via the CCS absorber stacks. The CCS boilers will exhaust through their equipment-specific stacks during the limited periods of startup (SU) and shutdown (SD). Once the CCS system is operational, CCS boiler flue gas, along with HRSG exhaust gas, will be re-directed to the CCS system and exhaust through the CCS absorber stacks. The system will use air-cooled heat exchangers (ACHEs) supplemented, as needed, with an 8-cell wet cooling tower. A separate 2,000-kW (mechanical) emergency generator firing ultra-low sulfur distillate (ULSD) will serve the CCS.

Project Scope

The project scope includes the following:

Combustion Turbine Generators, Heat Recovery Steam Generators, and Duct Burners

Energy will be produced in two CTGs through the combustion of natural gas as the sole fuel (EPNs CTG1_HRSG1 and CTG2_HRSG2, EPN CCS1 when directed to the CCS). The thermal energy in the CTG exhaust gas is transferred to steam in the HRSG and converted to mechanical energy in two STGs. The nominal heat input rate of the CTGs while firing natural gas will be approximately 4,100 MMBtu/hr (higher heating value or HHV) per unit with no duct burning and 4,950 MMBtu/hr HHV per unit with duct burning, both at International Standards Organization (ISO) conditions (100 percent load and at 59°F). The CTGs will exhaust through dedicated HRSGs that consists of superheaters, evaporators, and economizer sections that absorb the waste heat from the combustion gas stream to generate steam. Supplemental natural gas duct burning for the HRSGs is included in the CCGT. The nominal power rating for each of the two combustion turbine generators is expected to be 430 MW (net) per unit. On a generating facility basis, each train will

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have a nominal power rating of 660 MW (net), for a nominal total rating of 1,320 MW for the entire electric generating facility, i.e., both trains combined.

The add-on emission control technologies proposed for the exhaust gases associated with the CCGTs include: dry low NO_x (DLN) combustors and SCRs to control NO_x emissions, and oxidation catalysts to control CO and VOC emissions. DLN combustors will be integrated within the CTGs; the SCRs and the oxidation catalysts will be located within the HRSGs. The DLN combustor controls NO_x formation by pre-mixing the natural gas-firing and combustion air immediately prior to combustion. Pre-mixing inhibits NO_x formation by minimizing both the flame temperature and the concentration of oxygen in the combustor flame. Emissions of SO₂, PM/PM₁₀/PM_{2.5}, and sulfuric acid (H₂SO₄) will be minimized through use of natural gas as the sole fuel in the CTGs.

SCR catalyst, a post-combustion chemical process, will be installed in the HRSGs to treat exhaust gases downstream of the CTGs. The SCR process will use 19 percent aqueous ammonia (NH₃) as a reagent. Aqueous NH₃ will be injected into the flue gas stream upstream of the SCR catalysts, where it will mix with NO_x. The catalyst beds will be in temperature zones of the HRSGs where the catalysts are most effective. The mixture will pass over the catalysts, and the NO_x will react with NH₃ and O₂ to form nitrogen gas and water vapor. The SCR systems will reduce NO_x concentrations to within 2.0 ppmvd corrected to 15 percent O₂, averaged over an hour at all steady-state load conditions and ambient temperatures. A small amount of NH₃, called the "ammonia slip," will remain unreacted as the flue gas stream passes through the catalysts. The ammonia slip will be limited to 5.0 ppmvd corrected to 15 percent O₂, averaged over one hour, during all steady-state operating conditions. SCR operations will commence during CCGT startup when the flue gas temperature has reached the allowable SCR temperature range at the catalyst bed. Since the ammonia to be used for the SCR system will be in aqueous form, a disaster review is not triggered since the ammonia used is not in anhydrous form that would trigger a disaster review as specified in the TCEQ guidance "Disaster Review Fact Sheet" linked from the PI-1 form.

An oxidation catalyst system will be located within the HRSGs to control emissions of CO and VOC. Exhaust gases from the CTGs will flow through the catalyst beds where excess air will oxidize the CO and VOC to form CO₂ and H₂O. The oxidation catalyst system will reduce CO concentrations to 2.0 ppmvd corrected to 15 percent O₂, averaged over one hour, in the exhaust gas under all steady-state load conditions and ambient temperatures. During steady-state operating conditions, VOC concentrations in the exhaust gas will be limited to 1.0 ppmvd corrected to 15 percent O₂ averaged over one hour.

CCS Related Equipment

The CCS system will consist of two CCS trains, and each train will include two 182-MMBtu/hr natural gas-fired CCS boilers (for a total of four CCS boilers). The CCS boilers will support CCS startup, and provide the balance of the needed steam to the CCS. The CCS boilers will exhaust from their equipment-specific stacks during the limited periods of SU/SD (EPNs CCS1BLR1, CCS1BLR2, CCS2BLR1, and CCS2BLR2) and, once the CCS system is operational, CCS boiler flue gas will be re-directed, along with HRSG exhaust gas, to the CCS system and exhaust through the CCS absorber stacks (EPNs CCS1 and CCS2).

Each CCS train will exhaust from a single absorber stack (EPNs CCS1 and CCS2). When the CCS is in use, emissions exhausting through these stacks will include emissions from the generating facility and the CCS boilers. The CCS trains will receive flue gas from the CCGT and CCS boilers, process the flue gas for cooling and removal of unwanted contaminants in the quencher, absorb CO₂ from the flue gas using solvent in the absorber, and remove heat stable salts from the solvent circulation system. The two-train CCS is designed to recover upwards of 4 million metric tons per year of CO₂ from the flue gas.

The CO₂-rich amine solvent fluid will be heated with steam in the amine stripper vessel, removing the CO₂ from the amine. The CO₂ vapor will then be cooled by an overhead condenser prior to compression and dehydration. Throughout the process, particulates are continuously removed from the system to avoid flooding, erosion, or fouling in the CO₂ capture system, using a system of filters.

The solvent reclaiming system (thermal reclaimer) will remove soluble solvent degradation products such as heat stable salts, soluble metals, and suspended solid from the lean solution created by the amine stripper. The unit includes systems to assist in evaporation of solvent and break down of heat stable salts to release pure solvent. The sludge

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effluent from the thermal reclaimer will be disposed off-site.

The CO₂ gas stripped from the amine solvent will be compressed and dehydrated prior to transport. The CO₂ compressor(s) will be electric driven with multiple stages of compression. Additional oxygen removal will be followed by a dehydration unit used for each CCS train (i.e., two CCS trains and thus two dehydration units total), where moisture in the CO₂ will be removed. After the dehydration units, CO₂ will be returned to the compressor and compressed up to 2,200 psig, above the threshold necessary for supercritical conditions. After compression, the CO₂ will be further cooled before it is directed to the CO₂ pipeline that will deliver the CO₂ offsite.

The CCS system will primarily use ACHES. However, it is anticipated that certain higher ambient temperature conditions will require supplementary cooling. For such times, the CCS system will incorporate an 8-cell mechanical draft wet cooling tower with a maximum circulation water flow rate of 111,630 gallons per minute. Condensate water, produced from the CCS quencher, will be stored on-site in a pond for use as cooling tower make-up.

A mechanical draft cooling tower (EPN CTWR) provides cooling of the circulating water by spraying the warm circulating water over sheets of plastic material known as fill. This exposes the circulating water to ambient air being drawn in through the sides of the tower towards a fan generally located above the fill. A fraction of the circulating water evaporates into this air, warming it and causing it to become saturated with moisture. A small portion of the circulating water will be entrained in this air flow. Each cell of the cooling tower will be equipped with drift eliminators that are typically located above the water sprays to remove the vast majority of these entrained droplets and return them to the fill. The eliminators will have a drift rate of 0.0005%. However, a small fraction of these droplets will escape into the fan discharge and be released to the atmosphere. The droplets that are released to the atmosphere contain dissolved solids that form particulates when the droplets evaporate and, therefore, are a source of particulate matter (PM/PM₁₀/PM_{2.5}) emissions.

Ancillary Equipment

The proposed CCGT will utilize ancillary support equipment including: an auxiliary boiler; an emergency diesel generator engine; a fuel gas heater and emergency fire pump engine which are shared with the CSS; aqueous NH₃ storage tanks; and other small, dedicated or integrated storage tanks providing ULSD for the emergency engines. The CCS will also include an emergency diesel generator engine with an integrated ULSD storage tank and several other storage tanks that will be used to store process materials. The evaporation ponds anticipated to be used for wastewater control will also include atomizers that have been considered as a potential source of fugitive PM emissions. The ancillary equipment is described in more detail below.

Auxiliary Boiler - The generating facility auxiliary boiler (EPN CTGBLR) will use natural gas as its sole fuel, operating as needed to keep the HRSGs warm during periods of Project shutdown, and to provide steam to the STGs during startups. The auxiliary boiler will have a maximum input capacity of 95.5 MMBtu/hr and will be equipped with a DLN burner. The boiler's operation will be limited to 382,074 MMBtu/12-month period (based on 4,000 hours/year).

Fuel gas heater - The fuel gas heater (EPN FHEAT) will use natural gas as its sole fuel, operating as needed to regulate the temperature of the fuel for optimal CCGTs' performance. The fuel gas heater will incorporate low-NOx burners, will have an approximate input capacity of 16 MMBtu/hr, and will be permitted to operate 8,760 hours per rolling 12-month period to allow for operating flexibility. The fuel gas heater will serve both the generating facility and the CCS.

Emergency diesel generators - The generating facility and the CCS will each have an emergency generator (i.e., two engines total) powered by a 2,682 hp (2.000 kW) diesel engine to provide on-site emergency power capabilities independent of the utility grid (EPNs CTGEG and CCSEG). The emergency generator engines will be fueled with ULSD and will typically operate only for maintenance and readiness testing, with less frequent operation expected for actual emergencies. A small ULSD storage tank will be integrated into this equipment. Non-emergency generator operation will be limited to less than 100 hours per rolling 12-month period.

Emergency diesel fire pump - The project will include a 282 bhp (210 kW) emergency fire pump engine to provide on-site firefighting capabilities (EPN FPUMP). The emergency fire pump will be fueled with ULSD and will typically operate only for maintenance and readiness testing, with less frequent operation expected for actual emergencies. A small ULSD storage tank will be provided with this equipment. Non-emergency operation of the fire pump will be limited to less than 100 hours per rolling 12-month period.

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Evaporation pond mechanical evaporators – The applicant proposed to enhance the existing natural evaporation in the evaporation ponds using mechanical evaporators. The Project will utilize five land-based evaporators (four operating and one backup). The mechanical evaporators will be atomizer-style units. These units are cannon-shaped, with nozzles around the outside of the cannon rim. The nozzles are designed to generate varying size droplets depending on the nozzle parameter. These units operate by pumping feed water from the pond and forcing it through spiral nozzles via compressed air. At the center axis of the cannon is a fan which directs the droplets generated by the nozzles over the pond surface. While some of the water droplets drift, the rest will fall back to the pond. However, the formation of the water droplets increases the available surface area for evaporation. The trajectory of the droplets is dependent on several factors, most notably wind speed and wind direction. The evaporation system will be equipped with a weather station to optimize operation according to these parameters. The evaporators will be linked to the weather station via a process control system. Using this system, the evaporators will be controlled such that they only operate when the wind speed and wind direction result in a trajectory over the pond, allowing the bulk of the water droplets to drop back into the water. The drifting droplets that do not fall back into the ponds and are released to the atmosphere contain dissolved solids that form particulates when the droplets evaporate. Therefore, the water evaporators can be a fugitive source of particulate matter (PM/PM₁₀/PM_{2.5}) emissions (EPN WE).

Storage tanks - The CCS storage tanks include six amine solvent tanks (EPNs TK1, TK2, TK3, TK4, TK14, and TK15), two fresh amine solvent storage tanks (EPNs TK5 and TK6), two reclaimed waste tanks (EPNs TK7 and TK8), four triethylene glycol (TEG) storage tanks (EPNs TK9, TK10, TK16, and TK17), and three diesel fuel tanks (EPNs TK11 through TK13). These tanks will incorporate secondary containment to accommodate the entire volume of any single tank and sufficient freeboard for precipitation. The storage will be located outdoors within an impermeable containment area. Aqueous ammonia storage tanks will not have emissions under normal operating conditions and therefore their emissions are not authorized by this permit. Such tanks are not directly vented to atmosphere and have systems to prevent ammonia vapor release (e.g., pressure setpoint maintained, vacuum breaker to let air into the tank under vacuum conditions, and vapor return connection during refilling).

Maintenance activities – supporting maintenance activities being authorized for the project include NO_x and CO emissions associated with CEMS calibrations, VOC emissions associated with small equipment maintenance including inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment, and VOC emissions associated with low-VOC vapor pressure small equipment maintenance.

CAA §112(g) Case-by-Case HAP MACT Permit Review Summary

Case-by-case MACT permits apply to affected sources that are not exempted from the requirements and do not have an applicable MACT standard and for which a major HAP source is constructed, meaning any individual HAP exceeds 10 tpy or total HAPs exceed 25 tpy, as specified in 30 TAC 116.400(a), 40 CFR 63.40(b), and Section 112(g) of the federal Clean Air Act, specifically, 42 U.S.C. 7412(g)(2)(B) of the CAA. The applicant represented that case-by-case MACT permitting requirements of Section 112(g) of the Federal Clean Air Act, 40 CFR 63 Subpart B, and 30 TAC 116.400 do not apply. Specifically, the application supplement noted that that CCS is not subject to any NESHAP source categories under 40 CFR 63 MACT standards and represented that the CCS falls under an explicit exemption from an existing NESHAP subpart, i.e., section CAA 112(d) standard, for control equipment. The CCS is considered control technology at a stationary combustion turbine regulated under 40 CFR 63 Subpart YYYYY and therefore is not subject to the NESHAP Subpart B case-by-case MACT review requirements. However, in an effort to be comprehensive, the applicant provided a case-by-case MACT review to support a major source HAP permit.

There are no applicable MACT standards for carbon capture/recovery processes. The proposed total HAP emissions from each CCS absorber vent is 118.61 tpy or 237.22 tpy from both absorbers combined (EPNs CCS1 and CCS2), which exceeds the 25 tpy threshold for triggering a case-by-case MACT permit, conservatively assuming that the control equipment exemption noted above does not apply. Additionally, the acetaldehyde (HAP) annual emission rate from each CCS absorber vent is 106.00 tpy or 212.00 tpy from both absorbers combined (EPNs CCS1 and CCS2), which exceeds the individual HAP threshold of 10 tpy. The HAP emissions from the proposed project are summarized in the table below.

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HAP Air Contaminant	Proposed Allowable HAP Hourly Emission Rates (lb/hr)	Proposed Allowable HAP Annual Emission Rates (tpy)
<i>CCS1 Absorber (EPN CCS1)</i>		
Acetaldehyde	24.90	106.00
Acetonitrile	0.96	4.02
Formaldehyde	1.33	5.81
n-Hexane	0.63	2.77
Other HAPs	<0.01	0.01
CCS1 Absorber Total HAPs:	27.82	118.61
<i>CCS2 Absorber (EPN CCS2)</i>		
Acetaldehyde	24.90	106.00
Acetonitrile	0.96	4.02
Formaldehyde	1.33	5.81
n-Hexane	0.63	2.77
Other HAPs	<0.01	0.01
CCS2 Absorber Total HAPs:	27.82	118.61
<i>Other Project Sources - Total HAPs</i>		
CCS TEG Dehydrators (EPNs CCS1-CO2VT and CCS2-CO2VT)	<0.01	0.02
CTG Boiler (EPN CTGBLR)	0.17	0.35
CCS MSS Activities (EPNs CCS1-CO2VT and CCS2-CO2VT)	12.77	0.27
Fuel heater (EPN FHEAT)	0.03	0.13
CTG Em Gen (EPN CTGEG)	0.03	<0.01
CCS Em Gen (EPN CCSEG)	0.03	<0.01
Fire Pump (EPN FPUMP)	0.01	<0.01
Project Total HAPs	68.68	237.99

The federal rule, 40 CFR 63.43(c), provides three options for obtaining a case-by-case MACT permit, which are the following:

- 1) Obtain a preconstruction Title V permit, either voluntarily or as required [40 CFR 63.43(c)(1)];
- 2) Apply for and obtain a Notice of MACT Approval (NOMA), and follow the procedures outlined in 40 CFR § 63.43(f) through (h) [40 CFR 63.43(c)(2)(i)]; or

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- 3) Apply for a MACT determination “under any other administrative procedures for preconstruction review and approval established by the permitting authority for a State...” which adhere to the general principles of MACT determination specified in 40 CFR 63 Subpart B [40 CFR 63.43(c)(2)(ii)].

The applicant chose option 3 above to pursue a case-by-case permit pursuant to 40 CFR 63.43(c)(2)(ii). Regardless of the application avenue chosen, 40 CFR 63.43(c)(4) specifies that the MACT limitation and standards must be consistent with the principles specified in 40 CFR 63.43(d), which include:

- 1) The emission limitation may not be less stringent than the emission control which is achieved in practice by the best controlled similar source [40 CFR 63.43(d)(1)];
- 2) The emission limitation must achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction [40 CFR 63.43(d)(2)];
- 3) The applicant may recommend a specific design, equipment, work practice, or operational standard, or a combination thereof, and the permitting authority may approve such a standard if the permitting authority specifically determines that it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in Section 112(h)(2) of the CAA [40 CFR 63.43(d)(3)]; and
- 4) If the Administrator has either proposed a relevant emission standard pursuant to section 112(d) or section 112(h) of the Act or adopted a presumptive MACT determination for the source category which includes the constructed or reconstructed major source, then the MACT requirements applied to the constructed or reconstructed major source shall have considered those MACT emission limitations and requirements of the proposed standard or presumptive MACT determination [40 CFR 63.43(d)(4)].

The case-by-case MACT permit application requirements are specified in 40 CFR 63.43(e) and 30 TAC 116.404, the latter of which refers to 30 TAC 116.110 for the permit application requirements which the applicant is meeting by the application submittal including form PI-1. The case-by-case MACT determination principles including the MACT emission limitation and control technology evaluation are specified in 40 CFR 63.43(d), which the applicant demonstrated as follows.

The applicant noted that VOC emissions can be produced from the absorber as a result of evaporative loss of the amine-based solvent used for CO₂ capture and physical losses of the amine solvent as “liquid carryover” in the form of mists and aerosols that are not removed by the mist elimination section of the absorber tower and are discharged from the CCS absorber stack. Although various types of air permits have been issued for multiple configurations of existing and proposed CCS operations, the applicant identified only one permit for similar CCS process that provides a comparable MACT determination, which is for Quail Run Carbon (QRC) in Odessa, Texas that was authorized to construct a CCS to capture carbon emissions from an existing CCGT, the Quail Run Energy Center. While a permit has not been issued for this project when CPV’s application was submitted, the permit was subsequently issued (TCEQ Permit Nos. 173197, PSDTX1622, and HAP83; TCEQ Project No. 359380 issued on February 2, 2024). The QRC project completed a case-by-case MACT analysis to support their major source HAP permit and determined that add-on controls were not required and that minimization of organic HAP emissions from the CCS absorbers through implementation of good design and operating practices was MACT.

The CCS absorber HAP control options identified by CPV for their proposed project for HAP emissions control include adsorption, thermal oxidizers, catalytic oxidizers, flares, absorption, condensation, and alternative raw materials. The feasibility of each control option is discussed in the BACT table below for the CCS absorbers (EPNs CCS1 and CCS2). As shown in the table below in the BACT discussion for total HAPs control, the most cost effective option evaluated is calculated by the applicant to have a cost effectiveness of \$56,076 per ton of total HAPs removed for carbon adsorption. Supporting this as not being cost effective, CPV considered technologies and control thresholds typically used in the synthetic organic chemical manufacturing industry (SOCMI) as a basis for review due to similarities between the CCS and SOCMI sources.

As part of the 2023 proposed SOCMI NESHAP rulemaking, the applicant noted that the EPA performed a technology review for continuous process vents subject to the Hazardous Organic NESHAPs (HON), and this rule was subsequently promulgated (Federal Register, May 16, 2024, Volume 89, No. 96, page 42932). Continuous process vents, either

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designated as Group 1 or Group 2 based on the criteria specified in the regulations, are an affected source under the HON. These process vents would be considered the most analogous sources to the CCS Absorber vent stream. The EPA did not identify any control device options, beyond those already commonly used by the SOCM source (i.e., activated carbon adsorbers, condensers, flares, oxidizers - thermal and catalytic, and absorbers to reduce VOC and organic HAP emissions from chemical process vent streams). For the various HAP emissions reduction schemes considered, the EPA identified and evaluated the total capital investment, total annual costs, VOC emissions reductions, and HAP emissions reductions. The results of this analysis were published Table 14 of the HON proposed rule preamble titled "Nationwide Emissions Reductions and Cost Impacts of Control Options Considered for Continuous Process Vents at HON Facilities" (Federal Register, April 25, 2023, Volume 88, No. 79, page 25130). Within this table, the applicant noted that Control Option 2 was considered "not cost effective" at an annualized cost of \$19,400 per ton of HAP removed. This control option involved future closed vent system and control device installations on existing Group 2 continuous process vents with a total organic HAP emission rate greater than 0.10 lb/hr. For purposes of this MACT analysis, the CCS absorber vents could be considered analogous to the sources under Control Option 2.

Finally, the applicant represented that the proposed and final versions of the HON include a parameter, the total resource effectiveness index value or "TRE index value" (defined in 40 CFR 63.101), that is derived from the cost effectiveness associated with HAP control by a flare or thermal oxidation. The TRE index is a measure of how costly a particular process vent is to control (the higher the TRE index, the more costly the control). The index is a function of vent stream flow rate, vent stream net heating value, hourly emissions, and a set of coefficients. In general, continuous process vents with a TRE index value equal to or less than between 1.0 and 5.0 are required to be controlled under the various NSPS and NESHAP regulations which adopt this concept. The applicant stated that if they were to derive a TRE index value for the CCS absorber vent stream, the resulting TRE index value would be expected to significantly exceed the typical threshold requiring controls by more than an order of magnitude.

Therefore, the applicant's argument that no further control is required to satisfy the §112(g) case-by-case MACT permitting requirements for the CCS absorbers was deemed valid. To minimize emissions from the CCS absorbers, the applicant proposed to minimize organic HAP emissions from the CCS absorbers by implementing good design and operating practices consistent with the underlying engineering basis used to quantify the proposed organic HAP limit. These work practices will specifically target minimization of amine solvent carryover and evaporation during the flue gas CO₂ removal process.

SC No. 39 of the permit will require the applicant to maintain a continuous monitoring system to measure and record the liquid supply temperature to the first water wash section of each CCS Absorber and SC No. 40 will require the applicant to measure the amine solvent mixture concentration (wt.%) in the lean CO₂-absorbing solution supplied to the CO₂ recovery section of each CCS Absorber daily, respectively, to help ensure that the HAP emission limits for the CCS absorbers are met.

The CCS TEG Dehydrators (EPNs CCS1-CO₂VT and CCS2-CO₂VT) are a source of HAP emissions, though the proposed total HAP emission rate of 0.021 tpy from both dehydrator units combined is less than the major HAP source trigger. The applicant considered flare and catalytic oxidation controls as potentially feasible control technologies for the dehydration unit vent. The estimated cost effectiveness of flare control based on the application representations is \$220,989,550 per ton of total HAPs removed, and the estimated cost effectiveness of catalytic oxidation control is \$9,383,100 per ton of total HAPs removed based on a pre-control dehydration units total HAPs emission rate of 0.021 tpy from both dehydrator units combined and 98% control for a flare and 98% control for the catalytic oxidation unit. The applicant stated that routing the dehydration units' vent streams to add-on control is not cost effective, which was deemed valid. Therefore, good design and operating practices consistent with the underlying engineering basis used was proposed to meet BACT and §112(g) case-by-case MACT permitting requirements for the dehydrator units. SC No. 26 of the permit will require the applicant to operate and maintain the Dehydration Units as specified by the manufacturer or engineering design and to utilize a triethylene glycol (TEG) solution as the contactor (absorber) solution. SC No. 26 will also require on-line monitoring of the temperature of the dehydration vent with a high-temperature alarm to help prevent excessive TEG carry-over as well as monitoring the TEG make-up rate.

The other HAP emitting sources listed in the table above are relatively small and are discussed further in the BACT discussion below.

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Special Conditions and MAERT

The permit special conditions (SCs) and MAERT for this initial permit are summarized below.

New SC No.	Description
1	Standard TCEQ boilerplate permit language for the scope of the permit that specifies that the permit only authorizes the sources listed in the MAERT.
2	Standard TCEQ boilerplate permit language related to unauthorized non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing volatile organic compounds (VOC) at a concentration of greater than 1 percent.
3	Standard TCEQ boilerplate permit language related to federal applicability that includes 40 CFR 60 Subparts A, Db, Dc, IIII, KKKK, and TTTTa.
4	Standard TCEQ boilerplate permit language related to federal applicability that includes 40 CFR 63 Subparts A, B, YYYY, ZZZZ, and DDDDD.
5	Nominal power output (MW) and duct burner firing rate limits for the two natural gas fired combustion turbine generator/duct burner units (EPNs CTG1_HRSG1 and CTG2_HRSG2; EPNs CCS1 and CCS2 when directed to the carbon capture system). The condition also specifies that the combustion turbines and duct burners shall utilize SCR and oxidation catalyst control systems. This condition is based on other recently issued turbine permits (for example, NRG Permit Nos. 160538 and 171485).
6	NO_x, CO, and NH₃ 1-hour concentration limits at 15% O₂ of 2.0 ppmvd, 2.0 ppmvd, and 5.0 ppmvd, respectively, for the turbine and duct burners (EPNs CTG1_HRSG1 and CTG2_HRSG2 when not directed to the carbon capture system; EPNs CCS1 and CCS2 when directed to the carbon capture system). For clarity, a paragraph below the concentration limits table specifies that the CEMS data for each turbine/duct burner train must be measured prior to the CCS Absorbers (EPNs CCS1 and CCS2) as specified in Special Condition No. 34 shall be used to demonstrate compliance with the NO_x and CO emission limits in this special condition and the MAERT hourly and annual emission rate limits. Paragraph A includes the definitions and maximum durations for the authorized cold startups, warm startups, hot startups, and shutdowns when the routine NO_x, CO, and NH₃ concentration limits do not apply. Paragraph B states that the emissions from the maintenance activities listed in Attachment B are excluded from the concentration limits in the first paragraph. Paragraph C specifies the turbines normal operating range of approximately 25 to 100 percent. This condition was developed based on other recently issued turbine permits (for example, NRG Permit Nos. 160538 and 171485 and Entergy Permit No. 166032).
7	Combustion turbine and duct burner fuel flow meter requirements based on the boilers/heaters standard TCEQ boilerplate permit language (there is not a specific Air Permit Division, APD, turbine boilerplate permit language). The condition also specifies the rolling 12-month firing rate limits for the turbines and duct burners on a higher heating value basis (MMBtu per rolling 12-month period on a gross or higher heating value basis) of 35,531,436 MMBtu/year per turbine and 7,853,340 MMBtu/year per duct burner based on the application representations.
8	CTG output specific CO ₂ emission factor limit of 800 lb CO ₂ /MWh-gross on a rolling 12-month basis or as specified in NSPS Subpart TTTTa prior to 1/1/2032 and 100 lb CO ₂ /MWh-gross on a rolling 12-month basis or as specified in NSPS Subpart TTTTa effective 1/1/2032 and later pursuant to 40 CFR 60 Subpart TTTTa. However, in the event that NSPS Subpart TTTTa does not apply, such as in the case if the rule were repealed in the future, then the CO ₂ emission factor limit specified in the condition is 925 lb CO ₂ /MWh-gross based on meeting BACT. This condition is being added because the project triggers PSD for GHGs and is based on other recently issued GHG turbine permits (for example, NRG Permit Nos. 160538/ GHGPSDTX204

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	and 171485/GHGPSDTX230), but changed to reflect NSPS Subpart TTTTa applicability. The condition also requires monthly and on a 12-month rolling average recordkeeping to demonstrate compliance condition.
9	This condition requires the combustion turbine lube oil vents, EPNs LUB-CTG and LUB-CCS, to have mist eliminators to minimize the VOC and PM/PM ₁₀ /PM _{2.5} emissions according to the application BACT representations.
10	The two emergency diesel generators (EPNs CTGEG and CCSEG) and the fire pump (EPN FPUMP) support the combustion turbines. This condition requires a non-resettable run time meter on each generator engine and the fire pump engine and limits each generator engine and the fire pump engine to a maximum of 100 hours of non-emergency operation per year on a rolling 12-month period per unit. This condition also requires that records of the diesel fuel delivery be maintained. This condition was developed based on the BACT representation and PowerSecure Inc. Permit No. 168222 that authorized a diesel fired emergency generator in Houston.
11	NOx and CO concentration limits for the natural gas fired CCS1 Boiler 1 (EPN CCS1), CCS1 Boiler 2 (EPN CCS1), CCS2 Boiler 1 (EPN CCS2), CCS2 Boiler 2 (EPN CCS2), CTG Boiler (EPN CTGBLR) and Fuel Heater (EPN FHEAT) are specified in this condition, which is based on TCEQ boilerplate permit language for boilers and heaters. The concentration limits for the CTG Boiler and Fuel Heater include MSS activities while the concentration limits for the CCS boilers do not include MSS activities as specified in SC Nos. 14 and 15. For clarity, added a paragraph that specifies that the CEMS data for CCS Boilers shall be measured prior to the CCS Absorbers (EPNs CCS1 and CCS2) as specified in Special Condition No. 34 and shall be used to demonstrate compliance with the NO_x and CO emission limits in this Special Condition and the MAERT hourly and annual emission rate limits. For the CTG Boiler (EPN CTGBLR) This condition specifies that the most recent stack test shall be used to demonstrate compliance with the NOx and CO limits in the condition and that CEMS is not required to demonstrate continuous compliance. CEMS is not being required for the CTG Boiler since it has a maximum firing rate of 95.5 MMBtu/hr (HHV), as CEMS is typically only required for units greater than 100 MMBtu/hr according to TCEQ APD policy. Similarly, for the Fuel Heater (EPN FHEAT), the condition specifies that compliance with the NOx and CO limits in the condition is based on maintaining vendor documentation of the emissions basis at the site, and no additional initial or continuous compliance is required to demonstrate compliance. The reason for not requiring CEMS is that the Fuel Heater is small, with a maximum firing rate of 16 MMBtu/hr (HHV), which does not usually require CEMS as noted above. Initial and recurring stack tests for the Fuel Heater is also not being required due to its small size, as stack testing is typically only required for boilers and heaters greater than 40 MMBtu/hr according to TCEQ APD policy.
12	Maximum hourly and maximum annual 12-month rolling firing rate limits for the CCS Boilers (FINs / EPNs CCS1BLR1 / CCS1, CCS1BLR2 / CCS1, CCS2BLR1 / CCS2, CCS2BLR2 / CCS2), CTG Boiler (FIN / EPN CTGBLR / CTGBLR), and Fuel Heater (FIN / EPN FHEAT / FHEAT) based on other recently issued permits (for example, NRG Permit No. 160538).
13	Requirement to have a totalizing fuel flow meter to measure the natural gas fuel usage for the CCS1 Boiler 1 (FIN CCS1BLR1), CCS1 Boiler 2 (FIN CCS1BLR2), CCS2 Boiler 1 (FIN CCS2BLR1), CCS2 Boiler 2 (FIN CCS2BLR2), CTG Boiler (FIN / EPN CTGBLR / CTGBLR), and Fuel Heater (FIN / EPN FHEAT / FHEAT) based on TCEQ boilerplate permit language for boilers and heaters.
14-15	Special conditions related to emission standards and operating specifications for planned startup activities for the CCS1 Boiler 1 (FIN/EPN CCS1BLR1), CCS1 Boiler 2 (FIN/EPN CCS1BLR2), CCS2 Boiler 1 (EPN FIN/EPN CCS2BLR1), and CCS2 Boiler 2 (FIN/EPN CCS2BLR2). These special conditions were developed based on language used for other permits and the permit application representations for the planned MSS events (for example,

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	Quail Run Carbon Permit No. 173197). SC No. 14 also specifies that the CCS Boilers are authorized to be emitted from their individual stacks, EPNs CCS1BLR1, CCS1BLR2, CCS2BLR1, and CCS2BLR2, rather than from the CCS absorber stacks, EPNs CCS1 and CCS2, during planned startup, maintenance, and shutdown activities.
16	Natural gas fuel limit of 0.5 grains total sulfur per 100 dry standard cubic feet (dscf) on an hourly and annual basis based on the BACT representations and the TCEQ boilerplate permit language for boilers and heaters.
17	Natural gas sampling of once every 6 months to determine total sulfur and net heating value, which case be satisfied using test results from the fuel supplier. This condition is based on TCEQ boilerplate permit language for boilers and heaters.
18	Diesel fuel limit of no more than 15 parts per million by weight (ppmw) sulfur based on other recently issued turbine permits (for example, NRG Permit Nos. 160538 and 171485). This condition also specifies that if the diesel fuel is designated ultra-low sulfur diesel (ULSD) on the fuel delivery receipt, then this is acceptable as showing compliance with sulfur limitations of this condition (this language was taken from PowerSecure Inc. Permit No. 168222).
19	Visible emissions requirements including a maximum limit of 5 percent averaged over a six-minute period (15 percent averaged over a six-minute period during MSS events) and quarterly (calendar) visible emission observation requirements. This condition is based on other recently issued turbine permits (for example, NRG Permit Nos. 160538 and 171485).
20-22	Standard TCEQ boilerplate permit language related to emission standards and operating specifications for storage tanks. All of the storage tanks are fixed roof tanks.
23	Ammonia system requirements to maintain prevention and protection measures for the ammonia storage system based on other recently issued turbine permits (for example, NRG Permit Nos. 160538 and 171485).
24	Standard TCEQ boilerplate permit language related to emission standards and operating specifications for particulate matter (PM/PM₁₀/PM_{2.5}) emissions from the Cooling Tower, EPN CTWR, except the TDS monitoring for particulate matter emissions compliance was clarified in paragraph C to apply "when operating" at the applicant's request. The applicant did not represent any VOC emissions from the cooling tower, as they stated that any incidental VOC that may be directed to the cooling tower has been assumed to be emitted from the CCS absorber stacks. Therefore, paragraph F of this condition states VOC emissions from the cooling tower are not authorized and requires monthly VOC cooling water monitoring to indicate faulty heat exchange equipment. The monthly VOC sampling may be reduced to at least once every six months if the monitoring detects no VOC in the cooling tower water for 12 consecutive months, but can revert back to monthly sampling if VOC is measured by the sampling. Paragraph F was adapted from TCEQ cooling tower boilerplate language for VOC cooling water monitoring and based on SC No. 15.F of Permit No. 173197 for Quail Run Carbon, LLC, which also represented that there are no VOC emissions from their cooling tower.
25	This condition for the water evaporators, EPN WE, was adapted from the standard TCEQ boilerplate permit language related to emission standards and operating specifications for particulate matter (PM/PM ₁₀ /PM _{2.5}) emissions from the cooling towers since the emission calculations provided by the applicant are similar to cooling towers - the particulate matter emission rates are based on a system water flow rate and TDS concentration. This condition also limits the operation of each of the four operating evaporators to a maximum of 2,500 hours per year on a rolling 12-month period to match the application/emission calculation representations. Note that the application represented that they may have one redundant non-operating backup evaporator, which is also specified in the condition.
26	This condition for the CCS1 TEG Dehydrator (EPN CCS1-CO2VT) and CCS2 TEG Dehydrator (EPN CCS2-CO2VT) states that they must be operated and maintained as specified by the manufacturer or engineering design and that a triethylene glycol (TEG) solution is used as the contactor (absorber) solution. This condition was developed based on BACT representations in

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	the permit application and SC No. 17 of Permit No. 173197 for Quail Run Carbon issued in TCEQ Project No. 359380. The monitoring specified in paragraphs A, B, and C of this condition are based on high-temperature excursions of the vent gas, the sampling of the vent stream for TEG content during such temperature excursions, and TEG make-up tracking, which were specified based on parameters identified by the applicant to ensure proper operation of the dehydration units.
27	Paragraph A states that Gas Turbine/Duct Burner Unit 1 represented by FIN CTG1_HRSG1 is authorized to be emitted from EPN CTG1_HRSG1 when not directed to the carbon capture system or alternatively may be directed to the CCS1 Absorber (EPN CCS1) to be treated for CO₂ recovery and emitted from EPN CCS1 except during planned MSS activities. Paragraph B likewise states that Gas Turbine/Duct Burner Unit 2 represented by FIN CTG1_HRSG1 is authorized to be emitted from EPN CTG1_HRSG1 when not directed to the carbon capture system or alternatively may be directed to the CCS1 Absorber (EPN CCS2) to be treated for CO₂ recovery and emitted from EPN CCS2 except during planned MSS activities. This condition is based on the application representations that the gas turbine/duct burner units may be emitted from the HRSG stacks or alternatively may be emitted from the carbon capture system for CO₂ recovery except during planned MSS activities.
28	Paragraph A states that the CCS1 Boiler 1 represented by FIN CCS1BLR1 and the CCS1 Boiler 2 represented by FIN CCS1BLR2 must be routed to the CCS1 Absorber (EPN CCS1) to be treated for CO₂ recovery and emitted from EPN CCS1 except during planned MSS activities. Likewise, paragraph B states that the CCS2 Boiler 1 represented by FIN CCS2BLR1 and the CCS2 Boiler 2 represented by FIN CCS2BLR2 must be routed to the CCS2 Absorber (EPN CCS2) to be treated for CO₂ recovery and emitted from EPN CCS2 except during planned MSS activities. This condition is based on the application representations that the natural gas fired CCS boilers directed to the carbon capture system for CO₂ recovery except during planned MSS activities.
29	This condition for the CCS1 Absorber (EPN CCS1) and CCS2 Absorber (EPN CCS2) states that they must be operated and maintained as specified by the manufacturer or engineering design and that an amine solvent mixture will be used as the absorber solution in the CCS Absorbers. This condition also requires the permit holder to minimize degradation of the amine solution by using the solvent specified by the engineering design for the unit and by assessing the relevant physical and chemical properties of the recirculating amine solvent at least quarterly to ensure the quality and appropriate CO₂ removal characteristics. This condition was developed based on BACT representations in the permit application.
30	This conditions states that continuous compliance for the CCS1 Absorber (EPN CCS1) and CCS2 Absorber (EPN CCS2) shall be conducted as specified in SC Nos. 39 and 40.
31	Standard TCEQ boilerplate permit language related to emission standards and operating specifications for the 28VHP LDAR program for equipment leak fugitives, EPNs SOLVFUG and NGFUG.
32	Standard TCEQ boilerplate permit language related to emission standards and operating specifications for the 28AVO LDAR program for equipment leak fugitives in ammonia service associated with the SCR system, EPN NH3FUG. The standard boilerplate language requires audio, olfactory, and visual checks to be conducted every four hours, but this language is being changed to twice per shift to match the represented BACT, which is Tier I BACT for ammonia equipment leak fugitives.
33	Standard TCEQ boilerplate permit language related to initial compliance via stack testing (and subsequent stack testing when requested by the TCEQ Executive Director). The pollutants and sources to be measured are the following: 1) NO_x, CO, PM, PM₁₀, PM_{2.5}, SO₂, VOC, NH₃, and O₂ from each Combustion Turbine

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	2) Generator/Duct Burner represented by FINs CTG1_HRSG1 and CTG2_HRSG2 to be sampled prior to CCS Absorbers including both no duct burner and duct burner firing modes; 3) NO_x, CO, PM, PM₁₀, PM_{2.5}, SO₂, VOC, and O₂ from each CCS Boiler represented by FINs CCS1BLR1, CCS1BLR2, CCS2BLR1, and CCS2BLR2 to be sampled prior to CCS Absorbers when they are directed to the CCS Absorbers during non-MSS events; 4) NO_x, CO, PM, PM₁₀, PM_{2.5}, SO₂, VOC, and O₂ from the CTG Boiler represented by EPN CTGBLR; and 5) VOC, acetaldehyde (CAS 75-07-0), formaldehyde (CAS 50-00-0), acetone (CAS 67-64-1), and acetonitrile (CAS 75-05-8) from each CCS Absorber represented by EPNs CCS1 and CCS2. The sum of the emission rates of acetaldehyde, formaldehyde, and acetonitrile represent the HAPs to be tested. Language was added to paragraph B to state that fuel sampling according to 40 CFR 60.4415 may be conducted in lieu of stack sampling for SO₂ or it may be exempted from SO₂ fuel monitoring according to 40 CFR 60.4365. This language was taken from Entergy Permit No. 166032 and is also consistent with NRG Permit No. 160538. Stack sampling is required for combustion units that exceed maximum firing rates of 40 MMBtu/hour. Therefore, stack testing is being included for the combustion turbines (4,100 MMBtu/hr per unit)/duct burners (nominally 897 MMBtu/hr per unit), CCS Boilers (182 MMBtu/hr per unit), CTG Boiler (95.5 MMBtu/hr), expressed on a higher heating value basis. Stack testing is not being required for the Fuel Heater (16 MMBtu/hr) based on the size. Stack testing is also not being required for the two emergency diesel generators (EPNs CTGEG and CCSEG) and fire pump (EPN FPUMP) due to the limited use of no more than 100 hours/year per unit being authorized in the permit.
34	Standard TCEQ boilerplate permit language related to continuous compliance for continuous emission monitoring system (CEMS) that applies to NO_x, CO, and O₂ from the Combustion Turbine Generator/Duct Burner CCTG1 (FINs CTG1_HRSG1), Combustion Turbine Generator/Duct Burner CCTG2 (CTG2_HRSG2), CCS1 Boiler 1 (FIN CCS1BLR1), CCS1 Boiler 2 (FIN CCS1BLR2), CCS2 Boiler 1 (FIN CCS2BLR1), and CCS2 Boiler 2 (FIN CCS2BLR2). The NO_x, CO, and O₂ concentrations from each subject combustion unit are required by this condition to be measured prior to CCS Absorbers so they can be attributed specifically to these sources since the CCS Absorbers treat both the turbine/duct burner units and boilers combined. This condition specifies that CEMS are not required for the CCS Boilers (CCS1 Boiler 1, CCS1 Boiler 2, CCS2 Boiler 1, and CCS2 Boiler 2) during MSS events when they are not directed to the CCS Absorbers and instead emit from their individual stacks, EPNs CCS1BLR1, CCS1BLR2, CCS2BLR1, and CCS2BLR2. The reason that CEMS are not required during these MSS events is that they are only being authorized at a limited number of hours of no more than 263 hours per 12-month rolling basis per CCS Boiler as specified in the table of MSS activities listed in SC No. 14.
35	Continuous compliance for the measurement or calculations of the ammonia slip from Combustion Turbine Generator/Duct Burner CCTG1 (FIN CTG1_HRSG1) and Combustion Turbine Generator/Duct Burner CCTG2 (FIN CTG2_HRSG2) using ammonia CEMS, NO_x CEMS and a mass balance approach, dual stream system of NO_x CEMS, or an approach approved by the TCEQ Midland Regional Office. This condition is based on other recently issued turbine permits (for example, NRG Permit Nos. 160538 and 171485).
36-37	Continuous compliance for the sulfur hexafluoride (SF₆) fugitive emissions associated with circuit breakers that specifies a maximum annual SF₆ leak rate of 0.5 weight % consistent with emission calculations in the application and represented BACT. The conditions require the circuit breakers to be totally enclosed, equipped with low pressure alarms, and provisions to repair or replacement of the leaking component in the circuit breaker. These condition are

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	based on other recently issued turbine permits (for example, NRG Permit Nos. 160538 and 171485).
38	The condition specifies that SF ₆ emissions must be calculated annually (calendar year) in accordance with the mass balance approach provided in equation DD-1 of the Mandatory GHG Reporting Rule for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD and that the total SF ₆ inventory of the circuit breakers shall not exceed 1,601 lb with leak detection based on the application representations. This condition is based on other recently issued turbine permits (for example, Entergy Permit No. 166032).
39	Continuous monitoring system requirements to measure and record the liquid supply temperature to the first water wash section of the CCS Absorbers (EPNs CCS1 and CCS2). These temperature data are reduced to 3-hour rolling average temperatures that are not to exceed the maximum temperature specified by the manufacturer, with a provision to retest within 365 days if the maximum 3-hour average temperature value measured during the last satisfactory stack test is not within 20°F of the manufacturer's recommended maximum value and the measured VOC or HAP emission rate during the stack test is at or above 90% of the MAERT hourly emission rate limits to ensure the validity of the stack test measured temperature and emissions compliance. This temperature limit is being set since staying below the limit is a parametric monitoring approach to indicate VOC and HAP MAERT compliance. This condition was added to promote continuous compliance with the VOC and HAP emission rate limits in the MAERT from EPNs CCS1 and CCS2 as parametric monitoring since the system is not amenable to a THC CEMs due to the inability of the THC CEMS to measure some of the species including oxidized carbon compounds such as formaldehyde. This condition is based on SC No. 26 of Permit No. 173197 for Quail Run Carbon issued in TCEQ Project No. 359380.
40	Monitoring of the proprietary amine solvent mixture concentration (wt.%) in the lean CO₂-absorbing solution supplied to the CO₂ recovery section of the CCS Absorbers (EPNs CCS1 and CCS2) at least once every 24-hours. The absolute value of the maximum amine concentration in the lean CO₂-absorbing solution is considered proprietary by the applicant and therefore the concentration data are normalized by dividing by the minimum of the following: 1) the maximum concentration value established by manufacturer's design and operation specifications for ensuring compliant VOC and HAP emissions rates, or 2) the maximum concentration value measured during the last satisfactory stack test. The relative concentration is specified to less than 1.0 since staying below this limit is a parametric monitoring approach to indicate VOC and HAP MAERT compliance. Like the previous condition, this condition was added to promote continuous compliance with the VOC and HAP emission rate limits in the MAERT from EPNs CCS1 and CCS2 as parametric monitoring since the system is not amenable to a THC CEMs due to the inability of the THC CEMS to measure some of the species including oxidized carbon compounds such as formaldehyde. This condition is based on SC No. 27 of Permit No. 173197 for Quail Run Carbon issued in TCEQ Project No. 359380.
41	This special condition specifies that planned MSS activities are restricted as listed in Attachment A, Attachment B, and the table entitled "Emission Sources - Maximum Allowable Emission Rates" attached to this permit. This condition is not in the standard TCEQ boilerplate permit language, but rather is used to reference the attachments and MAERT for planned MSS activities.
42	This condition refers to SC No. 6.A for the event durations and number of events for startup and shutdown activities for the turbines and duct burners (EPNs CTG1_HRSG1 and CTG2_HRSG2 when not directed to the carbon capture system and EPNs CCS1 and CCS2 when directed to

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	the carbon capture system). This condition also refers to SC No. 14 for the event durations and number of events for startup activities for the CCS1 Boiler 1 (FIN/EPN CCS1BLR1), CCS1 Boiler 2 (FIN/EPN CCS1BLR2), CCS2 Boiler 1 (EPN FIN/EPN CCS2BLR1), and CCS2 Boiler 2 (FIN/EPN CCS2BLR2).
43	This condition refers to Attachment A for the inherently low emitting (ILE) MSS activities that are authorized by the permit, states that these ILE MSS activities are considered to be equal to the potential to emit as represented in the permit application, and the estimated emissions from the Attachment A activities must be revalidated annually. This condition is based on other recently issued turbine permits (for example, Entergy Permit No. 166032).
44	This condition specifies the compliance of the planned non-ILE MSS activities specified in Attachment B including the use of CEMS data for those units that have a CEMS installed. This condition specifies the recordkeeping for the planned MSS activities including comparing the hourly and rolling 12-month emission totals to the MAERT limits. This condition is based on other recently issued turbine permits (for example, Entergy Permit No. 166032).
45	This condition states that associated Permit Number HAP85 represents the requirements of Section 112(g) of the Federal Clean Air Act, 40 CFR 63 Subpart B, and 30 TAC 116.400 for case-by-case MACT permitting. Special Condition Nos. 26, 29, 30, 33.B, 39, and 40 are referenced by this condition since they have been developed to demonstrate compliance with the case-by-case MACT permit. This condition is based on SC No. 28 of Permit No. 173197 for Quail Run Carbon issued in TCEQ Project No. 359380.
46	Since the project triggers PSD for GHGs, this condition requires GHG emissions monitoring, quality assurance/quality control requirements, emission calculation methodologies, recordkeeping, and reporting requirements related to GHG emissions to follow the applicable requirements in the GHG regulations, 40 CFR Part 98. This condition is based on SC No. 36 in Seadrift Coke Permit Nos. 70898/PSDTX410M4/GHGPSDTX232 that also triggered GHG permitting.
47	This condition requires CO₂e emissions to be calculated on a 12-month rolling basis, based on the procedures and global warming potentials (GWPs) specified in the GHG regulations, 40 CFR Part 98, Subpart A, Table A-1. This condition is based on SC No. 37 in Seadrift Coke Permit Nos. 70898/PSDTX410M4/GHGPSDTX232 that also triggered GHG permitting.
48	New condition added as a result of triggering PSD for GHGs that requires compliance with 30 TAC 116.164. This condition is based on SC No. 38 in Seadrift Coke Permit Nos. 70898/PSDTX410M4/GHGPSDTX232 that also triggered GHG permitting.
49	Recordkeeping requirement for GHGs that references SC Nos. 46 through 48. This condition is based on SC No. 39 in Seadrift Coke Permit Nos. 70898/PSDTX410M4/GHGPSDTX232 that also triggered GHG permitting.
50	Recordkeeping requirement that includes the records to be kept for the life of the permit including a copy of the permit, the permit application and subsequent updates, and initial and subsequent stack test reports. This condition was developed based on other recently issued turbine permits (for example, NRG Permit Nos. 160538 and 171485 and Entergy Permit No. 166032).
51	Recordkeeping requirements that include the records specified in each special condition that are required to be kept for at least five years and are required to be made available upon request to representatives of the TCEQ, the EPA, or any local air pollution control program having jurisdiction. This condition was developed based on other recently issued turbine permits (for example, NRG Permit Nos. 160538 and 171485 and Entergy Permit No. 166032).
Att. A	Attachment A referenced in the special conditions above for inherently low emitting MSS activities as represented in the application. This attachment was developed based on other recently issued turbine permits (for example, NRG Permit Nos. 160538 and 171485 and Entergy Permit No. 166032).
Att. B	Attachment B referenced in the special conditions above for non-inherently low emitting activities as represented in the application. This attachment was developed based on other recently issued turbine permits (for example, NRG Permit Nos. 160538 and 171485 and

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	Entergy Permit No. 166032).
MAERT	New MAERT for the initial permit that specifies the maximum hourly and annual emission rate limits for each EPN authorized by the permit. Note that footnote number 6 to the non-GHG MAERT states that planned maintenance, startup, and shutdown (MSS) emissions for all pollutants are authorized even if not specifically identified as MSS and that during any clock hour that includes one or more minutes of planned MSS, that pollutant's maximum hourly emission rate shall apply during that clock hour. This footnote is typically included in other MAERTs for turbine power projects, including Entergy Permit No. 166032 and NRG Permit Nos. 160538 and 171485.

Best Available Control Technology

BACT for the proposed project is summarized in the table below for each emitting source and the pollutants that triggered PSD review, which are CO, NO_x, PM, PM₁₀, PM_{2.5}, SO₂, VOC, H₂SO₄, and GHGs as CO₂e. State minor BACT was also evaluated for the other pollutants that did not trigger PSD review and is also summarized in the table below (e.g., lead, NH₃, acetone). HAPs are also included in the table below as a result of triggering a Clean Air Act §112(g) Case-by-Case MACT evaluation. The applicant submitted RACT/BACT/LAER Clearinghouse (RBLC) database search summaries for the pollutants that triggered PSD review (CO, NO_x, PM, PM₁₀, PM_{2.5}, SO₂, VOC, H₂SO₄, and GHGs as CO₂e), and these RBLC search summary results are included in the table below. The EPA has agreed to accept the TCEQ three-tier BACT approach as equivalent to the EPA top-down BACT approach for PSD review when the following are considered: recently issued/approved permits within the state of Texas; recently issued/approved permits in other states; and control technologies contained within the EPA's RBLC. The applicant fulfilled these requirements.

Source Name	EPN	Best Available Control Technology Description
CCTG1-no DB, CCTG1-w/DB, CCTG1 no CCS – annual	CTG1_HRSG1	The generating facility includes two natural gas fired H-class GE 7HA.03 combustion turbine generators (CTGs) and two HRSGs with DBs and two steam turbine generators in a 2x2x2 configuration, which is a combined cycle plant. The nominal heat input rate of the CTGs while firing natural gas will be approximately 4,100 MMBtu/hr (HHV) per unit with no duct burning and 4,950 MMBtu/hr HHV per unit with duct burning, both at ISO conditions (100 percent load and at 59°F). The nominal power rating for each of the two combustion turbine generators is expected to be 430 MW (net) per unit. On a generating facility basis, each train will have a nominal power rating of 660 MW (net), for a nominal total rating of 1,320 MW for the entire electric generating facility, i.e., both trains combined. Each unit is being permitted at 8,760 hours per year. A carbon capture system (CCS) is also being proposed as an option to reduce greenhouse gas (GHG) emissions. BACT for each pollutant is discussed below. NO_x: 2.0 ppmvd at 15% O₂, 1-hour average, without duct firing and with duct firing, achieved through the use of dry low-NO_x (DLN) combustors as lean pre-mix DLN combustors for natural gas firing, which limits NO_x formation by reducing peak flame temperatures by pre-mixing the natural gas-firing and combustion air immediately prior to combustion, in conjunction with SCR that uses ammonia as the reducing agent to convert NO_x into nitrogen and water. The TCEQ Tier I BACT for combined cycle turbines is 2.0 ppmvd at 15% O₂, 24-hour average, typically achieved with dry low
CCTG1-no DB, CCTG1-w/DB, CCS1 - annual	CCS1	
CCTG2-no DB, CCTG2-w/DB, CCTG2 no CCS - annual	CTG2_HRSG2	
CCTG2-no DB, CCTG2-w/DB, CCS2 - annual	CCS2	

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		NOx burner, water/steam injection, limiting fuel consumption, or SCR. Therefore, Tier I BACT is met. The units will have CEMS that will ensure that the NOx emission limits are met. The applicant conducted RACT/BACT/LAER Clearinghouse (RBLC) searches for recently permitted CCTG projects larger than 100 MW firing natural gas which showed that recently approved BACT emission limits for NOx control are equivalent to or higher than the Tier I NOx level. CO: 2.0 ppmvd at 15% O₂, 1-hour average, without and with duct firing achieved through the application of good combustion practices and an oxidation catalyst system which converts the CO to CO₂. Oxidation catalyst systems consist of a passive reactor comprised of a grid of metal panels with a platinum catalyst which can typically achieve CO reduction efficiencies of 80 to 90 percent, although the CO reduction may occasionally be less than these values due to the low inlet concentrations expected from the combined-cycle gas turbine (CCGT) units. The TCEQ Tier I BACT for combined cycle turbines is 2-4 ppmvd at 15% O₂, typically achieved with good combustion practices and/or oxidation catalyst. Therefore, Tier I BACT is met. The units will have CEMS that will ensure that the CO emission limits are met. The applicant conducted RBLC searches for recently permitted CCTG projects larger than 100 MW firing natural gas that showed that most of the recently approved BACT emission limits for CO are equivalent to or higher than the TCEQ Tier I levels and are generally achieved through use of an oxidation catalyst and good combustion controls. Therefore, the use of an oxidation catalyst is considered to represent the most stringent level of CO control achieved in practice. The lowest CO limits for any project identified by the applicant in the RBLC for natural gas-fueled CCGTs greater than 100 MW is 0.9 ppmvd at 15% O₂ without duct burning and 1.7 ppmvd at 15% O₂ with duct burning for the Killingly Energy Center project in Connecticut. However, this project is not moving forward according to the applicant, and therefore its emission levels have not been demonstrated in practice. The RBLC search showed that the Chickahominy Power project in Virginia has a permitted CO limit of 1.0 ppmvd at 15% O₂, but this project has also been canceled. Another determination in the RBLC, the Lincoln Land Energy Center in Illinois, has a CO limit of 1.8 ppmvd at 15% O₂ at less than 60 percent load and 1.5 ppmvd at 15% O₂ without duct burning at greater than 60 percent load. The applicant stated that the overall limit of 1.8 ppmvd at 15% O₂ is generally consistent with the proposed limit of 2.0 ppmvd at 15% O₂. The applicant noted that the VOC emission limit for the Lincoln Land Energy Center (without duct burning) is 1.1 ppmvd, a little higher than the proposed limit for the CPV project of 1.0 ppmvd at 15% O₂ without duct firing. The applicant stated that it is common
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		that optimizing combustion for lower VOC emissions could result in a concurrent increase in CO emissions. The Lincoln Land Energy Center has not yet been constructed according to the applicant, and therefore, these limits have not been verified. The Jackson Generation site in Illinois listed in the RBLC has a CO BACT limit of 2.0 ppmvd at 15% O₂, with a lower limit of 1.5 ppmvd at 15% O₂ required 36 months after commissioning. However, supporting documentation for the facility's BACT analysis, and the information in the RBLC confirm, that BACT for this facility was determined to be 2.0 ppmvd at 15% O₂ and not 1.5 ppmvd at 15% O₂ according to CPV. VOC: 1.0 ppmvd at 15% O₂ without duct firing and 2.0 ppmvd at 15% O₂ with duct firing achieved through the application of good combustion practices and an oxidation catalyst system which oxidizes the VOC to form CO₂ and water. Oxidation catalyst systems consist of a passive reactor comprised of a grid of metal panels with a platinum catalyst. The optimal location of the catalyst for VOC control is the 900°F to 1,100°F. However, at the high temperatures necessary optimize VOC reduction, the undesirable oxidation of SO₂ to SO₃ occurs, which results in increased emissions of H₂SO₄ and/or ammonium salts (PM/PM₁₀/PM_{2.5}). Therefore, the oxidation catalyst is most frequently located in a slightly lower temperature section of the HRSG, normally just upstream of the SCR system, to maintain a high efficiency for CO reduction while also reducing VOC emissions. The TCEQ Tier I BACT for combined cycle turbines is 2 ppmvd at 15% O₂ if no duct burner, 4 ppmvd with duct burner. Achieved through good combustion practices. Therefore, Tier I BACT is met. The applicant conducted RBLC searches for recently permitted CCTG projects larger than 100 MW firing natural gas which showed that recently approved BACT emission limits for VOC control are consistent with the project's proposed BACT and generally lower than the Tier I limit generally achieved through use of an oxidation catalyst and good combustion controls. The RBLC searches identified three projects that proposed lower VOC concentrations as BACT, which are the Killingly Energy Center project in Connecticut, the Chickahominy Power project in Virginia, and the Novi Power Project in Virginia. However, the applicant stated that these projects were permitted at least four years ago and have not been constructed due to being cancelled and therefore never actually implemented. PM/PM₁₀/PM_{2.5}: Good combustion practices and fuel limited to pipeline quality natural gas, which is the TCEQ Tier I BACT for combined cycle turbines. The applicant assumed that all of the PM/PM₁₀/PM_{2.5} emitted from the CCTGs is conservatively assumed to be less than 2.5 microns in diameter, and, therefore, the PM, PM₁₀, and PM_{2.5} emission rates are assumed to be the same. During full-load steady state conditions, PM/PM₁₀/PM_{2.5} emissions from the exhaust stack will be limited to 0.0034 lb/MMBtu (HHV) without duct burning and 0.0052 lb/MMBtu (HHV) with duct burning. The applicant stated that there are no practically feasible
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		post-combustion control technologies available to reduce PM/PM₁₀/PM_{2.5} emissions from CCGTs since post-combustion PM/PM₁₀/PM_{2.5} control technologies such as fabric filters (baghouses), electrostatic precipitators, and/or wet scrubbers, which are commonly used on solid and liquid fuel boilers, are not available for CCGTs since the large amount of excess air inherent to CCGT technology would create an unacceptable amount of backpressure for CCGT operation. The applicant's RBLC search for PM/PM₁₀/PM_{2.5} BACT precedents for CCTG projects larger than 100 MW firing natural gas showed that use of clean-burning fuels and good combustion practices are the most stringent available technologies for controlling CCGT particulate matter emissions. The RBLC review of the permitted PM/PM₁₀/PM_{2.5} emission limits for natural gas-fired CCGTs shows a wide range of values from 0.0022 to 0.0084 lb/MMBtu, and typically, but not always, with higher rates during duct burning. The RBLC searches showed that GE turbine technologies tend to have PM/PM₁₀/PM_{2.5} guaranteed limits on the higher end of the emissions range. The differences in PM/PM₁₀/PM_{2.5} emission limits among various projects appears to be due to different emission guarantee philosophies of the various suppliers and are not believed to be actual differences in the quantity of PM/PM₁₀/PM_{2.5}. SO₂: The applicant conservatively assumed 100% molar conversion of natural gas sulfur to SO₂ (conservative since SO₂ and H₂SO₄ emissions are double counted). BACT was represented as good combustion practices, units fire only pipeline quality natural gas with no more than 0.5 grains sulfur/100 dscf fuel. Based on the CCGT design heat rates, full load steady state emissions of SO₂ are proposed at 0.0017 lb/MMBtu (HHV) with and without duct burning. TCEQ Tier I BACT for combined cycle turbines is good combustion practices and firing pipeline quality natural gas with no more than 5 grains sulfur/100 dscf fuel on an hourly basis and 1 grain sulfur/100 dscf fuel on an annual basis. Therefore, TCEQ Tier I BACT is met. The applicant stated that there are no post-combustion control technologies readily available for SO₂/H₂SO₄ emissions from CCGTs, as post-combustion SO₂/H₂SO₄ control technologies, such as dry or wet scrubbers that are commonly used on solid fuel boilers, are not technically feasible for CCGTs since the large amount of excess air inherent to CCGT technology would create an unacceptable amount of backpressure for CCGT operation. The applicant's RBLC search showed that the only SO₂/ H₂SO₄ BACT technology identified for natural gas fired large CCGTs (greater than 100 MW firing) is the use of clean fuel (i.e., natural gas), as there were no cases identified of any post-combustion controls used to control these emissions from CCGTs. H₂SO₄: The applicant conservatively assumed 100% molar conversion of natural gas sulfur, 0.5 grains sulfur/100 dscf fuel, to SO₂ and 5% molar conversion of that SO₂ to SO₃ due to combustion, 40% molar conversion of the remaining SO₂ to SO₃ due to the oxidation
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		catalyst, and 2% molar conversion of the remaining SO₂ to SO₃ due to the SCR. A 17.5% safety margin was added to the SO₃ and the applicant assumed that all of the SO₃ is converted to H₂SO₄. Full load steady state emissions of H₂SO₄ are proposed at 0.0011 lb/MMBtu (HHV) without duct burning and 0.0012 lb/MMBtu (HHV) with duct burning. BACT was represented as good combustion practices, units fire only pipeline quality natural gas with no more than 0.5 grains sulfur/100 dscf fuel. TCEQ Tier I BACT is good combustion practices and firing pipeline quality natural gas with no more than 5 grains sulfur/100 dscf fuel on an hourly basis and 1 grain sulfur/100 dscf fuel on an annual basis. Therefore, TCEQ Tier I BACT is met. The applicant stated that there are no post-combustion control technologies readily available for SO₂/H₂SO₄ emissions from CCGTs, as post-combustion SO₂/H₂SO₄ control technologies, such as dry or wet scrubbers that are commonly used on solid fuel boilers, are not technically feasible for CCGTs since the large amount of excess air inherent to CCGT technology would create an unacceptable amount of backpressure for CCGT operation. The applicant's RBLC search showed that the only SO₂ /H₂SO₄ BACT technology identified for large CCGTs is the use of clean fuel (i.e., natural gas), as there were no cases identified of any post-combustion controls used to control these emissions from CCGTs. A relatively wide range of BACT emission rates were found for gas firing in the RBLC, with the largest at 0.0022 lb/MMBtu and most being around 0.001 lb/MMBtu, which reflects a range of assumed natural gas sulfur contents and SO₂ to SO₃ conversion rates. NH₃: Ammonia slip of 5.0 ppmvd at 15% O₂, 1-hour average, using effective process control. SCR involves the injection of NH₃ into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH₃ reacts with the NO_x (NO and NO₂) contained within the flue gas to form N₂ and water. NH₃ is injected and mixed into the exhaust gas upstream in greater than stoichiometric amounts to achieve optimal conversion of NO_x. Excess NH₃ that is not reacted in the catalyst bed is emitted through the stack which is referred to as "ammonia slip." As the SCR catalyst nears its end of life, replacement catalyst will be installed to ensure 5 ppmvd at 15% O₂ is not exceeded. TCEQ Tier I BACT for combined cycle turbine units is ammonia slip of 7-10 ppmvd at 15% O₂, achieved by controlling the ammonia injection system to minimize ammonia slip. Therefore, TCEQ Tier I BACT is met. Pb: The applicant proposed combustion of natural gas and good combustion practices. The lead emission rates are less than 0.01 lb/hr and 0.01 tpy from each turbine unit. HAPs: Application of good combustion practices and an oxidation catalyst system used to meet BACT for VOC discussed above will also limit the HAP emissions. Total HAP emissions are represented as 9.89 tpy from each CCTG unit (there are a total of two CCTG units as noted above).
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CO₂e: The CTGs will operate at an annual 12-month rolling emission factor of 925 lb CO₂/MW-hr (gross) firing natural gas fuel during steady state full load conditions (without CCS) assuming 8,760 hours per year of duct burner firing and will meet 40 CFR 60 Subpart TTTTa as applicable, which requires a 12-month rolling limit of 800 lb CO₂/MWh gross (for turbine units with a base load rating of 2,000 MMBtu/h or more) prior to January 1, 2032 and 90% carbon capture at a 12-month rolling standard of 100 lb CO₂/MWh-gross starting on January 1, 2032 for new base load (capacity factor greater than 40%) natural gas turbines constructed after May 23, 2023. These proposed rates are achieved by implementation of high-efficiency technology and the lowest carbon fuel (i.e., natural gas). The greatest proportion of potential GHGs emissions associated with the generating facility, over 99 percent, will be CO₂ emissions resulting from the combustion of natural gas in the CCGTs, with trace amounts of CH₄ and N₂O emitted during combustion in varying quantities depending on operating conditions; however, they will be negligible compared to CO₂ emissions. There is no TCEQ Tier I BACT provided for GHGs.

The facility will utilize combined-cycle CTG technology, which provides greater power output per fuel input, and will burn natural gas as the sole fuel. In addition, NSPS, 40 CFR 60 Subpart TTTTa, Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units, was promulgated on May 9, 2024 and effective on July 8, 2024 (Federal Register, May 9, 2024, Volume 89, No. 91, page 39798). This rule applies to stationary combustion turbine that commences construction or reconstruction after May 23, 2023 and therefore applies to the proposed turbine units. As regulated in 40 CFR 60.5520a(a) and Table 1 to Subpart TTTTa, Title 40, the rule specifies a 12-month rolling limit of 800 lb CO₂/MWh gross (for turbine units with a base load rating of 2,000 MMBtu/h or more) prior to January 1, 2032 and 90% carbon capture at a 12-month rolling standard of 100 lb CO₂/MWh-gross starting on January 1, 2032 for new base load (capacity factor greater than 40%) natural gas turbines constructed after May 23, 2023. The applicant stated that they will operate the units to comply with these limits as applicable (or any applicable limits in Subpart TTTTa if the rule changes), which can be accomplished with the CCS system being authorized in the project. However, in the event that NSPS Subpart TTTTa does not apply, such as in the case if the rule were repealed in the future, then the CO₂ emission factor limit specified in the SC No. 8 is 925 lb CO₂/MWh-gross based on meeting BACT.

Because emissions of CO₂ are directly related to the amount of fuel combusted, an effective means of reducing GHG emissions is through efficient power generation technologies. By utilizing more efficient technology, less fuel is required to produce the same amount of electrical output. The applicant proposed to use natural

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	gas-fired CCGT technology, which is the most efficient commercially available fossil fuel electric generation technology. The applicant also identified pollution prevention through the use of inherently low-emitting fuels as an option to reduce CO₂ emissions turbine and duct burners. The project's turbines and duct burners will combust natural gas as the sole fuel, which is the lowest CO₂-emitting fossil fuel. The applicant provided the following CO₂ emission factors taken from Subpart C of 40 CFR 98 to demonstrate that the natural gas will minimize CO₂ emissions compared to other fossil fuels: • Natural gas – 117 lb CO₂/MMBtu • Distillate Fuel No. 2 - 162 lb CO₂/MMBtu • Coal, mixed for electric power generation - 210 lb CO₂/MMBtu Carbon capture and storage or sequestration is another control option to reduce CO₂ emissions from combustion turbines, which is considered by the EPA to be a technically feasible add-on control option for CO₂ (see the discussion above regarding 40 CFR 60 Subpart TTTTa applicability). After capturing the carbon, it is transported off-site for final disposition including enhanced oil recovery (EOR) or commercial sequestration. The first step in the carbon capture and sequestration process is capture of the CO₂ from the CCGT exhaust gas in a form that is suitable for transport. There are several methods that may be used for capturing CO₂ from gas streams, including chemical and physical absorption, adsorption, cryogenic separation, and membrane separation. Exhaust streams from CCGTs have relatively low CO₂ concentrations due to the high level of excess air in the combustion process. Therefore, only chemical absorption would be considered technically feasible for a high percentage capture of CO₂ in a high volume, low CO₂ concentration gas stream. The next step in the carbon capture and sequestration process is transportation of the captured CO₂ for final disposition including EOR or commercial sequestration. Currently, development of commercially available CO₂ storage sites is in its infancy as is EOR from non-natural occurring CO₂. In addition, pipelines for transport of the compressed CO₂ to storage or EOR sites are not currently available. The capital expenditure required to capture and compress CO₂ from the CCGT exhaust gas and transport it for sequestration is very significant according to the applicant. The applicant estimated that the proposed CCS trains will reduce CO₂ emissions by approximately 4,600,000 tons facility wide. While capturing CO₂ is the major cost contributor, it is important to consider the transportation and sequestration of CO₂, as well, for total cost. The applicant estimated the cost of CCS control of \$102 per ton of CO₂e removed (2024 dollars) that included estimated transportation and sequestration costs, with the details of the cost estimate submitted confidentially. Taking into account the parasitic load caused by a CCS system, the overall efficiency of the project is reduced while increasing all other regulated pollutants on a per
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	megawatt-hour (MW-hr) basis. Note that the dollars per ton value that the applicant estimated was based on the pollutant CO₂ captured by the CCS system. However, the applicant stated that it can be assumed there will be negligible capture of other GHGs associated with combustion, i.e., CH₄ and N₂O, and therefore the dollars per ton can be assumed to be per ton of CO₂e. There are not many BACT determinations for CCS available that provide cost-effectiveness values in the RBLC. The applicant cited a determination for Arauco North America's Grayling particleboard facility (RBLC ID MI-0448) of \$105 per ton of CO₂ removed that was deemed as not cost effective (note the permit reviewer checked the RBLC and the determination was in fact \$102 per ton of CO₂e that was deemed to not be cost effective). Additionally, the determination for the Marshall Energy Center (North and South Plants, RBLC ID MI-0451 and MI-0452) indicates that \$100 per ton of CO₂e removed is not cost effective. Based on comparisons with these values, the costs associated with the CPV carbon capture and sequestration option are prohibitively expensive for consideration as BACT. The applicant's RBLC searches for CCTG projects larger than 100 MW firing natural gas showed no projects with carbon capture and storage. The lowest GHG BACT emission limits in the RBLC for natural gas firing are generally for new and clean condition, with a design margin that does not include normal degradation. The lowest limit provided in the RBLC is 726 lb/MW-hr, 12-month rolling average. There are other new and clean permit limits listed in RBLC between 794 and 1,000 lb/MW-hr that are limited to full operating load for various CCGTs technologies. There are also several other projects permitted with annual average GHG limits in units of lb/MW-hr ranging from 850 to 1,000 lb/MW-hr, which take into account all modes of operation. Based on the estimated cost of CCS at \$102 per ton of CO₂e removed, which is similar to the range of \$100 to \$102 per ton of CO₂e removed in the RBLC searches noted above, the applicant stated that "CCS is not currently economically feasible as BACT for the Project, and is being proposed, not as BACT, but to advance the technology for future development and commercialization as it relates to the power generation industry". High-generation efficiency and low-carbon fuels are technically feasible, and in combination, represent the most effective GHG control technology demonstrated in practice on CCGTs. Further, the applicant stated that they believe that carbon capture and sequestration is not cost effective based on recent project-specific cost estimates compared to recent RBLC determinations indicating that \$100 per ton of CO₂e removed is not cost-effective. The applicant stated that EPA's position in the Subpart TTTTa rulemaking is based on modeled control costs of \$57/ton CO₂ removed taking advantage of expected cost reductions and efficiencies by 1) assuming that the cost of the control technology will decrease at a consistent rate over the next decade, 2) tax
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credit offsets equivalent to \$40.76/ton (30-year amortization), and 3) a presumed operation with an average capacity factor of 51% over a project's operating life. Note the above referenced \$57/ton CO₂ removed is based on \$46/ton CO₂ removed for an H-Class Turbine referenced on page 39934 of the Subpart TTTTa rulemaking (Federal Register, May 9, 2024, Volume 89, No. 91) plus \$11/metric ton CO₂ removed for transportation and storage taken from "Carbon Dioxide Transport and Storage Costs in NETL Studies", August 2019, Table ES-1 for Texas (conservatively assumed by the applicant to be \$11/short ton CO₂ removed). The 51% capacity factor is taken from page 39934 of the Subpart TTTTa rulemaking reference also noted above.

The project's estimated engineering cost estimate is \$102/ton of CO₂e removed at a 100% capacity factor, which is the usual assumption for BACT analyses for consistency with the permit basis. The applicant stated that these costs would not benefit from projected future decreases in estimated costs of control, nor can a guarantee of tax credit availability be assumed. The applicant stated that these costs are higher than EPA's represented \$57/ton CO₂ control costs for Subpart TTTTa rulemaking, and are even higher if adjusting for EPA assumptions of 51% capacity factor and \$40.76/ton tax credit:

$(\$102 \text{ per ton CO}_2 \text{ removed} / 0.51) - (\$40.76 / \text{ton CO}_2 \text{ removed}) = \$159 \text{ per ton CO}_2 \text{ removed.}$

The applicant stated that at \$159/ton CO₂ removed, the amount is nearly three times greater than the "generic" estimate of \$57/ton CO₂ removed and over 50% above the cost effectiveness threshold of roughly \$100-102 ton CO₂e removed.

However, consistent with the statutory command of Section 111 of the Clean Air Act (CAA), 42 U.S. Code §7411, recently promulgated NSPS Subpart TTTTa reflects the application of the Best System of Emission Reduction (BSER) that is required by the CAA to account for the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements to be adequately demonstrated to promulgate the rule. Since Subpart TTTTa was recently promulgated on May 9, 2024, it is considered to be equivalent to BACT, which is defined in 30 TAC 116.10(1) as control through experience and research that has proven to be operational, obtainable, and capable of reducing or eliminating emissions from the facility and is considered technically practical and economically reasonable for the facility. Regardless of the determinations listed in the RBLC, recently promulgated Subpart TTTTa defines BSER and therefore equivalent BACT unless the rule is subsequently vacated or otherwise no longer applicable. As such, BACT is considered to be a 12-month rolling limit of 800 lb CO₂/MWh gross (for turbine units with a base load rating of 2,000 MMBtu/h or more) prior to January 1, 2032 and 90% carbon capture at a 12-month rolling standard of 100 lb CO₂/MWh-gross starting on January 1, 2032 as regulated in 40 CFR 60 Subpart TTTTa (or any applicable limits in

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		Subpart TTTTa if the rule changes). MSS: See discussion below for source names identified as CCTG1-MSS and CCTG2-MSS. The proposed BACT for the natural gas turbine and duct burner units meet the TCEQ Tier I guidelines and is consistent with the RBLC searches.																																																	
CCTG1-MSS, CCTG1 no CCS - annual	CTG1_HRSG1	The applicant proposed to meet TCEQ Tier I BACT for combined cycle turbines planned MSS activities, which is minimizing the duration of MSS activities, minimizing the amount of time the turbine is outside the performance mode where the controls can be used, and operating the facility in accordance with best management practices and good air pollution control practices. The turbine vendor, GE, provided the emissions associated with each startup or shutdown (SU/SD) event and defined its own minimum downtime associated with each startup event as summarized in the tables below. Note that SO₂ and GHGs are not listed in the second table below since they are dependent on fuel use and therefore the SU/SD emissions will not exceed the emission rates during routine operations. <table><thead><tr><th>SU/SD Event</th><th>Maximum Annual Events, per Turbine (events/12-month rolling basis)</th><th>Minimum Downtime Preceding Event per Event per Turbine (hours)</th><th>Maximum Duration per Event, per Turbine (minutes/event)^a</th></tr></thead><tbody><tr><td>Cold SU</td><td>10</td><td>72</td><td>70</td></tr><tr><td>Warm SU</td><td>42</td><td>48</td><td>60</td></tr><tr><td>Hot SU</td><td>200</td><td>0</td><td>30</td></tr><tr><td>SD</td><td>252</td><td>0</td><td>12</td></tr></tbody></table> ^a Maximum duration until the turbine reaches the minimum emissions compliance load (MECL). <table><thead><tr><th rowspan="2">SU/SD Event</th><th colspan="4">Emissions per Event (pounds)</th></tr><tr><th>NOx</th><th>CO</th><th>VOC</th><th>PM/PM₁₀ / PM_{2.5}</th></tr></thead><tbody><tr><td>Cold SU</td><td>450</td><td>310</td><td>27</td><td>19</td></tr><tr><td>Warm SU</td><td>260</td><td>226</td><td>16</td><td>16</td></tr><tr><td>Hot SU</td><td>120</td><td>215</td><td>13</td><td>8</td></tr><tr><td>SD</td><td>30</td><td>215</td><td>50</td><td>3</td></tr></tbody></table> The units will have CEMS that will ensure that the NOx and CO emission limits are met. The RBLC searches are discussed above with the routine emissions. The planned MSS activities for the turbine units meet BACT.	SU/SD Event	Maximum Annual Events, per Turbine (events/12-month rolling basis)	Minimum Downtime Preceding Event per Event per Turbine (hours)	Maximum Duration per Event, per Turbine (minutes/event) ^a	Cold SU	10	72	70	Warm SU	42	48	60	Hot SU	200	0	30	SD	252	0	12	SU/SD Event	Emissions per Event (pounds)				NOx	CO	VOC	PM/PM ₁₀ / PM _{2.5}	Cold SU	450	310	27	19	Warm SU	260	226	16	16	Hot SU	120	215	13	8	SD	30	215	50	3
SU/SD Event	Maximum Annual Events, per Turbine (events/12-month rolling basis)		Minimum Downtime Preceding Event per Event per Turbine (hours)	Maximum Duration per Event, per Turbine (minutes/event) ^a																																															
Cold SU	10	72	70																																																
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	NOx	CO	VOC	PM/PM ₁₀ / PM _{2.5}																																															
Cold SU	450	310	27	19																																															
Warm SU	260	226	16	16																																															
Hot SU	120	215	13	8																																															
SD	30	215	50	3																																															
CCTG2-MSS, CCTG2 no CCS - annual	CTG2_HRSG2																																																		
CCS1 Absorber	CCS1	The project includes two absorbers to capture the emissions from the CCGTs and CCS boilers. The absorber will use a proprietary																																																	

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CCS2 Absorber	CCS2																
CCS1 MSS Activities	CCS1-CO2VT	The applicant stated that the CCS absorber stacks do not have increased emissions during MSS events, but MSS events may occur when a CO₂-rich vent stream must be discharged to facilitate start-ups and shutdowns of the CCS Regenerator and CO₂ Compressor sections and responding to trips of the CO₂ Compressor. During these times, the CO₂-rich vent stream may need to be re-routed from its normal process connection to the dedicated CO₂-rich stream exhaust point. The facility will have two CO₂ MSS vent stacks, i.e., one stack dedicated to each train, and these MSS vent stacks emit from the same stacks as used for the CCS1 TEG Dehydrator and CCS2 TEG Dehydrator units discussed separately (see later in this table for a discussion of the dehydrator units). The CO₂ MSS events may result in maximum emissions per train/vent stack of 13.48 lb/hr and 0.28 tpy for VOC, 6.39 lb/hr and 0.13 tpy for total HAPs, 0.69 lb/hr and 0.01 tpy for acetone, and 10,973.36 tpy for CO₂e. For the trains/vent stack combined, these emission rates are 26.96 lb/hr and 0.56 tpy for VOC, 12.77 lb/hr and 0.27 tpy for total HAPs, 1.37 lb/hr and 0.03 tpy for acetone, and 21,946.71 tpy for CO₂e. These CO₂ MSS emission estimates are based on the following maximum expected frequency and durations: <table><thead><tr><th>MSS Event</th><th>Maximum Events per Year per CCS Train</th><th>Maximum Event Duration (hours/event)</th></tr></thead><tbody><tr><td>Cold Startup</td><td>2</td><td>12</td></tr><tr><td>Shutdown</td><td>2</td><td>2</td></tr><tr><td>Hot Startup</td><td>5</td><td>6</td></tr><tr><td>Compressor Trip</td><td>5</td><td>2</td></tr></tbody></table> The TCEQ Tier I BACT for combustion MSS activities is the use of good air pollution control practices and safe operating practices and limiting the frequency and duration of the activities. The applicant stated that the MSS activities associated with the proposed project are undertaken to ensure the proper operability and safety of equipment. The frequency and duration of the identified startup and shutdown activities will be minimized to the extent possible such that associated emissions are limited. The applicant stated that that the emissions associated with these activities are so low that alternative work practices, were they feasible, would not result in meaningful emission reductions. The limited duration and frequency of the identified activities summarized in the table above will minimize emissions to meet BACT.	MSS Event	Maximum Events per Year per CCS Train	Maximum Event Duration (hours/event)	Cold Startup	2	12	Shutdown	2	2	Hot Startup	5	6	Compressor Trip	5	2
MSS Event	Maximum Events per Year per CCS Train		Maximum Event Duration (hours/event)														
Cold Startup	2		12														
Shutdown	2		2														
Hot Startup	5	6															
Compressor Trip	5	2															
CCS2 MSS Activities	CCS2-CO2VT																
CCS1 Boiler 1	CCS1																
CCS1 Boiler 2	CCS1																

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		four CCS boilers). The CCS boilers will support CCS startup and provide the balance of the needed steam to the CCS. The CCS boilers (along with turbine HRSG exhaust gas) will be directed to the CCS system and exhaust through the CCS absorber stack.
CCS2 Boiler 1	CCS2	
CCS2 Boiler 2	CCS2	

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		0.007 lb/MMBtu, which is consistent with the precedents listed in the RBLC. PM/PM₁₀/PM_{2.5}: Emission factor of 0.007 lb/MMBtu (HHV) using good combustion practices and fuel limited to pipeline quality natural gas and less than 5% opacity. The TCEQ Tier I BACT for natural gas fired boilers greater than 40 MMBtu/hr is good combustion practices and less than 5% opacity. The applicant assumed that all of the PM/PM₁₀/PM_{2.5} emitted from the boilers is conservatively assumed to be less than 2.5 microns in diameter, and, therefore, the PM, PM₁₀, and PM_{2.5} emission rates are assumed to be the same. The applicant's RBLC searches showed that PM/PM₁₀/PM_{2.5} BACT determinations range from 0.005 to 0.008 lb/MMBtu, with the exception of one outlier. The most stringent level of control identified for a natural gas-fired boiler is 0.00181 lb/MMBtu for the Allegheny Energy Center in West Newton, Pennsylvania utilizing good combustion practices. The applicant stated that this limit is considered an unrealistically low-emissions guarantee for a boiler of this type because of the uncertainty and variability with available PM/PM₁₀/PM_{2.5} test methods, and the risk of artifact emissions resulting in a tested exceedance. All new natural gas-fired boilers that are properly operated are expected to have intrinsically low PM/PM₁₀/PM_{2.5} emissions. In addition, the application stated that the Allegheny Energy Center project has recently been cancelled and therefore not actually implemented. The CPV project proposes to combust natural gas with good combustion controls to maintain a PM/PM₁₀/PM_{2.5} emission limit of 0.007 lb/MMBtu, which is consistent with the precedents listed in the RBLC. SO₂: The applicant assumed 100% molar conversion of natural gas sulfur to SO₂, conservatively not reducing SO₂ emissions due to conversion to H₂SO₄. BACT was represented as good combustion practices and firing only pipeline quality natural gas with no more than 0.5 grains sulfur/100 dscf natural gas fuel, which results in a corresponding SO₂ emission factor of 0.0014 lb/MMBtu (HHV). The TCEQ Tier I BACT for natural gas fired boilers greater than 40 MMBtu/hr is firing low sulfur fuel and good combustion practices. The SO₂ limits in the RBLC searches ranged from 0.0011 to 0.002 lb/MMBtu. A project's SO₂ and H₂SO₄ emissions can vary greatly depending on the maximum sulfur content of the fuel and assumptions related to conversion of SO₂ to H₂SO₄, which is indicated by the wide range of emission limits shown in the RBLC. The CPV project proposes to combust natural gas with a maximum sulfur content of 0.5 grains sulfur/100 dscf natural gas with an SO₂ emission factor of 0.0014 lb/MMBtu, which is consistent with the precedents listed in the RBLC. H₂SO₄: The applicant assumed 100% molar conversion of natural gas sulfur to SO₂ and 10% molar conversion of SO₂ to SO₃ (conservatively not reducing the SO₂ emissions) and 100% conversion of SO₃ to H₂SO₄. BACT was represented as good
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		combustion practices firing only pipeline quality natural gas with no more than 0.5 grains sulfur/100 dscf fuel, which results in a corresponding H₂SO₄ emission factor of 0.00021 lb/MMBtu (HHV). The TCEQ Tier I BACT for natural gas fired boilers greater than 40 MMBtu/hr is firing pipeline quality natural gas and good combustion practices. For H₂SO₄, the levels of control in the RBLC searches ranged from 0.00011 to 0.0018 lb/MMBtu. A project's SO₂ and H₂SO₄ emissions can vary greatly depending on the maximum sulfur content of the fuel and assumptions related to conversion of SO₂ to H₂SO₄, which is indicated by the wide range of emission limits shown in the RBLC. The CPV project proposes to combust natural gas with a maximum sulfur content of 0.5 grains sulfur/100 dscf natural gas with an H₂SO₄ emission factor of 0.00021 lb/MMBtu, which is consistent with the precedents listed in the RBLC. Pb: The applicant proposed combustion of natural gas and a lead emission factor of 4.83E-07 lb/MMBtu taken from Table 1.4-2 of AP-42 dated July 1998. The lead emission rates are less than 0.01 lb/hr and 0.01 tpy from each boiler unit. HAPs: Application of good combustion practices used to meet BACT for VOC as discussed above will also limit the HAP emissions. Total HAP emissions are represented as 1.45 tpy from each boiler (there are a total of four boilers as noted above). CO₂e: The CCS boilers will fire natural gas, which is the lowest carbon fuel available. Therefore, formation of CO₂ from combustion of the fuel will be minimized. The represented natural gas combustion emission factors taken from Tables C-1 and C-2 of 40 CFR 98 are 117.00 lb/MMBtu for CO₂, 2.20E-03 lb/MMBtu for CH₄, and 2.20E-04 lb/MMBtu for N₂O, which convert to an overall CO₂e emission factor of 117.12 lb/MMBtu (all HHV). Good operating and maintenance practices for the boilers include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintaining the proper air/fuel ratio so that sufficient oxygen is provided to promote complete combustion of the fuel while at the same time preventing introduction of more air than is necessary into the boilers. The boilers will fire natural gas with good combustion control to meet BACT. The RBLC searches for GHG showed that the control technologies are the use of low carbon fuels and good operating and maintenance procedures. MSS: See discussion below regarding BACT for planned MSS activities for the CCS boilers. EPNs CCS1BLR1, CCS1BLR2, CCS2BLR1, CCS2BLR2. The proposed BACT for the CCS boiler units meet the TCEQ Tier I guidelines and is consistent with the RBLC searches.
	CCS1BLR1	

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CCS1 Boiler 1 - MSS		Emissions during startup of the boilers may, for some pollutants, result in an increase in short-term lb/hr emission rates – this was only true for NOx, so it is the only pollutant for which higher SU emissions are reflected in the MAERT. The emissions will depend upon how long the CCS has been shut down - the longer the shutdown period, the longer the startup period. To reflect these differences, startups were divided into three categories: a cold startup; a warm startup; and a hot startup (each dependent on a minimum downtime prior to the startup). A boiler vendor provided the emissions associated with each event and defined its own minimum downtime associated with each startup event, as presented in the two tables below, which is the basis of the BACT. Note that SO₂ (and H₂SO₄) and GHGs are not listed in the second table below since they are dependent on fuel use and therefore the SU/SD emissions will not exceed the emission rates during routine operations. <table><thead><tr><th>Startup Event</th><th>Maximum Annual Events, per Boiler (events/12-month rolling basis)</th><th>Minimum Downtime Preceding Event, per Boiler (hours/event)</th><th>Maximum Event Duration, per Boiler (minutes/ event)</th></tr></thead><tbody><tr><td>Cold SU</td><td>10</td><td>72</td><td>247</td></tr><tr><td>Warm SU</td><td>42</td><td>48</td><td>121</td></tr><tr><td>Hot SU</td><td>200</td><td>0</td><td>41</td></tr></tbody></table> <table><thead><tr><th>Startup Event</th><th colspan="4">Emissions per Event (pounds) per Boiler</th></tr><tr><th></th><th>NOx</th><th>CO</th><th>VOC</th><th>PM₁₀ / PM_{2.5}</th></tr></thead><tbody><tr><td>Cold SU</td><td>9.17</td><td>18.35</td><td>2.02</td><td>1.73</td></tr><tr><td>Warm SU</td><td>3.93</td><td>7.86</td><td>0.86</td><td>0.73</td></tr><tr><td>Hot SU</td><td>1.63</td><td>3.26</td><td>0.36</td><td>0.30</td></tr></tbody></table> CEMS are not required for the CCS boilers when they emit from their individual stacks, EPNs CCS1BLR1, CCS1BLR2, CCS2BLR1, and CCS2BLR2, during MSS events due to the limited number of hours in which they will emit from their individual stacks during such MSS events as summarized in the table above (i.e., a maximum of 263 hours of MSS activities per 12-month rolling basis per CCS boiler). However, once the CCS boilers reach steady state and are directed to the CCS absorbers, then NOx and CO CEMS are required as summarized above under EPNs CCS1 and CCS2. The RBLC searches are discussed above with the routine emissions. The TCEQ Tier I BACT for MSS activities for boilers rated greater than 40 MMBtu/hr is to minimize the duration of these MSS activities and operate the facility in accordance with best management practices and good air pollution control practices. The applicant stated they will meet Tier I BACT, as well as limiting the number of MSS as noted above. Therefore, the planned MSS activities for the four CCS boiler units meet BACT.	Startup Event	Maximum Annual Events, per Boiler (events/12-month rolling basis)	Minimum Downtime Preceding Event, per Boiler (hours/event)	Maximum Event Duration, per Boiler (minutes/ event)	Cold SU	10	72	247	Warm SU	42	48	121	Hot SU	200	0	41	Startup Event	Emissions per Event (pounds) per Boiler					NOx	CO	VOC	PM ₁₀ / PM _{2.5}	Cold SU	9.17	18.35	2.02	1.73	Warm SU	3.93	7.86	0.86	0.73	Hot SU	1.63	3.26	0.36	0.30
Startup Event	Maximum Annual Events, per Boiler (events/12-month rolling basis)		Minimum Downtime Preceding Event, per Boiler (hours/event)	Maximum Event Duration, per Boiler (minutes/ event)																																							
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Hot SU	1.63	3.26	0.36	0.30																																							
CCS1 Boiler 2 - MSS	CCS1BLR2																																										
CCS2 Boiler 1 - MSS	CCS2BLR1																																										
CCS2 Boiler 2 - MSS	CCS2BLR2																																										

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CTG Boiler	CTGBLR	A natural gas-fired CTG auxiliary boiler rated at 95.5 MMBtu/hr will be used as needed to keep the HRSGs warm during periods of project shutdown, and to provide steam to the steam turbine generators (STGs) during startups. The CTG Boiler will be limited to will be limited to 382,074 MMBtu/12-month period (based on 4,000 hours/year). BACT for each pollutant is discussed below. NOx: Emission factor of 0.01 lb/MMBtu (HHV) using a dry low NOx (DLN) burner. The TCEQ Tier I BACT for natural gas fired boilers greater than 40 MMBtu/hr is 0.01 lb/MMBtu achieved by using dry-low NOx combustors or SCR. Therefore, Tier I BACT is met. The applicant conducted RBLC searches for recently permitted boilers (NSPS Subpart Dc sized, i.e., 10-100 MMBtu/hr) at large (>100 MW) CCGT facilities and recent BACT/LAER Determinations for boilers (NSPS Subpart Db sized, i.e., > 100 MMBtu/hr) with a focus on Texas installations. These RBLC searches showed NOx emission factors of 0.0085 to 0.05 lb/MMBtu as BACT. Several of the boilers permitted with ultra-low NOx burners were located in ozone non-attainment areas and were therefore subject to LAER. The proposed BACT limit for NOx for the project's CTG auxiliary boiler is 0.01 lb/MMBtu, which is on the lower end of the range of determinations in the RBLC. CO: Emission factor of 0.037 lb/MMBtu (HHV) using good combustion practices. The TCEQ Tier I BACT for natural gas fired boilers greater than 40 MMBtu/hr is 50 ppmv at 3% O₂ achieved by good combustion practices or oxidation catalyst; note the 50 ppmv at 3% O₂ concentration converts to a CO emission factor of approximately 0.037 lb/MMBtu (HHV). The applicant's RBLC searches showed CO emission factors ranged from 0.031 to 0.08 lb/MMBtu, with the most recent BACT determination at 0.037 lb/MMBtu. These projects utilize good combustion practices to achieve these levels. The proposed BACT limit for CO for the CPV CTG auxiliary boiler is 0.037 lb/MMBtu, which is consistent with the precedents listed in the RBLC. VOC: Emission factor of 0.007 lb/MMBtu (HHV) using good combustion practices. The TCEQ Tier I BACT for natural gas fired boilers greater than 40 MMBtu/hr is good combustion practices. VOC determinations in the RBLC searches range from 0.0031 lb/MMBtu to 0.055 lb/MMBtu, with the exception of one outlier. The most stringent level of control for VOCs from a boiler is Lincoln Land Energy Center in Pawnee, Illinois at 0.0015 lb/MMBtu based on a three-hour average. Lincoln Land Energy Center does not propose any add-on controls, but plans to achieve this limit through combustion controls. The CPV project proposes to utilize good combustion controls to maintain a VOC emission limit of 0.007 lb/MMBtu, which is consistent with the precedents listed in the RBLC.
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		PM/PM₁₀/PM_{2.5}: Emission factor of 0.007 lb/MMBtu (HHV) using good combustion practices and fuel limited to pipeline quality natural gas and less than 5% opacity. The TCEQ Tier I BACT for natural gas fired boilers greater than 40 MMBtu/hr is good combustion practices and less than 5% opacity. The applicant assumed that all of the PM/PM₁₀/PM_{2.5} emitted from the boiler is conservatively assumed to be less than 2.5 microns in diameter, and, therefore, the PM, PM₁₀, and PM_{2.5} emission rates are assumed to be the same. The applicant's RBLC searches showed that PM/PM₁₀/PM_{2.5} BACT determinations range from 0.005 lb/MMBtu to 0.008 lb/MMBtu, with the exception of one outlier. The most stringent level of control identified for a natural gas-fired boiler is 0.00181 lb/MMBtu for the Allegheny Energy Center in West Newton, Pennsylvania utilizing good combustion practices. The applicant stated that this limit is considered an unrealistically low-emissions guarantee for a boiler of this type because of the uncertainty and variability with available PM/PM₁₀/PM_{2.5} test methods, and the risk of artifact emissions resulting in a tested exceedance. All new natural gas-fired boilers that are properly operated are expected to have intrinsically low PM/PM₁₀/PM_{2.5} emissions. In addition, the application stated that the Allegheny Energy Center project has recently been cancelled and therefore not actually implemented. The CPV project proposes to combust natural gas with good combustion controls to maintain a PM/PM₁₀/PM_{2.5} emission limit of 0.007 lb/MMBtu, which is consistent with the precedents listed in the RBLC. SO₂: The applicant assumed 100% molar conversion of natural gas sulfur to SO₂, conservatively not reducing SO₂ emissions due to conversion to H₂SO₄. BACT was represented as good combustion practices and firing only pipeline quality natural gas with no more than 0.5 grains sulfur/100 dscf natural gas fuel, which results in a corresponding SO₂ emission factor of 0.0014 lb/MMBtu (HHV). The TCEQ Tier I BACT for natural gas fired boilers greater than 40 MMBtu/hr is firing pipeline quality natural gas and good combustion practices. The SO₂ limits in the RBLC searches ranged from 0.0011 lb/MMBtu to 0.002 lb/MMBtu. A project's SO₂ and H₂SO₄ emissions can vary greatly depending on the maximum sulfur content of the fuel and assumptions related to conversion of SO₂ to H₂SO₄, which is indicated by the wide range of emission limits shown in the RBLC. The CPV project proposes to combust natural gas with a maximum sulfur content of 0.5 grains sulfur/100 dscf natural gas with an SO₂ emission factor of 0.0014 lb/MMBtu, which is consistent with the precedents listed in the RBLC. H₂SO₄: The applicant assumed 100% molar conversion of natural gas sulfur to SO₂ and 10% molar conversion of SO₂ to SO₃ (conservatively not reducing the SO₂ emissions) and 100% conversion of SO₃ to H₂SO₄. BACT was represented as good combustion practices firing only pipeline quality natural gas with no
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		more than 0.5 grains sulfur/100 dscf fuel, which results in a corresponding H₂SO₄ emission factor of 0.00021 lb/MMBtu (HHV). The TCEQ Tier I BACT for natural gas fired boilers greater than 40 MMBtu/hr is firing pipeline quality natural gas and good combustion practices. For H₂SO₄, the levels of control in the RBLC searches ranged from 0.00011 to 0.0018 lb/MMBtu. A project's SO₂ and H₂SO₄ emissions can vary greatly depending on the maximum sulfur content of the fuel and assumptions related to conversion of SO₂ to H₂SO₄, which is indicated by the wide range of emission limits shown in the RBLC. The CPV project proposes to combust natural gas with a maximum sulfur content of 0.5 grains sulfur/100 dscf natural gas with an H₂SO₄ emission factor of 0.00021 lb/MMBtu, which is consistent with the precedents listed in the RBLC. Pb: The applicant proposed combustion of natural gas and a lead emission factor of 4.83E-07 lb/MMBtu taken from Table 1.4-2 of AP-42 dated July 1998. The lead emission rates are less than 0.01 lb/hr and 0.01 tpy from the CTG auxiliary boiler unit. HAPs: Application of good combustion practices used to meet BACT for VOC as discussed above will also limit the HAP emissions. Total HAP emissions are represented as 0.35 tpy from the auxiliary boiler. CO₂e: The CTG auxiliary boiler will fire natural gas, which is the lowest carbon fuel available. Therefore, formation of CO₂ from combustion of the fuel will be minimized. The represented natural gas combustion emission factors taken from Tables C-1 and C-2 of 40 CFR 98 are 117.00 lb/MMBtu for CO₂, 2.20E-03 lb/MMBtu for CH₄, and 2.20E-04 lb/MMBtu for N₂O, which convert to an overall CO₂e emission factor of 117.12 lb/MMBtu (all HHV). Good operating and maintenance practices for the CTG auxiliary boiler include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintaining the proper air/fuel ratio so that sufficient oxygen is provided to promote complete combustion of the fuel while at the same time preventing introduction of more air than is necessary into the boiler. The CTG auxiliary boiler will fire natural gas with good combustion control to meet BACT. The RBLC searches for GHG showed that the control technologies are the use of low carbon fuels and good operating and maintenance procedures. MSS: Planned MSS emissions are not being authorized for the CTG auxiliary boiler. The proposed BACT for the CTG auxiliary boiler meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Fuel Heater	FHEAT	A natural gas-fired fuel heater rated at 16 MMBtu/hr will be used to regulate the temperature of the fuel for optimal CCGTs'

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		performance. The fuel gas heater is being permitted at 8,760 hours per year. BACT for each pollutant is discussed below. NOx: Emission factor of 0.037 lb/MMBtu (HHV) using a low NOx burner based on vendor data. The TCEQ Tier I BACT for natural gas fired heaters less than 40 MMBtu/hr is the use of burners with the best NOx performance given the burner configuration and gaseous fuel used and justification if the NOx emission factor is greater than 0.01 lb/MMBtu. Based on the small size of the fuel heater (16 MMBtu/hr) and the location of the project in an attainment area, the applicant justified the proposed low NOx burner meeting 0.037 lb/MMBtu as meeting BACT. Additionally, the applicant justified the proposed BACT level with RBLC searches for miscellaneous boilers, furnaces, and heaters (RBLC process code 19.600) and commercial / institutional sized boilers combusting natural gas (RBLC process code 13.310) that showed NOx emission factors ranging from 0.011 to 0.05 lb/MMBtu, with several using low NOx burners at 0.037 lb/MMBtu. The applicant's review of the heaters permitted with ultra-low NOx burners indicate that they were all located in non-attainment areas for ozone and several were subject to LAER, which does not apply to the subject site. The most recent Texas RBLC entry for a facility located in an attainment area for ozone (Nacero Penwell Facility) has a NOx limit of 0.03 lb/MMBtu, just slightly less than the proposed BACT. CO: Emission factor of 0.037 lb/MMBtu (HHV) based on vendor data using good combustion practices. The TCEQ Tier I BACT for natural gas fired heaters less than 40 MMBtu/hr is 50 ppmv at 3% O₂, which converts to a CO emission factor of approximately 0.037 lb/MMBtu (HHV). The applicant's RBLC searches showed CO emission factors ranged from 0.037 lb/MMBtu (50 ppmv at 3% O₂) to 0.087 lb/MMBtu, with the most recent BACT determination at 50 ppmv at 3% O₂ (which converts to approximately 0.037 lb/MMBtu). The proposed BACT limit for CO for the CPV fuel heater is 0.037 lb/MMBtu, which is consistent with the precedents listed in the RBLC. VOC: Emission factor of 0.025 lb/MMBtu (HHV) based on vendor data using good combustion practices. The TCEQ Tier I BACT for natural gas fired heaters less than 40 MMBtu/hr is firing pipeline quality natural gas and good combustion practices. The VOC determinations in the RBLC searches range from 0.025 lb/MMBtu to 0.057 lb/MMBtu. The CPV project proposes to utilize good combustion controls to maintain a VOC emission limit of 0.025 lb/MMBtu, which is consistent with the precedents listed in the RBLC. PM/PM₁₀/PM_{2.5}: Emission factor of 0.0048 lb/MMBtu (HHV) based on vendor data using good combustion practices and fuel limited to pipeline quality natural gas, and the opacity will not exceed 5%. The TCEQ Tier I BACT for natural gas fired heaters less than 40
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		MMBtu/hr is a maximum opacity 5%. The applicant assumed that all of the PM/PM₁₀/PM_{2.5} emitted from the heater is conservatively assumed to be less than 2.5 microns in diameter, and, therefore, the PM, PM₁₀, and PM_{2.5} emission rates are assumed to be the same. The applicant's RBLC searches showed that PM/PM₁₀/PM_{2.5} BACT determinations range from 0.007 lb/MMBtu to 0.008 lb/MMBtu. The CPV project proposes to combust natural gas with good combustion controls to maintain a PM/PM₁₀/PM_{2.5} emission limit of 0.0048 lb/MMBtu, which is lower than the precedents listed in the RBLC. SO₂: The applicant assumed 100% molar conversion of natural gas sulfur to SO₂, conservatively not reducing SO₂ emissions due to conversion to H₂SO₄. BACT was represented as good combustion practices and firing only pipeline quality natural gas with no more than 0.5 grains sulfur/100 dscf natural gas fuel, which results in a corresponding SO₂ emission factor of 0.0014 lb/MMBtu (HHV). The TCEQ Tier I BACT for natural gas fired heaters less than 40 MMBtu/hr is firing low sulfur fuel and good combustion practices. The SO₂ limits in the RBLC searches showed the sulfur contents ranged from 0.2 grains sulfur/100 dscf to 5 grains sulfur/100 dscf. The CPV project proposes to combust natural gas with a maximum sulfur content of 0.5 grains sulfur/100 dscf natural gas with an SO₂ emission factor of 0.0014 lb/MMBtu, which is consistent with the precedents listed in the RBLC. H₂SO₄: The applicant assumed 100% molar conversion of natural gas sulfur to SO₂ and 10% molar conversion of SO₂ to SO₃ (conservatively not reducing the SO₂ emissions) and 100% conversion of SO₃ to H₂SO₄. BACT was represented as good combustion practices firing only pipeline quality natural gas with no more than 0.5 grains sulfur/100 dscf fuel, which results in a corresponding H₂SO₄ emission factor of 0.00021 lb/MMBtu (HHV). The TCEQ Tier I BACT for natural gas fired heaters less than 40 MMBtu/hr is not specified. For H₂SO₄, the limits in the RBLC searches showed the sulfur contents ranged from 0.2 grains sulfur/100 dscf to 5 grains sulfur/100 dscf. A project's SO₂ and H₂SO₄ emissions can vary greatly depending on the maximum sulfur content of the fuel and assumptions related to conversion of SO₂ to H₂SO₄. The CPV project proposes to combust natural gas with a maximum sulfur content of 0.5 grains sulfur/100 dscf natural gas with an H₂SO₄ emission factor of 0.00021 lb/MMBtu, which is consistent with the precedents listed in the RBLC. Pb: The applicant proposed combustion of natural gas and a lead emission factor of 4.83E-07 lb/MMBtu taken from Table 1.4-2 of AP-42 dated July 1998. The lead emission rates are less than 0.01 lb/hr and 0.01 tpy from the fuel heater unit.
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		HAPs: Application of good combustion practices used to meet BACT for VOC as discussed above will also limit the HAP emissions. Total HAP emissions are represented as 0.13 tpy from the fuel gas heater. CO₂e: The fuel heater will fire pipeline quality natural gas, which is the lowest carbon fuel available. Therefore, formation of CO₂ from combustion of the fuel will be minimized. The represented natural gas combustion emission factors taken from Tables C-1 and C-2 of 40 CFR 98 are 117.00 lb/MMBtu for CO₂, 2.20E-03 lb/MMBtu for CH₄, and 2.20E-04 lb/MMBtu for N₂O, which convert to an overall CO₂e emission factor of 117.12 lb/MMBtu (HHV). Good operating and maintenance practices for the heater include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintaining the proper air/fuel ratio so that sufficient oxygen is provided to promote complete combustion of the fuel while at the same time preventing introduction of more air than is necessary into the heater. The heater will fire natural gas with good combustion control to meet BACT. The RBLC searches for GHG showed that no capture systems are utilized, and the previous determinations were based on a CO₂e emission factor of 117.1 lb/MMBtu, consistent with the proposed project. MSS: Separate planned MSS emissions are not being authorized for the fuel heater. The applicant represented that they will minimize the duration of MSS activities and operate with best management practice. The proposed BACT for the fuel heater meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
CTG Em Gen	CTGEG	Two ultra-low sulfur diesel fired emergency generators each rated at approximately 2,000 kW (2,682 hp) will be used to provide on-site emergency power capabilities independent of the utility grid. One engine provides ancillary support to the generating facility and the other provides support to the CCS. Each diesel generator engine is being permitted at 100 hours per rolling 12-month period. The TCEQ Tier I BACT for emergency diesel fired engines is meeting the requirements of 40 CFR Part 60, Subpart IIII, firing ultra-low sulfur diesel fuel (no more than 15 ppmw sulfur), limited to 100 hrs/yr of non-emergency operation, and having a non-resettable runtime meter. Additionally, for particulate matter, Tier I BACT is no visible emissions leaving the property, with visible emissions determined by a standard of no visible emissions exceeding 30 seconds in duration in any six-minute period as determined using EPA Method 22 or equivalent. The two emergency generator engines will meet the above listed Tier I BACT guidelines and employ good combustion design. The emission factors that were represented in the emission
CCS Em Gen	CCSEG	

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		calculations to meet NSPS Subpart IIII and therefore BACT are summarized below. The engines each have a displacement of less than 30 liters per cylinder. The NO_x, CO, VOC, and PM emission factors are specified in NSPS Subpart IIII in 40 CFR 60.4205(b), which refers to 40 CFR 60.4202(a)(2), which refers to Table 2 of 40 CFR part 1039, Appendix I. NO_x: 4.8 g/hp-hr (converted from 6.4 g/kW-hr listed in the rule). This emission factor is represented in the cited rule as NO_x + NMHC and the applicant conservatively assumed the NO_x + NMHC as 100% NO_x. CO: 2.61 g/hp-hr (converted from 3.5 g/kW-hr listed in the rule). VOC: 0.32 g/hp-hr (converted from 0.000705 lb/hp-hr), based on information from the vendor, who used emission factor from AP-42 Table 3.4-1. PM/PM₁₀/PM_{2.5}: 0.15 g/hp-hr (converted from 0.2 g/kW-hr listed in the rule). The rule represents only PM, but the applicant assumed PM₁₀ and PM_{2.5} equal total PM. SO₂: 0.0055 g/hp-hr. This emission factor is not specified in Subpart IIII, but rather calculated from the ultra-low sulfur diesel sulfur content of 15 ppmw sulfur and assuming 100% conversion of fuel sulfur to SO₂. H₂SO₄: 0.00084 g/hp-hr. This emission factor is not specified in Subpart IIII, but rather calculated by the applicant assuming 100% molar conversion of sulfur in the diesel fuel to SO₂ and 10% molar conversion of SO₂ to SO₃ (conservatively not reducing the SO₂ emissions) and 100% conversion of SO₃ to H₂SO₄. HAPs: Meeting BACT for VOC as discussed above will also limit the HAP emissions. Total HAP emissions are represented at less than 0.01 tpy from each emergency generator engine (there are a total of two emergency generator engines as noted above). CO_{2e}: The emergency generator engines will fire diesel fuel, which will meet BACT by using good combustion practices. The represented diesel combustion emission factors taken from Tables C-1 and C-2 of 40 CFR 98 are 73.96 kg/MMBtu for CO₂, 3.00E-03 kg/MMBtu for CH₄, and 6.00E-04 kg/MMBtu for N₂O, which convert to an overall CO_{2e} emission factor of 74.21 kg/MMBtu (HHV) or 163.6 lb/MMBtu (HHV). MSS: Separate planned MSS emissions are not being authorized for the emergency generator engines. The applicant represented that they will minimize the duration and occurrence of MSS activities. The applicant's RBLC searches showed the proposed BACT is consistent with the recent determinations listed in the RBLC.
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		The proposed BACT for the emergency generator engines meet the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Fire Pump	FPUMP	An ultra-low sulfur diesel operated fire pump engine rated at approximately 282 brake hp (210 kW) will be used to provide on-site firefighting capabilities and will be shared by the CCGT and the CCS. The pump will typically operate only for maintenance and readiness testing, with less frequent operation expected for actual emergencies. Non-emergency operation of the fire pump is being permitted at 100 hours per rolling 12-month period. The TCEQ Tier I BACT for emergency diesel fired engines is meeting the requirements of 40 CFR Part 60, Subpart IIII, firing ultra-low sulfur diesel fuel (no more than 15 ppmw sulfur), limited to 100 hrs/yr of non-emergency operation, and having a non-resettable runtime meter. Additionally, for particulate matter, Tier I BACT is no visible emissions leaving the property, with visible emissions determined by a standard of no visible emissions exceeding 30 seconds in duration in any six-minute period as determined using EPA Method 22 or equivalent. The fire pump engine will meet the above listed Tier I BACT guidelines and employ good combustion design. The emission factors that were represented in the emission calculations to meet NSPS Subpart IIII and therefore BACT are summarized below. The engine has a displacement of less than 30 liters per cylinder and has a model year after 2008. The NO_x, CO, VOC, and PM emission factors are defined in NSPS Subpart IIII in 40 CFR 60.4205(c), which refers to Table 4 of 40 CFR Subpart IIII. NO_x: 3.0 g/hp-hr (4.0 g/kW-hr). This emission factor is represented in the cited rule as NO_x + NMHC and the applicant conservatively assumed the NO_x + NMHC as 100% NO_x. CO: 2.6 g/hp-hr (3.5 g/kW-hr). VOC: 0.40 g/hp-hr, based on information from the vendor. PM/PM₁₀/PM_{2.5}: 0.15 g/hp-hr (0.20 g/kW-hr). The rule represents only PM, but the applicant assumed PM₁₀ and PM_{2.5} equal total PM. SO₂: 0.0055 g/hp-hr. This emission factor is not specified in Subpart IIII, but rather calculated from the ultra-low sulfur diesel sulfur content of 15 ppmw sulfur and assuming 100% conversion of fuel sulfur to SO₂. H₂SO₄: 0.00084 g/hp-hr. This emission factor is not specified in Subpart IIII, but rather calculated by the applicant assuming 100% molar conversion of sulfur in the diesel fuel to SO₂ and 10% molar conversion of SO₂ to SO₃ (conservatively not reducing the SO₂ emissions) and 100% conversion of SO₃ to H₂SO₄.

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		HAPs: Meeting BACT for VOC as discussed above will also limit the HAP emissions. Total HAP emissions are represented at less than 0.01 tpy from the fire pump engine. CO₂e: The fire pump engine will fire diesel fuel, which will meet BACT by using good combustion practices. The represented diesel combustion emission factors taken from Tables C-1 and C-2 of 40 CFR 98 are 73.96 kg/MMBtu for CO₂, 3.00E-03 kg/MMBtu for CH₄, and 6.00E-04 kg/MMBtu for N₂O, which convert to an overall CO₂e emission factor of 74.21 kg/MMBtu (HHV) or 163.6 lb/MMBtu (HHV). MSS: Separate planned MSS emissions are not being authorized for the fire pump engine. The applicant represented that they will minimize the duration and occurrence of MSS activities. The applicant's RBLC searches showed the proposed BACT is consistent with the recent determinations listed in the RBLC. The proposed BACT for the fire pump engine meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Cooling Tower	CTWR	A cooling tower associated with the carbon capture system will be an 8-cell mechanical draft cooling tower. PM – The particulate matter emissions were estimated assuming a maximum total dissolved solids (TDS) content of 12,000 ppm, a maximum cooling water circulation rate of 111,630 gallons per minute, and drift loss rate of 0.0005% using drift eliminators in each cooling tower cell. The PM₁₀ emission rates were calculated following an AWMA presentation titled "Calculating Realistic PM₁₀ Emissions from Cooling Towers", #216, Orlando Florida June 2001, consistent with TCEQ air permitting policies. The PM_{2.5} emission rate was conservatively assumed to be the same as the PM₁₀ emission rate. The TCEQ Tier I BACT guideline for cooling towers is a drift loss less than 0.001% achieved by drift eliminators. Therefore, the cooling tower meets Tier I BACT. The applicant submitted RBLC searches for PM/PM₁₀/PM_{2.5} from cooling towers which showed BACT as using drift eliminators achieving 0.0005% to 0.0010% drift loss as BACT. VOC – The applicant did not represent any VOC emissions from the cooling tower, as they stated that any incidental VOC that may be directed to the cooling tower has been assumed to be emitted from the CCS absorber stacks. Therefore, SC No. 24.F of the permit states VOC emissions from the cooling tower are not authorized and requires monthly VOC cooling water monitoring to indicate faulty heat exchange equipment. The monthly VOC sampling may be reduced to at least once every six months if the monitoring detects no VOC in the cooling tower water for 12 consecutive months, but can revert back to monthly sampling if VOC is measured by the sampling.

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		The proposed BACT for the cooling tower meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Solvent Storage Tanks	TK1, TK2, TK3, TK4	Four identical vertical fixed roof tanks painted white with a nominal capacity of 450,000 gallons per tank that are proposed to store CCS Solvent (as MEA) with a maximum hourly fill rate of 75,000 gallons/hour per tank, a maximum annual throughput of 100,800,000 gallons/year per tank, and a maximum VOC vapor pressure of approximately 0.0133 psia at 95°F. The TCEQ's Tier I BACT guidelines for fixed roof storage tanks with a capacity less than 25,000 gal or a true vapor pressure less than 0.50 psia is submerged fill and uninsulated exterior surfaces exposed to the sun that are white or aluminum in color. The TCEQ's Tier I BACT guideline for planned MSS activities is to send liquid to a covered vessel when draining; if there is any standing liquid within the tank, and the tank is opened to the atmosphere or ventilated, the vapor stream must be controlled until there is no standing liquid or the VOC vapor pressure is less than 0.02 psia; control device must meet BACT. The tanks will meet the Tier I BACT guidelines. The applicant submitted RBLC searches for VOC storage tanks (RBLC process code 42.009) and fixed roof petroleum tanks (RBLC process code 42.005) that showed that recent RBLC determinations are less stringent or consistent with the proposed BACT (i.e., were white, used submerged fill, and/or good tank design). Those entries that are more stringent (i.e., require add-on control) are LAER determinations for sources in nonattainment areas that does not apply to the proposed project. The proposed BACT for tanks meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Fresh Solvent Tanks	TK5, TK6	Two identical vertical fixed roof tanks painted white with a nominal capacity of 95,000 gallons per tank that are proposed to store CCS Solvent (as MEA) with a maximum hourly fill rate of 11,875 gallons/hour per tank, a maximum annual throughput of 396,825 gallons/year per tank, and a maximum VOC vapor pressure of approximately 0.0133 psia at 95°F. The TCEQ's Tier I BACT guidelines for fixed roof storage tanks with a capacity less than 25,000 gal or a true vapor pressure less than 0.50 psia is submerged fill and uninsulated exterior surfaces exposed to the sun that are white or aluminum in color. The TCEQ's Tier I BACT guideline for planned MSS activities is to send liquid to a covered vessel when draining; if there is any standing liquid within the tank, and the tank is opened to the atmosphere or ventilated, the vapor stream must be controlled until there is no standing liquid or the VOC vapor pressure is less than 0.02 psia; control device must meet BACT. The tanks will meet the Tier I BACT guidelines.

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		The applicant submitted RBLC searches for VOC storage tanks (RBLC process code 42.009) and fixed roof petroleum tanks (RBLC process code 42.005) that showed that recent RBLC determinations are less stringent or consistent with the proposed BACT (i.e., were white, used submerged fill, and/or good tank design). Those entries that are more stringent (i.e., require add-on control) are LAER determinations for sources in nonattainment areas that does not apply to the proposed project. The proposed BACT for tanks meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Reclaimed Waste Tanks	TK7, TK8	Two identical horizontal fixed roof tanks painted white with a nominal capacity of 24,000 gallons per tank that are proposed to store Reclaimed Waste (as MEA) with a maximum hourly fill rate of 1,500 gallons/hour per tank, a maximum annual throughput of 1,248,000 gallons/year per tank, and a maximum VOC vapor pressure of approximately 0.0133 psia at 95°F. The TCEQ's Tier I BACT guidelines for fixed roof storage tanks with a capacity less than 25,000 gal or a true vapor pressure less than 0.50 psia is submerged fill and uninsulated exterior surfaces exposed to the sun that are white or aluminum in color. The TCEQ's Tier I BACT guideline for planned MSS activities is to send liquid to a covered vessel when draining; if there is any standing liquid within the tank, and the tank is opened to the atmosphere or ventilated, the vapor stream must be controlled until there is no standing liquid or the VOC vapor pressure is less than 0.02 psia; control device must meet BACT. The tanks will meet the Tier I BACT guidelines. The applicant submitted RBLC searches for VOC storage tanks (RBLC process code 42.009) and fixed roof petroleum tanks (RBLC process code 42.005) that showed that recent RBLC determinations are less stringent or consistent with the proposed BACT (i.e., were white, used submerged fill, and/or good tank design). Those entries that are more stringent (i.e., require add-on control) are LAER determinations for sources in nonattainment areas that does not apply to the proposed project. The proposed BACT for tanks meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
TEG Storage Tanks	TK9, TK10	Two identical horizontal fixed roof tanks painted white with a nominal capacity of 10,000 gallons per tank that are proposed to store triethylene glycol with a maximum hourly fill rate of 10,000 gallons/hour per tank, a maximum annual throughput of 43,000 gallons/year per tank, and a maximum VOC vapor pressure of approximately 0.0001 psia at 95°F. The TCEQ's Tier I BACT guidelines for fixed roof storage tanks with a capacity less than 25,000 gal or a true vapor pressure less than 0.50 psia is submerged fill and uninsulated exterior surfaces

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		exposed to the sun that are white or aluminum in color. The TCEQ's Tier I BACT guideline for planned MSS activities is to send liquid to a covered vessel when draining; if there is any standing liquid within the tank, and the tank is opened to the atmosphere or ventilated, the vapor stream must be controlled until there is no standing liquid or the VOC vapor pressure is less than 0.02 psia; control device must meet BACT. The tanks will meet the Tier I BACT guidelines. The applicant submitted RBLC searches for VOC storage tanks (RBLC process code 42.009) and fixed roof petroleum tanks (RBLC process code 42.005) that showed that recent RBLC determinations are less stringent or consistent with the proposed BACT (i.e., were white, used submerged fill, and/or good tank design). Those entries that are more stringent (i.e., require add-on control) are LAER determinations for sources in nonattainment areas that does not apply to the proposed project. The proposed BACT for tanks meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
CTG EG Diesel Storage Tanks	TK11, TK12	Two identical horizontal fixed roof tanks painted white with a nominal capacity of 3,733 gallons per tank that are proposed to store diesel fuel with a maximum hourly fill rate of 3,733 gallons/hour per tank, a maximum annual throughput of 14,910 gallons/year per tank, and a maximum VOC vapor pressure of approximately 0.0193 psia at 95°F. The TCEQ's Tier I BACT guidelines for fixed roof storage tanks with a capacity less than 25,000 gal or a true vapor pressure less than 0.50 psia is submerged fill and uninsulated exterior surfaces exposed to the sun that are white or aluminum in color. The TCEQ's Tier I BACT guideline for planned MSS activities is to send liquid to a covered vessel when draining; if there is any standing liquid within the tank, and the tank is opened to the atmosphere or ventilated, the vapor stream must be controlled until there is no standing liquid or the VOC vapor pressure is less than 0.02 psia; control device must meet BACT. The tanks will meet the Tier I BACT guidelines. The applicant submitted RBLC searches for VOC storage tanks (RBLC process code 42.009) and fixed roof petroleum tanks (RBLC process code 42.005) that showed that recent RBLC determinations are less stringent or consistent with the proposed BACT (i.e., were white, used submerged fill, and/or good tank design). Those entries that are more stringent (i.e., require add-on control) are LAER determinations for sources in nonattainment areas that does not apply to the proposed project. The proposed BACT for tanks meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Emergency FP	TK13	Horizontal fixed roof tank painted white with a nominal capacity of 181

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Diesel Storage Tank		gallons that is proposed to store diesel fuel with a maximum hourly fill rate of 181 gallons/hour, a maximum annual throughput of 1,370 gallons/year, and a maximum VOC vapor pressure of approximately 0.0193 psia at 95°F. The TCEQ's Tier I BACT guidelines for fixed roof storage tanks with a capacity less than 25,000 gal or a true vapor pressure less than 0.50 psia is submerged fill and uninsulated exterior surfaces exposed to the sun that are white or aluminum in color. The TCEQ's Tier I BACT guideline for planned MSS activities is to send liquid to a covered vessel when draining; if there is any standing liquid within the tank, and the tank is opened to the atmosphere or ventilated, the vapor stream must be controlled until there is no standing liquid or the VOC vapor pressure is less than 0.02 psia; control device must meet BACT. The tank will meet the Tier I BACT guidelines. The applicant submitted RBLC searches for VOC storage tanks (RBLC process code 42.009) and fixed roof petroleum tanks (RBLC process code 42.005) that showed that recent RBLC determinations are less stringent or consistent with the proposed BACT (i.e., were white, used submerged fill, and/or good tank design). Those entries that are more stringent (i.e., require add-on control) are LAER determinations for sources in nonattainment areas that does not apply to the proposed project. The proposed BACT for tanks meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Amine Drain Vessels	TK14, TK15	Two identical horizontal fixed roof tanks painted white with a nominal capacity of 25,000 gallons per tank that are proposed to store CCS Solvent (as MEA) with a maximum hourly fill rate of 1,563 gallons/hour per tank, a maximum annual throughput of 1,300,000 gallons/year per tank, and a maximum VOC vapor pressure of approximately 0.0133 psia at 95°F. The TCEQ's Tier I BACT guidelines for fixed roof storage tanks with a capacity less than 25,000 gal or a true vapor pressure less than 0.50 psia is submerged fill and uninsulated exterior surfaces exposed to the sun that are white or aluminum in color. The TCEQ's Tier I BACT guideline for planned MSS activities is to send liquid to a covered vessel when draining; if there is any standing liquid within the tank, and the tank is opened to the atmosphere or ventilated, the vapor stream must be controlled until there is no standing liquid or the VOC vapor pressure is less than 0.02 psia; control device must meet BACT. The tanks will meet the Tier I BACT guidelines. The applicant submitted RBLC searches for VOC storage tanks (RBLC process code 42.009) and fixed roof petroleum tanks (RBLC process code 42.005) that showed that recent RBLC determinations are less stringent or consistent with the proposed BACT (i.e., were white, used submerged fill, and/or good tank design). Those entries that are more stringent (i.e., require add-on

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		control) are LAER determinations for sources in nonattainment areas that does not apply to the proposed project. The proposed BACT for tanks meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
TEG Drain Vessel	TK16, TK17	Two identical horizontal fixed roof tanks painted white with a nominal capacity of 10,000 gallons per tank that are proposed to store triethylene glycol with a maximum hourly fill rate of 10,000 gallons/hour per tank, a maximum annual throughput of 43,000 gallons/year per tank, and a maximum VOC vapor pressure of approximately 0.0001 psia at 95°F. The TCEQ's Tier I BACT guidelines for fixed roof storage tanks with a capacity less than 25,000 gal or a true vapor pressure less than 0.50 psia is submerged fill and uninsulated exterior surfaces exposed to the sun that are white or aluminum in color. The TCEQ's Tier I BACT guideline for planned MSS activities is to send liquid to a covered vessel when draining; if there is any standing liquid within the tank, and the tank is opened to the atmosphere or ventilated, the vapor stream must be controlled until there is no standing liquid or the VOC vapor pressure is less than 0.02 psia; control device must meet BACT. The tanks will meet the Tier I BACT guidelines. The applicant submitted RBLC searches for VOC storage tanks (RBLC process code 42.009) and fixed roof petroleum tanks (RBLC process code 42.005) that showed that recent RBLC determinations are less stringent or consistent with the proposed BACT (i.e., were white, used submerged fill, and/or good tank design). Those entries that are more stringent (i.e., require add-on control) are LAER determinations for sources in nonattainment areas that does not apply to the proposed project. The proposed BACT for tanks meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Water Evaporators	WE	Mechanical evaporators will be used to enhance the existing natural evaporation in the evaporation ponds which will consist of five land-based evaporators (four operating and one backup). These units operate by pumping feed water from the pond and forcing it through spiral nozzles via compressed air. Some of the water droplets drift while the rest will fall back to the pond. The drifting droplets that do not fall back into the ponds and are released to the atmosphere contain dissolved solids that form particulates when the droplets evaporate. Therefore, the water evaporators may be a fugitive source of particulate matter (PM/PM₁₀/PM_{2.5}) emissions. Each of the four operating evaporators will have a maximum feed rate of 600 gallons/minute. The maximum total dissolved solids (TDS) concentration is 15,000 ppm. The evaporators are being permitted for a maximum of 2,500 hours per year per evaporator. The PM/PM₁₀/PM_{2.5} emission rates were estimated using test data presented in "Emission Factor Development for Mechanical

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		Evaporators” by Trinity Consultants, 2017. There is no published TCEQ Tier I BACT for the mechanical evaporators. The applicant proposed good process control to minimize water feed rate, operating the evaporators only when climatic conditions are appropriate, annual water evaporator inspections, and operation and maintenance consistent with manufacturer requirements. The applicant searched the RBLC for process code 99.999 for other miscellaneous sources. Their search excluded cooling towers, which are not considered representative of the mechanical evaporators proposed for the project. Only one facility was found in the RBLC with mechanical evaporators. An additional permit was identified by the applicant for Materion Natural Resources, which was not included in the RBLC. The BACT for these two projects are to use good operating practices, reduce plume loft, minimize atmospheric residence time, and minimize plume drift to reduce particle settling outside the pond boundary for Materion and follow manufacturer specifications and quarterly inspections of spray nozzles for the project listed in the RBLC (Tucson Electric Power Springerville Generating Station). An annual inspection of the water evaporators is being included in SC No. 25.B based on the annual inspection requirement included in the TCEQ boilerplate language for annual inspections of cooling tower drift eliminators. The proposed emissions are 2.52 lb/hr and 3.15 tpy of PM, 2.52 lb/hr and 3.15 tpy of PM₁₀, and 1.15 lb/hr and 1.44 tpy of PM_{2.5}. BACT for the mechanical evaporators was deemed acceptable.
Solvent Leaks	SOLVFUG	Equipment leak fugitives were estimated using the SOCM1 without ethylene average emission factors and the selected LDAR control factors. The emissions from this fugitive EPN consist of VOC emissions, specifically monoethanolamine (MEA). The TCEQ Tier I BACT guidelines for equipment leak fugitives are the following: • Uncontrolled VOC emissions < 10 tpy: no control. • 10 tpy < uncontrolled VOC emissions < 25 tpy: 28M leak detection and repair program. 75% credit for 28M. • Uncontrolled VOC emissions > 25 tpy: 28VHP leak detection and repair program. 97% credit for valves, 85% for pumps and compressors. The uncontrolled VOC emissions from the proposed project exceed 25 tpy and therefore the 28VHP LDAR program will be used to meet Tier I BACT. The applicant submitted RBLC searches that showed that previous BACT determinations were leak detection and repair programs that meet 40 CFR 63 Subparts H or UU, 40 CFR 60 Subparts YY or VVa, or the TCEQ 28PI, 28PET, 28VHP / 28CNTA, 28VHP /

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		28CNTQ, or 28VHP LDAR programs. The 28LAER LDAR program was also listed in the RBLC, but those listings were for LAER determinations rather than PSD or were located in nonattainment areas, which do not apply to the proposed project. The proposed BACT for equipment leak fugitives under EPN SOLVFUG meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Ammonia Leaks	NH3FUG	Ammonia service equipment leak fugitives were estimated using the SOCM without ethylene average emission factors and the selected LDAR control factors. The only pollutant emitted from this fugitive EPN is ammonia. NH₃: The TCEQ Tier I BACT for ammonia fugitive emissions is conducting audio, visual, and olfactory (AVO) inspections twice per shift and taking appropriate credit for the AVO program. The applicant proposed to implement the 28AVO LDAR program for the ammonia service fugitives that includes the AVO inspections twice per shift, which meets TCEQ Tier I BACT. The applicant's RBLC search also showed that the 28AVO program has been used to meet BACT for fugitive emissions.
Methane Leaks	NGFUG	Equipment leak fugitives were estimated using the Oil and Gas Production Operation average emission factors and the selected LDAR control factors. The emissions from this fugitive EPN primarily consist of CH₄ and CO₂, and small quantities of VOC emissions. The TCEQ Tier I BACT guidelines for equipment leak fugitives are the following: • Uncontrolled VOC emissions < 10 tpy: no control. • 10 tpy < uncontrolled VOC emissions < 25 tpy: 28M leak detection and repair program. 75% credit for 28M. • Uncontrolled VOC emissions > 25 tpy: 28VHP leak detection and repair program. 97% credit for valves, 85% for pumps and compressors. The uncontrolled VOC emissions from the proposed project exceed 25 tpy and therefore the 28VHP LDAR program will be used to meet Tier I BACT. Note that the fugitive emissions were calculated assuming speciation of the streams as mostly non-VOCs, represented in the emission calculations as 94 weight % CH₄, 5 weight % CO₂, and 1 weight % VOC, but the 28VHP program is considered acceptable as BACT due to treating methane and VOC as using similar approaches to reducing fugitive emissions. The applicant submitted RBLC searches that showed that previous BACT determinations were leak detection and repair programs that meet 40 CFR 63 Subparts H or UU, 40 CFR 60 Subparts YY or VVa, or the TCEQ 28PI, 28PET, 28VHP / 28CNTA, 28VHP / 28CNTQ, or 28VHP LDAR programs. The 28LAER LDAR program was also listed in the RBLC, but those listings were for

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		LAER determinations rather than PSD or were located in nonattainment areas, which do not apply to the proposed project. The proposed BACT for equipment leak fugitives under EPN NGFUG meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Sulfur Hexafluoride (SF ₆) Leaks	SF6FUG	The circuit breakers associated with the proposed generating facility will be insulated with Sulfur Hexafluoride (SF₆), which is a colorless, odorless, non-flammable gas with an extremely stable molecular structure. The unique chemical properties of SF₆ make it an efficient electrical insulator. SF₆ is only used in sealed and safe systems, which under normal circumstances do not leak gas. However, there is a potential for some leakage of SF₆, which is a greenhouse gas with a global warming potential of 22,800 as specified in Table A-1 of 40 CFR 98. Based on a maximum capacity of the circuit breakers of 1,601 pounds of SF₆ and an assumed maximum annual leak rate of 0.5 weight %, the calculated SF₆ allowable emission rate is 0.0040 tpy SF₆ or 91.26 tpy as CO₂e. The TCEQ does not specify Tier I BACT for SF₆ emissions from circuit breakers. However, the applicant proposed to use state-of-the-art, totally enclosed pressurized SF₆ circuit breakers (leak-tight closed systems) with leak detection including a density alarm that provides a warning when SF₆ has escaped and maximum annual leak rate of 0.5 weight %, which is consistent with BACT for other similar recently issued projects (see, for example, TCEQ Project No. 352417 for NRG Greens Bayou Station's Permit Nos. 171485, PSDTX1616, GHGPSDTX230, and N308).
Natural Gas Purging and Venting	NGPURGE	There will be periods during operation of the generating facility when natural gas will need to be purged from the piping system. The natural gas emissions from this purging were estimated using the predicted capacities of several piping systems and a maximum number of purges per year. These emissions were represented as CH₄, CO₂, and VOC, with the calculated maximum annual emission rates of 3.03 tpy for VOC and 1,368.34 tpy for CO₂e. The applicant proposed to minimize these emissions by following the recommended maintenance procedures to minimize the frequency of these types of MSS activities. The TCEQ Tier 1 BACT for combustion source MSS activities is the use of good air pollution control practices, safe operating practices, and limiting the frequency and duration of the activities. Therefore, Tier I BACT is satisfied.
Equipment Maintenance	MSS-MAINT	Maintenance activities being authorized for the project include NO_x and CO emissions associated with CEMS calibrations, VOC emissions associated with small equipment maintenance including inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment, and VOC emissions associated with low-VOC vapor pressure small equipment maintenance. BACT

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		associated with these activities is summarized below. CEMS calibrations – The NO_x and CO emissions associated with the calibration gas cylinders is <0.01 lb/hour and <0.01 tpy for NO_x and 0.01 lb/hour and <0.01 tpy for CO. These daily calibrations are conducted as necessary for the NO_x and CO CEMS, and the emission rates are based on daily calibration usages of up to 60 calibration gas cylinders used per year with a volume of 146 cubic feet per cylinder. Small equipment maintenance – The VOC emissions associated with inspections, repairs, replacements, adjusting, testing, and calibration of analytical equipment are estimated at 0.01 lb/hour and <0.01 tpy. These emissions were estimated based on assuming up to 4 activities per hour and 40 activities per year. Low-VOC vapor pressure small equipment maintenance – The VOC emissions associated with inspections, repairs, replacements, adjusting, testing, and calibration of analytical equipment are estimated at 1.13 lb/hour and 0.01 tpy. These emissions were estimated based on assuming up to 10 activities per hour and 260 activities per year. The proposed maintenance activities were represented as being undertaken to ensure the proper operability and safety of equipment and are conducted using best management practices. The frequency and duration of the identified maintenance activities will be limited such that the calculated emissions will be low enough to be classified as inherently low emitting (ILE) activities. The applicant stated that the emissions associated with these ILE maintenance activities are so low that alternative work practices would not result in meaningful emission reductions. The limited duration and frequency of the identified ILE maintenance activities result in low emission rates. The Tier 1 BACT for combustion source MSS activities is the use of good air pollution control practices, safe operating practices, and limiting the frequency and duration of the activities. The application represented that the filters associated with the turbine air intakes will have an automatic pulse cleaning system that uses air to remove the particulate matter from the outside of the filter cones when a pre-set pressure differential is met. The removed particulate matter will drop to the bottom of the filter housing for collection. The filter housings will be enclosed and maintained under negative pressure such that any particulate generating during cleaning would remain in the filter housing and not be released as fugitives. Also, the application stated that emissions associated with online turbine washing, another potential ILE activity, and combustion turbine optimization, tuning and testing, a potential non-ILE activity, are less than the estimated emissions for normal or planned startup and shutdown operations. Therefore, the applicant stated that these emissions are already included in the emission rate estimates represented for the EPNs listed separately for the emitting stacks.
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		The proposed BACT for maintenance activities authorized under EPN MSS-MAINT meets the TCEQ Tier I guidelines.																		
CCS1 TEG Dehydrator	CCS1-CO2VT	The project will include two CCS TEG dehydrator units, with one dehydrator unit per CCS train. The CCS TEG dehydrators use TEG as the absorption solution to remove water or water vapor present in the CO₂ compressor feed stream. The exhaust stream from the dehydrator is comprised of predominantly water and CO₂ with a small molar percentage (<0.01%) of glycol and other VOCs including HAPs. Potential emissions of VOC and CO₂ (GHG) from the dehydrators were estimated using the exhaust stream concentrations and flow rate provided by the design engineers, assuming 8,760 hours per year of operation. The facility will have two dehydrator vent stacks, i.e., one stack dedicated for each train, and these dehydrator vent stacks emit from the same stacks as used for the CCS1 MSS vent stack and CCS2 MSS vent stack discussed separately (see above in this table for a discussion of the CCS MSS vent stacks). The proposed emissions from both CCS TEG Dehydrators combined are 0.01 lb/hr and 0.05 tpy for VOC, <0.01 lb/hr and <0.01 tpy for acetone, <0.01 lb/hr and 0.02 tpy for HAPs, and 1,694 tpy of CO₂e. The TCEQ Tier I BACT guidelines for glycol dehydrators is to route the reboiler stills vent to a flare with 98% DRE or a firebox with 99+% DRE. The applicant stated that the CCS TEG Dehydrator units will be used for a predominantly CO₂ stream with a low VOC concentration, and the CCS dehydrators are unlike typical glycol dehydrators used in the oil and gas industry. For this reason, the applicant stated that Tier I or Tier II BACT would not be applicable to this unit and proceeded to a TCEQ Tier III BACT analysis, which is similar to a traditional EPA top-down analysis. Following the Tier III BACT analysis, an economic analysis was performed to determine if use of a flare or catalytic oxidizer would be considered cost effective. The costs of implementing flaring and catalytic oxidation as add-on control technologies to control VOC emissions from dehydrators were estimated by the applicant using EPA's cost estimation spreadsheets. The applicant stated that if controls were implemented for the two dehydration units, the most practical approach would be to combine the two exhaust streams and direct the combined exhaust to common control equipment. Therefore, the cost summary that follows is based on the combined total of the two dehydration units. <table><tr><th>Control Option</th><th>Total Capital Investment</th><th>Total Annual Direct and Indirect Costs (\$/year)</th><th>Control Eff. (%)</th><th>Annual VOC Controlled^a (tpy)</th><th>Annualized Control Cost^b (\$/ton VOC removed)</th></tr><tr><td>Flaring</td><td>\$747,861 (1 flare)</td><td>\$4,419,791</td><td>98%</td><td>0.050</td><td>\$88,107,479</td></tr><tr><td>Catalytic Oxidation</td><td>\$584,439 (1 oxidation)</td><td>\$187,662</td><td>98%</td><td>0.050</td><td>\$3,741,007</td></tr></table>	Control Option	Total Capital Investment	Total Annual Direct and Indirect Costs (\$/year)	Control Eff. (%)	Annual VOC Controlled ^a (tpy)	Annualized Control Cost ^b (\$/ton VOC removed)	Flaring	\$747,861 (1 flare)	\$4,419,791	98%	0.050	\$88,107,479	Catalytic Oxidation	\$584,439 (1 oxidation)	\$187,662	98%	0.050	\$3,741,007
Control Option	Total Capital Investment	Total Annual Direct and Indirect Costs (\$/year)	Control Eff. (%)	Annual VOC Controlled ^a (tpy)	Annualized Control Cost ^b (\$/ton VOC removed)															
Flaring	\$747,861 (1 flare)	\$4,419,791	98%	0.050	\$88,107,479															
Catalytic Oxidation	\$584,439 (1 oxidation)	\$187,662	98%	0.050	\$3,741,007															

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		unit)																												
CCS2 TEG Dehydrator	CCS2-CO2VT	^a Pre-control VOC emissions are 0.051 tpy from both dehydration units combined. ^b Based on dollar-year of 2023. The dollars per ton of VOC removed for the flaring and catalytic oxidation control options listed above were not considered cost effective. The table below summarizes the cost effectiveness calculation for HAPs based on the application representations for the costs to control VOC and the proposed HAP emission rate from the dehydrator unit. <table><tr><td></td><td></td><td>Total Annual Direct and Indirect Costs (\$/year)</td><td>Control Eff. (%)</td><td>Annual HAP Controlled^a (tpy)</td><td>Annualized Control Cost^b (\$/ton HAP removed)</td></tr><tr><td>Control Option</td><td>Total Capital Investment</td><td></td><td></td><td></td><td></td></tr><tr><td>Flaring</td><td>\$747,861 (1 flare)</td><td>\$4,419,791</td><td>98%</td><td>0.02</td><td>\$220,989,550</td></tr><tr><td>Catalytic Oxidation</td><td>\$584,439 (1 oxidation unit)</td><td>\$187,662</td><td>98%</td><td>0.02</td><td>\$9,383,100</td></tr></table> ^a Pre-control HAP emissions are 0.021 tpy from both dehydration units combined. ^b Based on dollar-year of 2023. Similar to VOC, the dollars per ton of total HAP removed for the flare and catalytic oxidation control options listed above were not considered cost effective. The applicant will minimize VOC, acetone, and HAP emissions from the dehydration unit by implementing good design and operating practices consistent with the underlying engineering basis used to quantify the proposed emission limits to meet BACT. The applicant will monitor operating and process parameters including the dehydration vent temperatures and TEG make-up quantities to confirm that the system is operating consistent with the engineering design basis as specified in SC No. 26. The applicant stated that there are no add-on control technologies that are appropriate for controlling GHGs (CO₂) from the dehydration unit. The most effective means to minimize GHG emissions from the dehydrator unit is to implement good design and operating practices consistent with the underlying engineering basis used to quantify the proposed GHG emission limit. The applicant noted the CO₂ from the dehydrator is a small fraction of the CO₂ that is being captured and transported offsite by the CCS. The applicant will monitor operating and process parameters including the dehydration vent temperatures and TEG make-up quantities to confirm that the system is operating consistent with the engineering design basis as specified in SC No. 26. MSS: System will maintain good design and operating practices. Separate MSS emissions were not represented for the dehydrator unit.							Total Annual Direct and Indirect Costs (\$/year)	Control Eff. (%)	Annual HAP Controlled ^a (tpy)	Annualized Control Cost ^b (\$/ton HAP removed)	Control Option	Total Capital Investment					Flaring	\$747,861 (1 flare)	\$4,419,791	98%	0.02	\$220,989,550	Catalytic Oxidation	\$584,439 (1 oxidation unit)	\$187,662	98%	0.02	\$9,383,100
		Total Annual Direct and Indirect Costs (\$/year)	Control Eff. (%)	Annual HAP Controlled ^a (tpy)	Annualized Control Cost ^b (\$/ton HAP removed)																									
Control Option	Total Capital Investment																													
Flaring	\$747,861 (1 flare)	\$4,419,791	98%	0.02	\$220,989,550																									
Catalytic Oxidation	\$584,439 (1 oxidation unit)	\$187,662	98%	0.02	\$9,383,100																									
Lube Oil Vent for	LUB-CTG	The CCGTs will be equipped with a dedicated lubrication system that will service both CCTG trains and a separate system that will																												

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Generating Facility		
Lube Oil Vent for CCS	LUB-CCS	service the compression units for the CCS. Lubricating oil will be circulated through the turbine machinery from the oil sump, and the heating of recirculating lube oil in the turbine and generator housings will create oil vapor and oil condensate droplets in the oil reservoir compartments. Emissions of the condensed droplets will be controlled by a mist eliminator serving each reservoir to satisfy BACT. The calculation of emissions from the lube oil vents was based on lube oil replacement rates for similar units equipped with mist eliminators. The lube oil vent emissions are counted both as VOCs and PM/PM₁₀/PM_{2.5} for the emission points. These emissions are small, represented as 0.01 lb/hr and 0.03 tpy of VOC and 0.01 lb/hr and 0.03 tpy of PM/PM₁₀/PM_{2.5} from EPN LUB-CTG and <0.01 lb/hr and 0.01 tpy of VOC and <0.01 lb/hr and 0.01 tpy of PM/PM₁₀/PM_{2.5} from EPN LUB-CCS. The TCEQ does not provide Tier 1 BACT guidelines lube oil vent emissions. There is no process code associated with lube oil vents that can be searched in the RBLC. However, a search by the applicant for combined cycle energy projects in the RBLC and a review of other available permits identified a few recently permitted facilities with lube oil vent listed as a process source. These recent RBLC determinations identify mist eliminators as the control method. The proposed use of mist eliminators satisfies BACT.

Permits Incorporation

Permit by Rule (PBR) / Standard Permit / Permit Nos.	Description (include affected EPNs)	Action (Reference / Consolidate / Void)
N/A	N/A	N/A

Impacts Evaluation

Was modeling conducted? **Yes** Type of Modeling: **AERMOD version 23132**

Is the site within 3,000 feet of any school? **No**

Additional site/land use information: **Applicant assumed rural dispersion option**

The applicant provided an air quality analysis, which was audited by the TCEQ ADMT. The air quality analysis is acceptable for all review types and pollutants. More detailed information regarding the air quality analysis may be found in the ADMT modeling memo, ADMT Project No. 9300, dated September 10, 2024. The modeling results are summarized below.

Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (µg/m³)

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Pollutant	Averaging Time	GLCmax ($\mu\text{g}/\text{m}^3$)	De Minimis ($\mu\text{g}/\text{m}^3$)
SO ₂	1-hr	5.93	7.8
SO ₂	3-hr	5.25	25
SO ₂	24-hr	2.01	5
SO ₂	Annual	0.25	1
PM ₁₀	24-hr	7.66	5
PM ₁₀	Annual	1.19	1
PM _{2.5} (NAAQS)	24-hr	6.04	1.2
PM _{2.5} (NAAQS)	Annual	1.14	0.13
PM _{2.5} (Increment)	24-hr	7.66	1.2
PM _{2.5} (Increment)	Annual	1.19	0.13
NO ₂	1-hr	78	7.5
NO ₂	Annual	3	1
CO	1-hr	812	2000
CO	8-hr	317	500

Modeling Results for
Ozone PSD De Minimis

Analysis in Parts per Billion (ppb)

Pollutant	Averaging Time	GLCmax (ppb)	De Minimis (ppb)
O ₃	8-hr	0.88	1

Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax ($\mu\text{g}/\text{m}^3$)	Significance ($\mu\text{g}/\text{m}^3$)
SO ₂	24-hr	2.01	13
PM ₁₀	24-hr	7.66	10
NO ₂	Annual	3	14

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CO	8-hr	317	575
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Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m³)	Background (µg/m³)	Total Conc. = [Background + GLCmax] (µg/m³)	Standard (µg/m³)
PM ₁₀	24-hr	6	88	94	150
PM _{2.5}	24-hr	3	20	23	35
PM _{2.5}	Annual	1.14	6.6	7.74	9
NO ₂	1-hr	66	58	124	188
NO ₂	Annual	4	9	13	100

Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m³)	Increment (µg/m³)
PM ₁₀	24-hr	7	30
PM ₁₀	Annual	1	17
PM _{2.5}	24-hr	7	9
PM _{2.5}	Annual	1	4
NO ₂	Annual	4	25

Additional Impacts Analysis

The applicant performed an Additional Impacts Analysis as part of the PSD AQA. The applicant conducted a growth analysis and determined that population will not significantly increase as a result of the proposed project. The applicant conducted a soils and vegetation analysis and determined that all evaluated criteria pollutant concentrations are below their respective secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with the opacity requirements of 30 TAC Chapter 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Carlsbad Caverns National Park, is located approximately 112 kilometers (km) from the proposed site.

The H₂SO₄ 24-hr maximum predicted concentration of 0.67 µg/m³ occurred approximately 212 meters from the property line towards the northwest. The H₂SO₄ 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 29 km from the proposed sources, in the direction of the Carlsbad Caverns National Park Class I area is 0.24 µg/m³. The

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Carlsbad Caverns National Park Class I area is an additional 86 km from the edge of the receptor grid. Therefore, emissions of H₂SO₄ from the proposed project are not expected to adversely affect the Carlsbad Caverns National Park Class I area.

The predicted concentrations of PM₁₀, PM_{2.5}, NO₂, and SO₂ for all averaging times, are all less than de minimis levels at an approximate distance of 24 km from the proposed sources in the direction the Carlsbad Caverns National Park Class I area. The Carlsbad Caverns National Park Class I area is an additional 88 km from the location where the predicted concentrations of PM₁₀, PM_{2.5}, NO₂, and SO₂ for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Carlsbad Caverns National Park Class I area.

Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m ³)	Standard (µg/m ³)
SO ₂	1-hr	7	1021
H ₂ SO ₄	1-hr	4.51	50
H ₂ SO ₄	24-hr	1.34	15

Total Concentrations for Minor NSR NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m ³)	Background (µg/m ³)	Total Conc. = [Background + GLCmax] (µg/m ³)	Standard (µg/m ³)
Pb	3-mo	0.001	0.07	0.071	0.15

Minor NSR Project (Increases Only) Modeling Results for Health Effects

Pollutant & CAS#	Averaging Time	GLCmax (µg/m ³)	10% ESL (µg/m ³)
1,3-butadiene 106-99-0	1-hr	0.01	51
1,3-butadiene 106-99-0	Annual	4.23E-05	0.99
3-methylcholanthrene 56-49-5	1-hr	3.64E-06	0.002
7,12-dimethylbenz[a]anthracene 57-97-6	1-hr	3.24E-05	0.05
acetaldehyde 75-07-0	Annual	2.20	4.5
acetone 67-64-1	1-hr	1.04	780
acetonitrile 75-05-8	1-hr	0.003	34
acrolein 107-02-8	1-hr	0.05	0.32
ammonia 7664-41-7	Annual	6.72	9.2

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anthracene 120-12-7	1-hr	0.001	0.01
benzo[a]anthracene 56-55-3	1-hr	0.001	0.05
benzene 71-43-2	1-hr	0.92	17
benzene 71-43-2	Annual	0.01	0.45
benzo[a]pyrene 50-32-8	Annual	4.47E-07	0.005
benzo[b]fluoranthene 205-99-2	1-hr	0.001	0.05
benzo[g,h,i]perylene 191-24-2	1-hr	0.001	0.05
benzo[k]fluoranthene 207-08-9	1-hr	0.0002	0.05
chrysene 218-01-9	1-hr	0.002	0.05
dibenz[a,h]anthracene 53-70-3	1-hr	0.0004	0.05
ethylbenzene 100-41-4	1-hr	0.13	2600
ethylbenzene 100-41-4	Annual	0.01	57
fluoranthene 206-44-0	1-hr	0.005	0.05
formaldehyde 50-00-0	Annual	0.23	0.33
hexane, mixed isomers 92112-69-1	1-hr	5.24	560
hexane, mixed isomers 92112-69-1	Annual	0.46	20
indeno[1,2,3-cd]pyrene 193-39-5	1-hr	0.0004	0.05
pentane, all isomers 92046-46-3	1-hr	2.31	5900
propylene oxide 75-56-9	1-hr	0.12	7
pyrene 129-00-0	1-hr	0.004	0.05
toluene 108-88-3	1-hr	0.87	450
xylene 1330-20-7	1-hr	0.48	220
xylene 1330-20-7	Annual	0.03	18

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arsenic 7440-38-2	1-hr	0.0004	0.3
arsenic 7440-38-2	Annual	0.00003	0.0067
beryllium 7440-41-7	1-hr	3.49E-05	0.002
cadmium 7440-43-9	1-hr	0.003	0.54
cadmium 7440-43-9	Annual	0.0003	0.00033
chromium, elemental 7440-47-3	1-hr	0.004	0.36
chromium, elemental 7440-47-3	Annual	0.0004	0.0041
cobalt 7440-48-4	1-hr	0.0002	0.021
cobalt 7440-48-4	Annual	0.00002	0.00017
manganese 7439-96-5	1-hr	0.001	0.27
manganese 7439-96-5	Annual	0.0001	0.025
mercury 7439-97-6	1-hr	0.001	0.025
nickel 7440-02-0	1-hr	0.01	0.033
nickel 7440-02-0	Annual	0.001	0.0059
vanadium 7440-62-2	1-hr	0.002	2
zinc 7440-66-6	1-hr	0.03	2
polycyclic aromatic hydrocarbons 130498-29-2	1-hr	0.01	0.05
paraffins (petroleum), normal C5-20 64771-72-8	1-hr	2.28	350

Minor NSR Site-wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax (µg/m³)	GLCmax Location	ESL (µg/m³)
acetaldehyde	75-07-0	1-hr	97	E Property Line	120
ammonia	7664-41-7	1-hr	88	E Property Line	180
formaldehyde	50-00-0	1-hr	7	E Property Line	15

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2-diethylaminoethanol	100-37-8	1-hr	176	E Property Line	53
2-diethylaminoethanol	100-37-8	Annual	2	E Property Line	9.6

Minor NSR Hours of Exceedance for Health Effects

Pollutant	Averaging Time	1 X ESL GLCmax	2 X ESL GLCmax
2-diethylaminoethanol	1-hr	74	9

The applicant provided a health effects review as specified in the TCEQ's Modeling and Effects Review Applicability (MERA) guidance (APDG 5874 dated March 2018) for project emission increases of non-criteria pollutants. The project emissions of non-criteria pollutants listed below satisfy the MERA and are protective of human health and the environment.

Note that there may be some inconsistencies between the results in the MERA summary table below compared to the summary table provided above from the ADMT audit memo due to emission rate changes that occurred during the audit review, which was discussed by the permit reviewer with the ADMT reviewer. However, this discrepancy does not change the overall conclusions since all pollutants screen out of the MERA except for the one chemical that triggered a Toxicology review as noted in the table below.

Health Effects Review - Minor NSR Project-Related Results^a

Pollutant & CAS#	Averaging Time	GLCmax (µg/m ³)	ESL (µg/m ³)	Modeling and Effects Review Applicability (MERA) Step in Which Pollutant Screened Out
Methane 74-82-8	1-hr	N/A	N/A	Step 0 – simple asphyxiate
	Annual	N/A	N/A	Step 0 – simple asphyxiate
Carbon Dioxide 124-38-9	1-hr	N/A	N/A	Step 0 – simple asphyxiate
	Annual	N/A	N/A	Step 0 – simple asphyxiate
Propane 74-98-6	1-hr	N/A	N/A	Step 0 – simple asphyxiate
	Annual	N/A	N/A	Step 0 – simple asphyxiate
CCS Solvent (2-diethylaminoethanol) 100-37-8	1-hr	176	53	Toxicology Division review triggered – See tables above for the number of exceedances and the discussion that follows below regarding the Toxicology Division review
	Annual	2.11	9.6	Toxicology Division review triggered – See tables above for the number of exceedances and the discussion that follows below regarding the Toxicology Division review
Triethylene glycol 112-27-6	1-hr	N/A	10,000	Step 2 – long-term ESL ≥ 10% of short-term ESL, short-term ESL ≥ 3,500 µg/m ³ and production emissions increase ≤ 0.4 lb/hr

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	Annual	N/A	1000	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Paraffins (petroleum), normal C5-20 64771-72-8	1-hr	202	3500	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.005	350	Step 3 - GLCmax $\leq$ 10% ESL
1,3-Butadiene 106-99-0	1-hr	0.01	510	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.00005	9.9	Step 3 - GLCmax $\leq$ 10% ESL
2-Methylnaphthalene 91-57-6	1-hr	N/A	200	Step 2 – long-term ESL $\geq$ 10% of short-term ESL, $2 \mu\text{g}/\text{m}^3 \leq$ short-term ESL $< 500 \mu\text{g}/\text{m}^3$ and production emission increase $< 0.04 \text{ lb/hr}$
	Annual	N/A	20	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
3-Methylchloranthrene 56-49-5	1-hr	3.96E-06	0.02	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	7.69E-08	0.002	Step 3 - GLCmax $<$ 10% ESL
7,12-Dimethylbenz(a)anthracene 57-97-6	1-hr	3.52E-05	0.5	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	6.84E-07	0.05	Step 3 - GLCmax $\leq$ 10% ESL
Acenaphthene 83-32-9	1-hr	N/A	100	Step 2 – long-term ESL $\geq$ 10% of short-term ESL, $2 \mu\text{g}/\text{m}^3 \leq$ short-term ESL $< 500 \mu\text{g}/\text{m}^3$ and production emission increase $< 0.04 \text{ lb/hr}$
	Annual	N/A	10	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Acenaphthylene 208-96-8	1-hr	N/A	100	Step 2 – long-term ESL $\geq$ 10% of short-term ESL, $2 \mu\text{g}/\text{m}^3 \leq$ short-term ESL $< 500 \mu\text{g}/\text{m}^3$ and production emission increase $< 0.04 \text{ lb/hr}$
	Annual	N/A	10	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Acetaldehyde 75-07-0	1-hr	97.4	120	Step 7 – sitewide modeling deemed acceptable by ADMT
	Annual	0.55	45	Step 3 - GLCmax $\leq$ 10% ESL
Acetone 67-64-1	1-hr	14.44	7800	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.03	4800	Step 3 - GLCmax $\leq$ 10% ESL
Acetonitrile 75-05-8	1-hr	9.10	340	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.0008	34	Step 3 - GLCmax $\leq$ 10% ESL

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Acrolein 107-02-8	1-hr	0.05	3.2	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.0007	0.82	Step 3 - GLCmax ≤ 10% ESL
Ammonia 7664-41-7	1-hr	88.17	180	Step 7 – sitewide modeling deemed acceptable by ADMT
	Annual	1.60	92	Step 3 - GLCmax ≤ 10% ESL
Anthracene 120-12-7	1-hr	0.0015	1	Step 3 - GLCmax ≤ 10% ESL
	Annual	3.98E-07	0.1	Step 3 - GLCmax ≤ 10% ESL
Benz(a)anthracene 56-55-3	1-hr	0.00084	0.5	Step 3 - GLCmax ≤ 10% ESL
	Annual	2.45E-07	0.05	Step 3 - GLCmax ≤ 10% ESL
Benzene 71-43-2	1-hr	0.94	170	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.0016	4.5	Step 3 - GLCmax ≤ 10% ESL
Benzo(a)pyrene 50-32-8	1-hr	N/A	Not Available	Step 0 – no current ESL listed in the Toxicity Factor Database; BACT is satisfied as discussed in the BACT section above
	Annual	9.69E-08	0.017	Step 3 - GLCmax ≤ 10% ESL
Benzo(b)fluoranthene 205-99-2	1-hr	0.0011	0.5	Step 3 - GLCmax ≤ 10% ESL
	Annual	2.94E-07	0.05	Step 3 - GLCmax ≤ 10% ESL
Benzo(g,h,i)perylene 191-24-2	1-hr	0.0006	0.5	Step 3 - GLCmax ≤ 10% ESL
	Annual	1.75E-07	0.05	Step 3 - GLCmax ≤ 10% ESL
benzo[k]fluoranthene 207-08-9	1-hr	0.00024	0.5	Step 3 - GLCmax ≤ 10% ESL
	Annual	1.25E-07	0.05	Step 3 - GLCmax ≤ 10% ESL
Chrysene 218-01-9	1-hr	0.0016	0.5	Step 3 - GLCmax ≤ 10% ESL
	Annual	3.93E-07	0.05	Step 3 - GLCmax ≤ 10% ESL
dibenz[a,h]anthracene 53-70-3	1-hr	0.00042	0.5	Step 3 - GLCmax ≤ 10% ESL
	Annual	1.36E-07	0.05	Step 3 - GLCmax ≤ 10% ESL

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Dichlorobenzene (as "Dichlorobenzene, all isomers") 25321-22-6	1-hr	N/A	900	Step 2 – long-term ESL $\geq$ 10% of short-term ESL, $500 \mu\text{g}/\text{m}^3 \leq$ short-term ESL < 3500 $\mu\text{g}/\text{m}^3$ and production emission increase $\leq$ 0.1 lb/hr
	Annual	N/A	160	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Ethylbenzene 100-41-4	1-hr	0.13	26,000	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.0033	570	Step 3 - GLCmax $\leq$ 10% ESL
Fluoranthene 206-44-0	1-hr	0.005	0.5	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	1.13E-06	0.05	Step 3 - GLCmax $\leq$ 10% ESL
Fluorene 86-73-7	1-hr	N/A	10	Step 2 – long-term ESL $\geq$ 10% of short-term ESL, $2 \mu\text{g}/\text{m}^3 \leq$ short-term ESL $< 500 \mu\text{g}/\text{m}^3$ and production emission increase < 0.04 lb/hr
	Annual	N/A	1	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Formaldehyde 50-00-0	1-hr	6.65	15	Step 7 – sitewide modeling deemed acceptable by ADMT
	Annual	0.056	3.3	Step 3 - GLCmax $\leq$ 10% ESL
Hexane, mixed isomers 92112-69-1	1-hr	5.56	5600	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.12	200	Step 3 - GLCmax $\leq$ 10% ESL
Indeno(1,2,3-cd)pyrene 193-39-5	1-hr	0.0005	0.5	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	1.70E-07	0.05	Step 3 - GLCmax $\leq$ 10% ESL
Naphthalene 91-20-3	1-hr	N/A	440	Step 2 – long-term ESL $\geq$ 10% of short-term ESL, $2 \mu\text{g}/\text{m}^3 \leq$ short-term ESL $< 500 \mu\text{g}/\text{m}^3$ and production emission increase < 0.04 lb/hr
	Annual	N/A	50	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Polycyclic Aromatic Hydrocarbons 130498-29-2	1-hr	0.015	0.5	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	N/A	0.05	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Pentane (as "pentane, all isomers") 92046-46-3	1-hr	2.31	59,000	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.059	7100	Step 3 - GLCmax $\leq$ 10% ESL

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Phenanthrene 85-01-8	1-hr	N/A	8	Step 2 – long-term ESL $\geq$ 10% of short-term ESL, $2 \mu\text{g}/\text{m}^3 \leq$ short-term ESL $< 500 \mu\text{g}/\text{m}^3$ and production emission increase $< 0.04 \text{ lb/hr}$
	Annual	N/A	0.8	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Propylene Oxide 75-56-9	1-hr	0.12	70	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.003	7	Step 3 - GLCmax $\leq$ 10% ESL
Pyrene 129-00-0	1-hr	0.0043	0.5	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	1.08E-06	0.05	Step 3 - GLCmax $\leq$ 10% ESL
Toluene 108-88-3	1-hr	0.87	4500	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.014	1200	Step 3 - GLCmax $\leq$ 10% ESL
Xylene (mixed isomers) 1330-20-7	1-hr	0.49	2200	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.0067	180	Step 3 - GLCmax $\leq$ 10% ESL
Arsenic 7440-38-2	1-hr	0.0004	3	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	8.55E-06	0.067	Step 3 - GLCmax $\leq$ 10% ESL
Barium 7440-39-3	1-hr	N/A	5	Step 2 – long-term ESL $\geq$ 10% of short-term ESL, $2 \mu\text{g}/\text{m}^3 \leq$ short-term ESL $< 500 \mu\text{g}/\text{m}^3$ and production emission increase $< 0.04 \text{ lb/hr}$
	Annual	N/A	0.5	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Beryllium 7440-41-7	1-hr	0.00004	0.02	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	7.83E-07	0.002	Step 3 - GLCmax $\leq$ 10% ESL
Cadmium 7440-43-9	1-hr	0.0034	5.4	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.00007	0.0033	Step 3 - GLCmax $\leq$ 10% ESL
Chromium 7440-47-3	1-hr	0.0043	3.6	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.00009	0.041	Step 3 - GLCmax $\leq$ 10% ESL
Cobalt 7440-48-4	1-hr	0.0003	0.21	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	5.48E-06	0.0017	Step 3 - GLCmax $\leq$ 10% ESL

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Manganese 7439-96-5	1-hr	0.0012	2.7	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.00002	0.25	Step 3 - GLCmax $\leq$ 10% ESL
Mercury 7439-97-6	1-hr	0.0008	0.25	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.00002	0.025	Step 3 - GLCmax $\leq$ 10% ESL
Molybdenum 7439-98-7	1-hr	N/A	30	Step 2 – long-term ESL $\geq$ 10% of short-term ESL, $2 \mu\text{g}/\text{m}^3 \leq$ short-term ESL $< 500 \mu\text{g}/\text{m}^3$ and production emission increase $< 0.04 \text{ lb/hr}$
	Annual	N/A	3	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Nickel 7440-02-0	1-hr	0.0065	0.33	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.00014	0.059	Step 3 - GLCmax $\leq$ 10% ESL
Selenium 7782-49-2	1-hr	N/A	2	Step 2 – long-term ESL $\geq$ 10% of short-term ESL, $2 \mu\text{g}/\text{m}^3 \leq$ short-term ESL $< 500 \mu\text{g}/\text{m}^3$ and production emission increase $< 0.04 \text{ lb/hr}$
	Annual	N/A	0.2	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Copper 7440-50-8	1-hr	N/A	10	Step 2 – long-term ESL $\geq$ 10% of short-term ESL, $2 \mu\text{g}/\text{m}^3 \leq$ short-term ESL $< 500 \mu\text{g}/\text{m}^3$ and production emission increase $< 0.04 \text{ lb/hr}$
	Annual	N/A	1	Step 0 – long-term ESL $\geq$ 10% of short-term ESL
Vanadium 7440-62-2	1-hr	0.002	20	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.00005	2	Step 3 - GLCmax $\leq$ 10% ESL
Zinc 7440-66-6	1-hr	0.026	20	Step 3 - GLCmax $\leq$ 10% ESL
	Annual	0.0007	2	Step 3 - GLCmax $\leq$ 10% ESL

^a There may be some inconsistencies between the results in this table compared to the other table provided earlier from the ADMT audit memo due to emission rate changes that occurred during the audit review, which was discussed by the permit reviewer and the ADMT reviewer. However, this discrepancy does not change the overall conclusions since all pollutants screen out of the MERA except for the one chemical that triggered a Toxicology review as noted in the table.

The results indicate that the sitewide modeled 1-hour GLCmax for CCS Solvent that was modeled as “2-diethylaminoethanol (CAS 100-37-8),” exceeds the formal Tier II approval criteria established by the TCEQ for health effects evaluations in the Air Quality Modeling Guidelines (APDG 6232, dated June 2024) and discussed in Appendix D of the March 2018 MERA guidance and, therefore, a Tier III toxicology review was required. A Request for Comments (RFC) regarding these results was submitted to the TCEQ Toxicology Division for review on September 14, 2024.

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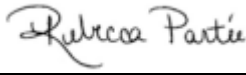
Toxicology Review:

Toxicology does not anticipate that any short- or long-term adverse health effects will occur among the general public as a result of exposure to the proposed emissions from the facility as summarized in a memo from Stanley Aniagu, MSc., Ph.D., DABT of the TCEQ Toxicology, Risk Assessment, and Research Division dated September 18, 2024. (Toxicology Control No. 7844).

In summary, the applicant has demonstrated that the proposed project's emissions will not adversely affect public health and welfare, which includes NAAQS, additional impacts, minor new source review of regulated pollutants without a NAAQS, and air toxics review. The proposed increases in health effects pollutants will not cause or contribute to any federal or state exceedances. Therefore, emissions from the facility are not expected to have an adverse impact on public health or the environment.

Permit Concurrence and Related Authorization Actions

Is the applicant in agreement with special conditions?	Yes
Company representative(s):	Lynn Gresock, consultant on behalf of the applicant (the applicant was copied on the concurrence email)
Contacted Via:	Email
Date of contact:	9/23/2024
Other permit(s) or permits by rule affected by this action:	N/A
List permit and/or PBR number(s) and actions required or taken:	N/A

	11/23/2024		11/25/2024
Project Reviewer Christopher Loughran, P.E.	Date	Assistant Deputy Director Rebecca Partée	Date