Preliminary Determination Summary

CPV Basin Ranch Holdings, LLC
Permit Numbers 175063, HAP85, PSDTX1634, and GHGPSDTX237

I. Applicant

CPV Basin Ranch Holdings LLC
50 Braintree Hill Office Park Ste 300
Braintree, MA 02184-8739

II. Project Location

From Business Loop 20 and Farm-to-Market Road 516 South/Mackey Avenue intersection in Barstow, then 0.3 mile north to County Road 73/West Concho Street, then left onto County Road 73/West Concho Street for 5.7 miles to County Road 3398, then left onto Farm-to-Market Road 3398 for 0.2 mile to County Road 175, then right onto CR 175 for 1.3 miles to site entrance on the left.

City of Barstow, Ward County, Texas 79772

III. Project Description

CPV Basin Ranch Holdings, LLC (CPV) submitted an 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 PSD review for CO, NOx, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, H_2SO_4, and Greenhouse Gases (GHGs as CO_2e).

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.

IV. Emissions

The total allowable emission rates to be authorized by Permit Nos. 175063, HAP85, PSDTX1634, and GHGPSDTX237 after the permits are issued are summarized in the table below.

Air Contaminant	Proposed Allowable Emission Rates (tpy)
VOC	405.35
NO_x	366.88
SO_2	74.29

CO	406.90
$PM/PM_{10}/PM_{2.5}$	230.23 / 217.31 / 215.60
H_2SO_4	54.19
H_2S	0
NH_3	300.00
Lead (Pb)	0.01
Acetone	11.59
Formaldehyde	11.65
HAPs	237.99
CO_2	5,269,205.64
CH_4	162.39
SF_6	0.0040
N_2O	9.60
CO_2 Equivalents (CO_2e) [1]	5,276,217.05
CO_2 Equivalents (CO_2e) [2]	5,276,390.27

[1] Carbon dioxide equivalent (CO_2e) 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 CO_2, 25 for CH_4, 298 for N_2O, and 22,800 for SF_6.
[2] CO_2e 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 CO_2, 28 for CH_4, 265 for N_2O, and 23,500 for SF_6.

Planned MSS emissions are included in the table above. The draft permit includes specific limits on the duration and annual frequency of planned MSS activities for the turbine and duct burners (EPNs CTG1_HRSG1 and CTG2_HRSG2), and separate short-term hourly emission rate limits are specified in the permit's draft Maximum Allowable Emission Rates Table (MAERT). Similar permit restrictions and MAERT limits also apply to the CCS Boilers (EPNs CCS1BLR1, CCS1BLR2, CCS2BLR1, and CCS2BLR2). Additionally, Attachment A of the draft permit lists the authorized Inherently Low Emitting (ILE) planned MSS activities while Attachment B lists the authorized non-ILE MSS activities, and provisions for these activities are specified in both the draft permit special conditions draft MAERT.

V. Federal Applicability

PSD Review Summary

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.

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, PM_{10}, $PM_{2.5}$, 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 at 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, SO_2 and H_2SO_4 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 CO_2e must be evaluated for PSD applicability. As shown in the table below, the GHG annual emission rate as CO_2e 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 CO_2e 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.

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 [1]	N/A [1]	**Yes**
NOx	366.88	100	Yes	40 [1]	N/A [1]	**Yes**
PM	230.23	100	Yes	25 [1]	N/A [1]	**Yes**
PM_{10}	217.31	100	Yes	15 [1]	N/A [1]	**Yes**
$PM_{2.5}$	215.60	100	Yes	10 [1]	N/A [1]	**Yes**
SO_2	74.29	100	No	40	Yes [2]	**Yes**
VOC	405.35	100	Yes	40 [1]	N/A [1]	**Yes**
Pb	0.01	100	No	0.6	No	No
H_2SO_4	54.19	100	No	7	Yes	**Yes**
GHGs, CO_2e	5,276,217.05 [3] 5,276,390.27 [4]	N/A	N/A	75,000	Yes	**Yes**

[1] 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 it respective PSD significant emission rate threshold.
[2] The rules do not allow contemporaneous netting at existing minor sources.
[3] CO_2e 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 CO_2, 25 for CH_4, 298 for N_2O, and 22,800 for SF_6.
[4] CO_2e 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 CO_2, 28 for CH_4, 265 for N_2O, and 23,500 for SF_6.

Clean Air Act (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 YYYY 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.

HAP Air Contaminant	**Proposed Allowable HAP Hourly Emission Rates (lb/hr)**	**Proposed Allowable HAP Annual Emission Rates (tpy)**
CCS1 Absorber (EPN CCS1)		
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
CCS2 Absorber (EPN CCS2)		
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
Other Project Sources - Total HAPs		
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
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 control technology evaluation and emission limitation is summarized in the next section below.

VI. Control Technology Review

A control technology review was conducted that includes a Best Available Control Technology (BACT) analysis for criteria pollutants and a case-by-case MACT evaluation pursuant to §112(g) of the federal Clean Air Act. These control technology reviews are summarized below.

BACT Evaluation

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, NOx, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, H_2SO_4, and GHGs as CO_2e. State minor BACT was also evaluated for the other pollutants that did no trigger PSD review and is also summarized in the table below, which includes HAPs. The applicant submitted RACT/BACT/LAER Clearinghouse (RBLC) database search summaries for the pollutants that triggered PSD review (CO, NOx, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, H_2SO_4, and GHGs as CO_2e), 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.

<table>
<tr><th>Source Name</th><th>EPN</th><th>Best Available Control Technology Description</th></tr>
<tr><td>CCTG1-no DB,
CCTG1-w/DB,
CCTG1 no CCS – annual</td><td>CTG1_HRSG1</td><td rowspan="4">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.

NOx: 2.0 ppmvd at 15% O_2, 1-hour average, without duct firing and with duct firing, achieved through the use of dry low-NOx (DLN) combustors as lean pre-mix DLN combustors for natural gas firing, which limits NOx 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 NOx into nitrogen and water. The TCEQ Tier I BACT for combined cycle turbines is 2.0 ppmvd at 15% O_2, 24-hour average, typically achieved with dry low 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% O_2, 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 CO_2.</td></tr>
<tr><td>CCTG1-no DB,
CCTG1-w/DB,
CCS1 - annual</td><td>CCS1</td></tr>
<tr><td>CCTG2-no DB,
CCTG2-w/DB,
CCTG2 no CCS - annual</td><td>CTG2_HRSG2</td></tr>
<tr><td>CCTG2-no DB,
CCTG2-w/DB,
CCS2 - annual</td><td>CCS2</td></tr>
</table>

		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% O_2, 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% O_2 without duct burning and 1.7 ppmvd at 15% O_2 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 Virgina has a permitted CO limit of 1.0 ppmvd at 15% O_2, 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% O_2 at less than 60 percent load and 1.5 ppmvd at 15% O_2 without duct burning at greater than 60 percent load. The applicant stated that the overall limit of 1.8 ppmvd at 15% O_2 is generally consistent with the proposed limit of 2.0 ppmvd at 15% O_2. 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% O_2 without duct firing. The applicant stated that it is common 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% O_2, with a lower limit of 1.5 ppmvd at 15% O_2 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% O_2 and not 1.5 ppmvd at 15% O_2 according to CPV. VOC: 1.0 ppmvd at 15% O_2 without duct firing and 2.0 ppmvd at 15% O_2 with duct firing achieved through the application of good combustion practices and an oxidation catalyst system which oxidizes the VOC to form CO_2 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 SO_2 to SO_3 occurs, which results in increased emissions of H_2SO_4 and/or ammonium salts ($PM/PM_{10}/PM_{2.5}$). 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% O_2 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. $PM/PM_{10}/PM_{2.5}$: 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 $PM/PM_{10}/PM_{2.5}$ emitted from the CCGTs is conservatively assumed to be less than 2.5 microns in diameter, and, therefore, the PM, PM_{10}, and $PM_{2.5}$ emission rates are assumed to be the same. During full-load steady state conditions, $PM/PM_{10}/PM_{2.5}$ 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 post-combustion control technologies available to reduce $PM/PM_{10}/PM_{2.5}$ emissions from CCGTs since post-combustion $PM/PM_{10}/PM_{2.5}$ 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 $PM/PM_{10}/PM_{2.5}$ 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 $PM/PM_{10}/PM_{2.5}$ 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 $PM/PM_{10}/PM_{2.5}$ guaranteed limits on the higher end of the emissions range. The differences in $PM/PM_{10}/PM_{2.5}$ 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 $PM/PM_{10}/PM_{2.5}$.

		SO_2: The applicant conservatively assumed 100% molar conversion of natural gas sulfur to SO_2 (conservative since SO_2 and H_2SO_4 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 SO_2 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 SO_2/H_2SO_4 emissions from CCGTs, as post-combustion SO_2/H_2SO_4 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 SO_2 / H_2SO_4 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. H_2SO_4: The applicant conservatively assumed 100% molar conversion of natural gas sulfur, 0.5 grains sulfur/100 dscf fuel, to SO_2 and 5% molar conversion of that SO_2 to SO_3 due to combustion, 40% molar conversion of the remaining SO_2 to SO_3 due to the oxidation catalyst, and 2% molar conversion of the remaining SO_2 to SO_3 due to the SCR. A 17.5% safety margin was added to the SO_3 and the applicant assumed that all of the SO_3 is converted to H_2SO_4. Full load steady state emissions of H_2SO_4 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 SO_2/H_2SO_4 emissions from CCGTs, as post-combustion SO_2/H_2SO_4 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 SO_2 / H_2SO_4 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 SO_2 to SO_3 conversion rates.

		NH_3: Ammonia slip of 5.0 ppmvd at 15% O_2, 1-hour average, using effective process control. SCR involves the injection of NH_3 into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 reacts with the NOx (NO and NO_2) contained within the flue gas to form N_2 and water. NH_3 is injected and mixed into the exhaust gas upstream in greater than stoichiometric amounts to achieve optimal conversion of NOx. Excess NH_3 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% O_2 is not exceeded. TCEQ Tier I BACT for combined cycle turbine units is ammonia slip of 7-10 ppmvd at 15% O_2, 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). CO_2e: The CTGs will operate at an annual 12-month rolling emission factor of 925 lb CO_2/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 CO_2/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 CO_2/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 CO_2 emissions resulting from the combustion of natural gas in the CCGTs, with trace amounts of CH_4 and N_2O emitted during combustion in varying quantities depending on operating conditions; however, they will be negligible compared to CO_2 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 CO_2/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 CO_2/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 CO_2 emission factor limit specified in the SC No. 8 is 925 lb CO_2/MWh-gross based on meeting BACT. Because emissions of CO_2 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 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 CO_2 emissions turbine and duct burners. The project's turbines and duct burners will combust natural gas as the sole fuel, which is the lowest CO_2-emitting fossil fuel. The applicant provided the following CO_2 emission factors taken from Subpart C of 40 CFR 98 to demonstrate that the natural gas will minimize CO_2 emissions compared to other fossil fuels: • Natural gas – 117 lb CO_2/MMBtu • Distillate Fuel No. 2 - 162 lb CO_2/MMBtu • Coal, mixed for electric power generation - 210 lb CO_2/MMBtu Carbon capture and storage or sequestration is another control option to reduce CO_2 emissions from combustion turbines, which is considered by the EPA to be a technically feasible add-on control option for CO_2 (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 CO_2 from the CCGT exhaust gas in a form that is suitable for transport. There are several methods that may be used for capturing CO_2 from gas streams, including chemical and physical absorption, adsorption, cryogenic separation, and membrane separation. Exhaust streams from CCGTs have relatively low CO_2 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 CO_2 in a high volume, low CO_2 concentration gas stream. The next step in the carbon capture and sequestration process is transportation of the captured CO_2 for final disposition including EOR or commercial sequestration. Currently, development of commercially available CO_2 storage sites is in its infancy as is EOR from non-natural occurring CO_2. In addition, pipelines for transport of the compressed CO_2 to storage or EOR sites are not currently

		available. The capital expenditure required to capture and compress CO_2 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 CO_2 emissions by approximately 4,600,000 tons facility wide. While capturing CO_2 is the major cost contributor, it is important to consider the transportation and sequestration of CO_2, as well, for total cost. The applicant estimated the cost of CCS control of $102 per ton of CO_2e 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 megawatt-hour (MW-hr) basis. Note that the dollars per ton value that the applicant estimated was based on the pollutant CO_2 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., CH_4 and N_2O, and therefore the dollars per ton can be assumed to be per ton of CO_2e. 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 CO_2 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 CO_2e 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 CO_2e 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 CO_2e removed, which is similar to the range of $100 to $102 per ton of CO_2e 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 CO_2e 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 CO_2 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 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 CO_2 removed is based on $46/ton CO_2 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 CO_2 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 CO_2 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 CO_2e 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 CO_2 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 per ton CO_2 removed/0.51) – ($40.76/ton CO_2 removed) = $159 per ton CO_2 removed. The applicant stated that at $159/ton CO_2 removed, the amount is nearly three times greater than the "generic" estimate of $57/ton CO_2 removed and over 50% above the cost effectiveness threshold of roughly $100-102 ton CO_2e 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

<table>
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<td>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 CO_2/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 CO_2/MWh-gross starting on January 1, 2032 as regulated in 40 CFR 60 Subpart TTTTa (or any applicable limits in 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.</td>
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<tr>
<td>CCTG1-MSS, CCTG1 no CCS - annual</td>
<td>CTG1_HRSG1</td>
<td rowspan="2">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 SO_2 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>
<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>
<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>
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[a] Maximum duration until the turbine reaches the minimum emissions compliance load (MECL).
<table>
<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/PM_{10} / $PM_{2.5}$</th></tr>
<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>
</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.</td>
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<tr>
<td>CCTG2-MSS, CCTG2 no CCS - annual</td>
<td>CTG2_HRSG2</td>
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		The planned MSS activities for the turbine units meet BACT.
CCS1 Absorber	CCS1	The project includes two absorbers to capture the emissions from the CCGTs and CCS boilers. The absorber will use a proprietary amine-based solvent with properties similar to monoethanolamine (MEA). VOC emissions can be produced from the absorber as a result of evaporative loss of the amine-based solvent used for CO_2 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. In addition to VOC, emissions from the CCS absorption process also consist of HAPs and acetone from the amine-based scrubbing process. Acetone is a non-VOC “exempt solvent” according to 30 TAC 101.1(116) and 40 CFR 51.100(s). The HAPs associated with the CCS absorber include acetaldehyde and formaldehyde. A CCS design vendor has not been chosen for the project. However, the applicant contacted vendors who provided estimated VOC and HAP emission rates from the CCS absorber for the CCGT operating cases. Each CCS absorber unit is being permitted at 8,760 hours per year. BACT for VOC and HAPs is discussed below, and BACT for VOC also applies to acetone. VOC, HAPs, and Acetone: The applicant did not identify any commercially operating facilities in the TCEQ Tier I or Tier II BACT analysis for the CCS BACT. Although various types of air permits have been issued for multiple configurations of existing and proposed CCS operations, CPV has not identified any PSD permits for comparable CCS facilities that would contain comparable BACT limits or control technology determinations. As a result, no RBLC entries are available for comparison of VOC emissions levels or selected BACT control options. The applicant noted that Quail Run Carbon (QRC) is a project in Odessa, Texas that is proposing 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 Tier III analysis concluded that implementation of good design and operating practices consistent with the underlying engineering basis used to quantify the proposed VOC emissions is considered BACT. Since CPV was unable to identify Tier I and Tier II BACT, they progressed to a Tier III analysis for VOC emissions from the CCS absorbers. Therefore, the applicant conducted a TCEQ Tier III analysis, which is very similar to an EPA top-down BACT analysis. The TCEQ Tier III analysis provided by the applicant follows the approach outlined in Appendix G of the TCEQ’s Air Pollution Control guidance document, APDG 6110v2 dated January 2011 and is summarized below. Note that the TCEQ Tier III BACT analysis summarized in Appendix G of TCEQ’s APDG 6110v2 guidance document is very similar to the EPA top-down BACT approach discussed in Appendix E of the same TCEQ guidance document.
CCS2 Absorber	CCS2	

Step 1 – Identification of all control options to reduce the VOC emissions from the CCS absorbers. For this step, the applicant searched the RBLC and recently issued Texas air permits for other CCS systems for CCGT projects, and by consulting other state agency web pages. Below are the feasible VOC control options identified by the applicant for the CCS absorbers.

- Adsorption
- Thermal Oxidization
- Catalytic Oxidization
- Flaring
- Absorption
- Condensation
- Alternative Raw Materials

Step 2 - Eliminate technically infeasible options, as summarized below from CPV's application:

- Adsorption - VOCs could be removed through adsorption onto activated carbon or zeolite adsorbents. Both have been used to remove a wide variety of VOCs from air streams. While the concentration of VOC in the CCS exhaust stream is relatively low (2 to 5 ppmv), the exhaust stream flow rate from the absorber stacks is very high, approximately 1.5 million actual cubic feet per minute (acfm). As such, carbon adsorption is not suitable for this type of exhaust stream. Controlling the exhaust stream with a carbon adsorption system would require many units operating in parallel to accommodate the flowrate. The logistics of installing this type of system (considering duct work and space constraints) is bordering on technically infeasible. However, in an effort to take a conservative approach, carbon adsorption was considered technically feasible for purposes of the BACT analysis.

- Thermal oxidation - Thermal oxidation refers to the essentially complete, gas-phase combustion of the VOCs to produce carbon dioxide and water vapor and is achieved by heating the VOC exhaust in the presence of oxygen. The destruction efficiency of a thermal oxidizer can exceed 99% with a combustion temperature of 1,500°F and a residence time of 1.0 seconds. Thermal oxidation systems are not as well suited to controlling exhaust streams that cycle on-and-off or that have an inlet concentration of less than 100 ppmv. The exhaust flow rate from each absorber stack is approximately 1.5 million acfm and would require excessive fuel to maintain the design combustion temperature. Additionally, because of the low inlet VOC concentration from the CCS absorbers, the waste gas VOC will not significantly contribute to the energy required to raise the exhaust gas to combustion temperatures. For these reasons, thermal oxidation was not considered technically feasible nor practical for this process.

- Catalytic oxidation - Catalytic oxidation refers to the essentially complete combustion of VOCs to produce carbon dioxide and water vapor through use of an oxidation catalyst. Oxidation is achieved by heating the VOC in the presence of oxygen and a catalyst and occurs at a lower temperature,

		• typically between 650 and 800°F (340 to 430°C). As with thermal oxidation, supplemental fuel is required for dilute streams. Destruction efficiencies are typically of greater than 95%. Catalytic oxidizers have been shown to be effective at inlet concentrations as low as 1 ppmv. However, even with a lower design combustion temperature, the fuel required to heat the CCS absorber exhaust stream to combustion temperature would still be excessive, practically infeasible. However, in efforts to take a conservative approach, catalytic oxidation is considered technically feasible for purposes of this BACT analysis. • Absorption – Gas absorption systems, which are commonly referred to as wet scrubbers, control pollutant emissions by enabling intimate contact between the gaseous pollutant in the exhaust stream and the scrubbing liquid. Installing another absorber for VOC emissions removal downstream of the CCS absorber does not make sense because it would use the same physical mechanism as the amine absorber and would not offer any further VOC emissions reduction from the CCGT exhaust stream. While well-designed scrubbers can achieve greater than 90 percent control of VOC emissions when applied to exhaust streams with VOC concentrations in excess of 250 ppmv, low inlet concentrations do not provide enough driving force for effective mass transfer. The VOC concentration in the CCS absorber stack exhaust gas is 2 to 5 ppmv, which is orders of magnitude less than the minimum inlet loading for effective operation of a scrubber. In addition, each CCS absorber stack flow rate is approximately 1.5 million acfm, which is far above the maximum flow capacity of a typical scrubber unit used for air pollution control. Therefore, absorption (scrubber operation) is not considered to be a technically feasible control option for the CCS absorbers. • Condensation - VOCs could be removed through condensation. This technology has been used to control VOC emissions in streams with concentrations greater than 10,000 ppmv, and is most common when solvent recovery is desired. However, condensation has not been effective with relatively dilute air streams. Low removal efficiencies would be expected, and the condensate would likely be disposed of as a waste. An expensive cryogenic system would be required to achieve a higher removal efficiency (> 90%), made even more difficult to implement due to the high exhaust flowrate. Given the low removal efficiency, the large capital cost of a cryogenic system, and the transfer of the problem to another medium, this system was considered ill-suited to purpose and technically infeasible for this process. • Alternative raw materials - Alternative solvent materials with lower VOC contents could be considered as a potential control option for BACT. However, the specific properties of the proprietary amine solvent are necessary to achieve the desired CO_2 removal for the generating facility. The solvent is an inherent part of the CSS process, and it is technically infeasible to utilize other materials in the process. As such, this control strategy was removed from the BACT analysis.

Carbon adsorption and catalytic oxidation were determined to be potentially technically feasible for this process.

Step 3 - Rank remaining control technologies by control effectiveness, as summarized in the table below.

Rank	Control Option	Approximate Control Efficiency
1 (tie)	Adsorption	98%
1 (tie)	Flaring	98%
1 (tie)	Catalytic oxidation	98%

Step 4 - Perform quantitative cost analysis to determine the cost-effectiveness (dollars per ton of pollutant reduced) of each the remaining emission reduction option. The estimated cost impacts for the remaining control options that were not eliminated in step 2 were estimated by the applicant using EPA guidance and EPA BACT costs spreadsheets as summarized in the table below, which are based on the costs per absorber unit.

Control Option	Total Capital Investment[a]	Total Annual Direct and Indirect Costs ($/year)	Control Eff. (%)	Annual VOC Controlled[b] (tpy)	Annualized Control Cost[c] ($/ton VOC removed)
Adsorption	$39,837,644 (14 total units per absorber)	$6,518,175	98%	192.49	$33,862
Flaring	$111,277,960 (2 total units per absorber)	$1,504,160,109	98%	192.49	$7,814,160
Catalytic Oxidation	$126,772,619 (37 total units per absorber)	$47,933,747	98%	192.49	$249,017

[a]Total capital investment shown includes the cost of the ductwork.
[b] Pre-control VOC emissions are 196.42 tpy per CCS absorber unit.
[c] Based on dollar-year of 2023. Costs are per CCS absorber unit (there are two trans and thus two CCS absorber units).

The dollars per ton of VOC removed for the adsorption, flaring, and catalytic oxidation control options listed above were not considered cost effective, in addition to the technical feasibility issues noted above.

Energy and environmental impacts are addressed within the cost analysis provided in the previous section. The costs associated with the additional energy required to transport the exhaust gas through the carbon units and the steam demand to regenerate the units has been included in the annual operating costs.

A similar analysis was conducted for HAPs. The table below summarizes the applicant's cost effectiveness calculation for HAPs.

Control Option	Total Capital Investment[a]	Total Annual Direct and Indirect Costs ($/year)	Control Eff. (%)	Annual HAP Controlled[b] (tpy)	Annualized Control Cost[c] ($/ton HAPs removed)
Adsorption	$39,837,644 (14 total units per absorber)	$6,518,175	98%	116.24	$56,076
Flaring	$111,277,960 (2 total units per absorber)	$1,504,160,109	98%	116.24	$12,941,461
Catalytic Oxidation	$126,772,619 (37 total units per absorber)	$47,933,747	98%	116.24	$412,411

[a]Total capital investment shown includes the cost of the ductwork.

		[b] Pre-control HAP emissions are 118.61 tpy per CCS absorber unit. [c] Based on dollar-year of 2023. Costs are per CCS absorber unit (there are two trans and thus two CCS absorber units).
CCS2 Absorber	CCS2	Step 5 - Select BACT based on cost-effectiveness and performance. Since none of the control options listed above were considered cost effective, the applicant represented BACT for the CCS absorbers as minimizing VOC and HAP emissions from the CCS absorbers by implementing good design and operating practices consistent with the underlying engineering basis used to quantify the proposed VOC and HAP emission limits. These work practices will specifically target minimization of amine solvent carryover and evaporation during the flue gas CO_2 removal process. Furthermore, the applicant stated that they will minimize degradation of the amine solvent by regularly assessing the relevant physical and chemical properties of the recirculating amine solvent on a periodic basis to ensure quality and appropriate CO_2 removal characteristics as a standard operating procedure for the CCS absorber process (quarterly amine quality assessments are being included in SC No. 29). For each CCS absorber stack, the applicant is proposing a VOC emission rate limit of 196.42 tpy and a HAP emission rate limit of 118.61 tpy. The applicant proposed initial and periodic Method 18 stack testing (or equivalent method approved by TCEQ) for direct measurements of the speciated VOC compounds expected to be present the CCS Absorber exhaust gases that are generated by the amine solvent-based absorber tower. The applicant stated that a mass per time basis for the VOC BACT limit is the only appropriate emissions performance metric because the amount of VOC emissions generated is not a strong function of the amount of flue gas processed, but rather is influenced by a wide range of other process variables which cannot be introduced into the form of the VOC BACT limit. For example, mass emissions of VOC could be relatively constant while flue gas flow rates vary preventing a VOC concentration basis for the BACT limit. MSS – The applicant represented that site will send liquids to a closed drain system, degas to atmosphere, and de-heel all remaining liquids within a reasonable amount of time, which is the Tier I BACT for absorbers with a VOC vapor pressure of less than 0.5 psia. CCS MSS activities are addressed separately below under EPNs CCS1-CO2VT and CCS2-CO2VT. In summary, the CCS absorbers meet BACT as summarized above.
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 CO_2-rich vent stream must be discharged to facilitate start-ups and shutdowns of the CCS Regenerator and CO_2 Compressor sections and responding to trips of the CO_2 Compressor. During these times, the CO_2-rich vent stream may need to be re-routed from its normal process connection to the dedicated CO_2-rich stream exhaust point. The facility will have two CO_2 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).
CCS2 MSS Activities	CCS2-CO2VT	

		The CO_2 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 CO_2e. 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 CO_2e. These CO_2 MSS emission estimates are based on the following maximum expected frequency and durations: **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
CCS1 Boiler 1	CCS1	Two natural gas-fired CCS boilers each rated at 182 MMBtu/hr per unit will be used for supplemental steam production associated with each CCS train (two CCS trains are being authorized 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 (along with turbine HRSG exhaust gas) will be directed to the CCS system and exhaust through the CCS absorber stacks during normal (non-MSS) operations. Each unit is being permitted at 8,760 hours per year. BACT for each pollutant is discussed below. NOx: Emission factor of 0.01 lb/MMBtu (HHV) using a low NOx burners in each unit. The units will have CEMS that will ensure that the NOx emission limits are met. 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
CCS1 Boiler 2	CCS1	
CCS2 Boiler 1	CCS2	
CCS2 Boiler 2	CCS2	

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

		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 CCS boilers is 0.01 lb/MMBtu, which is on the lower end of the range of determinations in the RBLC. CO: Emissions of 50 ppmvd at 3% O_2, or approximately equivalent to a CO emission factor of 0.037 lb/MMBtu (HHV) using good combustion practices. The units will have CEMS that will ensure that the CO emission limits are met. The TCEQ Tier I BACT for natural gas fired boilers greater than 40 MMBtu/hr is 50 ppmv at 3% O_2 achieved by good combustion practices or oxidation catalyst. 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 boilers 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 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. PM/PM_{10}/$PM_{2.5}$: 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 is good combustion practices and less than 5% opacity. The applicant assumed that all of the PM/PM_{10}/$PM_{2.5}$ emitted from the boilers is conservatively assumed to be less than 2.5 microns in diameter, and, therefore, the PM, PM_{10}, and $PM_{2.5}$ emission rates are assumed to be the same. The applicant's RBLC searches showed that PM/PM_{10}/$PM_{2.5}$ 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/PM_{10}/$PM_{2.5}$ 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

		$PM/PM_{10}/PM_{2.5}$ 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 $PM/PM_{10}/PM_{2.5}$ emission limit of 0.007 lb/MMBtu, which is consistent with the precedents listed in the RBLC. SO_2: The applicant assumed 100% molar conversion of natural gas sulfur to SO_2, conservatively not reducing SO_2 emissions due to conversion to H_2SO_4. 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 SO_2 emission factor of 0.0014 lb/MMBtu (HHV). The TCEQ Tier I BACT is firing low sulfur fuel and good combustion practices. The SO_2 limits in the RBLC searches ranged from 0.0011 to 0.002 lb/MMBtu. A project's SO_2 and H_2SO_4 emissions can vary greatly depending on the maximum sulfur content of the fuel and assumptions related to conversion of SO_2 to H_2SO_4, 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 SO_2 emission factor of 0.0014 lb/MMBtu, which is consistent with the precedents listed in the RBLC. H_2SO_4: The applicant assumed 100% molar conversion of natural gas sulfur to SO_2 and 10% molar conversion of SO_2 to SO_3 (conservatively not reducing the SO_2 emissions) and 100% conversion of SO_3 to H_2SO_4. 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 H_2SO_4 emission factor of 0.00021 lb/MMBtu (HHV). The TCEQ Tier I BACT is firing low sulfur fuel. For H_2SO_4, the levels of control in the RBLC searches ranged from 0.00011 to 0.0018 lb/MMBtu. A project's SO_2 and H_2SO_4 emissions can vary greatly depending on the maximum sulfur content of the fuel and assumptions related to conversion of SO_2 to H_2SO_4, 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 H_2SO_4 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). CO_2e: The CCS boilers will fire natural gas, which is the lowest carbon fuel available. Therefore, formation of CO_2 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 CO_2, 2.20E-03 lb/MMBtu for CH_4, and 2.20E-04 lb/MMBtu for N_2O, which convert to an overall CO_2e 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.
CCS1 Boiler 1 - MSS	CCS1BLR1	The CCS boilers will exhaust from their equipment-specific stacks during the limited periods of startup and shutdown, 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. There are two CCS boilers per CCS train, with two CCS trains total, for a total of four CCS boilers, with each boiler rated at 182 MMBtu/hr. The proposed limits on the number and duration of startup events discussed below was proposed as BACT. 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 SO_2 (and H_2SO_4) 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.

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

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<tr><td>Hot SU</td><td>200</td><td>0</td><td>41</td></tr>
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<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>PM_{10} / $PM_{2.5}$</th></tr>
<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>
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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.
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<tr><td>CCS1 Boiler 2 - MSS</td><td>CCS1BLR2</td></tr>
<tr><td>CCS2 Boiler 1 - MSS</td><td>CCS2BLR1</td></tr>
<tr><td>CCS2 Boiler 2 - MSS</td><td>CCS2BLR2</td></tr>
<tr><td>CTG Boiler</td><td>CTGBLR</td><td>
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% O_2 achieved by good
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		combustion practices or oxidation catalyst; note the 50 ppmv at 3% O_2 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. $PM/PM_{10}/PM_{2.5}$: 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 $PM/PM_{10}/PM_{2.5}$ emitted from the boiler is conservatively assumed to be less than 2.5 microns in diameter, and, therefore, the PM, PM_{10}, and $PM_{2.5}$ emission rates are assumed to be the same. The applicant's RBLC searches showed that $PM/PM_{10}/PM_{2.5}$ 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 $PM/PM_{10}/PM_{2.5}$ 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 $PM/PM_{10}/PM_{2.5}$ 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 $PM/PM_{10}/PM_{2.5}$ emission limit of 0.007 lb/MMBtu, which is consistent with the precedents listed in the RBLC. SO_2: The applicant assumed 100% molar conversion of natural gas sulfur to SO_2, conservatively not reducing SO_2 emissions due to conversion to H_2SO_4. 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 SO_2 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 SO_2 limits in the RBLC searches ranged from 0.0011 lb/MMBtu to 0.002 lb/MMBtu. A project's SO_2 and H_2SO_4 emissions can vary greatly depending on the maximum sulfur content of the fuel and assumptions related to conversion of SO_2 to H_2SO_4, 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 SO_2 emission factor of 0.0014 lb/MMBtu, which is consistent with the precedents listed in the RBLC. H_2SO_4: The applicant assumed 100% molar conversion of natural gas sulfur to SO_2 and 10% molar conversion of SO_2 to SO_3 (conservatively not reducing the SO_2 emissions) and 100% conversion of SO_3 to H_2SO_4. 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 H_2SO_4 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 H_2SO_4, the levels of control in the RBLC searches ranged from 0.00011 to 0.0018 lb/MMBtu. A project's SO_2 and H_2SO_4 emissions can vary greatly depending on the maximum sulfur content of the fuel and assumptions related to conversion of SO_2 to H_2SO_4, 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 H_2SO_4 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. CO_2e: The CTG auxiliary boiler will fire natural gas, which is the lowest carbon fuel available. Therefore, formation of CO_2 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 CO_2, 2.20E-03 lb/MMBtu for CH_4, and 2.20E-04 lb/MMBtu for N_2O, which convert to an overall CO_2e 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' 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% O_2, 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% O_2) to 0.087 lb/MMBtu, with the most recent BACT determination at 50 ppmv at 3% O_2 (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. $PM/PM_{10}/PM_{2.5}$: 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 MMBtu/hr is a maximum opacity 5%. The applicant assumed that all of the $PM/PM_{10}/PM_{2.5}$ emitted from the heater is conservatively assumed to be less than 2.5 microns in diameter, and, therefore, the PM, PM_{10}, and $PM_{2.5}$ emission rates are assumed to be the same. The applicant's RBLC searches showed that $PM/PM_{10}/PM_{2.5}$ 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 $PM/PM_{10}/PM_{2.5}$ emission limit of 0.0048 lb/MMBtu, which is lower than the precedents listed in the RBLC. SO_2: The applicant assumed 100% molar conversion of natural gas sulfur to SO_2, conservatively not reducing SO_2 emissions due to conversion to H_2SO_4. 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 SO_2 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 SO_2 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 SO_2 emission factor of 0.0014 lb/MMBtu, which is consistent with the precedents listed in the RBLC. H_2SO_4: The applicant assumed 100% molar conversion of natural gas sulfur to SO_2 and 10% molar conversion of SO_2 to SO_3 (conservatively not reducing the SO_2 emissions) and 100% conversion of SO_3 to H_2SO_4. 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 H_2SO_4 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 H_2SO_4, 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 SO_2 and H_2SO_4 emissions can vary greatly depending on the maximum sulfur content of the fuel and assumptions related to conversion of SO_2 to H_2SO_4. The CPV project proposes to combust natural gas with a maximum sulfur

		content of 0.5 grains sulfur/100 dscf natural gas with an H_2SO_4 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. 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. CO_2e: The fuel heater will fire pipeline quality natural gas, which is the lowest carbon fuel available. Therefore, formation of CO_2 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 CO_2, 2.20E-03 lb/MMBtu for CH_4, and 2.20E-04 lb/MMBtu for N_2O, which convert to an overall CO_2e 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 CO_2e 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 CCS Em Gen	CTGEG CCSEG	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 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 NOx, 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. NOx: 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 NOx + NMHC and the applicant conservatively assumed the NOx + NMHC as 100% NOx. 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. $PM/PM_{10}/PM_{2.5}$: 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 PM_{10} and $PM_{2.5}$ equal total PM. SO_2: 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 SO_2. H_2SO_4: 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 SO_2 and 10% molar conversion of SO_2 to SO_3 (conservatively not reducing the SO_2 emissions) and 100% conversion of SO_3 to H_2SO_4. 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 CO_2, 3.00E-03 kg/MMBtu for CH_4, and 6.00E-04 kg/MMBtu for N_2O, 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. 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 NOx, 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. NOx: 3.0 g/hp-hr (4.0 g/kW-hr). This emission factor is represented in the cited rule as NOx + NMHC and the applicant conservatively assumed the NOx + NMHC as 100% NOx. CO: 2.6 g/hp-hr (3.5 g/kW-hr). VOC: 0.40 g/hp-hr, based on information from the vendor. $PM/PM_{10}/PM_{2.5}$: 0.15 g/hp-hr (0.20 g/kW-hr). The rule represents only PM, but the applicant assumed PM_{10} and $PM_{2.5}$ equal total PM. SO_2: 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 SO_2. H_2SO_4: 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 SO_2 and 10% molar conversion of SO_2 to SO_3 (conservatively not reducing the SO_2 emissions) and 100% conversion of SO_3 to H_2SO_4. 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.

		CO_2e: 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 CO_2, 3.00E-03 kg/MMBtu for CH_4, and 6.00E-04 kg/MMBtu for N_2O, 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 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 PM_{10} emission rates were calculated following an AWMA presentation titled "Calculating Realistic PM_{10} 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 PM_{10} 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 $PM/PM_{10}/PM_{2.5}$ 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. 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 the liquid to a covered vessel when draining the tank. 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 the liquid to a covered vessel when draining the tank. 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.
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 the liquid to a covered vessel when draining the tank. 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 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 the liquid to a covered vessel when draining the tank. 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 the liquid to a covered vessel when draining the tank. 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 Diesel Storage Tank	TK13	Horizontal fixed roof tank painted white with a nominal capacity of 181 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 the liquid to a covered vessel when draining the tank. 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 the liquid to a covered vessel when draining the tank. 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 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 the liquid to a covered vessel when draining the tank. 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/PM_{10}/$PM_{2.5}$) 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/PM_{10}/$PM_{2.5}$ emission rates were estimated using test data presented in "Emission Factor Development for Mechanical

		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 PM_{10}, 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 SOCMI without ethylene average emission factors. The emissions from this fugitive EPN consist of VOC emissions, specifically monoethanolamine (MEA). The TCEQ Tier I BACT guidelines for equipment leak fugitives is 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 / 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 SOCMI without ethylene average emission factors. The only pollutant emitted from this fugitive EPN is ammonia. NH_3: The TCEQ Tier I BACT for ammonia fugitive emissions is audio, visual, and olfactory (AVO) inspections twice per shift and appropriate credit for 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. The emissions from this fugitive EPN primarily consist of CH_4 and CO_2, and small quantities of VOC emissions. The TCEQ Tier I BACT guidelines for equipment leak fugitives is 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 % CH_4, 5 weight % CO_2, 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 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 (SF_6), which is a colorless, odorless, non-flammable gas with an extremely stable molecular structure. The unique chemical properties of SF_6 make

		it an efficient electrical insulator. SF_6 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 SF_6, 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 SF_6 and an assumed maximum annual leak rate of 0.5 weight %, the calculated SF_6 allowable emission rate is 0.0040 tpy SF_6 or 91.26 tpy as CO_2e. The TCEQ does not specify Tier I BACT for SF_6 emissions from circuit breakers. However, the applicant proposed to use state-of-the-art, totally enclosed pressurized SF_6 circuit breakers (leak-tight closed systems) with leak detection including a density alarm that provides a warning when SF_6 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 CH_4, CO_2, and VOC, with the calculated maximum annual emission rates of 3.03 tpy for VOC and 1,368.34 tpy for CO_2e. 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 NOx 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 associated with these activities is summarized below. CEMS calibrations – The NOx and CO emissions associated with the calibration gas cylinders is <0.01 lb/hour and <0.01 tpy for NOx and 0.01 lb/hour and <0.01 tpy for CO. These daily calibrations are conducted as necessary for the NOx 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. 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 CO_2 compressor feed stream. The exhaust stream from the dehydrator is comprised of predominantly water and CO_2, with a small molar percentage (<0.01%) of glycol and other VOCs including HAPs. Potential emissions of VOC and CO_2 (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).
CCS2 TEG Dehydrator	CCS2-CO2VT	

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 CO_2e.

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 CO_2 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.

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 unit)	$187,662	98%	0.050	$3,741,007

control VOC and the proposed HAP emission rate from the dehydrator unit.

Control Option	Total Capital Investment	Total Annual Direct and Indirect Costs ($/year)	Control Eff. (%)	Annual HAP Controlled[a] (tpy)	Annualized Control Cost[b] ($/ton HAP removed)
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

[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.

CCS2 TEG Dehydrator	CCS2-CO2VT	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 (CO_2) 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 CO_2 from the dehydrator is a small fraction of the CO_2 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.
Lube Oil Vent for Generating Facility	LUB-CTG	The CCGTs will be equipped with a dedicated lubrication system that will service both CCTG trains and a separate system that will 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 $PM/PM_{10}/PM_{2.5}$ 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 $PM/PM_{10}/PM_{2.5}$ 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 $PM/PM_{10}/PM_{2.5}$ 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.
Lube Oil Vent for CCS	LUB-CCS	

Clean Air Act §112(g) Case-by-Case MACT Evaluation

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 CO_2 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 above for the CCS absorbers (EPNs CCS1 and CCS2). As shown in the table above 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 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 SOCMI 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 CO_2 removal process.

Special Condition (SC) No. 39 of the draft 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 CO_2-absorbing solution supplied to the CO_2 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. See the table above in the BACT discussion for more details on the dehydrator HAPs control. SC No. 26 of the draft 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 HAP emissions table presented in Section V above are relatively small and are discussed further in the BACT discussion and BACT summary table provided above.

VII. Air Quality Analysis

The air quality analysis (AQA) is acceptable, as supplemented by ADMT, for all review types and pollutants. The results are summarized below.

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$ (NAAQS and Increment), and 1-hr and annual NO_2 exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for 1-hr, 3-hr, 24-hr, and annual SO_2 and 1-hr and 8-hr CO indicate that the project is below the respective de minimis concentrations and no further analysis is required.

The justification for selecting EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels is based on the assumptions underlying EPA's development of the 1-hr NO_2 and 1-hr SO_2 De Minimis levels. As explained in EPA guidance memoranda[1,2], EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr NO_2 and 1-hr SO_2 NAAQS.

The $PM_{2.5}$ and ozone De Minimis levels are EPA recommended De Minimis levels. The use of EPA recommended De Minimis levels is sufficient to conclude that a proposed source will not cause or contribute to a violation of an ozone and $PM_{2.5}$ NAAQS or $PM_{2.5}$ PSD increments based on the analyses documented in EPA guidance and policy memoranda[3].

While the De Minimis levels for both the NAAQS and increment are identical for $PM_{2.5}$ in the table below, the procedures to determine significance (that is, predicted concentrations to compare to the De Minimis levels) are different. This difference occurs because the NAAQS for $PM_{2.5}$ are statistically-based, but the corresponding increments are exceedance-based.

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (μg/m³)

Pollutant	Averaging Time	GLCmax (μg/m³)	De Minimis (μg/m³)
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

[1] www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf
[2] www.tceq.texas.gov/assets/public/permitting/air/memos/guidance_1hr_no2naaqs.pdf
[3] www.tceq.texas.gov/permitting/air/modeling/epa-mod-guidance.html

CO	8-hr	317	500

The 1-hr SO_2, 24-hr and annual $PM_{2.5}$ (NAAQS), and 1-hr NO_2 GLCmax are based on the highest five-year averages of the maximum predicted concentrations determined for each receptor. The GLCmax for all other pollutants and averaging times represent the maximum predicted concentrations over five years of meteorological data.

EPA intermittent guidance was relied on for the 1-hr NO_2 PSD De Minimis analyses. Refer to the Modeling Emissions Inventory section for details.

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 500 tpy Terry County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.04 $\mu g/m^3$ and 0.001 $\mu g/m^3$, respectively. Since the combined direct and secondary 24-hr and annual $PM_{2.5}$ impacts are above the De minimis levels, a full impacts analysis is required.

Table 2. 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

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project emissions of O_3 precursor emissions (NO_x and VOC). For the project NO_x and VOC emissions, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. The basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 500 tpy Terry County source, the applicant estimated an 8-hr O_3 concentration of 0.88 ppb. When the estimates of ozone concentrations from the project emissions are added together, the results are less than the De Minimis level.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 24-hr SO_2, 24-hr PM_{10}, annual NO_2, and 8-hr CO are below their respective monitoring significance level.

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Significance ($\mu g/m^3$)
SO_2	24-hr	2.01	13
PM_{10}	24-hr	7.66	10
NO_2	Annual	3	14
CO	8-hr	317	575

The GLCmax represent the maximum predicted concentrations over five years of meteorological data.

The applicant evaluated ambient $PM_{2.5}$ monitoring data to satisfy the requirements for the pre-application air quality analysis.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 350250008 located at 2320 N. Jefferson St., Hobbs, New Mexico. The three-year average (2021-2023) of the 98th percentile of the annual distribution of the 24-hr concentrations was used for the 24-hr value (19.7 µg/m^3). The three-year average (2021- 2023) of the annual concentrations was used for the annual value (6.6 µg/m^3). The use of this monitor is reasonable based on a comparison of county-wide emissions and population, as well as the monitor being located in a more suburban/light industrial area relative to the rural area for the project site. These background concentrations were also used as part of the NAAQS analysis.

Since the project has a net emissions increase of 100 tpy or more of VOC or NO_x, the applicant evaluated ambient O_3 monitoring data to satisfy the requirements for the pre-application air quality analysis.

A background concentration for O_3 was obtained from the EPA AIRS monitor 350250008 located at 2320 N. Jefferson St., Hobbs, New Mexico. A three-year average (2021-2023) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis (71 ppb). The use of this monitor is reasonable based on a comparison of county-wide emissions and population, as well as the monitor being located in a more suburban/light industrial area relative to the rural area for the project site. The proposed project is located in an attainment area for ozone and is required to obtain a PSD permit[4]. The PSD permitting program requires that proposed new major stationary sources and major modifications must demonstrate that the emissions from the proposed source or modification will not cause or contribute to a violation of any NAAQS[5]. The predicted concentrations in Table 2 demonstrate the proposed project would not cause or contribute to a violation of the NAAQS.

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 24-hr PM_{10}, 24-hr and annual $PM_{2.5}$, and 1-hr and annual NO_2 exceed the respective de minimis concentration and require a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 4. Total Concentrations for PSD 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)
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

[4] October 26, 2015 *Federal Register* (80 FR 65292)
[5] 40 Code of Federal Regulations (CFR) 52.21(k)

NO_2	Annual	4	9	13	100

The 24-hr PM_{10} GLCmax is the maximum high, sixth high predicted concentration over five years of meteorological data. The 24-hr $PM_{2.5}$ GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted 24-hr concentrations determined for each receptor. The annual $PM_{2.5}$ GLCmax is the maximum five-year average of the annual concentrations determined for each receptor. The 1-hr NO_2 GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor. The annual NO_2 GLCmax is the maximum predicted concentration over five years of meteorological data.

The primary NAAQS for 24-hr and annual SO_2 have been revoked for Ward County and are not reported above.

EPA intermittent guidance was relied on for the 1-hr NO_2 PSD NAAQS analyses. Refer to the Modeling Emissions Inventory section for details.

A background concentration for PM_{10} was obtained from the EPA AIRS monitor 481411021 at 6767 Ojo De Agua, El Paso, El Paso County. The high, second high 24-hr concentration from the most recent three years (2021-2023) was used for the 24-hr value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and the applicant's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 350250008 located at 2320 N. Jefferson St., Hobbs, New Mexico. The three-year average (2021-2023) of the 98th percentile of the annual distribution of the maximum daily 1-hr concentrations was used for the 1-hr value. The annual mean concentration from 2023 was used for the annual value. The ADMT was unable to verify the reported annual concentration; however, this discrepancy does not change the overall conclusions. The use of this monitor is reasonable based on a comparison of county-wide emissions and population, as well as the monitor being located in a more suburban/light industrial area relative to the rural area for the project site.

As stated above, to evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. Using data associated with the 500 tpy Terry County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.04 $\mu g/m^3$ and 0.001 $\mu g/m^3$, respectively. When these estimates are added to the GLCmax listed in Table 4 above, the results are less than the NAAQS.

D. Increment Analysis

The De Minimis analysis modeling results indicate that 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$, and annual NO_2 exceed the respective de minimis concentrations and require a PSD increment analysis.

Table 5. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Increment ($\mu g/m^3$)
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

The GLCmax for the 24-hr $PM_{2.5}$ and 24-hr PM_{10} is the maximum high, second high predicted concentration across five years of meteorological data. For annual NO_2, PM_{10}, and $PM_{2.5}$, the GLCmax represents the maximum predicted concentrations over five years of meteorological data.

The GLCmax for 24-hr and annual $PM_{2.5}$ reported in the table above represent the total predicted concentrations associated with modeling the direct $PM_{2.5}$ emissions and the contributions associated with secondary $PM_{2.5}$ formation (discussed above in the NAAQS Analysis section).

E. 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 H_2SO_4 24-hr maximum predicted concentration of 0.67 $\mu g/m^3$ occurred approximately 212 meters from the property line towards the northwest. The H_2SO_4 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 $\mu g/m^3$. The Carlsbad Caverns National Park Class I area is an additional 86 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Carlsbad Caverns National Park Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 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 PM_{10}, $PM_{2.5}$, NO_2, and SO_2 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.

F. Minor Source NSR and Air Toxics Review

Table 6. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Standard ($\mu g/m^3$)
SO_2	1-hr	7	1021

H_2SO_4	1-hr	4.51	50
H_2SO_4	24-hr	1.34	15

Table 7. Total Concentrations for Minor NSR NAAQS (Concentrations > De Minimis)

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

The GLCmax is the maximum predicted concentrations over five years of meteorological data. Please note that the lead GLCmax was calculated using unit modeling and is based on the maximum 1-hr concentration rather than the 3-month average. This is conservative. See Section 3 for additional details.

A background concentration for Pb was obtained from the EPA AIRS monitor 480850029 located at 7202 Stonebrook Parkway, Frisco, Collin County. The applicant used the highest rolling 3-month average from 2021-2023. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site. In addition, the monitor represents the highest lead monitored concentrations in the state.

Table 8. Generic Modeling Results

Source ID	1-hr GLCmax ($\mu g/m^3$ per lb/hr)	Annual GLCmax ($\mu g/m^3$ per lb/hr)
3B_7_C1	0.53	0.02
3B_7_C2	0.50	0.02
3B_7_C3	0.52	0.02
3B_7_C4	0.50	0.02
AB	13.57	0.33
CCGTP	178.48	1.48
CCSP1A	143.7	1.94
CCSP1B	143.70	1.93
CCSP1C	143.61	1.94
CCSP1D	143.21	1.93
CCSP1E	144.28	1.94
CCSP1F	145.01	1.94
CCSP1G	144.44	1.93

CCSP1H	144.85	1.95
CCSP2A	102.99	1.18
CCSP2B	102.64	1.17
CCSP2C	102.33	1.18
CCSP2D	102.92	1.18
CCSP2E	102.15	1.18
CCSP2F	103.03	1.18
CCSP2G	102.78	1.17
CCSP2H	102.81	1.18
DEHY1	8.90	0.15
DEHY2	8.86	0.15
EFP	68.63	1.14
EG1	25.73	0.47
EG2	24.36	0.56
FGH	38.59	1.30
LV1	316.59	0.83
LV2	161.23	0.95
TK14_15	232.99	2.01
TK16_17	232.99	2.01
TK1_4	124.16	1.25
TK5_6	124.16	1.25
TK7_8	232.99	2.01
TK9_10	232.99	2.01

Table 9. Minor NSR Project (Increases Only) Modeling Results for Health Effects

Pollutant & CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	10% ESL ($\mu g/m^3$)

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
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
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

Table 10. 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
2-diethylaminoethanol	100-37-8	1-hr	176	E Property Line	53
2-diethylaminoethanol	100-37-8	Annual	2	E Property Line	9.6

Table 11. 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 GLCmax locations are listed in Table 10 above. The applicant evaluated the GLCmax as the GLCni.

The frequencies reported in Table 11 represent the maximum number of exceedances out of the five years of meteorological data evaluated. Please note that the ADMT supplemented the frequencies in Table 11 based on the GLCmax location. The applicant reported the frequencies for all locations.

Modeling and Effects Review Applicability (MERA) Summary

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 9 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 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 below.

Health Effects Review - Minor NSR Project-Related Results[a]

Pollutant & CAS#	Averaging Time	GLCmax µg/m³	ESL µg/m³	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
	Annual	N/A	1000	Step 0 – long-term ESL ≥ 10% of short-term ESL
Paraffins (petroleum), normal C5-20 64771-72-8	1-hr	202	3500	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.005	350	Step 3 - GLCmax ≤ 10% ESL
1,3-Butadiene 106-99-0	1-hr	0.01	510	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.00005	9.9	Step 3 - GLCmax ≤ 10% ESL
2-Methylnaphthalene 91-57-6	1-hr	N/A	200	Step 2 – long-term ESL ≥ 10% of short-term ESL, 2 µg/m^3 ≤ short-term ESL < 500 µg/m^3 and production emission increase < 0.04 lb/hr
	Annual	N/A	20	Step 0 – long-term ESL ≥ 10% of short-term ESL
3-Methylchloranthrene 56-49-5	1-hr	3.96E-06	0.02	Step 3 - GLCmax ≤ 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 ≤ 10% ESL
	Annual	6.84E-07	0.05	Step 3 - GLCmax ≤ 10% ESL
Acenaphthene 83-32-9	1-hr	N/A	100	Step 2 – long-term ESL ≥ 10% of short-term ESL, 2 µg/m^3 ≤ short-term ESL < 500 µg/m^3 and production emission increase < 0.04 lb/hr
	Annual	N/A	10	Step 0 – long-term ESL ≥ 10% of short-term ESL

Acenaphthylene 208-96-8	1-hr	N/A	100	Step 2 – long-term ESL ≥ 10% of short-term ESL, 2 µg/m^3 ≤ short-term ESL < 500 µg/m^3 and production emission increase < 0.04 lb/hr
	Annual	N/A	10	Step 0 – long-term ESL ≥ 10% of short-term ESL
Acetaldehyde 107-07-0	1-hr	97.4	120	Step 7 – sitewide modeling deemed acceptable by ADMT
	Annual	0.55	45	Step 3 - GLCmax ≤ 10% ESL
Acetone 67-64-1	1-hr	14.44	7800	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.03	4800	Step 3 - GLCmax ≤ 10% ESL
Acetonitrile 75-05-8	1-hr	9.10	340	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.0008	34	Step 3 - GLCmax ≤ 10% ESL
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
Dichlorobenzene (as "Dichlorobenzene , all isomers") 25321-22-6	1-hr	N/A	900	Step 2 – long-term ESL ≥ 10% of short-term ESL, 500 µg/m^3 ≤ short-term ESL < 3500 µg/m^3 and production emission increase ≤ 0.1 lb/hr
	Annual	N/A	160	Step 0 – long-term ESL ≥ 10% of short-term ESL
Ethylbenzene 100-41-4	1-hr	0.13	26,000	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.0033	570	Step 3 - GLCmax ≤ 10% ESL
Fluoranthene 206-44-0	1-hr	0.005	0.5	Step 3 - GLCmax ≤ 10% ESL
	Annual	1.13E-06	0.05	Step 3 - GLCmax ≤ 10% ESL
Fluorene 86-73-7	1-hr	N/A	10	Step 2 – long-term ESL ≥ 10% of short-term ESL, 2 µg/m^3 ≤ short-term ESL < 500 µg/m^3 and production emission increase < 0.04 lb/hr
	Annual	N/A	1	Step 0 – long-term ESL ≥ 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 ≤ 10% ESL
Hexane, mixed isomers 92112-69-1	1-hr	5.56	5600	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.12	200	Step 3 - GLCmax ≤ 10% ESL
Indeno(1,2,3-cd)pyrene 193-39-5	1-hr	0.0005	0.5	Step 3 - GLCmax ≤ 10% ESL
	Annual	1.70E-07	0.05	Step 3 - GLCmax ≤ 10% ESL
Naphthalene 91-20-3	1-hr	N/A	440	Step 2 – long-term ESL ≥ 10% of short-term ESL, 2 µg/m^3 ≤ short-term ESL < 500 µg/m^3 and production emission increase < 0.04 lb/hr
	Annual	N/A	50	Step 0 – long-term ESL ≥ 10% of short-term ESL
Polycyclic Aromatic Hydrocarbons 130498-29-2	1-hr	0.015	0.5	Step 3 - GLCmax ≤ 10% ESL

	Annual	N/A	0.05	Step 0 – long-term ESL ≥ 10% of short-term ESL
Pentane (as “pentane, all isomers” 92046-46-3	1-hr	2.31	59,000	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.059	7100	Step 3 - GLCmax ≤ 10% ESL
Phenanthrene 85-01-8	1-hr	N/A	8	Step 2 – long-term ESL ≥ 10% of short-term ESL, 2 µg/m^3 ≤ short-term ESL < 500 µg/m^3 and production emission increase < 0.04 lb/hr
	Annual	N/A	0.8	Step 0 – long-term ESL ≥ 10% of short-term ESL
Propylene Oxide 75-56-9	1-hr	0.12	70	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.003	7	Step 3 - GLCmax ≤ 10% ESL
Pyrene 129-00-0	1-hr	0.0043	0.5	Step 3 - GLCmax ≤ 10% ESL
	Annual	1.08E-06	0.05	Step 3 - GLCmax ≤ 10% ESL
Toluene 108-88-3	1-hr	0.87	4500	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.014	1200	Step 3 - GLCmax ≤ 10% ESL
Xylene (mixed isomers) 1330-20-7	1-hr	0.49	2200	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.0067	180	Step 3 - GLCmax ≤ 10% ESL
Arsenic 7440-38-2	1-hr	0.0004	3	Step 3 - GLCmax ≤ 10% ESL
	Annual	8.55E-06	0.067	Step 3 - GLCmax ≤ 10% ESL
Barium 7440-39-3	1-hr	N/A	5	Step 2 – long-term ESL ≥ 10% of short-term ESL, 2 µg/m^3 ≤ short-term ESL < 500 µg/m^3 and production emission increase < 0.04 lb/hr
	Annual	N/A	0.5	Step 0 – long-term ESL ≥ 10% of short-term ESL
Beryllium 7440-41-7	1-hr	0.00004	0.02	Step 3 - GLCmax ≤ 10% ESL
	Annual	7.83E-07	0.002	Step 3 - GLCmax ≤ 10% ESL
Cadmium 7440-43-9	1-hr	0.0034	5.4	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.00007	0.0033	Step 3 - GLCmax ≤ 10% ESL
Chromium 7440-47-3	1-hr	0.0043	3.6	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.00009	0.041	Step 3 - GLCmax ≤ 10% ESL
Cobalt 7440-48-4	1-hr	0.0003	0.21	Step 3 - GLCmax ≤ 10% ESL

	Annual	5.48E-06	0.0017	Step 3 - GLCmax ≤ 10% ESL
Manganese 7439-96-5	1-hr	0.0012	2.7	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.00002	0.25	Step 3 - GLCmax ≤ 10% ESL
Mercury 7439-97-6	1-hr	0.0008	0.25	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.00002	0.025	Step 3 - GLCmax ≤ 10% ESL
Molybdenum 7439-98-7	1-hr	N/A	30	Step 2 – long-term ESL ≥ 10% of short-term ESL, 2 $\mu g/m^3$ ≤ short-term ESL < 500 $\mu g/m^3$ and production emission increase < 0.04 lb/hr
	Annual	N/A	3	Step 0 – long-term ESL ≥ 10% of short-term ESL
Nickel 7440-02-0	1-hr	0.0065	0.33	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.00014	0.059	Step 3 - GLCmax ≤ 10% ESL
Selenium 7782-49-2	1-hr	N/A	2	Step 2 – long-term ESL ≥ 10% of short-term ESL, 2 $\mu g/m^3$ ≤ short-term ESL < 500 $\mu g/m^3$ and production emission increase < 0.04 lb/hr
	Annual	N/A	0.2	Step 0 – long-term ESL ≥ 10% of short-term ESL
Copper 7440-50-8	1-hr	N/A	10	Step 2 – long-term ESL ≥ 10% of short-term ESL, 2 $\mu g/m^3$ ≤ short-term ESL < 500 $\mu g/m^3$ and production emission increase < 0.04 lb/hr
	Annual	N/A	1	Step 0 – long-term ESL ≥ 10% of short-term ESL
Vanadium 7440-62-2	1-hr	0.002	20	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.00005	2	Step 3 - GLCmax ≤ 10% ESL
Zinc 7440-66-6	1-hr	0.026	20	Step 3 - GLCmax ≤ 10% ESL
	Annual	0.0007	2	Step 3 - GLCmax ≤ 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 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.

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 Tier III review was required. A Request for Comments (RFC) regarding these results was submitted to the TCEQ Toxicology Division for review on September 14, 2024.

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).

G. Greenhouse Gases

EPA has stated that unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs, including no PSD increment. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [EPA's PSD and Title V Permitting Guidance for GHGs at 48]. Thus, EPA has concluded in other GHG PSD permitting actions it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit.

The TCEQ has determined that an air quality analysis would provide no meaningful data and has not required the applicant to perform one. As stated in the preamble to TCEQ's adoption of the GHG PSD program, the impacts review for individual air contaminants will continue to be addressed, as applicable, in the state's traditional minor and major NSR permits program per 30 TAC Chapter 116.

VIII. Conclusion

In summary, the applicant has demonstrated that the proposed project's emissions will comply with applicable state and federal rules, meet BACT, and will not adversely affect public health and welfare, which includes NAAQS, additional impacts, minor new source review of regulated pollutants without a NAAQS, increments, and air toxics review. The proposed emissions of 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.

The Executive Director's preliminary determination is to issue Permit Nos. 175063, HAP85, PSDTX1634, and GHGPSDTX237.