TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

NOTICE OF APPLICATION AND PRELIMINARY DECISION FOR AIR QUALITY PERMITS

PROPOSED AIR QUALITY PERMIT NUMBERS 181895, PSDTX1684, AND GHGPSDTX260

APPLICATION AND PRELIMINARY DECISION. Energy Forge One LLC, 1500 Louisiana Street, Houston, Texas 77002-7308, has applied to the Texas Commission on Environmental Quality (TCEQ) for issuance of proposed State Air Quality Permit 181895, issuance of Prevention of Significant Deterioration (PSD) Air Quality Permit PSDTX1684, and issuance of Greenhouse Gas (GHG) PSD Air Quality Permit GHGPSDTX260 for emissions of GHGs, which would authorize construction of the Kilby Power Plant located at the following driving directions: From the intersection of U.S. 285 and I-20, travel Southeast on US 285 for approximately 16 miles and turn right on Ranch Road 2007. Travel Southwest for approximately 8 miles, turn right on Farm-to-Market Road 112, and travel West for about 2 miles to reach the site in Reeves County, Pecos, Texas 79780. This application was processed in an expedited manner, as allowed by the commission's rules in 30 Texas Administrative Code, Chapter 101, Subchapter J. **AVISO DE IDIOMA ALTERNATIVO.** El aviso de idioma alternativo en espanol está disponible en https://www.tceq.texas.gov/permitting/air/newsourcereview/airpermits-pendingpermit-apps. The proposed facility will emit the following air contaminants in a significant amount: carbon monoxide, greenhouse gases, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, sulfur dioxide and sulfuric acid mist. In addition, the facility will emit the following air contaminants: hazardous air pollutants.

The degree of PSD increment predicted to be consumed by the proposed facility and other increment-consuming sources in the area is as follows:

PM_{10}

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
24-hour	8	30
Annual	1	17

Nitrogen Dioxide

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
Annual	2	25

$PM_{2.5}$

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
24-hour	8	9
Annual	1	4

This application was submitted to the TCEQ on October 17, 2025. The executive director has determined that the emissions of air contaminants from the proposed facility which are subject to PSD review will not violate any state or federal air quality regulations and will not have any significant adverse impact on soils, vegetation, or visibility. All air contaminants have been evaluated, and "best available control technology" will be used for the control of these contaminants.

The executive director has completed the technical review of the application and prepared a draft permit which, if approved, would establish the conditions under which the facility must operate. The permit application, executive director's preliminary decision, draft permit, and the executive director's preliminary determination summary and executive director's air quality analysis, will be available for viewing and copying at the TCEQ central office, the TCEQ Midland regional office, and at the Reeves County Library, 315 South Oak Street, Pecos, Reeves County, Texas beginning the first day of publication of this notice. The facility's compliance file, if any exists, is available for public review at the TCEQ Midland Regional Office, 10 Desta Drive, Suite 350E, Midland, Texas. The application, including any updates, is available electronically at the following webpage: https://www.tceq.texas.gov/permitting/air/airpermit-applications-notices.

INFORMATION AVAILABLE ONLINE. These documents are accessible through the Commission's Web site at www.tceq.texas.gov/goto/cid: the executive director's preliminary decision which includes the draft permit, the executive director's preliminary determination summary, air quality analysis, and, once available, the executive director's response to comments and the final decision on this application. Access the Commissioners' Integrated Database (CID) using the above link and enter the permit number for this application. The public location mentioned above, the Reeves County Library, provides public access to the internet. This link to an electronic map of the site or facility's general location is provided as a public courtesy and not part of the application or notice. For exact location, refer to application. https://gisweb.tceq.texas.gov/LocationMapper/?marker=-103.438308,31.134286&level=13.

PUBLIC COMMENT/PUBLIC MEETING. You may submit public comments or request a public meeting to the Office of the Chief Clerk at the address below. The purpose of a public meeting is to provide the opportunity to submit comment or to ask questions about the application. The TCEQ will hold a public meeting if the executive director determines that there is a significant degree of public interest in the application, if requested by an interested person, or if requested by a local legislator. A public meeting is not a contested case hearing. **You may submit additional written public comments within 30 days of the date of newspaper publication of this notice in the manner set forth in the AGENCY CONTACTS AND INFORMATION paragraph below.**

After the deadline for public comment, the executive director will consider the comments and prepare a response to all relevant and material or significant public comment. **The response to comments, along with the executive director's decision on the application, will be mailed to everyone who submitted public comments or is on a mailing list for this application. The mailing will also provide instructions for requesting a contested case hearing or reconsideration of the executive director's decision.**

OPPORTUNITY FOR A CONTESTED CASE HEARING. You may request a contested case hearing regarding the portions of the application for State Air Quality Permit Number 181895 and for PSD Air Quality Permit Number PSDTX1684. There is no opportunity to request a contested case hearing regarding the portion of the application for GHG PSD Air Quality Permit Number GHGPSDTX260. A contested case hearing is a legal proceeding similar to a civil trial in a state district court. A person who may be affected by emissions of air contaminants, other than GHGs, from the facility is entitled to request a hearing. A contested case hearing request must include the following: (1) your name (or for a group or association, an official representative), mailing address, daytime phone number; (2) applicant's name and permit number; (3) the statement "I/we request a contested case hearing;" (4) a specific description of how you would be adversely affected by the application and air emissions from the facility in a way not common to the general public; (5) the location and distance of your property relative to the facility; (6) a description of how you use the property which may be impacted by the facility; and (7) a list of all disputed issues of fact that you submit during the comment period. If the request is made by a group or association, one or more members who have standing to request a hearing must be identified by name and physical address. The interests the group or association seeks to protect must also be identified. You may also submit your proposed adjustments to the application/permit which would satisfy your concerns. Requests for a contested case hearing must be submitted in writing within 30 days following this notice to the Office of the Chief Clerk, at the address provided in the information section below.

A contested case hearing will only be granted based on disputed issues of fact or mixed questions of fact and law that are relevant and material to the Commission's decisions on the application. The Commission may only grant a request for a contested case hearing on issues the requestor submitted in their timely comments that were not subsequently withdrawn. Issues that are not submitted in public comments may not be considered during a hearing.

EXECUTIVE DIRECTOR ACTION. The executive director may issue final approval of the application for the portion of the application for GHG PSD Air Quality Permit GHGPSDTX260. If a timely contested case hearing request is not received or if all timely contested case hearing requests are withdrawn regarding State Air Quality Permit Number 181895 and for PSD Air Quality Permit Number PSDTX1684, the executive director may issue final approval of the application. The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application, and will be posted electronically to the CID. If any timely hearing requests are received and not withdrawn, the executive director will not issue final approval of the State Air Quality Permit Number 181895 and for PSD Air Quality Permit Number PSDTX1684 and will forward the application and requests to the Commissioners for their consideration at a scheduled commission meeting.

MAILING LIST. You may ask to be placed on a mailing list to obtain additional information on this application by sending a request to the Office of the Chief Clerk at the address below.

AGENCY CONTACTS AND INFORMATION. Public comments and requests must be submitted either electronically at www.tceq.texas.gov/goto/comment, or in writing to the Texas Commission on Environmental Quality, Office of the Chief Clerk, MC 105, P.O. Box 13087, Austin, Texas 78711-3087. Please be aware that any contact information you provide, including your name, phone number, email address and physical address will become part of the agency's public record. For more information about the permitting process, please call the TCEQ Public Education Program, Toll Free, at 1-800-687-4040 or visit their website at www.tceq.texas.gov/goto/pep. Si desea información en Español, puede llamar al 1-800-687-4040. You can also view our website for public participation opportunities at www.tceq.texas.gov/goto/participation.

Further information may also be obtained from Energy Forge One LLC at the address stated above or by calling Mr. Brian Kane, Permitting Lead at (713) 920-4177.

Notice Issuance Date: April 15, 2026

COMISIÓN DE CALIDAD AMBIENTAL DE TEXAS

EJEMPLO A

AVISO DE SOLICITUD Y DECISIÓN PRELIMINAR PARA UN PERMISO DE CALIDAD DEL AIRE

PERMISO DE CALIDAD DEL AIRE NÚMEROS PROPUESTOS: 181895, PSDTX1684 Y GHGPSDTX260

SOLICITUD Y DECISIÓN PRELIMINAR. Energy Forge One LLC, 1500 Louisiana Street, Houston, Texas 77002-7308, ha solicitado a la Comisión de Calidad Ambiental de Texas (TCEQ, por sus siglas en inglés) la emisión del Permiso de Calidad del Aire Propuesto 181895,el Permiso de Prevención del Deterioro Significativo (PSD, por sus siglas en inglés) de Calidad del Aire PSDTX1684, y el Permiso PSD de Gases de Efecto Invernadero (GHG, por sus siglas en inglés) Número GHGPSDTX260, que autorizaría la construcción del Kilby Power Plant ubicada en el sitio al que se llega de la siguiente manera: desde la intersección de la US 285 y la I-20, viaje hacia el sureste por la US 285 durante aproximadamente 16 millas y gire a la derecha en Ranch Road 2007. Viaje hacia el suroeste durante aproximadamente 8 millas, gire a la derecha en Farm-to-Market Road 112 y viaje hacia el oeste durante aproximadamente 2 millas hasta llegar al sitio en Pecos, Condado de Reeves, Texas 79780. Esta solicitud se presentó a la TCEQ el 17 de octubre de 2025. La instalación propuesta emitirá los siguientes contaminantes del aire en una cantidad significativa: monóxido de carbono, gases de efecto invernadero, óxidos de nitrógeno, compuestos orgánicos, material particulado incluyendo material particulado con diámetros de 10 micrones o menos, material particulado incluyendo material particulado con diámetros de 2.5 micrones o menos, óxidos de azufre y neblina de ácido sulfúrico. Además, la instalación emitirá los siguientes contaminantes del aire: contaminantes atmosféricos peligrosos.

El grado de incremento de la PSD que se prevé que consumirá la instalación propuesta y otras fuentes de consumo incremental-en la zona es el siguiente:

PM_{10}

Máximo Tiempo Promedio	**Máximo Incremento Consumido (µg/m^3)**	**Incremento Permisible (µg/m^3)**
24 horas	8	30
Anual	1	17

Dióxido de Nitrógeno

Máximo Tiempo Promedio	**Máximo Incremento Consumido (µg/m^3)**	**Incremento Permisible (µg/m^3)**
Anual	2	25

$PM_{2.5}$

Máximo Tiempo Promedio	Máximo Incremento Consumido ($\mu g/m^3$)	Incremento Permisible ($\mu g/m^3$)
24 horas	8	9
Anual	1	4

El director ejecutivo ha determinado que las emisiones de contaminantes atmosféricos de la instalación propuesta que están sujetas a la revisión de la DSP no violarán ninguna regulación estatal o federal de calidad del aire y no tendrán ningún impacto adverso significativo en los suelos, la vegetación o la visibilidad. Todos los contaminantes del aire han sido evaluados, y se utilizará la "mejor tecnología de control disponible" para el control de estos contaminantes.

El director ejecutivo ha completado la revisión técnica de la solicitud y ha preparado un proyecto de permiso que, de ser aprobado, establecería las condiciones en las que la instalación debe operar. La solicitud de permiso, la decisión preliminar del director ejecutivo, el borrador del permiso y el resumen de determinación preliminar del director ejecutivo y el análisis de la calidad del aire del director ejecutivo, estarán disponibles para su visualización y copia en la oficina central de la TCEQ, la Midland oficina regional, y la Reeves County Library, 315 South Oak Street, Pecos, Condado de Reeves, Texas a partir del primer día de publicación de este aviso. El archivo de cumplimiento de la instalación, si existe alguno, está disponible para su revisión pública en la oficina regional de Midland de la TCEQ. La solicitud (cualquier actualización inclusive) está disponible electrónicamente en la siguiente página web: https://www.tceq.texas.gov/permitting/air/airpermit-applications-notices.

INFORMACIÓN DISPONIBLE EN LÍNEA. Estos documentos pueden consultarse a través del sitio Web de la Comisión en www.tceq.texas.gov/goto/cid: la decisión preliminar del director ejecutivo que incluye el proyecto de permiso, el resumen de la determinación preliminar del director ejecutivo, el análisis de la calidad del aire y, una vez disponible, la respuesta del director ejecutivo a los comentarios y la decisión final sobre esta solicitud. Acceda a la Base de Datos Integrada de comisionados (CID, por sus siglas en inglés) utilizando el enlace anterior e ingrese el número de permiso para esta solicitud. La ubicación pública mencionada anteriormente proporciona acceso público a Internet. Este enlace a un mapa electrónico de la ubicación general del sitio o instalación se proporciona como cortesía pública y no como parte de la solicitud o aviso. Para conocer la ubicación exacta, consulte la solicitud. https://gisweb.tceq.texas.gov/LocationMapper/?marker=-103.438308,31.134286&level=13.

COMENTARIO PÚBLICO/REUNIÓN PÚBLICA Puede enviar comentarios públicos o solicitar una reunión pública sobre esta solicitud. El propósito de una reunión pública es para brindar la oportunidad de enviar comentarios o hacer preguntas sobre la solicitud. La TCEQ convocará una reunión pública si el director ejecutivo determina que existe un grado significativo de interés público en la solicitud, si lo solicita una persona interesada o si lo solicita un legislador local. Una reunión pública no es una audiencia de caso impugnado. **Puede enviar comentarios públicos adicionales por escrito dentro de los 30 días posteriores a la fecha de publicación de este aviso en el periódico de la manera establecida en el párrafo CONTACTOS E INFORMACIÓN DE LA AGENCIA a continuación.**

Después de la fecha límite para comentarios públicos, el director ejecutivo considerará los comentarios y preparará una respuesta a todos los comentarios públicos. **La respuesta a los comentarios, junto con la decisión del director ejecutivo sobre la solicitud, se enviará por correo a todos los que enviaron comentarios públicos o están en una lista de correo para esta solicitud.**

OPORTUNIDAD PARA UNA AUDIENCIA DE CASO IMPUGNADO. Una audiencia de caso impugnado es un procedimiento legal similar a un juicio civil en un tribunal de distrito estatal. **Una persona que pueda verse afectada por las emisiones de contaminantes atmosféricos de la instalación tiene derecho a solicitar una audiencia. Una solicitud de audiencia de caso impugnado debe incluir lo siguiente: (1) su nombre (o para un grupo o asociación, un representante oficial), dirección postal, número de teléfono diurno; (2) nombre y número de permiso del solicitante; (3) la declaración "Yo/nosotros solicito/solicitamos una audiencia de caso impugnado;" (4) una descripción específica de cómo se vería afectado negativamente por la aplicación y las emisiones atmosféricas de la instalación de una manera no común para el público en general; (5) la ubicación y distancia de su propiedad en relación con la instalación; (6) una descripción de cómo usa la propiedad que puede verse afectada por la instalación; y (7) una lista de todos los problemas de hecho en disputa que envíe durante el periodo de comentarios. Si la solicitud es hecha por un grupo o asociación, uno o más miembros que tienen legitimación para solicitar una audiencia deben ser identificados por su nombre y dirección física. También deben identificarse los intereses que el grupo o asociación busca proteger. También puede presentar los ajustes propuestos a la solicitud / permiso que satisfagan sus inquietudes. Las solicitudes de una audiencia de caso**

impugnado deben presentarse por escrito dentro de los 30 días siguientes a este aviso a la Oficina del Secretario Oficial, en la dirección proporcionada en la sección de información a continuación.

Una audiencia de caso impugnado solo se concederá sobre la base de cuestiones de hecho en disputa o cuestiones mixtas de hecho y de derecho que sean relevantes y materiales para las decisiones de la Comisión sobre la solicitud. La Comisión sólo podrá conceder una solicitud de audiencia de un asunto impugnado sobre asuntos que el solicitante haya presentado en sus observaciones oportunas que no hayan sido retiradas posteriormente. Los asuntos que no se presentan en comentarios públicos no pueden ser considerados durante una audiencia.

ACCIÓN DEL DIRECTOR EJECUTIVO. Si no se recibe una solicitud de audiencia de caso impugnado oportunamente o si se retiran todas las solicitudes de audiencia de caso impugnado oportunamente, el director ejecutivo puede emitir la aprobación final de la solicitud. La respuesta a los comentarios, junto con la decisión del director ejecutivo sobre la solicitud, se enviará por correo a todos los que enviaron comentarios públicos o están en una lista de correo para esta solicitud, y se publicará electrónicamente en el CID. Si se reciben solicitudes de audiencia oportunas y no se retiran, el director ejecutivo no emitirá la aprobación final del permiso y enviará la solicitud y las solicitudes a los Comisionados para su consideración en una reunión programada de la comisión.

LISTA DE CORREO. Puede solicitar ser colocado en una lista de correo para obtener información adicional sobre esta solicitud enviando una solicitud a la Oficina del Secretario Oficial a la dirección a continuación.

CONTACTOS E INFORMACIÓN DE LA AGENCIA. Los comentarios y solicitudes públicas deben enviarse electrónicamente a www.tceq.texas.gov/goto/comment, o por escrito a la Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. Si se comunica con la TCEQ electrónicamente, tenga en cuenta que su dirección de correo electrónico, al igual que su dirección postal física, se convertirá en parte del registro público de la agencia. Para obtener más información sobre esta solicitud de permiso o el proceso de permisos, llame al Programa de Educación Pública al número gratuito 1-800-687-4040 o visite su sitio de web www.tceq.texas.gov/goto/pep. Si desea información en español, puede llamar al 1-800-687-4040. También puede visitar nuestro sitio de web para conocer las oportunidades de participación pública en www.tceq.texas.gov/goto/participation.

También se puede obtener más información de la Energy Forge One LLC en la dirección indicada anteriormente o llamando a Mr. Brian Kane, Permitting Lead al (713) 920-4177.

Fecha de Emisión del Aviso: 15 de abril de 2026

Special Conditions

Permit Numbers 181895, PSDTX1684, and GHGPSDTX260

1. This permit covers only those sources of emissions listed in the attached table entitled “Emission Sources – Maximum Allowable Emission Rates (MAERT),” including planned maintenance, startup, and shutdown (MSS) activities, and those sources are limited to the emission limits on that table and other conditions specified in this permit.

2. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing volatile organic compounds (VOC) at a concentration of greater than 1 percent are not authorized by this permit unless authorized on the MAERT. Any releases directly to atmosphere from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration greater than 1 weight percent are not consistent with good practice for minimizing emissions.

Federal Applicability

3. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources promulgated in Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

   A. Subpart A, General Provisions.

   B. Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units.

   C. Subpart IIII, Stationary Compression Ignition Internal Combustion Engines.

   D. Subpart JJJJ, Stationary Spark Ignition Internal Combustion Engines.

   E. Subpart KKKKa, Stationary Combustion Turbines.

4. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories in 40 CFR Part 63:

   A. Subpart A, General Provisions.

   B. Subpart YYYY, Stationary Combustion Turbines.

   C. Subpart ZZZZ, Stationary Reciprocating Internal Combustion Engines.

   D. Subpart DDDDD, Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

Emissions Standards and Operating Specifications

5. This permit authorizes 46 natural gas fired combustion generators (CTGs) consisting of the following configurations:

   A. Two General Electric (GE) model 7HA.02 CTGs operated in combined cycle mode [Emission Point Number (EPNs): 7HACC1, 7HACC2, CAP1, and CAP1_1]. Both turbines have an average heat input of 3,379.8 million British thermal units per hour (MMBtu/hr) with a rated nominal capacity of 555.7 gross megawatts (MW) at the ambient conditions of 59 °F; 13.25 psia; 2,850 feet elevation; and 60% relative humidity. Both CTGs will have a duct burner fired heat recovery steam generator (HRSG) with a maximum heat input of 870.8 MMBtu/hr. Each HRSG supplies steam to a single steam turbine that operates in a 1x1x1 configuration.

The CTG and duct burner units shall utilize selective catalytic reduction (SCR) and oxidation catalyst control systems.

B. Three GE model 7HA.02 CTGs operated in simple cycle mode (EPNs: 7HASC1, 7HASC2, 7HASC3, CAP2, and CAP2_1). Each turbine has an average heat input of 3,174.1 MMBtu/hr and a rated nominal capacity of 330.3 MW at the ambient conditions of 59 °F; 13.25 psia; 2,850 feet elevation; and 60% relative humidity. The CTG shall utilize selective catalytic reduction (SCR) and oxidation catalyst control systems.

C. 12 Solar Turbines model Titan 350 (T350) CTGs operated in simple cycle mode (EPNs T350SC1 through T350SC12, CAP3, and CAP3_1). Each turbine has an average heat input of 370.8 MMBtu/hr and a rated nominal capacity of 31.1 MW at the ambient conditions of 59 °F; 13.25 psia; 2,850 feet elevation; and 60% relative humidity. The CTG shall utilize selective catalytic reduction (SCR) and oxidation catalyst control systems.

D. 29 Solar Turbines model Titan 130 (T130) CTGs operated in simple cycle mode (EPNs T130SC1 through T130SC29, CAP4, and CAP4_1). Each turbine has an average heat input of 157.6 MMBtu/hr and a rated nominal capacity of 13.55 MW at the ambient conditions of 59 °F; 13.25 psia, 3,000 feet elevation; and 60% relative humidity. The CTG shall utilize selective catalytic reduction (SCR) and oxidation catalyst control systems.

6. The emission concentrations from the combined turbine and duct burner and simple cycle turbines identified in the table below shall not exceed the following concentrations in parts per million by volume, dry basis (ppmvd) at 15% oxygen (O_2), except during periods of planned maintenance, startup, and shutdown (MSS):

Turbine model and EPNs	Pollutant	Concentration (ppmvd at 15% O_2)	Averaging Time
Combined Cycle GE 7HA.02 CTGs: 7HACC1 and 7HACC2	Nitrogen oxide (NO_x)	2.0	24-hr rolling average
	Carbon monoxide (CO)	2.0	3-hr rolling average
	Ammonia (NH_3)	5.0	3-hr rolling average
Simple Cycle GE 7HA.02 CTGs: 7HASC1, 7HASC2, 7HASC3	Nitrogen oxide (NO_x)	2.5	3-hr rolling average
	Carbon monoxide (CO)	3.5	3-hr rolling average
	Ammonia (NH_3)	5.0	3-hr rolling average
Simple Cycle Solar T350 CTGs: T350SC1 through T350SC12	Nitrogen oxide (NO_x)	2.7	3-hr rolling average
	Carbon monoxide (CO)	2.5	3-hr rolling average
	Ammonia (NH_3)	5.0	3-hr rolling average
Simple Cycle Solar T130 CTGs: T130SC1 through T130SC29	Nitrogen oxide (NO_x)	2.7	3-hr rolling average
	Carbon monoxide (CO)	2.5	3-hr rolling average
	Ammonia (NH_3)	5.0	3-hr rolling average

A. A planned startup is defined as the period beginning when fuel is introduced and a combustion flame has been established in the combustion turbine and recorded by the plant's control system. A planned startup ends and normal operation begins when signals are received indicating that the CTG is in Environmental Compliance Mode, ammonia injection is in service, and the startup emissions have purged through the continuous emissions monitoring system (CEMS). Planned startups for combined cycle operation shall not exceed 70 minutes per startup. Planned startups for simple cycle operation shall not exceed 60 minutes per startup.

B. A planned shutdown is defined as the period beginning when signals are received demonstrating that the CT is no longer in Environmental Compliance Mode and that the ammonia injection is no longer in service for purposes of an intended shutdown (i.e., shutdown of the ammonia system was not caused by a system failure). A planned shutdown ends when a signal is received that the CT has flamed out. Planned shutdowns shall not exceed 60 minutes per shutdown.

C. Emissions from maintenance activities identified in Attachment B are excluded from the above concentration limits.

D. NO_X emissions during transitional load operations, defined as a CTG ramp rate greater than 32 MW per minute (MW/min) and not to exceed 60 minutes per event, may be excluded from the specified averaging time concentration limit for the specified CTG if all the following conditions are met:

(1) The 3-hour or 24-hour rolling average concentration is above the specified concentration limit for the specified CTG, as applicable for the specified CTG, and

(2) The qualifying NO_X concentration occurs during a 3-hour or 24-hour period where the turbine ramp rate exceeds 32 MW/minute during at least one hour in that period, as applicable for the specified CTG.

(3) The emissions from transitional load operations shall not exceed the MSS hourly emission rates for the specified CTG in the MAERT.

E. The averaging time periods for the above concentration limits for CO and NH_3 shall be rolling 24 hours during transitional load periods.

7. Authorized fuel for the combustion turbines, supplemental duct burners, the Black Start Generators, and the Auxiliary Boiler shall be limited to pipeline-quality, sweet natural gas containing the following:

A. No more than 0.5 grains of total sulfur per 100 dry standard cubic feet (gr S/100 dscf) for the GE 7HA.02 Turbines (EPNs 7HACC1, 7HACC2, 7HASC1, 7HASC2, and 7HASC3) and the Black Start Generators (EPNs BSGEN1 and BSGEN2).

B. No more than 1.2 gr S/100 dscf for the Solar Turbines T350 Turbines (EPNs T350SC1 through T350SC12) and the Solar Turbines T130 Turbines (EPNs T130SC1 through T130SC29).

C. No more than 5.0 gr S/100 dscf on an hourly basis and no more than 1.0 gr S/100 dscf on a 12-month rolling period for the Auxiliary Boiler (EPN BOILER).

8. The natural gas shall be sampled at least every 6 months to determine total sulfur and net heating value. Test results from the fuel supplier may be used to satisfy this requirement.

9. Each lube oil vent (EPN OILVENT) shall be equipped with a mist eliminator to remove oil mist from the lube oil reservoir air flow.

10. The performance specifications and concentration limits of Special Condition No. 6 and the MAERT apply beginning with commencement of operations following completion of construction. Construction is completed based on the date included in the notification required by 30 TAC

116.115 (b)(2)(A). The performance specifications and concentration limits of Special Condition No. 6 do not apply during periods of commissioning, during which the permit holder conducts initial operational and contractual testing and tuning to ensure the safe, efficient, and reliable operation of the electric generating unit. The short-term planned MSS emission rates and annual emission rates on the MAERT do apply during periods of commissioning. Upon initial startup of each emission source, performance testing shall occur within 180 days following startup or upon completion of stack sampling required under Special Condition No. 27 for the source and pollutant to which the emission limitation applies; whichever occurs first. The permit holder shall comply with all applicable requirements in federal and state regulations during commissioning periods.

The permit holder shall submit a permit application request for Permit No. 181895 within 180 days following the completion of the commissioning period for the CTGs to remove the special conditions related to the CTG commissioning period.

Opacity / Visible Emissions

11. Except during MSS activities, the opacity shall not exceed five percent (5%) averaged over a six-minute period from each CTG stack, each black start generator, each emergency diesel generator, the diesel fire pump, and the auxiliary boiler. During planned MSS activities, the opacity shall not exceed fifteen percent (15%) for the specified stack over a six-minute period (or other applicable opacity limit specified in 30 TAC § 111.111(a)(1)). The permit holder shall demonstrate compliance with this Special Condition in accordance with the following procedures:

    A. Visible emission observations shall be performed and recorded quarterly for each CTG stack, black start generator, emergency diesel generator, diesel fire pump, and the auxiliary boiler while the facilities are in operation, unless the emission unit is not operating for the entire calendar quarter.

    B. Each determination shall be made by first observing for visible emissions while each gas turbine is in operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point(s). Up to three emissions points may be read concurrently, provided that all three emissions points are within a 70 degree viewing sector or angle in front of the observer such that the proper sun position (at the observer's back) can be maintained for all three emission points. A certified opacity reader is not required for these visible emission observations.

    C. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using 40 CFR Part 60, Appendix A, Test Method 9. Contributions from uncombined water shall not be included in determining compliance with this condition.

    D. If the opacity exceeds 5% during normal operations or 15% during MSS activities, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one (1) week of first observation.

Ammonia Handling

12. The following requirements apply to the handling of ammonia:

    A. The ammonia (NH_3) used for the SCR system shall be aqueous ammonia that shall be stored in pressurized tanks with pressure release valves.

B. The permit holder shall maintain prevention and protection measures for the NH_3 storage system. The NH_3 storage tank area will be marked and protected so as to protect the NH_3 storage area from accidents that could cause a rupture.

C. Connecting lines between pressure vessels and pressure rated truck or railcars shall have double closures on each end of the line. The operator shall ensure emissions from disconnecting the lines after transferring material between vessels and trucks or railcars are minimized. Pumps, piping, hoses and connections shall comply with the applicable portions of 49 CFR 178 Subpart H and J. Records shall be maintained of any inspections, parts certification, and pressure testing to demonstrate compliance with this special condition.

D. The number of tank trucks unloading ammonia to the ammonia storage tank shall be recorded and updated monthly.

Auxiliary Boiler

13. The following requirements apply to the Auxiliary Boiler (EPN BOILER):

A. NO_x and CO emissions from the boiler shall not exceed the following:

0.01 lb NO_x/MMBtu (HHV) on an hourly average

50 ppmvd CO corrected to 3 percent oxygen on an hourly average

B. The boiler shall be limited to a maximum heat input of 99.9 MMBtu/hr during any operation.

C. The boiler shall be limited to 45,554 MMBtu/yr of operation on a rolling 12 month period.

D. The permit holder shall install and operate a totalizing fuel flow meter to measure the gas fuel usage for the boiler and fuel usage for each shall be recorded monthly. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent.

Quality assured (or valid) data must be generated when the boiler is operating. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the boiler operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

Black Start Generators

14. Emissions from the Black Start Generators (EPNs BSGEN1 and BSGEN2) shall not exceed the following:

Turbine model and EPNs	Pollutant	Concentration (grams per horsepower-hour [g/hp-hr])	Averaging Period
Black Start Generator 1 (BSGEN1)	Nitrogen oxide (NO_x)	0.70	1-hour
	Carbon monoxide (CO)	2.00	1-hour
	Nitrogen oxide (NO_x)	0.50	1-hour

Turbine model and EPNs	Pollutant	Concentration (grams per horsepower-hour [g/hp-hr])	Averaging Period
Black Start Generator 2 (BSGEN2)	Carbon monoxide (CO)	1.51	1-hour

Compliance with the NOx and CO limits in the table above for the Black Start Generators shall be based on maintaining vendor documentation of the emissions basis at the site.

15. Emissions from the Black Start Generators, EPNs BSGEN1 and BSGEN2, shall be limited to a total of 300 hours of operation per rolling 12-month period. Records of the hours of operation kept on a monthly and rolling 12-month basis shall be maintained by the holder of this permit.

16. A non-resettable run time meter shall be installed on each engine.

17. The engines and after-treatment control devices shall be operated and maintained according to the manufacturer's emission-related written instructions.

18. The permit holder shall install and operate a totalizing fuel flow meter to measure the fuel usage for each unit and fuel usage for each shall be recorded monthly. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer’s specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent.

    Quality assured (or valid) data must be generated when the combustion unit is operating. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the combustion unit operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

19. Maximum fuel usage for the Black Start Generators shall not exceed a total of 6.26 million standard cubic feet per year.

Emergency Engines and Fire Pump Engines

20. The Emergency Diesel Generators 1 through 4 (EPNs EDG1, EDG2, EDG3, and EDG4) and Diesel Fire Pump (EPN FIREPUMP) are each limited to 100 hours of non-emergency operation per year, on a calendar year basis, in accordance with 40 CFR 60.4211(f). Each emergency generator and fire pump engine shall be equipped with a non-resettable runtime meter.

21. The Emergency Diesel Generators 1 through 4 (EPNs EDG1, EDG2, EDG3, and EDG4) and Diesel Fire Pump (EPN FIREPUMP) shall be limited to diesel fuel containing no more than 15 ppm sulfur by weight.

Storage Tanks

22. Storage tank throughput and service shall be limited to the following:

Tank Identifier	Service	Fill/Withdrawal rate (gallons/hour)	Rolling 12 Month Throughput (gallons)
FPTNK1	Ultra-low sulfur diesel	12.9	3,000.0
EDGTNK1		105.0	12,500.0
EDGTNK2		105.0	12,500.0
EDGTNK3		105.0	12,500.0
EDGTNK4		105.0	12,500.0
EDGTNK5		105.0	12,500.0

23. Storage tanks are subject to the following requirements:

A. Except for labels, logos, etc. not to exceed 15 percent of the tank total surface area, uninsulated tank exterior surfaces exposed to the sun shall be white or unpainted aluminum. Storage tanks must be equipped with permanent submerged fill pipes.

B. The permit holder shall maintain a record of tank throughput for the previous month and the past consecutive 12 month period for each tank.

Fugitives

Piping, Valves, Pumps, and Compressors in contact with ammonia – 28AVO

24. Except as may be provided for in the Special Conditions of this permit, the following requirements apply to the above-referenced equipment:

A. Audio, olfactory, and visual checks for leaks within the operating area shall be made at least once every 12-hour shift.

B. Immediately, but no later than one hour upon detection of a leak, plant personnel shall take at least one of the following actions:

(1) Isolate the leak.

(2) Commence repair or replacement of the leaking component.

(3) Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

C. Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

Piping, Valves, Pumps, and Compressors in contact with natural gas and diesel – 28PI

25. Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

    A. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

    B. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

    C. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined in Title 30 Texas Administrative Code (30 TAC) Chapter 115, shall be identified in a list to be made available upon request.

    D. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter.

    E. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

    F. All piping components shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

    G. Damaged or leaking valves, connectors, compressor seals, and pump seals found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

    H. Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

Wastewater Collection

26. Process wastewater that contains VOC compounds shall be immediately directed to a covered system. All lift stations, manholes, junction boxes, conveyances, and any other wastewater facilities shall be covered to minimize emissions.

Initial Determination of Compliance

27. The permit holder shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the combined cycle gas turbines (EPNs 7HACC1 and 7HACC2), the simple cycle gas turbines (EPNs 7HASC1, 7HASC2, 7HASC3, T350SC1 through T350SC12, and T130SC1 through T130SC29) and the Auxiliary Boiler (EPN BOILER) to demonstrate compliance with the MAERT and control standards

in Special Condition Nos. 6 and 13.A. The permit holder is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. Sampling shall be conducted in accordance with the appropriate procedures of the Texas Commission on Environmental Quality (TCEQ) Sampling Procedures Manual and the U.S. Environmental Protection Agency (EPA) Reference Methods.

Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office of Air, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for 40 CFR Part 60 testing which must have EPA approval shall be submitted to the TCEQ Regional Director.

A. The appropriate TCEQ Regional Office shall be notified not less than 45 days prior to sampling. The notice shall include:

(1) Proposed date for pretest meeting.

(2) Date sampling will occur.

(3) Name of firm conducting sampling.

(4) Type of sampling equipment to be used.

(5) Method or procedure to be used in sampling.

(6) Description of any proposed deviation from the sampling procedures specified in this permit or TCEQ/EPA sampling procedures.

(7) Procedure/parameters to be used to determine worst-case emissions, such as turbine loads, during the sampling period. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with emission standards found in 40 CFR Part 60 Subpart KKKKa.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for the test reports. The TCEQ Regional Director must approve any deviation from specified sampling procedures.

B. Air contaminants emitted from the gas turbines to be tested for include (but are not limited to) CO, NO_X, VOC, formaldehyde, NH_3, SO_2, PM_{10}, and O_2. Air contaminants emitted from the auxiliary boiler to be tested for include (but are not limited to) CO, NO_X, and O_2. As noted below, fuel sampling using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for SO_2.

C. Fuel sampling using the methods and procedures of 40 CFR § 60.4415a may be conducted in lieu of stack sampling for SO_2. If fuel sampling is used, compliance with NSPS Subpart KKKKa SO_2 limits shall be based on 100 percent conversion of the sulfur in the fuel to SO_2. Any deviations from those procedures must be approved by the Executive Director of the TCEQ prior to sampling.

D. Sampling shall occur within 60 days after achieving the maximum operating rate at which the CTG or boiler will be operated, but no later than 180 days after initial start-up of the unit and at such other times as may be required by the TCEQ Executive Director. Requests for additional time to perform sampling shall be submitted to the appropriate regional office.

E. The facility being sampled shall operate at the maximum firing rate that can be reasonably achieved during stack emission testing. These conditions/parameters and any other primary operating parameters that affect the emission rate shall be monitored and recorded during the stack test. Any additional parameters shall be determined at the pretest meeting and shall be stated in the sampling report. Permit conditions and parameter limits may be waived during stack testing performed under this condition if the proposed condition/parameter range is identified in the test notice specified in paragraph A and accepted by the TCEQ Regional Office. Permit allowable emissions and emission control requirements are not waived and still apply during stack testing periods.

During subsequent operations, if the firing rate recorded over a rolling 1-hour average time period is greater than the highest hourly firing rate of the three runs recorded during the test period specified in the previous paragraph, then stack sampling shall be performed at the new operating conditions within 120 days. If each individual stack test result from the last successful stack test demonstrated that the actual emissions are less than 80% of the MAERT emission limits, then subsequent operations may include up to a 5% increase in the firing rate for the unit without requiring stack sampling at the new operating conditions unless required by the regional office. The retesting specified in this paragraph shall not apply to any pollutant(s) in which the unit is monitored using a CEMS for the respective pollutant(s).

F. Copies of the final sampling report shall be forwarded to the offices below within 60 days after sampling is completed. Sampling reports shall comply with the attached provisions entitled “Chapter 14, Contents of Sampling Reports” of the TCEQ Sampling Procedures Manual. The reports shall be distributed as follows:

One copy to the appropriate TCEQ Regional Office.

One copy to each local air pollution control program.

G. Sampling ports and platform(s) shall be incorporated into the design of the CTG stack according to the specifications set forth in the attachment entitled “Chapter 2, Guidelines For Stack Sampling Facilities” of the Texas Commission on Environmental Quality (TCEQ) Sampling Procedures Manual. Alternate sampling facility designs must be submitted for approval to the TCEQ Regional Director.

Continuous Demonstration of Compliance

28. The permit holder shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) to measure and record the in-stack concentrations of CO, NH_3, NO_x, and O_2 from the CTG exhaust stacks (EPNs 7HACC1, 7HACC2, 7HASC1, 7HASC2, 7HASC3, T350SC1 through T350SC12, and T130SC1 through T130SC29).

A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9 and 18, Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60), Appendix B. Performance Specification No. 18, 40 CFR Part 60, Appendix B shall be adapted for NH_3. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Air, Air Permits Division for requirements to be met.

B. Section 1 below applies to sources subject to the quality-assurance requirements of 40 CFR Part 60, Appendix F; section 2 applies to all other sources:

(1) The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1, except NH_3 shall

meet 40 CFR Part 60, Appendix F, Procedure 6 adapted for NH_3. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, Section 5.2.3 of Procedure 1 and Section 5.2.1 of Procedure 6 adapted for NH_3 and any CEMS downtime shall be reported to the appropriate TCEQ Regional Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager.

(2) The CEMS shall be zeroed and spanned daily, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable Performance Specification Nos. 1 through 9 and 18 adapted for NH_3, 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.

Each monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2 and Procedure 6, Section 5.2.3 adapted for NH_3, with the following exception: a relative accuracy test audit (RATA) is not required once every four quarters (i.e., four successive quarterly CGA may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur no closer than two months.

All CGA exceedances of +15 percent accuracy indicate that the CEMS is out of control.

C. The monitoring data shall be reduced to hourly average concentrations at least once every day, using a minimum of four equally-spaced data points from each one-hour period. At least two (2) valid data points shall be generated during an hourly period in which zero and span is performed. At least once every week, the valid hourly average concentrations shall be reduced to and recorded in units of parts per million by volume dry at 15% oxygen (ppmvd at 15% O_2) and lb/MMBtu and averaged over the specified averaging period to determine compliance with the concentration limits of Special Condition 6.

The measured average concentration from the CEMS shall be converted to a lb/MMBtu emission factor using the equations from EPA Method 19 relying on the measured fuel flow and dry F-factor and measured O_2 concentration. The average lb/MMBtu emission factor shall be multiplied by the hourly average natural gas fuel consumption data required by Subpart F of this Special Condition to determine the hourly emission limits of the MAERT from the unit. Pounds per hour data from the CTG/HRSG stack shall be summed monthly to tons per year and used to determine compliance with the annual emission limits of the MAERT.

D. All monitoring data and quality-assurance data shall be maintained by the source for a period of five (5) years and shall be made available to the TCEQ Executive Director or designated representative upon request. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

E. The appropriate TCEQ Regional Office shall be notified at least 30 days prior to any required relative accuracy test audit (RATA) in order to provide them the opportunity to observe the testing.

F. The permit holder shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the natural gas consumption of the CTG and duct burner. The monitored data shall be reduced to an hourly average flow rate at least once every day, using a minimum of four equally-spaced data points from each one-hour period. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent. The permit holder shall comply with the initial certification and quality assurances as specified in 40 CFR Part 75. In lieu of monitoring fuel flow, the permit holder may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (CFR) Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

G. If any emission monitor fails to meet specified performance, it shall be repaired or replaced as soon as reasonably possible.

H. Quality-assured (or valid) data must be generated when the gas turbine is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the gas turbine operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded. Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager.

I. As an approved alternative to an NH_3 CEMS, the permit holder may perform one of the following:

(1) The permit holder may install and operate a second NOx CEMS probe located between the duct burners (or turbine exhaust for simple cycle turbines) and the SCR, upstream of the stack NOx CEMS, which may be used in association with the stack NOx CEMS reading and NH_3 injection rate to calculate the estimated NH_3 slip. This condition shall not be construed to set a minimum NOx reduction efficiency on the SCR unit. These results shall be recorded and used to determine compliance limits of this permit.

(2) The permit holder may install and operate a dual stream system of NOx CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NOx CEMS and the other exhaust stream would be routed through a NH_3 converter to convert NH3 to NOx and then to a second NOx CEMS. The NH_3 slip concentration shall be calculated from the delta between the two NOx CEMS readings (converted and unconverted).

(3) Any other method used for measuring NH3 slip shall require prior approval from the TCEQ

29. For each CTG, the oxidation catalyst inlet temperature shall be maintained on a four-hour rolling average while fuel is fed into each turbine. The catalyst inlet temperature shall be maintained within the range suggested by the catalyst manufacturer.

The temperature measurement device shall reduce the temperature readings to an averaging period of one hour or less, using a minimum of four equally-spaced data points from each one-hour period, and record it at that frequency. The temperature monitor shall be installed, calibrated, or have a calibration check performed at least annually, and be maintained according to the manufacturer's specifications. The device shall have an accuracy of the greater of ± 0.75 % of the temperature being measured or ±4ºF.

Quality assured (or valid) monitoring data must be generated when the turbine is being fed fuel gas. Loss of valid data due to periods of monitor breakdown, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed

5 percent of the time (in minutes) that the turbine was fed fuel gas to control over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

Planned Maintenance, Startup, and Shutdown

30. This permit authorizes the emissions from the planned MSS activities listed in Attachment A, Attachment B, and the table entitled "Emission Sources - Maximum Allowable Emission Rates" (MAERT) attached to this permit.

31. Attachment A identifies the inherently low emitting MSS activities that may be performed at the plant. Emissions from activities identified in Attachment A shall be considered to be equal to the potential to emit represented in the permit application. The estimated emissions from the activities listed in Attachment A must be revalidated annually. This revalidation shall consist of the estimated emissions for each type of activity and the basis for that emission estimate.

32. Compliance with the emissions limits for planned maintenance activities identified in Attachment B may be demonstrated as follows.

    A. For each pollutant emitted during planned maintenance activities which is measured using a CEMS, the permit holder shall for each calendar month compare the pollutant's short-term (hourly) emissions as measured by the CEMS to the applicable short-term planned MSS emissions limit in the MAERT.

    B. For each pollutant emitted during a planned maintenance activities which is not measured using a CEMS, the permit holder shall for each calendar month determine the total emissions of the pollutant.

    C. The performance of each planned MSS activity and the emissions associated with it shall be recorded and include at least the following information:

        (1) the type of planned MSS activity and the reason for the planned activity;

        (2) the date and time of the MSS activity and its duration; and

        (3) the estimated quantity of each air contaminant, or mixture of air contaminants, emitted with the data and methods used to determine it. The emissions shall be estimated using the methods identified in the permit application, consistent with good engineering practice.

    D. Sum the rolling 12-month emissions for each EPN on a monthly basis to show compliance with the MAERT.

33. Emissions during planned startup and shutdown activities of each CTG shall be minimized by limiting the duration as specified and defined in Special Condition Nos. 6.A and 6.B. The number of startup events and hours of operation of the CTGs may be demonstrated by using recorded operating parameters such as natural gas fuel feed rates and power or steam generation records.

34. Additional occurrences of MSS activities authorized by this permit in Attachment A and B may be authorized under permit by rule only if conducted in compliance with this permit's procedures, emission controls, monitoring, and recordkeeping requirements applicable to the activity.

Greenhouse Gases Special Conditions

35. Each CTG train shall not exceed the following limits based on a 12-month rolling average. **(GHG)**

Turbine Operations	Input Specific CO_2 Emission Rate ($lbs\ CO_2/MMBtu$)
All Simple Cycle Turbines	116.98
All Combined Cycle Turbines	117.6

36. Monitoring, quality assurance/quality control requirements, emission calculation methodologies, record keeping, and reporting requirements related to Greenhouse Gas (GHG) emissions shall adhere to the applicable requirements in 40 CFR Part 98 and in this permit. **(GHG)**

37. The permit holder shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. **(GHG)**

38. The permit holder shall minimize emissions from components and equipment containing GHG as follows: **(GHG)**

    A. The sulfur hexafluoride (SF_6)-enclosed circuit breakers shall be designed to meet the latest American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers. The circuit breakers must be guaranteed to achieve a SF_6 leak rate of 0.5% by weight or less annually. The circuit interrupters must be in a totally enclosed, pressurized compartment equipped with an alarm that signals the plant control room in the event that any of the circuit breaker falls below the normal operating pressure as specified by the manufacturer.

        (1) SF_6 emissions shall be calculated annually (calendar year) in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting Rule for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD. The total SF_6 inventory of the circuit breakers shall not exceed 20,349 lb with leak detection.

        (2) The circuit breakers shall be equipped with a low pressure alarm and low pressure lockout. The SF_6 leak detection system shall be able to detect a leak of at least 0.5% by weight per year.

    B. As soon as practicable following the detection of a leak, plant personnel shall take one or more of the following actions:

        (1) Locate and isolate the leak, if necessary.

(2) Commence repair or replacement of the leaking component.

(3) Use a leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

Recordkeeping Requirements

39. The following records shall be kept at the plant for the life of the permit. All records required in this permit shall be made available at the request of personnel from the Texas Commission on Environmental Quality (TCEQ), EPA, or any local air pollution control agency with jurisdiction:

A. A copy of this permit.

B. Permit application received October 17, 2025, and subsequent representations submitted to the TCEQ.

C. A complete copy of the testing reports and records of the initial performance testing completed to demonstrate initial compliance.

D. Stack sampling results or other air emissions testing (other than CEMS data) that may be conducted on units authorized under this permit after the date of issuance of this permit.

E. A copy of the manufacturer's design and operation specifications and all emission-related maintenance requirements.

40. The following records (written or electronic) shall be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and shall be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:

A. The CEMS data of NO_X, CO, NH_3, and O_2 emissions from each CTG as specified in Special Condition No. 28 to demonstrate compliance with the emission rates listed in the MAERT and Special Condition No. 6.

B. Records of all CEMS data including calibration checks, adjustments, and maintenance performed on these systems in a permanent form suitable for inspection.

C. Records of dates and times for startups and shutdowns of the CTGs.

D. Records of the amount of natural gas fired each month and rolling 12-month totals for each of the CTGs, duct burners, the auxiliary boiler, and the black start generators.

E. Records of the sulfur content of natural gas fuel fired in the units at the site as specified in Special Condition Nos. 7 and 8.

F. Records of the number of non-emergency hours of operation for the emergency generator (EPN EDG1, EDG2, EDG3, and EDG4) and the Diesel Fire Pump (EPN FIREPUMP) on a monthly and 12-month rolling basis to demonstrate compliance with Special Condition No. 20.

G. Records of the auxiliary boiler hours of operation to demonstrate compliance with Special Condition No. 13.C.

H. Records of visible emissions, opacity observations, and any corrective action taken to demonstrate compliance with Special Condition No. 11.

I. Records of the number of tank trucks unloading ammonia for the CTGs to demonstrate compliance with Special Condition No. 12.D.

J. Vendor documentation of the emissions basis or emission factors for NO_X and CO for the black start generators (EPNs BSGEN1 and BSGEN2) as specified in Special Condition No. 14.

K. Records of the sulfur content of diesel fuel fired in the emergency engines and fire pump engines, hours of operations, as well as monthly diesel fuel deliveries, including delivery dates and fuel quantities to demonstrate compliance with Special Condition Nos. 20 and 21.

L. Records of monthly storage tank throughput and 12-month rolling average totals of storage tank throughput to demonstrate compliance with Special Condition 22.

M. Records of AVO checks, maintenance performed to any piping and valves or other equipment as required by 24.A and 25.F.

N. Records of monitored or calculated maintenance emissions to demonstrate compliance with Special Condition No. 31, 32, 33, and 34.

O. Records of maintenance or leak repairs performed on SF_6 containing circuit breakers to demonstrate compliance with Special Condition No. 38. Emission records from EPN FUG-SF6 to demonstrate compliance with Special Condition No. 38.A(1). **(GHG)**

P. Records of calculated GHG emissions on a 12-month rolling average basis to demonstrate compliance with Special Condition Nos. 35, 36, 37, and 38. **(GHG)**

Date: DRAFT

Permits 181895, PSDTX1684, and GHGPSDTX260

Attachment A

Inherently Low Emitting Activities

Planned Maintenance Activities							
Activities	EPN	Emissions					
		NO_x	CO	VOC	PM/ PM10/ PM2.5	SO_2	NH_3
Miscellaneous PM filter maintenance[1]	MSS				X		
Catalyst handling and maintenance[2]	MSS				X		
Online turbine blade washing	MSS				X		
Inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment, process instruments including sight glasses, meters, gauges, CEMS, PEMS	MSS	X	X	X			
Management of sludge from pits, ponds, sumps, and water conveyances[3]	MSS			X			

Date: DRAFT

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[1] Includes, but is not limited to: baghouse filters and combustion turbine air intake filters

[2] Includes, but is not limited to, replacement, cleaning, activation, and deactivation of SCR and oxidation catalysts.

[3] Includes, but is not limited to: mgmt. by vacuum truck/dewatering of material in open pits/ponds/sumps/tanks and other closed or open vessels. Material managed include water and sludge materials containing miscellaneous VOCs such as diesel, lube oil, and other waste oils.

Permits 181895, PSDTX1684, and GHGPSDTX260

Attachment B

Non-ILE Planned Maintenance Activities

Activities	EPN	Emissions					
		VOC	NO_x	CO	$PM/PM_{10}/PM_{2.5}$	SO_2 and H_2SO_4	NH_3
Process unit startup and shutdown	All combustion turbine stacks	X	X	X	X	X	X
Combustion unit tuning optimization[4]	All combustion turbine stacks	X	X	X	X	X	X
Gaseous fuel venting[5]	MSS	X					
Small equipment and fugitive component repair/replacement in VOC and NH_3 service[6]	MSS	X					X

Date: <u>DRAFT</u>

[4] Includes, but is not limited to: leak operability checks (e.g. turbine overspeed test, troubleshooting), seasonal tuning, islanding testing, and balancing.

[5] Includes, but is not limited to: venting prior to pipeline pigging and meter proving.

[6] Includes, but is not limited to: (1) repair/replacement of pumps, compressors, valves, pipes, flanges, transport lines, filters/screens in natural gas, fuel oil, diesel oil, ammonia, lube oil, and gasoline service; (2) vehicle and mobile equipment maintenance that may involve small VOC emissions, such as oil changes and transmission/hydraulic system service; (3) off-line NO_x control device maintenance including aqueous ammonia systems.

Emission Sources - Maximum Allowable Emission Rates

Permit Number 181895 and PSDTX1684

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
7HACC1	Combined Cycle 7HA Turbine 1 (6)	NO_x	31.80	(7)
		NO_x (MSS)	171.43	(7) (8)
		CO	19.36	(7)
		CO (MSS)	711.43	(7) (8)
		VOC	11.09	(7)
		VOC (MSS)	90.00	(7) (8)
		SO_2	5.95	26.05
		PM	23.80	104.26
		PM_{10}	23.80	104.26
		$PM_{2.5}$	23.80	104.26
		H_2SO_4	5.10	22.34
		NH_3	29.43	128.89
		CH_2O (9)	0.81	3.57
		HAPs (9)	11.46	50.18
7HACC2	Combined Cycle 7HA Turbine 2 (6)	NO_x	31.80	(7)
		NO_x (MSS)	171.43	(7) (8)
		CO	19.36	(7)
		CO (MSS)	711.43	(7) (8)
		VOC	11.09	(7)
		VOC (MSS)	90.00	(7) (8)
		SO_2	5.95	26.05
		PM	23.80	104.26
		PM_{10}	23.80	104.26
		$PM_{2.5}$	23.80	104.26

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		H_2SO_4	5.10	22.34
		NH_3	29.43	128.89
		CH_2O (9)	0.81	3.57
		HAPs (9)	11.46	50.18
CAP1	Combined Cycle 7HA Turbine Emission SUSD Cap	NO_x (8)	-	6.22
		CO (8)	-	22.02
		VOC (8)	-	4.87
CAP1_1	Combined Cycle 7HA Turbine Normal + SUSD Cap	NO_x (7)	-	283.56
		CO (7)	-	190.86
		VOC (7)	-	101.56
7HASC1	Simple Cycle 7HA Turbine 1 (6)	NO_x	29.69	(7)
		NO_x (MSS)	89.54	(7) (8)
		CO	25.30	(7)
		CO (MSS)	148.35	(7) (8)
		VOC	8.28	(7)
		VOC (MSS)	46.62	(7) (8)
		SO_2	4.44	19.45
		PM	20.20	88.48
		PM_{10}	20.20	88.48
		$PM_{2.5}$	20.20	88.48
		H_2SO_4	3.70	16.22
		NH_3	21.98	96.25
		CH_2O (9)	0.71	3.09
		HAPs (9)	1.71	7.50
7HASC2	Simple Cycle 7HA Turbine 2 (6)	NO_x	29.69	(7)
		NO_x (MSS)	89.54	(7) (8)
		CO	25.30	(7)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		CO (MSS)	148.35	(7) (8)
		VOC	8.28	(7)
		VOC (MSS)	46.62	(7) (8)
		SO_2	4.44	19.45
		PM	20.20	88.48
		PM_{10}	20.20	88.48
		$PM_{2.5}$	20.20	88.48
		H_2SO_4	3.70	16.22
		NH_3	21.98	96.25
		CH_2O (9)	0.71	3.09
		HAPs (9)	1.71	7.50
7HASC3	Simple Cycle 7HA Turbine 3 (6)	NO_x	29.69	(7)
		NO_x (MSS)	89.54	(7) (8)
		CO	25.30	(7)
		CO (MSS)	148.35	(7) (8)
		VOC	8.28	(7)
		VOC (MSS)	46.62	(7) (8)
		SO_2	4.44	19.45
		PM	20.20	88.48
		PM_{10}	20.20	88.48
		$PM_{2.5}$	20.20	88.48
		H_2SO_4	3.70	16.22
		NH_3	21.98	96.25
		CH_2O (9)	0.71	3.09
		HAPs (9)	1.71	7.50
CAP2	Simple Cycle 7HA Turbine Emission SUSD Cap	NO_x (8)	-	5.33
		CO (8)	-	13.65

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
		VOC (8)	-	4.42
CAP2_1	Simple Cycle 7HA Turbine Normal + SUSD Cap	NO_x (7)	-	394.26
		CO (7)	-	345.13
		VOC (7)	-	112.89
T350SC1	Solar T350 Turbine 1 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)
		VOC	0.87	(7)
		VOC (MSS)	6.73	(7) (8)
		SO_2	1.26	5.52
		PM	2.43	10.64
		PM_{10}	2.43	10.64
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
T350SC2	Solar T350 Turbine 2 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)
		VOC	0.87	(7)
		VOC (MSS)	6.73	(7) (8)
		SO_2	1.26	5.52
		PM	2.43	10.64
		PM_{10}	2.43	10.64

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
T350SC3	Solar T350 Turbine 3 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)
		VOC	0.87	(7)
		VOC (MSS)	6.73	(7) (8)
		SO_2	1.26	5.52
		PM	2.43	10.64
		PM_{10}	2.43	10.64
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
T350SC4	Solar T350 Turbine 4 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)
		VOC	0.87	(7)
		VOC (MSS)	6.73	(7) (8)
		SO_2	1.26	5.52
		PM	2.43	10.64

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		PM_{10}	2.43	10.64
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
T350SC5	Solar T350 Turbine 5 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)
		VOC	0.87	(7)
		VOC (MSS)	6.73	(7) (8)
		SO_2	1.26	5.52
		PM	2.43	10.64
		PM_{10}	2.43	10.64
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
T350SC6	Solar T350 Turbine 6 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)
		VOC	0.87	(7)
		VOC (MSS)	6.73	(7) (8)
		SO_2	1.26	5.52

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		PM	2.43	10.64
		PM_{10}	2.43	10.64
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
T350SC7	Solar T350 Turbine 7 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)
		VOC	0.87	(7)
		VOC (MSS)	6.73	(7) (8)
		SO_2	1.26	5.52
		PM	2.43	10.64
		PM_{10}	2.43	10.64
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
T350SC8	Solar T350 Turbine 8 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)
		VOC	0.87	(7)
		VOC (MSS)	6.73	(7) (8)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		SO_2	1.26	5.52
		PM	2.43	10.64
		PM_{10}	2.43	10.64
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
T350SC9	Solar T350 Turbine 9 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)
		VOC	0.87	(7)
		VOC (MSS)	6.73	(7) (8)
		SO_2	1.26	5.52
		PM	2.43	10.64
		PM_{10}	2.43	10.64
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
T350SC10	Solar T350 Turbine 10 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)
		VOC	0.87	(7)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		VOC (MSS)	6.73	(7) (8)
		SO_2	1.26	5.52
		PM	2.43	10.64
		PM_{10}	2.43	10.64
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
T350SC11	Solar T350 Turbine 11 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)
		VOC	0.87	(7)
		VOC (MSS)	6.73	(7) (8)
		SO_2	1.26	5.52
		PM	2.43	10.64
		PM_{10}	2.43	10.64
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
T350SC12	Solar T350 Turbine 12 (6)	NO_x	3.75	(7)
		NO_x (MSS)	13.12	(7) (8)
		CO	2.11	(7)
		CO (MSS)	98.76	(7) (8)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		VOC	0.87	(7)
		VOC (MSS)	6.73	(7) (8)
		SO_2	1.26	5.52
		PM	2.43	10.64
		PM_{10}	2.43	10.64
		$PM_{2.5}$	2.43	10.64
		H_2SO_4	1.93	8.45
		NH_3	2.57	11.25
		CH_2O (9)	0.08	0.36
		HAPs (9)	0.20	0.88
CAP3	Solar T350 Turbine Emission SUSD Cap	NO_x (8)	-	3.89
		CO (8)	-	38.23
		VOC (8)	-	2.38
CAP3_1	Solar T350 Turbine Normal + SUSD	NO_x (7)	-	200.49
		CO (7)	-	149.05
		VOC (7)	-	48.07
T130SC1	Titan T130 Turbine 1	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC2	Titan T130 Turbine 2	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC3	Titan T130 Turbine 3	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC4	Titan T130 Turbine 4	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC5	Titan T130 Turbine 5	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	**TPY (4)**
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC6	Titan T130 Turbine 6	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC7	Titan T130 Turbine 7	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC8	Titan T130 Turbine 8	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC9	Titan T130 Turbine 9	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC10	Titan T130 Turbine 10	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC11	Titan T130 Turbine 11	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC12	Titan T130 Turbine 12	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC13	Titan T130 Turbine 13	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC14	Titan T130 Turbine 14	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC15	Titan T130 Turbine 15	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC16	Titan T130 Turbine 16	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC17	Titan T130 Turbine 17	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC18	Titan T130 Turbine 18	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC19	Titan T130 Turbine 19	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC20	Titan T130 Turbine 20	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC21	Titan T130 Turbine 21	NO_x	1.59	(7)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC22	Titan T130 Turbine 22	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
T130SC23	Titan T130 Turbine 23	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC24	Titan T130 Turbine 24	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		HAPs (9)	0.09	0.37
T130SC25	Titan T130 Turbine 25	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC26	Titan T130 Turbine 26	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC27	Titan T130 Turbine 27	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC28	Titan T130 Turbine 28	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
T130SC29	Titan T130 Turbine 29	NO_x	1.59	(7)
		NO_x (MSS)	2.33	(7) (8)
		CO	0.90	(7)
		CO (MSS)	26.75	(7) (8)
		VOC	0.37	(7)
		VOC (MSS)	6.31	(7) (8)
		SO_2	0.54	2.35
		PM	1.04	4.56
		PM_{10}	1.04	4.56
		$PM_{2.5}$	1.04	4.56
		H_2SO_4	0.82	3.59
		NH_3	1.09	4.78
		CH_2O (9)	0.04	0.15
		HAPs (9)	0.09	0.37
CAP4	Solar T130 Turbine Emission SUSD Cap	NO_x (8)	-	1.04
		CO (8)	-	26.10
		VOC (8)	-	6.26
CAP4_1	Titan T130 Turbine Normal + SUSD	NO_x (7)	-	202.97
		CO (7)	-	139.93
		VOC (7)	-	53.20
BSGEN1	Black Start Generator 1	NO_x	4.56	-
		CO	13.02	-
		VOC	4.56	-
		SO_2	0.03	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		PM	0.21	-
		PM_{10}	0.21	-
		$PM_{2.5}$	0.21	-
		CH_2O (9)	1.11	-
		HAPs (9)	1.52	-
BSGEN2	Black Start Generator 2	NO_x	3.25	-
		CO	9.83	-
		VOC	2.41	-
		SO_2	0.03	-
		PM	0.21	-
		PM_{10}	0.21	-
		$PM_{2.5}$	0.21	-
		CH_2O (9)	1.13	-
		HAPs (9)	1.55	-
CAP5_1	Black Start Generator Emission Cap	NO_x	-	0.59
		CO	-	1.71
		VOC	-	0.52
		SO_2	-	<0.01
		PM	-	0.03
		PM_{10}	-	0.03
		$PM_{2.5}$	-	0.03
		CH_2O (9)	-	0.17
		HAPs (9)	-	0.23
EDG1	Emergency Diesel Generator 1	NO_x	22.02	1.10
		CO	12.69	0.63
		VOC	1.19	0.06
		SO_2	0.03	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
		PM	0.73	0.04
		PM_{10}	0.73	0.04
		$PM_{2.5}$	0.73	0.04
		CH_2O (9)	<0.01	<0.01
		HAPs (9)	0.02	<0.01
EDG2	Emergency Diesel Generator 2	NO_x	22.02	1.10
		CO	12.69	0.63
		VOC	1.19	0.06
		SO_2	0.03	<0.01
		PM	0.73	0.04
		PM_{10}	0.73	0.04
		$PM_{2.5}$	0.73	0.04
		CH_2O (9)	<0.01	<0.01
		HAPs (9)	0.02	<0.01
EDG3	Emergency Diesel Generator 3	NO_x	22.02	1.10
		CO	12.69	0.63
		VOC	1.19	0.06
		SO_2	0.03	<0.01
		PM	0.73	0.04
		PM_{10}	0.73	0.04
		$PM_{2.5}$	0.73	0.04
		CH_2O (9)	<0.01	<0.01
		HAPs (9)	0.02	<0.01
EDG4	Emergency Diesel Generator 4	NO_x	22.02	1.10
		CO	12.69	0.63
		VOC	1.19	0.06
		SO_2	0.03	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		PM	0.73	0.04
		PM_{10}	0.73	0.04
		$PM_{2.5}$	0.73	0.04
		CH_2O (9)	<0.01	<0.01
		HAPs (9)	0.02	<0.01
FIREPUMP	Diesel Fire Pump	NO_x	1.54	0.08
		CO	1.42	0.07
		VOC	0.08	<0.01
		SO_2	<0.01	<0.01
		PM	0.08	<0.01
		PM_{10}	0.08	<0.01
		$PM_{2.5}$	0.08	<0.01
		CH_2O (9)	<0.01	<0.01
		HAPs (9)	0.01	<0.01
BOILER	Auxiliary Boiler	NO_x	1.00	0.23
		CO	3.70	0.84
		VOC	0.54	0.12
		SO_2	1.43	0.07
		PM	0.74	0.17
		PM_{10}	0.74	0.17
		$PM_{2.5}$	0.74	0.17
		CH_2O (9)	0.01	<0.01
		HAPs (9)	0.19	0.04
FPTNK1	Diesel Tank For Fire Pump	VOC	<0.01	<0.01
EDGTNK1	Diesel Tank For EDG	VOC	0.01	<0.01
EDGTNK2	Diesel Tank For EDG	VOC	0.01	<0.01
EDGTNK3	Diesel Tank For EDG	VOC	0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
EDGTNK4	Diesel Tank For EDG	VOC	0.01	<0.01
EDGTNK5	Diesel Tank For EDG	VOC	0.01	<0.01
MSS	MSS	NO_x	<0.01	<0.01
		CO	<0.01	<0.01
		VOC	18.76	0.13
		PM	2.70	0.48
		PM_{10}	2.65	0.47
		$PM_{2.5}$	2.61	0.47
		NH_3	<0.01	0.01
FUG	Fugitives (5)	VOC	0.79	3.47
		NH_3	0.14	0.63
OILVENT	Lube Oil	VOC	1.00	4.39
		PM	1.00	4.39
		PM_{10}	1.00	4.39
		$PM_{2.5}$	1.00	4.39
FUG-SEP	Oil Water Separators	VOC	3.60	4.73

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon monoxide
HAP - hazardous air pollutant as listed in § 112(b) of the Federal Clean Air Act or Title 40 Code of Federal Regulations Part 63, Subpart C
H_2SO_4 - sulfuric acid
NH_3 - ammonia
CH_2O - formaldehyde
(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
(5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
(6) Planned Maintenance, Startup, and Shutdown (MSS) for all pollutants are authorized even if not specifically identified as MSS. During any clock hour that includes one or more minutes of planned MSS, that pollutant’s maximum hourly emission rate shall apply during that clock hour.

Emission Sources - Maximum Allowable Emission Rates

(7) Annual emissions associated with both routine operation and MSS operation shall be limited to the ‘Normal + SUSD’ emissions cap for the specified turbines. The ‘Normal + SUSD’ emissions cap and the ‘SUSD Cap’ emissions cap are not additive.
(8) Annual emissions associated with only startup and shutdown activities are limited to the ‘SUSD Cap’ emissions cap for the specified turbines. The ‘Normal + SUSD’ emissions cap and the ‘SUSD Cap’ emissions cap are not additive.
(9) The HAPs emission rates include formaldehyde emission rates.

Date: DRAFT

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX260

This table lists the maximum allowable emission rates of greenhouse gas (GHG) emissions, as defined in Title 30 Texas Administrative Code § 101.1, for all sources of GHG air contaminants on the applicant's property that are authorized by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities authorized by this permit.

Air Contaminants Data

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**
			TPY (4)
CAP1	Combined Cycle 7HA Turbine Emission SUSD Cap	CO_2 (5) (7)	7,645.13
		CH_4 (5) (7)	0.14
		N_2O (5) (7)	0.01
		CO_2e	7,652.94
CAP1_1	Combined Cycle 7HA Turbine Normal + SUSD Cap	CO_2 (5) (6)	4,366,916.31
		CH_4 (5) (6)	81.87
		N_2O (5) (6)	8.19
		CO_2e	4,371,377.99
CAP2	Simple Cycle 7HA Turbine Emission SUSD Cap	CO_2 (5) (7)	14,034.91
		CH_4 (5) (7)	0.27
		N_2O (5) (7)	0.03
		CO_2e	14,049.33
CAP2_1	Simple Cycle 7HA Turbine Normal + SUSD Cap	CO_2 (5) (6)	4,878,802.30
		CH_4 (5) (6)	91.95
		N_2O (5) (6)	9.20
		CO_2e	4,883,813.51
CAP3	Solar T350 Turbine Emission SUSD Cap	CO_2 (5) (7)	3,123.34
		CH_4 (5) (7)	0.06
		N_2O (5) (7)	0.01
		CO_2e	3,126.55
CAP3_1	Solar T350 Turbine Normal + SUSD	CO_2 (5) (6)	2,280,035.92
		CH_4 (5) (6)	42.97
		N_2O (5) (6)	4.30
		CO_2e	2,282,377.83
CAP4	Solar T130 Turbine Emission SUSD Cap	CO_2 (5) (7)	3,208.00
		CH_4 (5) (7)	0.06

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates TPY (4)
		N_2O (5) (7)	0.01
		CO_2e	3,211.30
CAP4_1	Solar Titan T130 Turbine Normal + SUSD	CO_2 (5) (6)	2,341,840.88
		CH_4 (5) (6)	44.14
		N_2O (5) (6)	4.41
		CO_2e	2,344,246.27
CAP5_1	Black Start Generator Emission Cap	CO_2 (5)	373.16
		CH_4 (5)	0.01
		N_2O (5)	<0.01
		CO_2e	373.55
EDG1	Emergency Diesel Generator 1	CO_2 (5)	118.56
		CH_4 (5)	0.01
		N_2O (5)	<0.01
		CO_2e	118.97
EDG2	Emergency Diesel Generator 2	CO_2 (5)	118.56
		CH_4 (5)	0.01
		N_2O (5)	<0.01
		CO_2e	118.97
EDG3	Emergency Diesel Generator 3	CO_2 (5)	118.56
		CH_4 (5)	0.01
		N_2O (5)	<0.01
		CO_2e	118.97
EDG4	Emergency Diesel Generator 4	CO_2 (5)	118.56
		CH_4 (5)	0.01
		N_2O (5)	<0.01
		CO_2e	118.97
FIREPUMP	Diesel Fire Pump	CO_2 (5)	14.57
		CH_4 (5)	<0.01
		N_2O (5)	<0.01
		CO_2e	14.61

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
BOILER	Auxiliary Boiler	CO_2 (5)	2664.41
		CH_4 (5)	0.05
		N_2O (5)	0.01
		CO_2e	2667.15
FUG-SF6	SF6 Emissions	SF_6 (5)	0.05
		CO_2e	1195.51
MSS	MSS	CO_2 (5)	0.10
		CH_4 (5)	4.81
		CO_2e	134.73
FUG	Fugitives	CO_2 (5)	2.60
		CH_4 (5)	128.41
		CO_2e	3,598.00

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) CO_2 - carbon dioxide
N_2O - nitrous oxide
CH_4 - methane
SF_6 - sulfur hexafluoride
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (GWPs).
The GWPs effective January 1, 2025 and later (89 FR 31894, April 25, 2024) are the following:
CO_2 (1), N_2O (265), CH_4 (28), SF_6 (23,500), HFC (various), PFC (various).
(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. These rates include emissions from maintenance, startup, and shutdown.
(5) Emission rate is given for informational purposes only and does not constitute enforceable limit.
(6) Annual emissions associated with both routine operation and MSS operation shall be limited to the ‘Normal + SUSD’ emissions cap for the specified turbines. The ‘Normal + SUSD’ emissions cap and the ‘SUSD Cap’ emissions cap are not additive.
(7) Annual emissions associated with only startup and shutdown activities are limited to the ‘SUSD Cap’ emissions cap for the specified turbines. The ‘Normal + SUSD’ emissions cap and the ‘SUSD Cap’ emissions cap are not additive.

Date: DRAFT

Preliminary Determination Summary

Energy Forge One LLC
Permit Numbers 181895, PSDTX1684, and GHGPSDTX260

I. Applicant

Energy Forge One LLC
1500 Louisiana St
Houston, TX 77002-7308

II. Project Location

Kilby Power Plant
The site located from the following driving directions: From the intersection of U.S. 285 and I-20, travel Southeast on US 285 for approximately 16 miles and turn right on Ranch Road 2007. Travel Southwest for approximately 8 miles, turn right on Farm-to-Market Road 112, and travel West for about 2 miles to reach the site in Reeves County, Pecos, Texas 79780.

III. Project Description

Energy Forge One LLC (EFO) proposes to construct and operate a greenfield natural gas-fired turbine power plant, referred to as the Kilby Power Plant, for onsite power generation. The proposed site operations consist of two (2) natural gas-fired combined cycle combustion turbines and 44 natural gas-fired simple cycle combustion turbines.

The proposed Kilby Power Plant's nominal power generation capacity will be approximately 2,869 megawatts (MW) at site conditions of 59°F inlet air temperature; 60% relative humidity; 2,850 feet elevation; and 13.25 psi atmospheric pressure. Supporting equipment emission sources include a natural gas-fired auxiliary boiler, two natural gas-driven black start generators, four diesel-driven emergency generators, a diesel-fired fire pump, six diesel storage tanks, fugitive equipment leaks, lube oil vents, an oil water separator, and planned maintenance, startup, and shutdown (MSS) activities.

IV. Emissions

Air Contaminant	Proposed Allowable Emission Rates (tpy)
VOC	329.34
NO_x	1,086.58
SO_2	244.86
CO	830.13
$PM/PM_{10}/PM_{2.5}$	738.97/738.96/738.96
H_2SO_4	299.00
NH_3	820.71
CO_2	13,871,124.49
CH_4	394.22
SF_6	0.05

N_2O	26.11
CO_2 Equivalents (CO_2e)	13,890,275.01

CO_2e - carbon dioxide equivalents based on global warming potentials of CH_4 = 25, N_2O = 298, SF_6 = 22,800.

MSS activities are authorized in this permit. Separate hourly CO, NOx, and VOC emissions for startup and shutdown activities are authorized from each of the turbines. All maintenance activities are authorized under a separate EPN MSS. These maintenance activities include online turbine blade washing; miscellaneous air intake filter changeouts; CEMS analyzer and other process instrument repair, replacement, testing, and calibrations; inlet fuel line venting; repair and replacement of small equipment and fugitive components; catalyst handling and maintenance; and sludge management.

V. Federal Applicability

The power plant will be located in Reeves County, which is currently in attainment for all criteria pollutants. Therefore, Nonattainment New Source Review (NNSR) does not apply.

The site will be a major named PSD source because the combined-cycle units proposed are considered "fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour (MMBtu/hr) heat input," and the emissions of at least one pollutant are greater than 100 tons per year. The Baseline Actual Emissions (BAE) associated with this initial permit are zero since this is a new greenfield site with no existing emissions.

The site will emit 100 tpy or more of CO, NO_x, VOC, SO_2, PM, PM_{10}, $PM_{2.5}$, and H_2SO_4 and be subject to PSD for these pollutants. Contemporaneous netting does not apply to new greenfield sites or other existing PSD minor sources. All other pollutants were then evaluated for significance but did not exceed the associated Significant Emissions Rate (SER) threshold.

PSD review also applies to greenhouse gas (GHG) since PSD review is triggered for other pollutants, and the project has a GHG as CO_2e emissions increase of greater than 75,000 tpy CO_2e. All global warming potentials (GWP) are based on 40 CFR 98 Table A-1, which was updated in the final rule for 89 Federal Register 31802 Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, effective January 1, 2025.

Pollutant	Project Increase (tpy) [1]	NA Major Source Trigger (tpy)	PSD Major Source Trigger (tpy)	Significant Emission Rate (tpy)	PSD Triggered Y/N	NA Triggered Y/N
VOC [2]	329.34	N/A	100	40	Y	N
NOx [2, 3]	1,086.58	N/A	100	40	Y	N
SO_2 [3]	244.86	N/A	100	40	Y	N
CO	830.13	N/A	100	100	Y	N
PM	738.97	N/A	100	25	Y	N
PM_{10}	738.96	N/A	100	15	Y	N
$PM_{2.5}$	738.96	N/A	100	10	Y	N

Pollutant	Project Increase (tpy) [1]	NA Major Source Trigger (tpy)	PSD Major Source Trigger (tpy)	Significant Emission Rate (tpy)	PSD Triggered Y/N	NA Triggered Y/N
H_2SO_4	299.00	N/A	100	7	Y	N
CO_2e	13,871,124.49	N/A	75,000	75,000	Y	N

[1] Project Increases: Comparison of Baseline Actual to PTE Increases only

[2] Ozone precursor. Either pollutant precursor can trigger BACT/LAER and impacts analysis, as applicable.

[3] $PM_{2.5}$ precursor. Not used to trigger $PM_{2.5}$ BACT/LAER or impacts analysis at this time.

Emissions from additional pollutants, such as NH_3 and hazardous air pollutants (HAPs) including formaldehyde are not regulated under PSD or NA review. These pollutants are addressed in the ‘Control Technology Review’ section and the ‘Minor Source NSR and Air Toxics Review’ section below.

VI. Control Technology Review

The TCEQ three-tier approach to BACT is used for the control technology review of all pollutants from this permit. TCEQ has determined that its three-tiered approach is equivalent to the EPA’s “top-down” approach, and the result from using either method is the same. For that reason, PSD BACT reviews are conducted using the same three-tiered process. EPA has agreed to accept the three tier approach as equivalent to the top-down method for PSD review when the following are considered: (1) recently issued/approved permits within the state of Texas; (2) recently issued/approved permits in other states; and (3) control technologies listed in the RBLC.

EFO used the TCEQ three-tier approach to BACT for the control technology review of all pollutants from this permit. The pollutants subject to PSD review include CO, NOx, VOC, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG (as CO_2e) emissions. For each of these pollutants, EFO conducted a search of the RACT/BACT/LAER Clearinghouse (RBLC) from 2015 to 2025, the TCEQ Turbine List, and recently-approved permits for combined-cycle gas turbines, simple-cycle gas turbines, and similar emissions sources authorized in Texas and other states. State minor BACT was evaluated for pollutants not subject to PSD review. All emission sources proposed on this permit meet BACT as follows:

<table>
<tr><th>Source Name</th><th>EPN</th><th>Best Available Control Technology Description</th></tr>
<tr><td>CC 7HA.02 Turbine 1</td><td>7HACC1</td><td rowspan="4">Two General Electric (GE) 7HA.02 combustion turbines (CT) will be used in combined-cycle mode. Both CTs will be fired exclusively with pipeline quality natural gas and are equipped with supplemental natural gas-fired duct burners and a steam turbine generator. The net output of each turbine is 555.7 MW in combined cycle mode. The maximum heat input is 3,379.8 MMbtu/hr HHV for the individual turbines only, while the duct burners have a maximum heat input of 870.8 MMBtu/hr HHV.
To estimate NO_x, CO, VOC, NH_3, and particulate matter emission rates for both turbines, EFO provided the combustion turbine manufacturer’s data for the exhaust pollutant concentrations in parts per million by volume dry basis (ppmvd), corrected to 15 percent oxygen or provided emission factors already converted to units of lb/MMBtu. The turbine manufacturer’s data</td></tr>
<tr><td>CC 7HA.02 Turbine 2</td><td>7HACC2</td></tr>
<tr><td>Combined Cycle 7HA Turbine Emission SUSD Cap</td><td>CAP1</td></tr>
<tr><td>Combined Cycle 7HA Turbine Normal + SUSD Cap</td><td>CAP1_1</td></tr>
</table>

Source Name	EPN	Best Available Control Technology Description
		was also used for estimating emissions of NOx, VOC, and CO from startup and shutdown periods, as well as the estimated durations of these periods. For sulfur compounds, emissions are based on the sulfur content of the fuel supplied to the site. Hazardous Air Pollutant (HAP) emissions are estimated based on EPA AP-42, Table 3.1-3 factors for natural gas-fired stationary combustion turbines. Formaldehyde emissions are based on the worst-case emission factor (lb/MMBtu) from the turbine vendor. Annual emission rates are based on 8,760 hours per year of operation. Startup and shutdown operations are part of an annual emissions cap EPN CAP1. The total routine and MSS activities are limited to a separate annual emissions cap EPN CAP1_1. **NOx:** Limited to 2.0 ppmvd at 15% O_2 on a 24-hour average. Dry Low-NOx (DLN) burners and an aqueous ammonia-based Selective Catalytic Reduction (SCR) system are used to reduce emissions and achieve this NOx concentration. Current TCEQ Tier I BACT is 2.0 ppmvd at 15% O_2 on a 24-hr average, typically achieved with dry low NOx burners, water/steam injection, limiting fuel consumption, or SCR. The numeric value and proposed technique are to be specified. RBLC searches performed yield a range of emission limits typically between 2.0 – 23.0 ppmvd at 15% O_2 but most commonly at 2 ppmvd at 15% O_2, achieved with SCR and DLN burners. **CO:** Limited to 2.0 ppmvd at 15% O_2 on a 3-hour average. Oxidation catalysts and good combustion practices are used to reduce emissions and achieve this CO concentration. Current TCEQ Tier I BACT is between 2.0 – 4.0 ppmvd at 15% O_2 on a 3-hour average, typically achieved with good combustion practices and/or oxidation catalyst. Specify numeric value and control technique. RBLC searches performed yield a range of emission limits from 0.9 – 5.0 ppmvd at 15% O_2 but most commonly at 2.0 ppmvd at 15% O_2, achieved with catalytic oxidation and good combustion practices. **VOC:** Limited to 2.0 ppmvd at 15% O_2 with duct burner operation and 1 ppmvd at 15% O_2 without duct burner operation, both on a 24-hr average. Oxidation catalysts and good combustion practices are used to reduce emissions and achieve this VOC concentration. Current TCEQ Tier I BACT is 2.0 ppmvd at 15% O_2 if no duct burner is used and 4.0 ppmvd with duct burner use. RBLC searches performed yield a range of emission limits between 0.7 – 4.0 ppmvd at 15% O_2 but most commonly 1.0 ppmvd at 15% O_2 without duct burner firing and between 1.5 – 4.0 ppmvd with duct burner firing, typically achieved with catalytic oxidation and good combustion practices. **HAPs:** All HAP emissions, except for formaldehyde, are estimated based on EPA AP-42, Table 3.1-3 emission factors for natural gas-fired stationary combustion turbines. Formaldehyde emissions are limited to 91.0 ppbvd at 15% O_2 except during turbine startup, according to MACT YYYY Table 1. Because the units will be controlled with oxidation catalysts, MACT YYYY Table 2 applies, which requires maintaining the 4-hr rolling average of the catalyst inlet temperature within range suggested by the catalyst manufacturer. **SO_2:** The turbine is limited to firing natural gas that will not exceed a sulfur content of 0.5 grains per 100 standard cubic feet (gr/100 scf). It is assumed that there is 100% conversion of the sulfur in the fuel to SO_2. Good combustion practices are used. Current TCEQ Tier I BACT is limiting fuel use to pipeline quality natural gas having a sulfur content of fuel not to

Source Name	EPN	Best Available Control Technology Description
		exceed 5 gr/100 scf on hourly basis and 1 gr/100 scf on annual basis. Good combustion practices are to be used. RBLC searches performed show a range of sulfur emission limits from 0.4 – 5.0 gr/100 scf using pipeline quality natural gas or other low sulfur fuels. **H_2SO_4:** Limited to a fuel sulfur content of 0.5 gr S/100 scf. This fuel sulfur content is equivalent to 0.0012 lb H_2SO_4/MMBtu when assuming a 100% conversion of the fuel sulfur to SO_2, an approximate 55% conversion of the SO_2 produced to SO_3, and then a 100% conversion of SO_3 to H_2SO_4. Current TCEQ Tier I BACT is limiting fuel use to pipeline quality natural gas having a sulfur content of fuel not to exceed 5 gr S/100 scf on hourly basis and 1 gr S/100 scf on annual basis. Good combustion practices are to be used. RBLC searches performed show a range of sulfur emission limits from 0.33 – 5.0 gr S/100 scf, achieved using pipeline quality natural gas or other low sulfur fuels. RBLC searches also show emission limits on a 'lb H_2SO_4/MMBtu' basis. However, these 'lb SO_2/MMbtu' emission limits cannot be used to determine reasonably equivalent emission factors of 'gr S/100 scf' since there is insufficient information on the RBLC regarding the full conversion of fuel sulfur to SO_2, SO_3, and finally H_2SO_4. **$PM/PM_{10}/PM_{2.5}$:** Limited to 0.0056 lb/MMBtu. Only pipeline quality natural gas is fired, and good combustion practices are used. It is conservatively assumed that total PM is equal to PM_{10}, which is equal to $PM_{2.5}$. Current TCEQ Tier I BACT is to limit fuel firing to pipeline quality natural gas and to use good combustion practices. RBLC searches performed show emission limits up to 0.044 lb/MMBtu but generally in the range of 0.0025 – 0.0085 lb/MMBtu using clean fuels. **NH_3:** Unreacted ammonia slip is limited to 5.0 ppmvd at 15% O_2 on a 3-hr average, achieved by controlling the ammonia injection/optimization of the SCR system used to control NOx emissions. Current TCEQ Tier I BACT is between 7 – 10 ppmvd at 15% O_2 on a 3-hr average, typically achieved through controlling the ammonia injection system to minimize ammonia slip. **GHG as CO_2e:** Limited to a mass input-based CO_2 emission factor of 117.6 lb/MMBtu based on vendor estimates, while the CH_4 and N_2O emission factors (0.001 kg/MMBtu and 0.0001 kg/MMBtu, respectively) are estimated from 40 CFR 98 Table C-2. EFO proposed an input-based GHG (as CO_2e) BACT limit of 117.72 CO_2e/MMBtu. Good combustion practices are used, and the fuel is limited to pipeline quality natural gas, which is considered a low GHG emitting fuel from 40 CFR 98 Table C-1 and C-2. RBLC searches performed show a range of energy output-based emission limits between 825 – 1,000 lb/MWh-gross, a range of input-based emission limits between 117 – 118 lb CO_2e/MMBtu, and a range of annual mass limits (tons CO_2e per year). There is insufficient information on the RBLC to reasonably determine equivalent emission factors using only annual mass limits. Regarding an input-based standard, EFO has stated that the majority of simple and combined-cycle turbines in the RBLC are in the context of the electric utility industry and are therefore part of a system of units that are interconnected with the grid. Power plants that are dedicated to powering a nearby data center or other large industrial loads are typically "behind-the-meter" and not interconnected to the grid. Power plants for the electric utility industry can shift generation to respond instantaneously to load and have interconnected utilities with multiple generation assets compared to "behind-the-meter" power plants.

Source Name	EPN	Best Available Control Technology Description
		EFO has referenced Permit 181009, Project 396274 for Fermi Equipment Holdco – Project Matador and Permit 181033, Project 396366 for Pacifico GW LLC – GW Ranch Energy Center. In both permits, an input-based GHG emission standard was chosen. For Permit 181033, a standard of 117 lb CO_2/MMBtu was used for the turbines in this permit, which includes both the large frame type turbines and the aeroderivative turbines and heat ratings between 500 MMBtu/hr and 3,000 MMBtu/hr. Fermi uses a standard of 117 lb CO_2/MMBtu for the turbines, which include the frame type units and aeroderivative units ranging from 443 MMbtu//hr to 478 MMbtu/hr. EFO also reviewed the potential technical and economic feasibility of carbon capture and sequestration (CCS) as a control mechanism for GHG emissions. CCS is a multi-stage process involving a series of technologies including a CO_2 capture system using absorption towers with solvent or sorbents, compression and transportation of the CO_2, and injection into subsurface formations for long-term CO_2 storage. EFO has stated that CCS is currently not technically feasible for the proposed facility since there is no operational sequestration facility nearby, there is no existing pipeline to transport the CO_2, and it has not been successfully demonstrated nor commercially operated at any gas fired combustion turbine site at the proposed scale. The Petra Nova Project is the only CCS unit for a power plant in the United States, located at the NRG W.A. Parish Electric Generating Station in Houston, TX. Petra Nova however, captures and sequesters CO_2 from a coal-fired boiler. Regardless, EFO has performed a cost analysis based on the “EPA Air Pollution Control Cost Manual” for implementing CCS for GHG emissions reduction. In this cost analysis, EFO estimated various capital costs and applied a capital recover factor to annualize these capital costs, estimated annual operating costs, and developed estimates of emissions and assumptions for operating parameters (e.g. fuel used, power consumed) used in the calculations. EFO estimated that multiple absorbers would be needed to capture the total CO_2 emissions from the proposed turbines at the site, with each absorber limited in capacity to one million tons per year. The capital recovery factor assumes a 20-year plant life and a 10% discount rate. EFO has used a 20-year project life cycle, stating it is widely used in CCS economic evaluations and aligns with typical equipment life assumptions and vendor performance guarantees for capture systems. EFO states that a 10% discount rate is also commonly applied in CCS economic studies to represent a reasonable cost of annual capital for CCS projects, and is consistent with approaches presented in CCS literature, including Rubin et al., 2011; and U.S. OSTI 2011. Transportation and storage costs per ton were added to produce a final estimate of $194/ton of CO_2 removed using 2024 numbers. CCS cost estimates used in other applications include: • Southwestern Public Service Company – Gaines County Power Plant, TCEQ Permit 179777 ($186/ton CO_2 removed), • NRG – Jewitt Energy Center, TCEQ Permit 180096 ($99/ton CO_2 removed), • CPV – Basin Ranch Energy Center, TCEQ Permit 175063 ($102/ton of CO_2 removed), • Marshall Energy Center – North & South Combined Cycle Projects (RBLC ID #MI-0451/0452) ($100/ton of CO_2 removed), and • Arauco North America – Gravling Particleboard Facility (RBLC ID #MI-

Source Name	EPN	Best Available Control Technology Description
		0448) ($102/ton of CO_2 removed). In all of these permits, the costs per ton calculated were determined to not be considered cost-effective. Therefore, the final estimate of $194/ton of CO_2 removed for the Kilby Power Plant is also considered not cost-effective. EFO has also estimated costs per ton at a 7% discount rate (instead of at a 10% discount rate), which resulted in a cost-effectiveness of $166/ton of CO_2 removed and is also considered not cost-effective. **MSS:** Elevated hourly emissions of NOx, CO, and VOC during startup and shutdown are expected compared to normal (routine) operations due to the transient operation of the DLN burners and SCR NO_X control systems, lower temperatures during catalyst interaction, and the duration since last shutdown of the equipment. Hourly emissions were based on emissions per event and event duration provided by vendor. To account for individual startup and shutdown events less than 60 minutes in duration, hourly startup and shutdown emissions estimates include the portion of routine emissions for the remainder of a full hour of operation. For combined cycle combustion turbines, emissions vary depending on whether the startup is a cold, warm, or hot startup. Cold startups are defined as startups when the unit has been shut down for 72 or more hours prior to startup. Warm startups are defined as startups when the unit has been shut down for between 8 and 72 hours. Hot startups are defined as startups when the unit has been shut down for no more than 8 hours. During transient conditions, such as rapid load changes or ramp rates resulting from rapid demand changes from the data center (or if one or more of the operating units trips), the combustion system undergoes adjustments that cause variations in air and fuel flow. These fluctuations lead to changes in combustion dynamics and resulting emissions of NOx, NH_3, and CO. Behind-the-meter units may also experience more frequent transient conditions than large-system, interconnected power plants. The turbines are therefore exempt from the NOx emission concentrations during transitional load operation, which is defined as a ramp rate greater than 32 MW per minute (MW/min) and not to exceed 60 minutes per event. For CO and NH_3, the concentration limits are still required to be met; however, the averaging time period is extended to 24-hours during transitional load periods. This alternative averaging time period has been authorized in TCEQ NSR Permits 176191 and 166032 for Entergy Texas. The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
SC 7HA Turbine 1	7HASC1	Three GE 7HA.02 combustion turbines will be used in simple-cycle mode and fired exclusively with pipeline quality natural gas. The net output of each turbine is 330.3 MW, and the maximum heat input of each turbine is 3,174.1 MMBtu/hr HHV. To estimate NO_x, CO, VOC, NH_3, and particulate matter emission rates for the three turbines, EFO provided the combustion turbine manufacturer's data for the exhaust pollutant concentrations in parts per million by volume dry basis (ppmvd), corrected to 15 percent oxygen or provided emission factors already converted to units of lb/MMBtu. The turbine manufacturer's data was also used for estimating emissions of NOx, VOC, and CO from startup and shutdown periods, as well as the estimated durations of these periods. For sulfur compounds, emissions are based on the sulfur content of the fuel supplied to the site. Hazardous Air Pollutant (HAP) emissions are estimated
SC 7HA Turbine 2	7HASC2	
SC 7HA Turbine 3	7HASC3	
Simple Cycle 7HA Turbine Emission SUSD Cap	CAP2	
Simple Cycle 7HA Turbine Normal + SUSD Cap	CAP2_1	

Source Name	EPN	Best Available Control Technology Description
		based on EPA AP-42, Table 3.1-3 factors for natural gas-fired stationary combustion turbines. Formaldehyde emissions are based on the worst-case emission factor (lb/MMBtu) from the turbine vendor. Annual emission rates for these simple cycle turbines are based on 8,760 hours per year of operation. Startup and shutdown operations are part of an annual emissions cap EPN CAP2. The total routine and MSS activities are limited to a separate annual emissions cap EPN CAP2_1. **NOx:** Limited to 2.5 ppmvd NOx at 15% O_2 on a 3-hr average. Dry Low-NOx (DLN) burners and an aqueous ammonia-based Selective Catalytic Reduction (SCR) system are used to reduce emissions and achieve this NOx concentration. Current TCEQ Tier I BACT is between 5.0 – 9.0 ppmvd at 15% O_2 on a 3-hr average, typically achieved with dry low NOx burner, water/steam injection, limiting fuel consumption, or SCR. The numeric value and proposed technique are to be specified. RBLC searches performed yield a range of emission limits between 2.0 – 15.0 ppmvd at 15% O_2 but most commonly between 2.0 – 9.0 ppmvd at 15% O_2, achieved using SCR or dry low NOx burners. **CO:** Limited to 3.5 ppmvd at 15% O_2 on a 3-hr average. Oxidation catalysts and good combustion practices are used to reduce emissions and achieve this CO concentration. Current TCEQ Tier I BACT is between 9.0 – 25.0 ppmvd at 15% O_2 on a 3-hr, typically achieved with good combustion practices and/or oxidation catalyst. Specify numeric value and control technique. RBLC searches performed yield a range of emission limits from 1.7 – 25.0 ppmvd at 15% O_2 but most commonly at 9.0 ppmvd at 15% O_2, achieved with catalytic oxidation and good combustion practices. **VOC:** Limited to 2.0 ppmvd at 15% O_2 on a 3-hr average. Oxidation catalysts and good combustion practices are used to reduce emissions and achieve this VOC concentration. Tier I BACT is 2.0 ppmvd at 15% O_2 through good combustion practices. RBLC searches performed show a range of emission limits from 0.7 – 2.0 ppmvd at 15% O_2 but most commonly at 2.0 ppmvd at 15% O_2, achieved with catalytic oxidation and good combustion practices. **HAPs:** All HAP emissions, except for formaldehyde, are estimated based on EPA AP-42, Table 3.1-3 emission factors for natural gas-fired stationary combustion turbines. Formaldehyde emissions are limited to 91.0 ppbvd at 15% O_2 except during turbine startup, according to MACT YYYY Table 1. Because the units will be controlled with oxidation catalysts, MACT YYYY Table 2 applies, which requires maintaining the 4-hr rolling average of the catalyst inlet temperature within range suggested by the catalyst manufacturer. **SO_2:** The turbines are limited to firing natural gas that will not exceed a sulfur content of 0.5 grains per 100 standard cubic feet (gr S/100 scf). It is assumed that there is 100% conversion of the sulfur in the fuel to SO_2. Good combustion practices are used. Current TCEQ Tier I BACT is limiting fuel use to pipeline quality natural gas having a sulfur content of fuel not to exceed 5 gr S/100 scf on hourly basis and 1 gr S/100 scf on annual basis. RBLC searches performed show range of emission limit of 1.0 – 5.0 gr S/100 scf using pipeline quality natural gas or other low sulfur fuels. **H_2SO_4:** Limited to 0.0012 lb/MMBtu, which is based on the sulfur content of 0.5 gr S/100 scf. It is assumed that an approximate 55% conversion of the SO_2 produced to SO_3, which is then assumed to have 100% conversion to H_2SO_4. Good combustion practices are used. Current TCEQ Tier I BACT is limiting fuel use to pipeline quality natural gas with a sulfur content of fuel

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		not to exceed 5 gr S/100 scf on hourly basis and 1 gr S/100 scf on annual basis. Good combustion practices are to be used. RBLC searches performed show a range of sulfur emission limits from 0.25 – 2.0 gr S/100 scf achieved using pipeline quality natural gas or a low sulfur fuel. RBLC searches also show emission limits on a ‘lb H_2SO_4/MMBtu’ basis. However, these ‘lb SO_2/MMbtu’ emission limits cannot be used to determine reasonably equivalent emission factors on a ‘gr S/100 scf’ basis since there is insufficient information on the RBLC regarding the conversion of fuel sulfur to SO_2, SO_3, and finally H_2SO_4. **$PM/PM_{10}/PM_{2.5}$:** Limited to 0.0064 lb/MMBtu. Only pipeline quality natural gas is fired, and good combustion practices are used. It is conservatively assumed that total PM is equal to PM_{10}, which is equal to $PM_{2.5}$. Current TCEQ Tier I BACT is to limit fuel firing to pipeline quality natural gas and to use good combustion practices. RBLC searches performed show emission limits up to 0.0183 lb/MMBtu but generally in the range of 0.003 – 0.009 lb/MMBtu using clean fuels. **NH_3:** Unreacted ammonia slip is limited to 5.0 ppmvd at 15% O_2 on a 3-hr average, achieved by controlling the ammonia injection/optimization of the SCR system used to control NOx emissions. Current TCEQ Tier I BACT is between 7 – 10 ppmvd at 15% O_2 on a 3-hr average, typically achieved through controlling the ammonia injection system to minimize ammonia slip. **GHG as CO_2e:** Limited to a mass input-based CO_2 emission factor of 116.98 lb/MMBtu estimated from 40 CFR 98 Table C-1, while the CH_4 and N_2O emission factors (0.001 kg/MMBtu and 0.0001 kg/MMBtu, respectively) are estimated from 40 CFR 98 Table C-2. EFO proposed an input-based GHG (as CO_2e) BACT limit of 117.10 lb CO_2e/MMBtu Good combustion practices are used, and the fuel is limited to pipeline quality natural gas, which is considered a low GHG emitting fuel from 40 CFR 98 Table C-1 and C-2. RBLC searches performed show a range of energy output-based emission limits between 800 – 1,514 lb CO_2e/MWh, a range of input-based emission limits between 117.1 lb – 120.0 CO_2e/MMBtu, and a range of annual mass limits (tons CO_2e per year). There is insufficient information on the RBLC to reasonably determine equivalent emission factors using only annual mass limits. Regarding an input-based standard, EFO has stated that the majority of simple and combined-cycle turbines in the RBLC are in the context of the electric utility industry and are therefore part of a system of units that are interconnected with the grid. Power plants that are dedicated to powering a nearby data center or other large industrial loads are typically “behind-the-meter” and not interconnected to the grid. Power plants for the electric utility industry can shift generation to respond instantaneously to load and have interconnected utilities with multiple generation assets compared to “behind-the-meter” power plants. EFO has referenced Permit 181009, Project 396274 for Fermi Equipment Holdco and Permit 181033, Project 396366 for Pacifico GW LLC – GW Ranch Energy Center in Pecos, TX. In both permits, an input-based GHG emission standard was chosen. For Permit 181033, a standard of 117 lb CO_2/MMBtu was used for the turbines in this permit, which includes both the large frame type turbines and the aeroderivative turbines and heat ratings between 500 MMBtu/hr and 3,000 MMBtu/hr. Fermi uses a standard of 117 lb CO_2/MMBtu for the turbines, which include the frame type units and aeroderivative units ranging from 443 MMbtu//hr to 478 MMbtu/hr.

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		EFO also reviewed the potential technical and economic feasibility of carbon capture and sequestration (CCS) as a control mechanism for GHG emissions. CCS is a multi-stage process involving a series of technologies including a CO_2 capture system using absorption towers with solvent or sorbents, compression and transportation of the CO_2, and injection into subsurface formations for long-term CO_2 storage. EFO has stated that CCS is currently not technically feasible for the proposed facility since there is no operational sequestration facility nearby, there is no existing pipeline to transport the CO_2, and it has not been successfully demonstrated nor commercially operated at any gas fired combustion turbine site at the proposed scale. The Petra Nova Project is the only CCS unit for a power plant in the United States, located at the NRG W.A. Parish Electric Generating Station in Houston, TX. Petra Nova however, captures and sequesters CO_2 from a coal-fired boiler. Regardless, EFO has performed a cost analysis based on the “EPA Air Pollution Control Cost Manual” for implementing CCS for GHG emissions reduction. In this cost analysis, EFO estimated various capital costs and applied a capital recover factor to annualize these capital costs, estimated annual operating costs, and developed estimates of emissions and assumptions for operating parameters (e.g. fuel used, power consumed) used in the calculations. EFO estimated that multiple absorbers would be needed to capture the total CO_2 emissions from the proposed turbines at the site, with each absorber limited in capacity to one million tons per year. The capital recovery factor assumes a 20-year plant life and a 10% discount rate. EFO has used a 20-year project life cycle, stating it is widely used in CCS economic evaluations and aligns with typical equipment life assumptions and vendor performance guarantees for capture systems. EFO states that a 10% discount rate is also commonly applied in CCS economic studies to represent a reasonable cost of annual capital for CCS projects, and is consistent with approaches presented in CCS literature, including Rubin et al., 2011; and U.S. OSTI 2011. Transportation and storage costs per ton were added to produce a final estimate of $194/ton of CO_2 removed using 2024 numbers. CCS cost estimates used in other applications include: • Southwestern Public Service Company – Gaines County Power Plant, TCEQ Permit 179777 ($186/ton CO_2 removed), • NRG – Jewitt Energy Center, TCEQ Permit 180096 ($99/ton CO_2 removed), • CPV – Basin Ranch Energy Center, TCEQ Permit 175063 ($102/ton of CO_2 removed), • Marshall Energy Center – North & South Combined Cycle Projects (RBLC ID #MI-0451/0452) ($100/ton of CO_2 removed), and • Arauco North America – Gravling Particleboard Facility (RBLC ID #MI-0448) ($102/ton of CO_2 removed). In all of these permits, the costs per ton calculated were determined to not be considered cost-effective. Therefore, the final estimate of $194/ton of CO_2 removed for the Kilby Power Plant is also considered not cost-effective. EFO has also estimated costs per ton at a 7% discount rate (instead of at a 10% discount rate), which resulted in a cost-effectiveness of $166/ton of CO_2 removed and is also considered not cost-effective. **MSS:** Elevated hourly emissions of NOx, CO, and VOC during startup and shutdown are expected compared to normal (routine) operations due to the

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		transient operation of the DLN burners and SCR NO_X control systems, lower temperatures during catalyst interaction, and the duration since last shutdown of the equipment. Hourly emissions were based on emissions per event and event duration provided by vendor. To account for individual startup and shutdown events less than 60 minutes in duration, hourly startup and shutdown emissions estimates include the portion of routine emissions for the remainder of a full hour of operation. During transient conditions, such as rapid load changes or ramp rates resulting from rapid demand changes from the data center (or if one or more of the operating units trips), the combustion system undergoes adjustments that cause variations in air and fuel flow. These fluctuations lead to changes in combustion dynamics and resulting emissions of NOx, NH_3, and CO. Behind-the-meter units may also experience more frequent transient conditions than large-system, interconnected power plants. The turbines are therefore exempt from the NOx emission concentrations during transitional load operation, which is defined as a ramp rate greater than 32 MW per minute (MW/min) and not to exceed 60 minutes per event. For CO and NH_3, the concentration limits are still required to be met; however, the averaging time period is extended to 24-hours during transitional load periods. This alternative averaging time period has been authorized in TCEQ NSR Permits 176191 and 166032 for Entergy Texas. The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Solar T350 Turbine 1	T350SC1	Twelve Solar Titan 350 (T350) combustion turbines will be used in simple-cycle mode and fired exclusively with pipeline quality natural gas. The net output of each turbine is 38 MW, and the maximum heat input of each turbine is 370.8 MMbtu/hr HHV. To estimate NO_x, CO, VOC, NH_3, and particulate matter emission rates for the three turbines, EFO provided the combustion turbine manufacturer's data for the exhaust pollutant concentrations in parts per million by volume dry basis (ppmvd), corrected to 15 percent oxygen or provided emission factors already converted to units of lb/MMBtu. The turbine manufacturer's data was also used for estimating emissions of NOx, VOC, and CO from startup and shutdown periods, as well as the estimated durations of these periods. For sulfur compounds, emissions are based on the sulfur content of the fuel supplied to the site and vendor provided emission factors (lb/MMBtu). Hazardous Air Pollutant (HAP) emissions are estimated based on EPA AP-42, Table 3.1-3 factors for natural gas-fired stationary combustion turbines. Formaldehyde emissions are based on the worst-case emission factor (lb/MMBtu) from the turbine vendor. Annual emission rates for these simple cycle turbines are based on 8,760 hours per year of operation. Startup and shutdown operations are part of an annual emissions cap EPN CAP3. The total routine and MSS activities are limited to a separate annual emissions cap EPN CAP3_1. **NOx:** Limited to 2.7 ppmvd NOx at 15% O_2 on a 3-hr average. Dry Low-NOx (DLN) burners and an aqueous ammonia-based Selective Catalytic Reduction (SCR) system are used to reduce emissions and achieve this NOx concentration. Current TCEQ Tier I BACT is between 5.0 – 9.0 ppmvd at 15% O_2 on a 3-hr average, typically achieved with dry low NOx burner, water/steam injection, limiting fuel consumption, or SCR. The numeric value and proposed technique are to be specified. RBLC searches performed
Solar T350 Turbine 2	T350SC2	
Solar T350 Turbine 3	T350SC3	
Solar T350 Turbine 4	T350SC4	
Solar T350 Turbine 5	T350SC5	
Solar T350 Turbine 6	T350SC6	
Solar T350 Turbine 7	T350SC7	
Solar T350 Turbine 8	T350SC8	
Solar T350 Turbine 9	T350SC9	
Solar T350 Turbine 10	T350SC10	
Solar T350 Turbine 11	T350SC11	
Solar T350 Turbine 12	T350SC12	
Solar T350 Turbine Emission SUSD Cap	CAP3	
Solar T350 Turbine Normal + SUSD	CAP3_1	

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		yield a range of emission limits between 2.0 – 15.0 ppmvd at 15% O_2 but most commonly between 2.0 – 9.0 ppmvd at 15% O_2, achieved using SCR or dry low NOx burners. **CO:** Limited to 2.5 ppmvd CO at 15% O_2 on a 3-hr average. Oxidation catalysts and good combustion practices are used to reduce emissions and achieve this CO concentration. Current TCEQ Tier I BACT is between 9.0 – 25.0 ppmvd at 15% O_2 on a 3-hr, typically achieved with good combustion practices and/or oxidation catalyst. Specify numeric value and control technique. RBLC searches performed yield a range of emission limits from 1.7 – 25.0 ppmvd at 15% O_2 but most commonly at 9.0 ppmvd at 15% O_2, achieved with catalytic oxidation and good combustion practices. **VOC:** Limited to 1.8 ppmvd at 15% O_2 on a 3-hr average. Oxidation catalysts and good combustion practices are used to reduce emissions and achieve this VOC concentration. Tier I BACT is 2.0 ppmvd at 15% O_2 through good combustion practices. RBLC searches performed show a range of emission limits from 0.7 – 2.0 ppmvd at 15% O_2 but most commonly at 2.0 ppmvd at 15% O_2, achieved with catalytic oxidation and good combustion practices. **HAPs:** All HAP emissions, except for formaldehyde, are estimated based on EPA AP-42, Table 3.1-3 emission factors for natural gas-fired stationary combustion turbines. Formaldehyde emissions are limited to 91.0 ppbvd at 15% O_2 except during turbine startup, according to MACT YYYY Table 1. Because the units will be controlled with oxidation catalysts, MACT YYYY Table 2 applies, which requires maintaining the 4-hr rolling average of the catalyst inlet temperature within range suggested by the catalyst manufacturer. **SO_2:** The turbine is limited to firing natural gas with a sulfur content of 1.2 gr S/100 scf. The equivalent SO_2 emission limit is 0.0034 lb/MMBtu, assuming a 100% conversion of the sulfur in the fuel to SO_2. Good combustion practices are used. Current TCEQ Tier I BACT is limiting fuel use to pipeline quality natural gas having a sulfur content of fuel not to exceed 5 gr S/100 scf on hourly basis and 1 gr S/100 scf on annual basis. RBLC searches performed show range of emission limit of 1.0 – 5.0 gr S/100 scf using pipeline quality natural gas or other low sulfur fuels. **H_2SO_4:** The turbine is limited to firing natural gas with a sulfur content of 1.2 gr S/100 scf. The equivalent H_2SO_4 emission limit is 0.0052 lb/MMBtu, which assumes full conversion of fuel sulfur to SO_2, SO_3, and finally H_2SO_4. Good combustion practices are used. Current TCEQ Tier I BACT is to limiting fuel firing to pipeline quality natural gas and to use good combustion practices. The sulfur content of fuel is not to exceed 5 gr S/100 scf on hourly basis and 1 gr S/100 scf on an annual basis. RBLC searches performed show a range of sulfur emission limits from 0.25 – 2.0 gr S/100 scf achieved using pipeline quality natural gas or a low sulfur fuel. RBLC searches also show emission limits on a ‘lb H_2SO_4/MMBtu’ basis. However, these ‘lb SO_2/MMbtu’ emission limits cannot be used to determine reasonably equivalent emission factors on a ‘gr S/100 scf’ basis since there is insufficient information on the RBLC regarding the conversion of fuel sulfur to SO_2, SO_3, and finally H_2SO_4. **$PM/PM_{10}/PM_{2.5}$:** Limited to 0.0066 lb/MMBtu. Only pipeline quality natural gas is fired, and good combustion practices are used. It is conservatively assumed that total PM is equal to PM_{10}, which is equal to $PM_{2.5}$. Current TCEQ Tier I BACT is to limit fuel firing to pipeline quality natural gas and to use good combustion practices. RBLC searches performed show emission

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		limits up to 0.0183 lb/MMBtu but generally in the range of 0.003 – 0.009 lb/MMBtu using clean fuels. **NH_3:** Unreacted ammonia slip is limited to 5.0 ppmvd at 15% O_2 on a 3-hr average, achieved by controlling the ammonia injection/optimization of the SCR system used to control NOx emissions. Current TCEQ Tier I BACT is between 7 – 10 ppmvd at 15% O_2 on a 3-hr average, typically achieved through controlling the ammonia injection system to minimize ammonia slip. **GHG as CO_2e:** Limited to a mass input-based CO_2 emission factor of 116.98 lb/MMBtu estimated from 40 CFR 98 Table C-1, while the CH_4 and N_2O emission factors (0.001 kg/MMBtu and 0.0001 kg/MMBtu, respectively) are estimated from 40 CFR 98 Table C-2. EFO proposed an input-based GHG (as CO_2e) BACT limit of 117.10 lb CO_2e/MMBtu Good combustion practices are used, and the fuel is limited to pipeline quality natural gas, which is considered a low GHG emitting fuel from 40 CFR 98 Table C-1 and C-2. RBLC searches performed show a range of energy output-based emission limits between 800 – 1,514 lb CO_2e/MWh, a range of input-based emission limits between 117.1 lb – 120.0 CO_2e/MMBtu, and a range of annual mass limits (tons CO_2e per year). There is insufficient information on the RBLC to reasonably determine equivalent emission factors using only annual mass limits. Regarding an input-based standard, EFO has stated that the majority of simple and combined-cycle turbines in the RBLC are in the context of the electric utility industry and are therefore part of a system of units that are interconnected with the grid. Power plants that are dedicated to powering a nearby data center or other large industrial loads are typically “behind-the-meter” and not interconnected to the grid. Power plants for the electric utility industry can shift generation to respond instantaneously to load and have interconnected utilities with multiple generation assets compared to “behind-the-meter” power plants. EFO has referenced Permit 181009, Project 396274 for Fermi Equipment Holdco and Permit 181033, Project 396366 for Pacifico GW LLC – GW Ranch Energy Center in Pecos, TX. In both permits, an input-based GHG emission standard was chosen. For Permit 181033, a standard of 117 lb CO_2/MMBtu was used for the turbines in this permit, which includes both the large frame type turbines and the aeroderivative turbines and heat ratings between 500 MMBtu/hr and 3,000 MMBtu/hr. Fermi uses a standard of 117 lb CO_2/MMBtu for the turbines, which include the frame type units and aeroderivative units ranging from 443 MMbtu//hr to 478 MMbtu/hr. EFO also reviewed the potential technical and economic feasibility of carbon capture and sequestration (CCS) as a control mechanism for GHG emissions. CCS is a multi-stage process involving a series of technologies including a CO_2 capture system using absorption towers with solvent or sorbents, compression and transportation of the CO_2, and injection into subsurface formations for long-term CO_2 storage. EFO has stated that CCS is currently not technically feasible for the proposed facility since there is no operational sequestration facility nearby, there is no existing pipeline to transport the CO_2, and it has not been successfully demonstrated nor commercially operated at any gas fired combustion turbine site at the proposed scale. The Petra Nova Project is the only CCS unit for a power plant in the United States, located at the NRG W.A. Parish Electric Generating Station in Houston, TX. Petra Nova however, captures and sequesters CO_2 from a coal-fired boiler.

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		Regardless, EFO has performed a cost analysis based on the "EPA Air Pollution Control Cost Manual" for implementing CCS for GHG emissions reduction. In this cost analysis, EFO estimated various capital costs and applied a capital recover factor to annualize these capital costs, estimated annual operating costs, and developed estimates of emissions and assumptions for operating parameters (e.g. fuel used, power consumed) used in the calculations. EFO estimated that multiple absorbers would be needed to capture the total CO_2 emissions from the proposed turbines at the site, with each absorber limited in capacity to one million tons per year. The capital recovery factor assumes a 20-year plant life and a 10% discount rate. EFO has used a 20-year project life cycle, stating it is widely used in CCS economic evaluations and aligns with typical equipment life assumptions and vendor performance guarantees for capture systems. EFO states that a 10% discount rate is also commonly applied in CCS economic studies to represent a reasonable cost of annual capital for CCS projects, and is consistent with approaches presented in CCS literature, including Rubin et al., 2011; and U.S. OSTI 2011. Transportation and storage costs per ton were added to produce a final estimate of $194/ton of CO_2 removed using 2024 numbers. CCS cost estimates used in other applications include: • Southwestern Public Service Company – Gaines County Power Plant, TCEQ Permit 179777 ($186/ton CO_2 removed), • NRG – Jewitt Energy Center, TCEQ Permit 180096 ($99/ton CO_2 removed), • CPV – Basin Ranch Energy Center, TCEQ Permit 175063 ($102/ton of CO_2 removed), • Marshall Energy Center – North & South Combined Cycle Projects (RBLC ID #MI-0451/0452) ($100/ton of CO_2 removed), and • Arauco North America – Gravling Particleboard Facility (RBLC ID #MI-0448) ($102/ton of CO_2 removed). In all of these permits, the costs per ton calculated were determined to not be considered cost-effective. Therefore, the final estimate of $194/ton of CO_2 removed for the Kilby Power Plant is also considered not cost-effective. EFO has also estimated costs per ton at a 7% discount rate (instead of at a 10% discount rate), which resulted in a cost-effectiveness of $166/ton of CO_2 removed and is also considered not cost-effective. **MSS:** Elevated hourly emissions of NOx, CO, and VOC during startup and shutdown are expected compared to normal (routine) operations due to the transient operation of the DLN burners and SCR NO_X control systems, lower temperatures during catalyst interaction, and the duration since last shutdown of the equipment. Hourly emissions were based on emissions per event and event duration provided by vendor. To account for individual startup and shutdown events less than 60 minutes in duration, hourly startup and shutdown emissions estimates include the portion of routine emissions for the remainder of a full hour of operation. During transient conditions, such as rapid load changes or ramp rates resulting from rapid demand changes from the data center (or if one or more of the operating units trips), the combustion system undergoes adjustments that cause variations in air and fuel flow. These fluctuations lead to changes in combustion dynamics and resulting emissions of NOx, NH_3, and CO. Behind-the-meter units may also experience more frequent transient conditions than large-system, interconnected power plants. The turbines

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		are therefore exempt from the NOx emission concentrations during transitional load operation, which is defined as a ramp rate greater than 32 MW per minute (MW/min) and not to exceed 60 minutes per event. For CO and NH_3, the concentration limits are still required to be met; however, the averaging time period is extended to 24-hours during transitional load periods. This alternative averaging time period has been authorized in TCEQ NSR Permits 176191 and 166032 for Entergy Texas. The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Solar T130 Turbine 1	T130SC1	29 Solar Titan 130 (T130) simple-cycle turbines will be used for early phase power. The nominal net output of these early-phase power turbines is approximately 13.55 MW each. To estimate NO_x, CO, VOC, NH_3, and particulate matter emission rates for the three turbines, EFO provided the combustion turbine manufacturer's data for the exhaust pollutant concentrations in parts per million by volume dry basis (ppmvd), corrected to 15 percent oxygen or provided emission factors already converted to units of lb/MMBtu. The turbine manufacturer's data was also used for estimating emissions of NOx, VOC, and CO from startup and shutdown periods, as well as the estimated durations of these periods. For sulfur compounds, emissions are based on the sulfur content of the fuel supplied to the site and vendor provided emission factors (lb/MMBtu). Hazardous Air Pollutant (HAP) emissions are estimated based on EPA AP-42, Table 3.1-3 factors for natural gas-fired stationary combustion turbines. Formaldehyde emissions are based on the worst-case emission factor (lb/MMBtu) from the turbine vendor. Annual emission rates for these simple cycle turbines are based on 8,760 hours per year of operation. Startup and shutdown operations are part of an annual emissions cap EPN CAP4. The total routine and MSS activities are limited to a separate annual emissions cap EPN CAP4_1. **NOx:** Limited to 2.7 ppmvd NOx at 15% O_2 on a 3-hr average. Dry Low-NOx (DLN) burners and an aqueous ammonia-based Selective Catalytic Reduction (SCR) system are used to reduce emissions and achieve this NOx concentration. Current TCEQ Tier I BACT is between 5.0 – 9.0 ppmvd at 15% O_2 on a 3-hr average, typically achieved with dry low NOx burner, water/steam injection, limiting fuel consumption, or SCR. The numeric value and proposed technique are to be specified. RBLC searches performed yield a range of emission limits between 2.0 – 15.0 ppmvd at 15% O_2 but most commonly between 2.0 – 9.0 ppmvd at 15% O_2, achieved using SCR or dry low NOx burners. **CO:** Limited to 2.5 ppmvd CO at 15% O_2 on a 3-hr average. Oxidation catalysts and good combustion practices are used to reduce emissions and achieve this CO concentration. Current TCEQ Tier I BACT is between 9.0 – 25.0 ppmvd at 15% O_2 on a 3-hr, typically achieved with good combustion practices and/or oxidation catalyst. Specify numeric value and control technique. RBLC searches performed yield a range of emission limits from 1.7 – 25.0 ppmvd at 15% O_2 but most commonly at 9.0 ppmvd at 15% O_2, achieved with catalytic oxidation and good combustion practices. **VOC:** Limited to 1.8 ppmvd at 15% O_2 on a 3-hr average. Oxidation catalysts and good combustion practices are used to reduce emissions and achieve this VOC concentration. Tier I BACT is 2.0 ppmvd at 15% O_2 through good combustion practices. RBLC searches performed show a range of emission
Solar T130 Turbine 2	T130SC2	
Solar T130 Turbine 3	T130SC3	
Solar T130 Turbine 4	T130SC4	
Solar T130 Turbine 5	T130SC5	
Solar T130 Turbine 6	T130SC6	
Solar T130 Turbine 7	T130SC7	
Solar T130 Turbine 8	T130SC8	
Solar T130 Turbine 9	T130SC9	
Solar T130 Turbine 10	T130SC10	
Solar T130 Turbine 11	T130SC11	
Solar T130 Turbine 12	T130SC12	
Solar T130 Turbine 13	T130SC13	
Solar T130 Turbine 14	T130SC14	
Solar T130 Turbine 15	T130SC15	
Solar T130 Turbine 16	T130SC16	
Solar T130 Turbine 17	T130SC17	
Solar T130 Turbine 18	T130SC18	
Solar T130 Turbine 19	T130SC19	
Solar T130 Turbine 20	T130SC20	
Solar T130 Turbine 21	T130SC21	
Solar T130 Turbine 22	T130SC22	
Solar T130 Turbine 23	T130SC23	
Solar T130 Turbine 24	T130SC24	
Solar T130 Turbine 25	T130SC25	
Solar T130 Turbine 26	T130SC26	
Solar T130 Turbine 27	T130SC27	
Solar T130 Turbine 28	T130SC28	

Source Name	EPN	Best Available Control Technology Description
Solar T130 Turbine 29	T130SC29	limits from 0.7 – 2.0 ppmvd at 15% O_2 but most commonly at 2.0 ppmvd at 15% O_2, achieved with catalytic oxidation and good combustion practices. **HAPs:** All HAP emissions, except for formaldehyde, are estimated based on EPA AP-42, Table 3.1-3 emission factors for natural gas-fired stationary combustion turbines. Formaldehyde emissions are limited to 91.0 ppbvd at 15% O_2 except during turbine startup, according to MACT YYYY Table 1. Because the units will be controlled with oxidation catalysts, MACT YYYY Table 2 applies, which requires maintaining the 4-hr rolling average of the catalyst inlet temperature within range suggested by the catalyst manufacturer. **SO_2:** The turbine is limited to firing natural gas with a sulfur content of 1.2 gr S/100 scf. The equivalent SO_2 emission limit is 0.0034 lb/MMBtu, assuming a 100% conversion of the sulfur in the fuel to SO_2. Good combustion practices are used. Current TCEQ Tier I BACT is limiting fuel use to pipeline quality natural gas having a sulfur content of fuel not to exceed 5 gr S/100 scf on hourly basis and 1 gr S/100 scf on annual basis. RBLC searches performed show range of emission limit of 1.0 – 5.0 gr S/100 scf using pipeline quality natural gas or other low sulfur fuels. **H_2SO_4:** The turbine is limited to firing natural gas with a sulfur content of 1.2 gr S/100 scf. The equivalent H_2SO_4 emission limit is 0.0052 lb/MMBtu, which assumes full conversion of fuel sulfur to SO_2, SO_3, and finally H_2SO_4. Good combustion practices are used. Current TCEQ Tier I BACT is to limiting fuel firing to pipeline quality natural gas and to use good combustion practices. The sulfur content of fuel is not to exceed 5 gr S/100 scf on hourly basis and 1 gr S/100 scf on an annual basis. RBLC searches performed show a range of sulfur emission limits from 0.25 – 2.0 gr S/100 scf achieved using pipeline quality natural gas or a low sulfur fuel. RBLC searches also show emission limits on a 'lb H_2SO_4/MMBtu' basis. However, these 'lb SO_2/MMbtu' emission limits cannot be used to determine reasonably equivalent emission factors on a 'gr S/100 scf' basis since there is insufficient information on the RBLC regarding the conversion of fuel sulfur to SO_2, SO_3, and finally H_2SO_4. **$PM/PM_{10}/PM_{2.5}$:** Limited to 0.0066 lb/MMBtu. Only pipeline quality natural gas is fired, and good combustion practices are used. It is conservatively assumed that total PM is equal to PM_{10}, which is equal to $PM_{2.5}$. Current TCEQ Tier I BACT is to limit fuel firing to pipeline quality natural gas and to use good combustion practices. RBLC searches performed show emission limits up to 0.0183 lb/MMBtu but generally in the range of 0.003 – 0.009 lb/MMBtu using clean fuels. **NH_3:** Unreacted ammonia slip is limited to 5.0 ppmvd at 15% O_2 on a 3-hr average, achieved by controlling the ammonia injection/optimization of the SCR system used to control NOx emissions. Current TCEQ Tier I BACT is between 7 – 10 ppmvd at 15% O_2 on a 3-hr average, typically achieved through controlling the ammonia injection system to minimize ammonia slip. **GHG as CO_2e:** Limited to a mass input-based CO_2 emission factor of 116.98 lb/MMBtu estimated from 40 CFR 98 Table C-1, while the CH_4 and N_2O emission factors (0.001 kg/MMBtu and 0.0001 kg/MMBtu, respectively) are estimated from 40 CFR 98 Table C-2. EFO proposed an input-based GHG (as CO_2e) BACT limit of 117.10 lb CO_2e/MMBtu Good combustion practices are used, and the fuel is limited to pipeline quality natural gas, which is considered a low GHG emitting fuel from 40 CFR 98 Table C-1 and C-2. RBLC searches performed show a range of energy output-based emission
Solar T130 Turbine Emission SUSD Cap	CAP4	
Solar Titan T130 Turbine Normal + SUSD	CAP4_1	

Source Name	EPN	Best Available Control Technology Description
		limits between 800 – 1,514 lb CO_2e/MWh, a range of input-based emission limits between 117.1 lb – 120.0 CO_2e/MMBtu, and a range of annual mass limits (tons CO_2e per year). There is insufficient information on the RBLC to reasonably determine equivalent emission factors using only annual mass limits. Regarding an input-based standard, EFO has stated that the majority of simple and combined-cycle turbines in the RBLC are in the context of the electric utility industry and are therefore part of a system of units that are interconnected with the grid. Power plants that are dedicated to powering a nearby data center or other large industrial loads are typically “behind-the-meter” and not interconnected to the grid. Power plants for the electric utility industry can shift generation to respond instantaneously to load and have interconnected utilities with multiple generation assets compared to “behind-the-meter” power plants. EFO has referenced Permit 181009, Project 396274 for Fermi Equipment Holdco and Permit 181033, Project 396366 for Pacifico GW LLC – GW Ranch Energy Center in Pecos, TX. In both permits, an input-based GHG emission standard was chosen. For Permit 181033, a standard of 117 lb CO_2/MMBtu was used for the turbines in this permit, which includes both the large frame type turbines and the aeroderivative turbines and heat ratings between 500 MMBtu/hr and 3,000 MMBtu/hr. Fermi uses a standard of 117 lb CO_2/MMBtu for the turbines, which include the frame type units and aeroderivative units ranging from 443 MMbtu//hr to 478 MMbtu/hr. EFO also reviewed the potential technical and economic feasibility of carbon capture and sequestration (CCS) as a control mechanism for GHG emissions. CCS is a multi-stage process involving a series of technologies including a CO_2 capture system using absorption towers with solvent or sorbents, compression and transportation of the CO_2, and injection into subsurface formations for long-term CO_2 storage. EFO has stated that CCS is currently not technically feasible for the proposed facility since there is no operational sequestration facility nearby, there is no existing pipeline to transport the CO_2, and it has not been successfully demonstrated nor commercially operated at any gas fired combustion turbine site at the proposed scale. The Petra Nova Project is the only CCS unit for a power plant in the United States, located at the NRG W.A. Parish Electric Generating Station in Houston, TX. Petra Nova however, captures and sequesters CO_2 from a coal-fired boiler. Regardless, EFO has performed a cost analysis based on the “EPA Air Pollution Control Cost Manual” for implementing CCS for GHG emissions reduction. In this cost analysis, EFO estimated various capital costs and applied a capital recover factor to annualize these capital costs, estimated annual operating costs, and developed estimates of emissions and assumptions for operating parameters (e.g. fuel used, power consumed) used in the calculations. EFO estimated that multiple absorbers would be needed to capture the total CO_2 emissions from the proposed turbines at the site, with each absorber limited in capacity to one million tons per year. The capital recovery factor assumes a 20-year plant life and a 10% discount rate. EFO has used a 20-year project life cycle, stating it is widely used in CCS economic evaluations and aligns with typical equipment life assumptions and vendor performance guarantees for capture systems. EFO states that a 10% discount rate is also commonly applied in CCS economic studies to represent a reasonable cost of annual capital for CCS

Source Name	EPN	Best Available Control Technology Description
		projects, and is consistent with approaches presented in CCS literature, including Rubin et al., 2011; and U.S. OSTI 2011. Transportation and storage costs per ton were added to produce a final estimate of \$194/ton of CO_2 removed using 2024 numbers. CCS cost estimates used in other applications include: • Southwestern Public Service Company – Gaines County Power Plant, TCEQ Permit 179777 (\$186/ton CO_2 removed), • NRG – Jewitt Energy Center, TCEQ Permit 180096 (\$99/ton CO_2 removed), • CPV – Basin Ranch Energy Center, TCEQ Permit 175063 (\$102/ton of CO_2 removed), • Marshall Energy Center – North & South Combined Cycle Projects (RBLC ID #MI-0451/0452) (\$100/ton of CO_2 removed), and • Arauco North America – Gravling Particleboard Facility (RBLC ID #MI-0448) (\$102/ton of CO_2 removed). In all of these permits, the costs per ton calculated were determined to not be considered cost-effective. Therefore, the final estimate of \$194/ton of CO_2 removed for the Kilby Power Plant is also considered not cost-effective. EFO has also estimated costs per ton at a 7% discount rate (instead of at a 10% discount rate), which resulted in a cost-effectiveness of \$166/ton of CO_2 removed and is also considered not cost-effective. **MSS:** Elevated hourly emissions of NOx, CO, and VOC during startup and shutdown are expected compared to normal (routine) operations due to the transient operation of the DLN burners and SCR NO_X control systems, lower temperatures during catalyst interaction, and the duration since last shutdown of the equipment. Hourly emissions were based on emissions per event and event duration provided by vendor. To account for individual startup and shutdown events less than 60 minutes in duration, hourly startup and shutdown emissions estimates include the portion of routine emissions for the remainder of a full hour of operation. During transient conditions, such as rapid load changes or ramp rates resulting from rapid demand changes from the data center (or if one or more of the operating units trips), the combustion system undergoes adjustments that cause variations in air and fuel flow. These fluctuations lead to changes in combustion dynamics and resulting emissions of NOx, NH_3, and CO. Behind-the-meter units may also experience more frequent transient conditions than large-system, interconnected power plants. The turbines are therefore exempt from the NOx emission concentrations during transitional load operation, which is defined as a ramp rate greater than 32 MW per minute (MW/min) and not to exceed 60 minutes per event. For CO and NH_3, the concentration limits are still required to be met; however, the averaging time period is extended to 24-hours during transitional load periods. This alternative averaging time period has been authorized in TCEQ NSR Permits 176191 and 166032 for Entergy Texas. The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Auxiliary Boiler	BOILER	A natural gas-fired auxiliary boiler is used to supply steam to the plant for startup operations of the combined-cycle turbines and building heating utility. The boiler will be limited to 456 hours per rolling 12 month period. The maximum operating heat input of the boiler will be 99.9 MMBtu/hr**.**

Source Name	EPN	Best Available Control Technology Description
		NOx: Limited to 0.01 lb/MMBtu on an hourly average. Dry-low NOx (DLN) combustors, flue gas recirculation (FGR), proper operation and maintenance of the boiler, and limiting the fuel consumption are used to achieve this NOx concentration and reduce emissions. Current TCEQ Tier I BACT when firing natural gas is 0.01 lb/MMBtu typically achieved using DLN combustors, limiting fuel consumption, SCR, and/or water or steam injection. RBLC searches for boilers less than 100 MMBtu/hr yield a range of emission limits between 0.007 – 0.155 lb/MMBtu but most commonly between 0.010 – 0.050 lb/MMBtu using natural gas, low-NOx burners, and good combustion practices. **CO:** Limited to 50 ppmvd at 3% O_2, which is equivalent to 0.037 lb/MMBtu, based on vendor estimates. Good combustion and maintenance practices are used to achieve this CO concentration and reduce emissions. Current Tier I BACT is 50 ppmv at 3% O_2 achieved by good combustion practices, oxidation catalyst, and/or maintenance of the boiler. RBLC searches for boilers less than 100 MMBtu/hr show a range from 0.0037 – 0.2 lb/MMBtu but typically in a range from 0.0194 lb/MMBtu – 0.0835 lb/MMBtu using natural gas and good combustion practices. **VOC:** Emission limits meet 0.005 lb/MMBtu, which is based on EPA AP-42 Chapter 1.4, Table 1.4-2. Good combustion practices are used to achieve this emission limit and reduce emissions. Current Tier I BACT is good combustion practices. RBLC searches for boilers less than 100 MMBtu/hr show a range from 0.0014 – 0.0057 lb/MMBtu using natural gas and good combustion practices. **SO_2 and H_2SO_4:** The natural gas fuel sulfur content is limited to 5.0 gr/100 scf on an hourly basis and 1.0 gr/100 scf on an annual basis. It is assumed that 100% of the fuel sulfur is converted to SO_2. Sulfuric acid mist (H_2SO_4) emissions are based on a 5% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4. These sulfur contents represent low sulfur fuel, and good combustion practices are used. Current TCEQ Tier I BACT is firing low sulfur fuel and good combustion practices. RBLC searches for boilers less than 100 MMBtu/hr show a range of sulfur emission limits from 0.2 – 5.0 gr /100 scf using natural gas and good combustion practices. **$PM/PM_{10}/PM_{2.5}$:** The exhaust stack is limited to less than 5% opacity, and good combustion practices are used. Emission limits meet 0.00745 lb/MMBtu, which is based on EPA AP-42 Chapter 1.4, Table 1.4-2. All PM is assumed to be less than 2.5 microns, so PM is equal to PM10, which is equal to PM2.5. Current Tier I BACT is less than 5% opacity and good combustion practices. RBLC searches for boilers less than 100 MMBtu/hr show a range between 0.0012 and 0.01 lb/MMBtu using natural gas and good combustion practices. **GHG as CO_2e:** Emissions are based on 116.98 lb/MMBtu CO_2 from 40 CFR 98 Table C-1, while CH_4 and N_2O emissions (0.001 kg/MMBtu and 0.0001 kg/MMBtu, respectively) are estimated from 40 CFR 98, Table C-2. Good combustion practices are used, and the fuel is limited to pipeline quality natural gas, which is considered a low GHG emitting fuel from 40 CFR 98 Table C-1 and C-2. RBLC searches for boilers less than 100 MMBtu/hr show a range of emission limits between 117.1 – 160.0 lb CO_2e/MMBtu and a range of annual mass limits (tons CO_2e per year) using natural gas and good combustion practices. There is insufficient information on the RBLC to reasonably determine equivalent emission factors using only annual mass limits.

Source Name	EPN	Best Available Control Technology Description
		The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Black Start Generator 1	BSGEN1	Two natural gas-fired black start generators will be used to start the Solar T350 turbines. Each generator will be equipped with a natural gas-fired (i.e., spark ignition) 4-stroke lean burn engine with a rating between 2,500 and 3,000 horsepower (hp). EFO proposes Caterpillar G3520 engines for installation. The manufacturer horsepower rating of 2,952 hp is proposed for Engine 1, while the manufacturer horsepower rating of 2,953 hp is proposed for Engine 2. However, any equivalent natural gas fired engine may be installed for these two engines. The estimated capacity of Engine 1 is 2,201 kW, while Engine 2 is 2,202 kW. The engines will each be EPA-certified to meet NSPS Subpart JJJJ. MACT ZZZZ and NSPS JJJJ include the following in the definition of emergency operation, which EFO has extended so that black-start operation may fall in this category: The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. The potential emissions of NOx, VOC, and CO from the black start generator engines were estimated based on vendor guaranteed emission factors or a completed TCEQ Table 29 Reciprocating Engines representing the vendor-supplied emission factors. The annual emissions cap for the two engines is calculated based on the emissions contributions from each engine operating for a maximum of 150 hours per year (including periodic testing). The site will have the flexibility to operate either engine up to 300 hours per year and ensure compliance with the overall annual emissions cap. Each engine will have a non-resettable runtime meter. The annual emissions are covered in an annual cap EPN CAP5_1. Due to the low hours of operation and intermittent nature of black start operation, increasing the hours of operation to allow for initial stack testing and recurring emissions monitoring and recordkeeping is unpractical. Compliance with the NOx and CO limits shall be based on maintaining vendor documentation of the emissions basis at the site, as well as monitoring and recording of fuel usage. **NO_X:** Black Start Generator 1 is limited to 0.70 g/hp-hr based on vendor estimates, while Black Start Generator 2 is limited to 0.50 g/hp-hr. Tier I BACT is 0.50 gr/bhp-hr for engines greater than or equal to 500 hp, but 0.7 g/bhp-hr is acceptable with vendor guarantee for engines greater than or equal to 500 hp. These limits are to be achieved through good combustion practices. For rich burn engines, a catalytic converter is required, and no liquid fuel is allowed except for a limited number of backup hours. RBLC searches for large (>500 hp) natural gas engines show a range between 0.5 – 2.0 g/hp-hr. **VOC:** Black Start Generator 1 is limited to 0.70 g/hp-hr based on vendor estimates, while Black Start Generator 2 is limited to 0.37 g/hp-hr. These limits are achieved with good combustion practices. Tier I BACT is 1.0 g/bhp-hr achieved through good combustion practices. RBLC searches for
Black Start Generator 2	BSGEN2	
Black Start Generator Emission Cap	CAP5_1	

Source Name	EPN	Best Available Control Technology Description
		large (>500 hp) natural gas engines show a minimum emission limit of 0.091 g/hp-hr but generally in the range of 0.5 – 1.0 g/hp-hr. **HAPs:** All HAP emissions are calculated using the EPA AP-42 emission factors for natural gas-fired reciprocating engines in Tables 3.2-2 (Uncontrolled Emission Factors for 4-Stroke Lean-Burn Engines). The emission factor for formaldehyde specifically is 5.28E-2 lb/MMBtu. **CO:** Black Start Generator 1 is limited to 2.0 g/hp-hr based on vendor estimates, while Black Start Generator 2 is limited to 1.51 g/hp-hr, based on vendor estimates. Tier I BACT is 3.0 g/hp-hr achieved through good combustion practices. RBLC searches for large (>500 hp) natural gas engines show a range from 0.3 – 4.0 g/hp-hr. **SO_2:** Emissions from each engine are limited to 0.5 grains of sulfur per 100 dscf (gr S/100 dscf) natural gas, which is equivalent to 0.005 grams/hp-hr and 0.0064 grams/kW-hr. Tier I BACT is implementing good combustion practices and using fuels meeting the requirements of 40 CFR 72.2 or 80.1604. RBLC searches for large (>500 hp) natural gas engines are limited but show values from 0.0005 – 0.005 grams/hp-hr using good combustion practices and natural gas as fuel. The only sulfur content provided in the RBLC search results is 2.0 gr S/100 dscf. Other RBLC search results show emission factors of 0.0015 grams/kW-hr and 162 ppmv sulfur. However, these emission factors cannot be used to determine reasonably equivalent emission factors on a ‘gr S/100 scf’ or ‘grams sulfur/hp-hr’ basis since there is insufficient information on the RBLC regarding the power rating or electric output of the specified engine. **$PM/PM_{10}/PM_{2.5}$:** Emissions from each engine are limited to 0.009987 lb/MMBtu (equivalent to 0.0323 lb/hp-hr for Black Start Generator 1 and 0.0330 lb/hp-hr for Black Start Generator 2) from AP-42 Table 3.2-2, which includes both condensable and filterable particulate matter. It is assumed that all PM is equal to PM_{10}, which is equal to $PM_{2.5}$. No visible emissions will occur, which will be determined by a standard of no visible emissions exceeding 30 seconds in duration in any six-minute period as determined using EPA Test Method (TM) 22 or equivalent. Tier I BACT is implementing good combustion practices and using fuels meeting the requirements of 40 CFR 72.2 or 80.1604. No visible emissions are to leave the property, determined by a standard of no visible emissions exceeding 30 seconds in duration in any six-minute period as determined using EPA TM 22 or equivalent. RBLC searches for large (>500 hp) natural gas engines show values of 0.016 g/hp-hr, 0.038 g/hp-hr, 0.0194 lb/MMBtu, and 0.01 lb/MMBtu. **GHG as CO_2e:** GHG emissions are estimated using emission factors for CO_2, CH_4, and N_2O for natural gas from 40 CFR 98, Subpart C, Tables C-1 and C-2. These emission factors are 116.98 lb/MMBtu for CO_2, 0.0022 lb/MMBtu for CH_4, and 0.00022 lb/MMbtu for N_2O. The resulting CO_2e emission factor is 117.1 lb CO_2e/MMbtu (equivalent to 1,119.93 lb/MWh for Black Start Generator 1 and 1,142.28 lb/MWh for Black Start Generator 2). Efficient internal combustion engines and good combustion and maintenance practices to minimize the formation and emission of GHGs. RBLC shows values of 1,250 lb/MWh; 1,110 lb/MWh; 1,100 lb/MWh, and a range of annual mass limits (tons CO_2e per year). There is insufficient information on the RBLC to reasonably determine equivalent emission factors using only annual mass limits. Emissions are calculated using worst-case emission factors and accommodate unit startup and shutdown operations.

Source Name	EPN	Best Available Control Technology Description
		The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Emergency Diesel Generator 1 through 4	EDG1, EDG2, EDG3, EDG4	Four diesel-driven emergency generators will be equipped with a diesel-fired (i.e., compression ignition) engine with a rating between 2,000 and 2,500 hp. EFO proposes Caterpillar 3512C engines with manufacturer horsepower rating of 2,206 hp at this time, but any equivalent generator set may be installed instead. The estimated capacity of each generator is 1,645 kilowatts (kW). Operation of these engines will each be limited to 100 hours per year of non-emergency operation (testing and maintenance) and for use during instances of complete power loss. Each engine will have a non-resettable runtime meter. The potential emissions of NOx, VOC, CO, and particulate matter from the diesel generator engines were estimated based on the applicable compression ignition internal combustion engine (CI ICE) NSPS Subpart IIII emission limits. Per 40 CFR §60.4205(b) and §60.4202(a)(2), the engines must meet Tier 2 emission limits listed in 40 CFR 1039, Appendix I. Except where noted below, EFO also provided completed TCEQ Table 29 Reciprocating Engines representing the vendor-supplied emission factors. Tier I BACT for NOx, VOC, CO, SO_2,and $PM/PM_{10}/PM_{2.5}$ emissions are identical, which consist of meeting the requirements of 40 CFR Part 60, Subpart IIII, firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight), limiting hours of operation to 100 hrs per year of non-emergency operation, and having a non-resettable runtime meter. Additional Tier I BACT for $PM/PM_{10}/PM_{2.5}$ emissions includes having no visible emissions leaving the property, determined by a standard of no visible emissions exceeding 30 seconds in duration in any six-minute period as determined using EPA TM 22 or equivalent. **NO_X:** Limited to 4.5 g/hp-hr (equivalent to 6.03 g/kW-hr) from the Tier 2 CI ICE limit in 40 CFR 1039 – Appendix I and EPA AP-42 Table 3.4-1. The Tier 2 'NOx + NMHC' limits were adjusted based on 95% by weight NOx and 5% by weight VOC. RBLC searches for large (>500 hp) fuel oil fired engines show a general range of emissions from 5.63 – 6.4 g/kW-hr and from 2.11 – 4.8 g/hp-hr. **VOC:** Limited to 0.25 g/hp-hr (equivalent to 0.335 g/kW-hr) from the Tier 2 CI ICE limit in 40 CFR 1039 – Appendix I and EPA AP-42 Table 3.4-1. The Tier 2 'NOx + NMHC' limits were adjusted based on 95% by weight NOx and 5% by weight VOC. RBLC searches for large (>500 hp) fuel oil fired engines show a general range of emissions from 0.11 – 6.4 g/kW-hr and from 0.11 – 0.29 g/hp-hr. **HAPs:** All HAP emissions are calculated using the EPA AP-42 emission factors for large diesel engines in Tables 3.4-3 and 3.4-4. The emission factor for formaldehyde specifically is 7.89E-5 lb/MMBtu. **CO:** Limited to 2.6 g/hp-hr (equivalent to 3.5 g/kW-hr) from the Tier 2 CI ICE limit in 40 CFR 1039 – Appendix I and EPA AP-42 Table 3.4-1. RBLC searches for large (>500 hp) fuel oil fired engines show a general range of emissions from 0.41 – 3.5 g/kW-hr and primarily at 2.6 g/hp-hr. **SO_2:** Ultra-low sulfur diesel (ULSD), with a fuel sulfur content of 15 parts per million by weight (ppmw), is used. An emission factor of 1.21E-05 lb/hp-hr is used from EPA AP-42 Table 3.4-1 emission factors for engines with a fuel sulfur content of 15 ppmw. RBLC searches for large (>500 hp) fuel oil

Source Name	EPN	Best Available Control Technology Description
		fired engines show most commonly a 15 ppm sulfur concentration and a range of SO_2 limits from 0.0015 – 0.0127 lb/MMBtu. **$PM/PM_{10}/PM_{2.5}$:** Limited to 0.15 g/hp-hr (equivalent to 0.20 g/kW-hr) from the Tier 2 CI ICE limit in 40 CFR 1039 – Appendix I. It is assumed that PM is equal to PM_{10}, which is equal to $PM_{2.5}$. No visible emissions will occur, which will be determined by a standard of no visible emissions exceeding 30 seconds in duration in any six-minute period as determined using EPA Test Method (TM) 22 or equivalent. RBLC searches for large (>500 hp) fuel oil fired engines show primarily 0.15 g/hp-hr but also a range from 0.076 – 0.4 g/kW-hr. **GHG as CO_2e:** GHG emissions are estimated using CO_2, CH_4, and N_2O emission factors for distillate fuel oil no. 2 (as representative for the ULSD burned in the engine) from 40 CFR 98, Subpart C, Tables C-1 and C-2 and global warming potentials (GWPs) from 40 CFR 98, Subpart A. These emission factors are 73.96 kg/MMBtu for CO_2, 0.003 kg/MMBtu for CH_4, and 0.0006 kg/MMBtu for N_2O. Efficient internal combustion engines and good combustion and maintenance practices are used to minimize the formation and emissions of GHGs. RBLC searches show most commonly a 164 lb CO_2e/MMBtu emission factor, corresponding to the requirements in 40 CFR 98 Subpart C. RBLC searches also show a range of annual mass limits (tons CO_2e per year). However, there is insufficient information on the RBLC to reasonably determine equivalent emission factors using only annual mass limits. Emissions are calculated using worst-case emission factors and accommodate unit startup and shutdown operations. The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Diesel Fire Pump	FIREPUMP	A diesel-fired fire pump engine with a rating between 200 and 250 hp will be used to maintain high water pressure in firewater pump systems during times of emergency. EFO proposes a Cummins 41360-F engine with a manufacturer horsepower rating of 247 hp at this time, but any equivalent fire pump engine may be installed. The estimated capacity of this fire pump engine is 184 kW. Operation of the engine will be limited to 100 hours per year of non-emergency operation (testing and maintenance). The engine will be equipped with a non-resettable runtime meter. The potential emissions of NOx, VOC, CO, and particulate matter from the fire pump engine were estimated based on the applicable compression ignition internal combustion engine (CI ICE) NSPS (40 CFR 60, Subpart IIII) emission limits. Per 40 CFR §60.4205(c) for fire pump engines with a displacement of less than 30 liters per cylinder, this engine must meet the emission limits in Table 4 of 40 CFR 60, Subpart IIII. EFO also provided a completed TCEQ Table 29 Reciprocating Engines representing the vendor-supplied emission factors. Tier I BACT for NOx, VOC, CO, SO_2,and $PM/PM_{10}/PM_{2.5}$ emissions are identical, which consist of meeting the requirements of 40 CFR Part 60, Subpart IIII, firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight), limiting hours of operation to 100 hrs per year of non-emergency operation, and having a non-resettable runtime meter. Additional Tier I BACT for $PM/PM_{10}/PM_{2.5}$ emissions includes having no visible emissions leaving the property, determined by a standard of no visible emissions

Source Name	EPN	Best Available Control Technology Description
		exceeding 30 seconds in duration in any six-minute period as determined using EPA TM 22 or equivalent. **NOx:** Limited to 2.8 g/hp-hr (equivalent to 3.76 g/hp-hr) from the CI ICE NSPS limit in 40 CFR §60.4205(c) and AP-42 Table 3.4-1. The 'NMHC + NO_x' emission factor is adjusted based on 95% by weight NOx and 5% by weight VOC. The EPA AP-42 Table 3.4-1 NOx and VOC emission factors were used to estimate the weight percent of NOx and VOC. RBLC searches for small (<500 hp) fuel oil fired engines show a general range of emissions from 3.31 – 5.36 g/kW-h and a range from 2.6 – 14.06 g/hp-hr. **VOC:** Limited to 0.2 g/hp-hr (equivalent to 0.27 g/kW-hr) from the CI ICE NSPS limit in 40 CFR §60.4205(c) and AP-42 Table 3.4-1. The 'NMHC + NO_x' emission factor is adjusted based on 95% by weight NOx and 5% by weight VOC. The EPA AP-42 Table 3.4-1 NOx and VOC emission factors were used to estimate the weight percent of NOx and VOC. RBLC searches for small (<500 hp) fuel oil fired engines show a general range of emissions from 0.11 – 4.0 g/kW-h and a range from 0.10 – 1.14 g/hp-hr. **HAPs:** All HAP emissions are calculated using the EPA AP-42 emission factors for diesel engines in Table 3.3-2. The emission factor for formaldehyde specifically is 1.18E-03 lb/MMBtu. **CO:** Limited to 2.6 g/hp-hr (equivalent to 3.5 g/kW-hr) from the CI ICE NSPS limit in 40 CFR §60.4205(c). RBLC searches for small (<500 hp) fuel oil fired engines show a general range of emissions from 0.6 – 3.5 g/kW-hr and a range from 0.53 – 3.03 g/hp-hr. **SO_2:** Ultra-low sulfur diesel (ULSD), with a fuel sulfur content of 15 parts per million by weight (ppmw), is used. An emission factor of 1.21E-05 lb/hp-hr is used from EPA AP-42 Table 3.4-1 emission factors for engines with a fuel sulfur content of 15 ppmw. RBLC searches for small (<500 hp) fuel oil fired engines show most commonly a 15 ppm sulfur concentration and an SO_2 limit of 0.0078 lb/MMBtu (equivalent to 9.21 ppmw sulfur at 3% O_2). **$PM/PM_{10}/PM_{2.5}$:** Limited to 0.15 g/hp-hr (equivalent to 0.20 g/kW-hr) from the CI ICE NSPS limit in 40 CFR §60.4205(c). It is assumed that PM is equal to PM_{10}, which is equal to $PM_{2.5}$. No visible emissions will occur, which will be determined by a standard of no visible emissions exceeding 30 seconds in duration in any six-minute period as determined using EPA Test Method (TM) 22 or equivalent. RBLC searches for small (<500 hp) fuel oil fired engines show a range of emission limits from 0.1 – 0.2 g/kW-hr and a range from 0.087 – 1.00 g/hp-hr. **GHG as CO_2e:** GHG emissions are estimated using CO_2, CH_4, and N_2O emission factors for distillate fuel oil no. 2 (as representative for the ULSD burned in the engine) from 40 CFR 98, Subpart C, Tables C-1 and C-2 and global warming potentials (GWPs) from 40 CFR 98, Subpart A. These emission factors are 73.96 kg/MMBtu for CO_2, 0.003 kg/MMBtu for CH_4, and 0.0006 kg/MMBtu for N_2O. Efficient internal combustion engines and good combustion and maintenance practices are used to minimize the formation and emissions of GHGs. RBLC searches show most commonly a 164 lb CO_2e/MMBtu emission factor, corresponding to the requirements in 40 CFR 98 Subpart C. RBLC searches also show a range of annual mass limits (tons CO_2e per year). However, there is insufficient information on the RBLC to reasonably determine equivalent emission factors using only annual mass limits. Emissions are calculated using worst-case emission factors and accommodate unit startup and shutdown operations.

Source Name	EPN	Best Available Control Technology Description
		The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Diesel Tank for Fire Pump	FPTNK1	One 400-gallon horizontal fixed roof tank will be used to supply diesel for the fire pump generator engine. EPA AP-42 Chapter 7, Section 1 Liquid Storage Tanks, September 2025 is used to calculate annual storage tank emission rates, while TCEQ APDG 6250 “Estimating Short-Term Emission Rates from Tanks” dated February 2020 is used to calculate hourly storage tank emission rates. Tier I BACT for fixed roof storage tanks storing chemicals with true vapor pressures below 0.5 psia or having a capacity less than 25,000 gallons in size is to use submerged fill and have uninsulated exterior surfaces exposed to the sun be white or aluminum. EFO uses submerged loading/bottom fill and will have the outer surfaces be white or aluminum. RBLC searches for diesel storage tanks show emission controls generally consisting of submerged fill, low vapor pressure material less than 0.5 psia, and white or light shell color. For tank MSS activities, the applicant represented that they will minimize the duration and frequency of MSS activities. Separate MSS emissions are not represented from the storage tanks. The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Diesel Tank for EDG	EDGTNK1, EDGTNK2, EDGTNK3, EDGTNK4, EDGTNK5	Five 1,250 gallon horizontal fixed roof tanks will be used to supply diesel for the emergency generators. EPA AP-42 Chapter 7, Section 1 Liquid Storage Tanks, September 2025 is used to calculate annual storage tank emission rates, while TCEQ APDG 6250 “Estimating Short-Term Emission Rates from Tanks” dated February 2020 is used to calculate hourly storage tank emission rates. Tier I BACT for fixed roof storage tanks storing chemicals with true vapor pressures below 0.5 psia or having a capacity less than 25,000 gallons in size is to use submerged fill and have uninsulated exterior surfaces exposed to the sun be white or aluminum. EFO uses submerged loading/bottom fill and will have the outer surfaces be white or aluminum. RBLC searches for diesel storage tanks show emission controls generally consisting of submerged fill, low vapor pressure material less than 0.5 psia, and white or light shell color. For tank MSS activities, the applicant represented that they will minimize the duration and frequency of MSS activities. Separate MSS emissions are not represented from the storage tanks. The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Fugitives	FUG	Fugitive emissions from natural gas piping systems, SCR systems, and diesel piping may be generated due to leakage from non-welded piping connections. Emissions are estimated according to the June 2018 TCEQ Technical Guidance Package for Equipment Leak Fugitives, APDG 6422. For VOC emissions, TCEQ Tier I BACT requires an LDAR program for sites with uncontrolled VOC fugitive emissions greater than 10 tpy. EFO proposes the total site-wide uncontrolled emissions from fugitive equipment leaks to be less than 10 tpy VOC. Therefore, no LDAR program is required for leaks in VOC service (natural gas and diesel). Natural gas leakage was estimated using Oil and Gas Production Operation emission factors and the

Source Name	EPN	Best Available Control Technology Description
		control efficiency for 28PI Program from APDG 6422. VOC emissions were conservatively estimated based on a typical natural gas analysis, which is 1.82% by weight CO_2 composition and a 90.16% by weight CH_4 composition. The diesel fugitive emissions were estimated using Oil and Gas Production Operation factors and the control efficiency for 28PI Program from APDG 6422. RBLC searches for fugitive VOC and CO_2e emissions show that either an AVO program is used or no LDAR programs are used. TCEQ Tier I BACT requires AVO inspections to be performed twice per shift for fugitive equipment leaks in NH_3 service. EFO proposes to implement 28AVO monitoring for fugitive piping components in NH_3 streams. The ammonia fugitive emissions were estimated using SOCMI factors for sources without ethylene and the control efficiency for 28AVO Program from APDG 6422. Ammonia emissions were estimated conservatively assuming the process stream is 100 weight percent ammonia. EFO proposes to perform AVO inspections once per shift. APDG 6422 allows for the inspection frequency given in the 28AVO condition to be reduced on a case-by-case basis but may not be reduced to less than once a shift. EFO has referenced Permits 181009 for Fermi Equipment Holdco – Project Matador, Permit 181033 for Pacifico GW LLC – GW Ranch Energy Center, and Permit 178462 for Luminant Generation Company Permian Basin Electric Station where inspections once per shift have been used for the 28AVO program. For both NH_3 and VOC service, any open-ended lines at the facility will be equipped with a cap, plug, blind flange or a second valve. Relief valves will also be equipped with a rupture disc and pressure sensing device between the valve and disc to monitor for disc integrity. The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.
Lube Oil Vents	OILVENT	The combustion turbines and steam turbines will each contain a closed-loop lube oil recirculation system to lubricate moving parts of the combustion turbines, steam turbines, and generator. Oil vapor (VOC) emissions will be generated by oil vaporization, due to heating of lube oil in the turbine and subsequent condensation of droplets when the vapor is cooled. Lube oil mist emissions will be controlled by a mist eliminator and exhausted through dedicated lube oil vents. Proposed emissions are based on similar lube oil usage and replacement from similar turbine equipment at other plants. Oil mist emissions from oil vaporization and condensation have the potential to include VOC components, PM, PM_{10}, and $PM_{2.5}$ emissions. Because mist oil emissions are the main concern of the closed-loop oil recirculation system for combustion turbines, EFO proposes to install oil mist eliminators to control lube oil mist emissions. The applicant has said that a centralized lube oil storage tank is not part of this project. Lube oil vents are the sole emission points where lube oil mist may be released. TCEQ does not provide Tier I BACT guidelines for lube oil vent emissions. However, the proposed BACT is consistent with similar recently issued projects. RBLC searches for lube oil vents show that mist eliminators and/or good engineering design and operating practices are used to minimize VOC and $PM/PM_{10}/PM_{2.5}$ emissions.

Source Name	EPN	Best Available Control Technology Description
SF6 Emissions	FUG-SF6	The generator circuit breakers associated with the proposed combined cycle combustion units will be insulated with SF_6, which is a colorless, odorless, non-flammable gas. Sulfur hexafluoride emission fugitive emissions may occur from circuit breaker leaks. Emissions are estimated using the weight of SF6 per piece of equipment, the number of pieces of each equipment, and an annual leakage rate of 0.5% by weight based on the International Electrotechnical Commission Standard 62271-1, 2004 for equipment leakage. The total capacity of SF6 at the site is not to exceed 20,349 lb. EFO proposes 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. TCEQ does not specify Tier I BACT for SF_6 emissions from circuit breakers. However, the assumed maximum annual SF_6 leak rate of 0.5% by weight is consistent with BACT for other similar recently issued projects. RBLC searches for SF_6 insulated circuit breakers show that totally enclosed and pressurized circuit breakers with a design SF_6 leak rate of no more than 0.5% and a density alarm for leak detection are used.
Oil Water Separator	FUG_SEP	An oil water separator is also used to separate oil, suspended solids, water mixtures into their separate components. The oil water separator will result in trace VOC emissions. EFO proposes to minimize VOC emissions through a closed top design and good housekeeping practices. The oil water separator will be covered, and all conveyances are covered to minimize emissions. Emissions are estimated using the oil/water separator emission factors from EPA AP-42 Chapter 5.1, Table 5.1-3. Tier I BACT for VOC emissions from wastewater facilities when the uncontrolled site-wide wastewater emissions are less than 5 tpy VOC are to have piped and covered conveyance to storage or biological treatment. RBLC searches for oil water separators are very limited. Either good housekeeping practices and closed top design are used, or no control systems and no pollution prevention practices are used.
MSS	MSS	Planned maintenance, startup, and shutdown (MSS) activities include on-line turbine water washing, combustion turbine inlet air filter changeouts and blowoffs, catalyst handling, analytical and process instrument service (which includes CEMS NOx and CO analyzer calibrations), gaseous fuel venting from the fuel line during turbine shutdown and maintenance, and small equipment maintenance in VOC and ammonia service. EFO proposes to minimize the duration and frequency of MSS activities and operating with best management practices for minimizing formation and release of pollutants, as summarized below. • Online turbine washing is estimated to be 365 events per year per turbine (a total of 16,790 events per year). Each activity is estimated to occur for one hour or less. Online turbine washing results in $PM/PM_{10}/PM_{2.5}$ emissions. • Turbine filter changeouts are estimated to occur a maximum of once every year for each turbine (total of 46 events per year). A maximum of one turbine filter changeout per turbine model will occur simultaneously (within the same hour). Each activity is estimated to occur for one hour or less. Turbine filter changeouts result in $PM/PM_{10}/PM_{2.5}$ emissions. • Catalyst handling is estimated to occur for one event for each turbine every year (total of 46 events per year). A maximum of one event for each combustion turbine type will occur simultaneously. Each activity is

Source Name	EPN	Best Available Control Technology Description
		estimated to occur for one hour or less. Catalyst handling results in $PM/PM_{10}/PM_{2.5}$ emissions. • Inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment and process instruments including sight glasses, meters, gauges, NOx and CO CEMS will occur. For NOx and CO CEMS analyzer calibrations, only one event will occur per hour for each calibration gas and up to 375 events per year for each calibration gas. Each activity is estimated to occur for one hour or less. • Gaseous fuel venting and small equipment venting result in VOC emissions. Each activity occurs once per hour, with up to 5 events for gaseous fuel line venting every year and 25 events for small equipment venting every year. • For small equipment maintenance, it is estimated that one repair/replacement will occur for one equipment/component in low vapor pressure VOC service, one equipment/component in high vapor pressure VOC service, and one equipment/component in NH_3 service simultaneously. A maximum of 365 events per year for equipment/components in low vapor pressure VOC service, 365 events per year for equipment/components in high vapor pressure VOC service, and 1095 events per year for equipment/components in NH_3 service will occur. All MSS activities listed above, aside from gaseous fuel venting and small equipment maintenance/repair/replacement, are considered inherently low-emitting (ILE) activities. The Tier I 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. RBLC searches performed show good air pollution control practices and safe operating practices are used for the same MSS activities. Entries for online turbine washing limits the activity to less than one hour per event. The proposed BACT meets the TCEQ Tier I guidelines and is consistent with the RBLC searches.

VII. Air Quality Analysis

The air quality analysis (AQA) is acceptable 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 1-hr and annual NO_2, 24-hr and annual $PM_{2.5}$, 24-hr and annual PM_{10}, and O_3 exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for 1-hr and 8-hr CO and 1-hr, 3-hr, 24-hr and annual SO_2 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 National Ambient Air Quality Standards (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 $PM_{2.5}$ Prevention of Significant Deterioration (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.

The secondary annual SO_2 NAAQS became effective January 27, 2025. The applicant did not address this standard in the AQA. ADMT reviewed the proposed project and determined EPA's alternative demonstration approach summarized in a memorandum dated December 10, 2024, with a subject "Alternative Demonstration Approach for the 2024 Secondary Sulfur Dioxide National Ambient Air Quality Standard under the Prevention of Significant Deterioration Program" [4], satisfies the annual average compliance requirement.

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

Pollutant	Averaging Time	GLCmax[5] (µg/m³)	De Minimis (µg/m³)
SO_2	1-hr	5.9	7.8
SO_2	3-hr	5	25
SO_2	24-hr	3	5
SO_2	Annual	0.4	1
PM_{10}	24-hr	9	5
PM_{10}	Annual	1.1	1
$PM_{2.5}$ (NAAQS)	24-hr	7.8	1.2
$PM_{2.5}$ (NAAQS)	Annual	1.1	0.13

[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
[4] https://www.epa.gov/system/files/documents/2024-12/secondary-so2-naaqs-psd-memo-12-10-24.pdf
[5] Ground level maximum concentration

Pollutant	Averaging Time	GLCmax[5] ($\mu g/m^3$)	De Minimis ($\mu g/m^3$)
$PM_{2.5}$ (Increment)	24-hr	8.9	1.2
$PM_{2.5}$ (Increment)	Annual	1.1	0.13
NO_2	1-hr	77	7.5
NO_2	Annual	1.7	1
CO	1-hr	480	2000
CO	8-hr	245	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 SO_2 and 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)[6]. 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 Terry County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.111 $\mu g/m^3$ and 0.003 $\mu g/m^3$, 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	2.24	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 EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by EPA referred to as MERPs[7]. Using data associated with the Terry County source, the applicant estimated an 8-hr O_3 concentration of 2.24 ppb. When the estimates of ozone concentrations from the project emissions are added together, the results are greater than the De Minimis level.

[6] https://www.epa.gov/sites/default/files/2020-09/documents/epa-454_r-19-003.pdf
[7] https://www.epa.gov/sites/default/files/2020-09/documents/epa-454_r-19-003.pdf

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that all pollutants and averaging times are below their respective monitoring significance level.

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (μg/m^3)	Significance (μg/m^3)
SO_2	24-hr	3	13
PM_{10}	24-hr	9	10
NO_2	Annual	1.7	14
CO	8-hr	245	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 EPA AIRS monitor 481351014 located at 2700 Disney St., Odessa, Ector County. The three-year average (2022-2024) of the 98th percentile of the annual distribution of the 24-hr concentrations was used for the 24-hr value (18 μg/m^3). The three-year average (2022-2024) of the annual average concentrations was used for the annual value (7.2 μg/m^3). The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative review of emissions from sources in the surrounding area of the monitor site relative to the project site. The background values were also used in the NAAQS analysis.

Since the project has a net emissions increase of 100 tons per year (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 EPA AIRS monitor 481410029 located at 10834 Ivanhoe, El Paso, El Paso County. A three-year average (2022-2024) of the annual fourth highest daily maximum 8-hr average concentrations was used in the analysis (64 ppb). The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative review of emissions from sources in the surrounding area of the monitor site relative to the project site. The background value was also used in the NAAQS analysis.

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 1-hr and annual NO_2, 24-hr and annual $PM_{2.5}$, and 24-hr PM_{10} exceed the respective de minimis concentrations 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 ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Conc. = [Background + GLCmax] ($\mu g/m^3$)	Standard ($\mu g/m^3$)
PM_{10}	24-hr	8	57	65	150
$PM_{2.5}$	24-hr	6	18	24	35
$PM_{2.5}$	Annual	1.1	7.2	8.3	9
NO_2	1-hr	67	64	131	188
NO_2	Annual	2	9	11	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 predicted 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.

A background concentration for PM_{10} was obtained from EPA AIRS monitor 480290060 located at 401 South Frio St, San Antonio, Bexar County. The highest, high-second-high monitored concentration from 2022-2024 was used for the 24-hr value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative review of emissions from sources in the surrounding area of the monitor site relative to the project site.

Background concentrations for NO_2 were obtained from EPA AIRS monitor 480290059 located at 14620 Laguna Rd., San Antonio, Bexar County. The three-year average (2022-2024) of the 98th percentile of the annual distribution of the daily maximum 1-hr concentrations was used for the 1-hr value. The annual concentration from 2024 was used for the annual value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative review of emissions from sources in the surrounding area of the monitor site relative to 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 EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs[8]. Using data associated with the Terry County source, the applicant estimated 24-hr and

[8] https://www.epa.gov/sites/default/files/2020-09/documents/epa-454_r-19-003.pdf

annual secondary $PM_{2.5}$ concentrations of 0.111 μg/m^3 and 0.003 μg/m^3, respectively. When these estimates are added to the GLCmax listed in Table 4 above, the results are less than the NAAQS.

Table 5. Total Ozone Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (ppb)	Background (ppb)	Total Conc. = [Background + GLCmax] (ppb)	Standard (ppb)
O_3	8-hr	2.24	64	66.24	70

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 EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs[9]. Using data associated with the Terry County source, the applicant estimated an 8-hr O_3 concentration of 2.24 ppb. When the estimates of ozone concentrations from the project emissions are added to the background concentration listed in the table above, the results are less than the NAAQS.

D. Increment Analysis

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

Table 6. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (μg/m^3)	Increment (μg/m^3)
PM_{10}	24-hr	8	30
PM_{10}	Annual	1	17
$PM_{2.5}$	24-hr	8	9
$PM_{2.5}$	Annual	1	4
NO_2	Annual	2	25

The GLCmax for 24-hr $PM_{2.5}$ and 24-hr PM_{10} are the maximum high, second high predicted concentrations across five years of meteorological data.

The annual 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

[9] https://www.epa.gov/sites/default/files/2020-09/documents/epa-454_r-19-003.pdf

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 Texas Administrative Code 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, is located approximately 150 kilometers (km) from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 3 μg/m^3 occurred at the eastern property line. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 75 km from the proposed sources, in the direction of the Carlsbad Caverns Class I area is 0.04 μg/m^3. The Carlsbad Caverns Class I area is an additional 75 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 Class I area.

The predicted concentrations of 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$, 3-hr, 24-hr and annual SO_2 and annual NO_2, are less than Class I increment de minimis levels at the edge of the receptor grid in all directions. The Carlsbad Caverns Class I area (the nearest Class I area) is an additional 75 km from the edge of the receptor grid. Therefore, emissions from the proposed project are not expected to adversely affect any Class I area.

F. Minor Source NSR and Air Toxics Review

Table 7. Site-Wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (μg/m^3)	Standard (μg/m^3)
SO_2	1-hr	6	1021
H_2SO_4	1-hr	7	50
H_2SO_4	24-hr	3	15

Table 8. Generic Modeling Results

Source ID	1-hr GLCmax (μg/m^3 per lb/hr)	Annual GLCmax (μg/m^3 per lb/hr)
7HACC01	0.266	0.011
7HACC02	0.255	0.013

Source ID	1-hr GLCmax (μg/m³ per lb/hr)	Annual GLCmax (μg/m³ per lb/hr)
7HASC01	0.034	0.001
7HASC02	0.034	0.001
7HASC03	0.034	0.001
350SC01	0.161	0.007
350SC02	0.161	0.007
350SC03	0.161	0.007
350SC04	0.161	0.007
350SC05	0.162	0.008
350SC06	0.162	0.009
350SC07	0.180	0.007
350SC08	0.180	0.007
350SC09	0.180	0.007
350SC10	0.181	0.008
350SC11	0.181	0.009
350SC12	0.181	0.011
BSGEN01	0.716	0.033
BSGEN02	0.680	0.030
EDG01	24.485	0.625
EDG02	14.413	0.130
EDG03	1.857	0.056
EDG04	1.866	0.049
FWP	7.717	0.116

Source ID	1-hr GLCmax (µg/m^3 per lb/hr)	Annual GLCmax (µg/m^3 per lb/hr)
BOILER	4.098	0.153
GEN001	0.256	0.013
GEN002	0.260	0.013
GEN003	0.264	0.013
GEN004	0.269	0.013
GEN005	0.273	0.013
GEN006	0.278	0.013
GEN007	0.283	0.013
GEN008	0.288	0.012
GEN009	0.293	0.012
GEN010	0.29736	0.012
GEN011	0.255	0.013
GEN012	0.259	0.013
GEN013	0.263	0.013
GEN014	0.268	0.013
GEN015	0.272	0.013
GEN016	0.277	0.013
GEN017	0.282	0.013
GEN018	0.287	0.012
GEN019	0.292	0.012
GEN020	0.297	0.012
GEN021	0.255	0.013

Source ID	1-hr GLCmax (µg/m^3 per lb/hr)	Annual GLCmax (µg/m^3 per lb/hr)
GEN022	0.260	0.013
GEN023	0.264	0.013
GEN024	0.267	0.013
GEN025	0.271	0.013
GEN026	0.276	0.013
GEN027	0.260	0.013
GEN028	0.285	0.012
GEN029	0.290	0.012
OV_01	17.909	0.644
OV_02	10.483	0.282
OV_03	10.543	0.165
OV_04	8.551	0.104
OV_05	7.446	0.073
OV_06	3.540	0.045
OV_07	3.478	0.047
OV_08	3.568	0.049
OV_09	3.715	0.050
OV_10	3.861	0.051
OV_11	3.979	0.053
OV_12	3.337	0.054
OV_13	3.377	0.057
OV_14	3.632	0.059

Source ID	1-hr GLCmax ($\mu g/m^3$ per lb/hr)	Annual GLCmax ($\mu g/m^3$ per lb/hr)
OV_15	3.582	0.060
OV_16	8.285	0.062
OV_17	3.750	0.063
OV_18	5.021	0.027
OV_19	5.014	0.027
OV_20	5.018	0.027
OV_21	5.022	0.027
OV_22	5.019	0.027
OV_23	5.020	0.027
OV_24	5.106	0.027
OV_25	5.184	0.027
OV_26	5.267	0.027
OV_27	5.355	0.027
OV_28	5.093	0.027
OV_29	5.097	0.027
OV_30	5.102	0.027
OV_31	5.099	0.027
OV_32	5.090	0.027
OV_33	5.100	0.027
OV_34	5.101	0.027
OV_35	5.168	0.027
OV_36	5.255	0.027

Source ID	1-hr GLCmax (µg/m^3 per lb/hr)	Annual GLCmax (µg/m^3 per lb/hr)
OV_37	5.339	0.027
OV_38	5.164	0.028
OV_39	5.173	0.028
OV_40	5.177	0.028
OV_41	5.168	0.028
OV_42	5.178	0.028
OV_43	5.180	0.028
OV_44	5.172	0.028
OV_45	5.179	0.028
OV_46	5.222	0.028
EDGTNK1	213.595	1.480
EDGTNK2	126.870	0.200
EDGTNK3	3.183	0.051
EDGTNK4	3.007	0.062
EDGTNK5	3.221	0.0524
FPTNK1	13.211	0.135
FUG_SEP	11.208	0.137
FUG_PIP	3.594	0.175
MSS_FUG	13.529	0.695

All health effects pollutants were evaluated either under Step 0 ‘Applicability and Procedures’, Step 2 ‘De Minimis Increase’, Step 3 ‘10% of ESL Evaluation’, or under Step 7: ‘Sitewide modeling’ of the TCEQ Modeling and Effects Review Applicability (MERA) guidance document (APDG 5874) dated March 2018 and determined acceptable. Step 0 is claimed for simple asphyxiants such as propane and ethane. For Tables 8 and 9 below, for the annual averaging time for pollutants that are not specified below, the pollutant passes step 0 of the MERA, which states that the long-term ESL must be equal to or greater than ten percent of the associated short-term ESL.

Table 9. Minor NSR Site-Wide Modeling Results for Health Effects – MERA Step 2

Pollutant	CAS#	Averaging Time	ESL (µg/m³)	Project Hourly Emissions Increase	Step 2: Is the increase less than de minimis?
2-Methylnaphthalene	91-57-6	1-hr	200	4.10E-05	Yes
		Annual	20	-	N/A. Annual ESL ≥ 10% Short-Term ESL
Acenaphthene	83-32-9	1-hr	100	3.07E-06	Yes
		Annual	10	-	N/A. Annual ESL ≥ 10% Short-Term ESL
Acenaphthylene	208-96-8	1-hr	100	3.07E-06	Yes
		Annual	10	-	N/A. Annual ESL ≥ 10% Short-Term ESL
Fluorene	86-73-7	1-hr	10	4.78E-06	Yes
		Annual	1.0	-	N/A. Annual ESL ≥ 10% Short-Term ESL
Dichlorobenzene	95-50-1	1-hr	900	2.05E-03	Yes
		Annual	160	-	N/A. Annual ESL ≥ 10% Short-Term ESL
Phenanthrene	85-01-8	1-hr	8	2.90E-05	Yes
		Annual	0.8	-	N/A. Annual ESL ≥ 10% Short-Term ESL
i-butane	75-28-5	1-hr	23000	0.03	Yes
		Annual	7100	-	N/A. Annual ESL ≥ 10% Short-Term ESL
i-pentane	78-78-4	1-hr	59000	0.01	Yes
		Annual	7100	-	N/A. Annual ESL ≥ 10% Short-Term ESL

Table 10. Minor NSR Site-Wide Modeling Results for Health Effects – MERA Step 3

Pollutant	CAS#	Averaging Time	ESL (µg/m³)	GLCmax (µg/m³)
toluene	108-88-3	1-hr	4500	15.87
		Annual	1200	0.02
naphthalene	91-20-3	1-hr	440	0.09
		Annual	50	2.60E-04
formaldehyde	50-00-0	1-hr	15	1.01
		Annual	3.3	0.04
benzene	71-43-2	1-hr	170	15.70
		Annual	4.5	3.92E-3
acetaldehyde	75-07-0	1-hr	120	0.19
		Annual	45	0.01
acrolein	107-02-8	1-hr	3.2	0.03
		Annual	0.8	1.13E-3
ethylbenzene	100-41-4	1-hr	26000	0.13
		Annual	570	0.01
propylene oxide	75-56-9	1-hr	70	0.12
		Annual	7	0.01
xylenes	1330-20-7	1-hr	2200	15.54
		Annual	180	0.01
polycyclic aromatic hydrocarbons	130498-29-2	Annual	0.1	7.57E-05
1,3-butadiene	106-99-0	1-hr	510	2.29E-3
		Annual	9.9	3.99E-04
Benzo(b)fluoranthene	205-99-2	1-hr	0.5	7.99E-07

Pollutant	**CAS#**	**Averaging Time**	**ESL (µg/m³)**	**GLCmax (µg/m³)**
		Annual	0.1	3.60E-08
Benzo(g,h,i)perylene	191-24-2	1-hr	0.5	5.33E-07
		Annual	0.1	2.40E-08
Chrysene	218-01-9	1-hr	0.5	7.99E-07
		Annual	0.1	3.60E-08
Fluoranthene	206-44-0	1-hr	0.5	1.33E-06
		Annual	0.1	6.01E-08
n-hexane	110-54-3	1-hr	5600	16.02
		Annual	200	0.04
Pyrene	129-00-0	1-hr	1	2.22E-06
		Annual	0.1	1.00E-7
n-butane	106-97-8	1-hr	66000	1.05
		Annual	7100	0.05
n-pentane	109-66-0	1-hr	59000	1.20
		Annual	7100	0.05
3-Methylcholanthrene	56-49-5	1-hr	0.02	7.99E-07
		Annual	0.002	3.60E-08
7,12-Dimethylbenz(a)anthracene	57-97-6	1-hr	0.5	7.10E-06
		Annual	0.1	3.20E-07
Anthracene	120-12-7	1-hr	1.0	1.07E-06
		Annual	0.1	4.80E-08
Benz(a)anthracene	56-55-3	1-hr	0.5	7.99E-07

Pollutant	CAS#	Averaging Time	ESL (µg/m³)	GLCmax (µg/m³)
		Annual	0.1	3.60E-08
Benzo(a)pyrene	50-32-8	1-hr	0.17	5.33E-07
		Annual	0.017	2.40E-08
Benzo(k)fluoranthene	207-08-9	1-hr	0.5	7.99E-07
		Annual	0.1	3.60E-08
Dibenzo(a,h)anthracene	53-70-3	1-hr	0.5	5.33E-07
		Annual	0.1	2.40E-08
Indeno(1,2,3-cd)pyrene	193-39-5	1-hr	0.5	7.99E-07
		Annual	0.1	3.60E-08
lubricating oils, petroleum, hydrotreated, spent	72623-86-0	1-hr	1000	511
		Annual	100	59.83
ammonia	7664-41-7	Annual	92	1.39
diesel fuel	68334-30-5	1-hr	1000	38.89
		Annual	100	0.23

Table 11. Minor NSR Site-Wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax (µg/m³)	ESL (µg/m³)
ammonia	7664-41-7	1-hr	32	180
polycyclic aromatic hydrocarbons (PM)	130498-29-2 (PM)	1-hr	0.06	0.5

The GLCmax are based on generic modeling.

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 multidimensional (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

As described above, the applicant has demonstrated that the project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The proposed emissions are not expected to have an adverse impact on public health or the environment. The Executive Director's preliminary determination is that the permits should be issued.