TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

**NOTICE OF APPLICATION AND PRELIMINARY DECISION
FOR AN AIR QUALITY PERMIT**

PROPOSED AIR QUALITY PERMIT NUMBERS: 117026, PSDTX1390, and N194

APPLICATION AND PRELIMINARY DECISION. Eagle Mountain Power Company LLC, 1601 Bryan Street, Dallas, Texas 75201-3430, has applied to the Texas Commission on Environmental Quality (TCEQ) for issuance of Proposed Air Quality Permit Number 117026, Prevention of Significant Deterioration (PSD) Air Quality Permit Number PSDTX1390, and Nonattainment Permit Number (NA) N194, which would authorize construction of the Eagle Mountain Steam Electric Station at 10029 Morris Dido Newark Road, Fort Worth, Tarrant County, Texas 76179. This application was submitted to the TCEQ on January 27, 2014. The proposed facility will emit the following air contaminants in a significant enough to require a PSD review: organic compounds, carbon monoxide, sulfur dioxide, nitrogen oxides, sulfuric acid, and particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less. The proposed facility will emit the following air contaminants in amounts significant enough to require a NA review: nitrogen oxides and organic compounds. In addition, the facility will emit the following air contaminant: ammonia.

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

Sulfur Dioxide

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
24-hour	5	91

$PM_{2.5}$

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
24-hour	6.9	9
Annual	0.44	4

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.

Tarrant County has been designated nonattainment for ozone because Continuous Ambient Air Monitoring Stations have shown that ambient concentrations of ozone exceed the National Ambient Air Quality Standards (NAAQS) for ozone. The Federal Clean Air Act (FCAA) requires that new major stationary sources and major modifications at sources in designated nonattainment areas must satisfy nonattainment new source review prior to commencement of construction.

As required by the nonattainment review, all air contaminants have been evaluated and the "lowest achievable emission rate" has been addressed for the control of these contaminants. The emission increases from this project will be offset with emission reductions by a ratio of 1.2 to 1. Furthermore, the applicant has demonstrated that the benefits of the proposed facility significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification. Finally, the applicant has certified that all major stationary sources owned or operated by the applicant in the state are in compliance or on a schedule for compliance with all applicable state and federal emission limitations and standards. The executive director, therefore, has made the preliminary determination to issue this permit.

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 Dallas/Fort Worth regional office, and at the John Ed Keeter Public Library, 355 West McLeroy Boulevard, Saginaw, Tarrant 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 Dallas/Fort Worth Regional Office, 2309 Gravel Drive, Fort Worth, Texas.

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, the 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 John Ed Keeter Public Library, 355 West McLeroy Boulevard, Saginaw, Tarrant County, Texas 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. .
http://www.tceq.texas.gov/assets/public/hb610/index.html?lat=32.906666&lng=-97.480277&zoom=13&type=r.

PUBLIC COMMENT/PUBLIC MEETING. You may submit public comments or request a public meeting about this application. 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 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.**

OPPORTUNITY FOR A CONTESTED CASE HEARING. 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 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, and fax number, if any; (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; and (6) a description of how you use the property which may be impacted by the facility. If the request is made by a group or association, then one or more members who have standing to request a hearing and 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 that are relevant and material to the Commission's decisions on the application. Further, the Commission will only grant a hearing on issues raised by you or others during the public comment period that have not been withdrawn. Issues that are not raised in public comments may not be considered during a hearing.

EXECUTIVE DIRECTOR ACTION. If a timely contested case hearing request is not received or if all timely contested case hearing requests are withdrawn, 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 permit 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/about/comments.html, 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. If you communicate with the TCEQ electronically, please be aware that your email address, like your physical mailing address, will become part of the agency's public record. For more information about this permit application or the permitting process, please call the Public Education Program toll free at 1-800-687-4040. Si desea información en Español, puede llamar al 1-800-687-4040.

Further information may also be obtained from Eagle Mountain Power Company LLC at the address stated above or by calling Mr. Paul Coon, Air Permitting Manager Environmental Services at (214) 875-8376.

Notice Issuance Date: March 26, 2015

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 117026, PSDTX1390, and N194

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)
Option 1				
EM-CT1S	Unit 1 (5) Siemens SGT6-5000 F(5)ee	NO_x	21.12	103.13
		NO_x (MSS)	148.80	-
		CO	12.86	199.40
		CO (MSS)	3612.00	-
		VOC	7.36	45.20
		VOC (MSS)	418.80	-
		PM	35.47	81.88
		PM_{10}	35.47	81.88
		$PM_{2.5}$	35.47	81.88
		SO_2	40.66	35.62
		H_2SO_4	15.56	13.63
		NH_3	27.37	122.75
		NH_3 (MSS)	50.00	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
EM-CT2S	Unit 2 (5) Siemens SGT6-5000 F(5)ee	NO_x	21.12	103.13
		NO_x (MSS)	148.80	-
		CO	12.86	199.40
		CO (MSS)	3612.00	-
		VOC	7.36	45.20
		VOC (MSS)	418.80	-
		PM	35.47	81.88
		PM_{10}	35.47	81.88
		$PM_{2.5}$	35.47	81.88
		SO_2	40.66	35.62
		H_2SO_4	15.56	13.63
		NH_3	27.37	122.75
		NH_3 (MSS)	50.00	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
Option 2				
EM-CT1S	Unit 1 (5) GE 7FA.05	NO_x	20.35	89.44
		NO_x (MSS)	232.80	-
		CO	12.39	107.93
		CO (MSS)	3032.40	-
		VOC	7.09	36.73
		VOC (MSS)	267.60	-
		PM	30.66	62.88
		PM_{10}	30.66	62.88
		$PM_{2.5}$	30.66	62.88
		SO_2	37.88	30.50
		H_2SO_4	14.50	11.67
		NH_3	26.36	110.89
		NH_3 (MSS)	50.00	-
EM-CT2S	Unit 2 (5) GE 7FA.05	NO_x	20.35	89.44
		NO_x (MSS)	232.80	-
		CO	12.39	107.93
		CO (MSS)	3032.40	-
		VOC	7.09	36.73
		VOC (MSS)	267.60	-
		PM	30.66	62.88
		PM_{10}	30.66	62.88
		$PM_{2.5}$	30.66	62.88
		SO_2	37.88	30.50
		H_2SO_4	14.50	11.67
		NH_3	26.36	110.89
		NH_3 (MSS)	50.00	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
Ancillary Emissions				
EM-ABS	Auxiliary Boiler (5)	NO_x	0.73	3.21
		CO	2.71	11.86
		VOC	0.40	1.75
		PM	0.55	2.41
		PM_{10}	0.55	2.41
		$PM_{2.5}$	0.55	2.41
		SO_2	1.04	0.91
EM-EDGV	Emergency Diesel Generator (5)	NO_x	16.54	0.83
		CO	9.56	0.48
		VOC	0.89	0.04
		PM	0.54	0.03
		PM_{10}	0.54	0.03
		$PM_{2.5}$	0.54	0.03
		SO_2	0.02	<0.01
EM-DFPV	Diesel Firewater Pump (5)	NO_x	1.74	0.09
		CO	1.88	0.09
		VOC	0.12	<0.01
		PM	0.09	<0.01
		PM_{10}	0.09	<0.01
		$PM_{2.5}$	0.09	<0.01
		SO_2	<0.01	<0.01
EM-EDGTV	Emergency Generator Diesel Storage Tank	VOC	0.02	<0.01
EM-DFPTV	Firewater Pump Diesel Storage Tank	VOC	0.02	<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)
EM-CT1LOV	Unit 1 Lube Oil Vent	VOC	<0.01	0.01
		PM	<0.01	0.01
		PM_{10}	<0.01	0.01
		$PM_{2.5}$	<0.01	0.01
EM-CT2LOV	Unit 2 Lube Oil Vent	VOC	<0.01	0.01
		PM	<0.01	0.01
		PM_{10}	<0.01	0.01
		$PM_{2.5}$	<0.01	0.01
EM-ST1LOV	Steam Turbine 1 Lube Oil Vent	VOC	<0.01	0.01
		PM	<0.01	0.01
		PM_{10}	<0.01	0.01
		$PM_{2.5}$	<0.01	0.01
EM-1&2LOF	Lube Oil Component Fugitives (6)	VOC	0.50	2.18
EM-1&2NH_3F	Ammonia Component Fugitives (6)	NH_3	0.12	0.51
EM-1&2NGF	Natural Gas Component Fugitives (6)	VOC	0.01	0.04
EM-MSSFUG	Planned Maintenance Activities Fugitives (6)	NO_x	<0.01	<0.01
		CO	<0.01	<0.01
		VOC	0.12	<0.01
		PM	0.05	<0.01
		PM_{10}	0.05	<0.01
		$PM_{2.5}$	0.05	<0.01
		NH_3	<0.01	<0.01

(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) NO_x - total oxides of nitrogen
CO - carbon monoxide
VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$

Emission Sources - Maximum Allowable Emission Rates

PM_{10}	-	total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$
$PM_{2.5}$	-	particulate matter equal to or less than 2.5 microns in diameter
SO_2	-	sulfur dioxide
H_2SO_4	-	sulfuric acid
NH_3	-	ammonia

(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.

(5) 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.

(6) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.

Date: ______________________

Special Conditions

Permit Numbers 117026, PSDTX1390, and N194

1. This permit authorizes 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.

Federal Applicability

2. These facilities shall comply with applicable requirements of the EPA regulations on Standards of Performance for New Stationary Sources, Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

   A. Subpart A: General Provisions.

   B. Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

   C. Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

   D. Subpart KKKK: Standards of Performance for Stationary Combustion Turbines.

3. These facilities shall comply with applicable requirements of the EPA regulations on National Emission Standards For Hazardous Air Pollutants (HAPS) for Source Categories, Title 40 Code of Federal Regulations Part 63 (40 CFR Part 63):

   A. Subpart A: General Provisions.

   B. Subpart ZZZZ: National Emission Standards for HAPs for Stationary Reciprocating Internal Combustion Engines (RICE).

4. This permit authorizes two natural gas fired combustion generators (CTGs) to operate in combined cycle mode [Emission Point Numbers (EPNs): EM-CT1S and EM-CT2S] from the following options:

   A. Option 1: Two Siemens Model SGT6-5000F (5)ee CTGs each rated at nominal capability of 231 gross megawatts (MW). Each CTG will have a duct fired heat recovery steam generator (HRSG) with a maximum heat input of 500 million British thermal units per hour (MMBtu/hr), operating as a combined cycle CTG.

   B. Option 2: Two General Electric Model 7FA.05 CTGs each rated at nominal capability of 210 gross megawatts (MW). Each CTG will have a duct fired heat recovery steam generator (HRSG) with a maximum heat input of 349.2 million British thermal units per hour (MMBtu/hr), operating as a combined cycle CTG.

Emission Rates/Operating Specifications

5. The CTGs (EPNs: EM-CT1S and EM-CT2S) during load operations greater than 60% shall not exceed the following emission limits expressed in parts per million by volume dry (ppmvd) at 15% oxygen (O_2) subject to exclusions noted in the subparagraphs of this Special Condition:

Pollutant	Concentration	Averaging Time
Nitrogen oxide (NO_x)	2.0	1-hr average
Carbon monoxide (CO)	2.0	24-hr rolling average
Ammonia (NH_3)	7.0	24-hr rolling average

A. Each startup period shall not exceed four hours and shall be excluded. A startup period ends when the CTG output achieves steady operation in the low NO_x operating mode, and the selective catalytic reduction (SCR) and oxidation catalytic control systems achieve steady operation.

B. Each shutdown period shall not exceed one hour and shall be excluded. A shutdown period will begin when the CTG receives a shutdown command and the CTG operating level drops below its minimum sustainable load. The shutdown period ends when a flame detection signal is no longer recorded in the plant's control system.

C. Excess emissions caused by emission events are excluded.

D. Emissions from maintenance activities (Attachments A and B) shall be excluded.

E. Emissions during reduced load operations defined as operational loads below 60% of full load shall be excluded. Emissions during reduced load operation shall not exceed the normal hourly emission rates in the MAERT.

F. NO_x emissions during transitional load operations, defined as a CTG ramp rate greater than 5 MW per minute (MW/min), may be excluded from the 1-hr average concentration limit if:

(1) the 1-hour average concentration is above 2 ppmvd at 15% O2, and

(2) the qualifying NO_x concentration occurs during an hour where the turbine ramp rate exceeds 5 MW/minute.

6. The auxiliary boiler shall not exceed, during normal operations, the following emission limitations subject to the exclusions noted in the subparagraphs of this Special Condition:

Pollutant	lb/MMBtu	Averaging time
NO_x	0.01	Rolling 3-hr average
CO	0.037	Rolling 3-hr average

A. Startup, shutdown, and hot standby emissions as defined in this Special Condition shall be excluded. The emissions from startup, shutdown, and hot standby shall not exceed the hourly emission rates in the MAERT.

B. Startup begins when an initial flame detection signal is recorded in the plant's DAHS and ends when the boiler reaches emissions compliance status. Startup shall not exceed 1 hour.

C. Shutdown begins when the boiler operation drops below 25% of design capacity and ends when a flame detection signal is no longer recorded in the plant's DAHS. Shutdown shall not exceed 1 hour.

D. Hot standby is defined as pilot ignitors in service.

E. Emissions from maintenance activities (Attachments A and B) shall be excluded.

7. The emergency generator (EPN: EM-EDGV) and firewater pump (EPN: EM-DFPV) are each limited to 100 hours of non-emergency operation per year on a calendar year basis.

8. During normal operations, opacity of emissions from each CTG and the auxiliary boiler stack authorized by this permit shall not exceed 5 percent averaged over a six-minute period. During periods of MSS operation of the CTGs and the auxiliary boiler, the opacity shall not exceed 15 percent averaged over a six minute period. The permit holder shall demonstrate compliance with this Special Condition in accordance with the following procedures:

A. Visible emission observations shall be conducted and recorded at least once during each calendar quarter while the facilities are in operation, unless the emission unit is not operating for the entire calendar quarter.

B. This determination shall be made by first observing for visible emissions while each facility 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 Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60), Appendix A, Reference Method 9.

D. If the opacity limitations of this Special Condition are exceeded, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.

Fuel Specifications

9. The CTGs, duct burners, and the auxiliary boiler shall be limited to the use of pipeline quality natural gas containing no more than 5.0 grains total sulfur per 100 dry standard cubic feet (gr/100 dscf) on an hourly basis and 1.0 gr/100 dscf on an annual basis.

10. The emergency generator and firewater pump shall be limited to diesel fuel containing no more than 15 ppm sulfur by weight.

Aqueous Ammonia (NH_3)

11. 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.

12. In addition to the requirements of Special Condition No. 11, the permit holder shall maintain the piping and valves in NH_3 service as follows:

    A. Audio, visual, and olfactory (AVO) checks for NH_3 leaks shall be made once a day.

    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.

Anhydrous Ammonia (NH_3)

13. The permit holder is authorized to maintain and operate two 12,500 gallon tanks of anhydrous NH_3 on-site. Additionally, the permit holder shall maintain prevention and protection measures for the NH_3 storage system as represented in the permit application which includes (but is not limited to) the following:

    A. The NH_3 storage tank area will be marked and secured so as to protect the NH_3 storage tank from accidents that could cause a rupture.

    B. A water deluge system shall be installed to cover the tank and loading area to mitigate any airborne releases of NH_3. The water deluge system must activate when an ambient safety sensor level of 200 ppmv of NH_3 is detected.

    C. The permit holder shall follow the mitigation procedures set out in the risk management plan with regard to anhydrous ammonia, as required by 40 CFR Part 68.

14. The permit holder shall maintain the piping and valves in NH_3 service as follows:

A. Audio, olfactory, and visual checks for NH_3 leaks within the operating area shall be made every 12 hours.

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/containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

Initial Determination of Compliance

15. Sampling ports and platforms shall be incorporated into the design of all exhaust stacks according to the specifications set forth in the manual entitled "Chapter 2, Stack Sampling Facilities." Alternate sampling facility designs may be submitted for approval by the TCEQ Regional Director.

16. The holder of this permit shall perform stack sampling and other testing as required to establish the actual quantities of air contaminants being emitted into the atmosphere from each CTG (EPNs: EM-CT1S, EM-CT2S), and the auxiliary boiler (EPN: EM-ABS) to determine initial compliance with all emission limits established in this permit. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods to be determined during the pretest meeting.

A. Air contaminants and diluents to be sampled and analyzed on the CTGs include (but are not limited to) NO_x, O_2, CO, volatile organic compounds, sulfur dioxide (SO_2), particulate matter less than 10 microns in diameter, and NH_3.

B. Air contaminants and diluents to be sampled and analyzed on the auxiliary boiler include (but are not limited to) NO_x, O_2, and CO.

C. Each CTG shall be tested with duct burners at maximum firing rate while the CTG is operating as close to base load as possible.

D. Fuel sampling using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for SO_2. If fuel sampling is used, compliance with New Source Performance Standards (NSPS) Subpart KKKK, 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. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

E. The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

F. The TCEQ Regional Office shall be contacted as soon as testing is scheduled but not less than 30 days prior to sampling to schedule a pretest meeting. The notice shall include:

(1) 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) Procedure used to determine turbine loads during and after the sampling period.

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 submitting the test reports. A written proposed description of any deviation from sampling procedures specified in permit conditions, or the TCEQ or EPA sampling procedures shall be made available to the TCEQ prior to the pretest meeting. The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures. 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 or equivalent procedure proposals for NSPS testing which must have EPA approval shall be submitted to the EPA and copied to TCEQ Regional Director.

G. Sampling as required by this condition shall occur within 60 days after achieving the maximum production rate at which each CTG will be operated, but no later than 180 days after initial start-up of each unit. Additional sampling may be required by TCEQ or EPA.

H. Within 60 days after the completion of the testing and sampling required herein, two copies of the sampling reports shall be distributed as follows:

(1) One copy to the TCEQ Dallas/Fort Worth Regional Office.

(2) One copy to the EPA Region 6 Office, Dallas.

Continuous Determination of Compliance

17. The holder of this permit shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) to measure and record the concentrations of NO_x, CO, and diluents (O_2 or carbon dioxide) in each CTG stack (EPNs: EM-CT1S and EM-CT2S).

A. The NO_x and diluent 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 specifications in 40 CFR Part 75, Appendices A and B. The requirements of 40 CFR Part 75, Appendices

A and B are deemed an acceptable alternative to the performance specifications and quality assurance requirements of 40 CFR Part 60. Data used to meet the requirements of this permit shall not include substitute data values derived from the missing data procedures in subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75.

B. The CO 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 specifications in 40 CFR Part 60, Performance Specification No. 4. The CO CEMS shall meet the applicable quality assurance requirements specified in 40 CFR Part 60, Appendix F, except that cylinder gas audits (CGA) conducted in all four quarters may be used in lieu of the annual relative accuracy test audit. Quarterly CGAs shall be conducted at least 60 days apart. A CGA is not required in any quarter in which the CT operates less than 168 hours. Relative accuracy exceedances (as specified in 40 CFR 60, Appendix F), CGA exceedances of ±15% accuracy, and any CO CEMS downtime shall be reported to the TCEQ Regional Director, and necessary corrective action shall be taken. Supplemental stack sampling may be required at the discretion of the TCEQ Regional Director.

C. The CEMS shall be zeroed and spanned each day the unit operates, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable Performance Specification.

D. For full operating hours, the monitoring data must be reduced to hourly average values at least once every day, using a minimum of four, and normally 60, approximately equally-spaced data points from each one-hour period. For hours in which calibration checks, zero and span adjustments, system breakdowns, or repairs occur, at least two valid data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) will be sufficient to quality-assure the hour.

E. The valid hourly average data from the CEMS shall be averaged over the specified averaging time and the resulting average shall be used to determine compliance with the concentration limits of Special Condition No. 5 and in conjunction with the hourly average natural gas fuel consumption data required by Special Condition No. 18, the hourly emission rate limits of the MAERT. Pounds per hour data from each CTG/HRSG stack must be summed monthly to tons per year and used to determine compliance with the annual emission limits of the MAERT.

18. The permit holder shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the average hourly natural gas consumption of each CTG, duct burner, and auxiliary boiler. The permit holder shall comply with the initial certification and quality assurances as specified in 40 CFR Part 75, Appendix D.

19. The NH_3 concentration in each CTG Stack (EPNs: EM-CT1S and EM-CT2S) shall be tested or calculated according to one of the methods listed below and shall be tested or calculated according to the frequency listed below. Testing for NH_3 slip is only required on days when the NH_3 injection to the SCR unit is in operation.

A. The holder of this permit may install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NH_3. The NH_3 concentrations shall be corrected and reported in accordance with Special Condition No. 5.

B. The permit holder may install and operate a second NO_x CEMS probe located between the duct burners and the SCR, upstream of the stack NO_x CEMS, which may be used in association with the SCR efficiency and NH_3 injection rate to estimate NH_3 slip. This condition shall not be construed to set a minimum NO_x reduction efficiency on the SCR unit. These results shall be recorded and used to determine compliance with Special Condition No. 5.

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

D. Any other method used for measuring NH_3 slip shall require prior approval from the TCEQ Regional Office.

Maintenance

20. Attachment A identifies the inherently low emitting (ILE) planned maintenance activities that this permit authorizes to be performed. Compliance with the emission limits in the MAERT for the ILE planned maintenance activities identified shall be demonstrated as follows.

A. The total emissions from all ILE planned maintenance activities shall be considered to be no more than the estimated potential-to-emit for those activities that are represented in the permit application.

B. The permit holder shall annually confirm the continued validity of the estimated potential-to-emit represented in the permit application for all ILE planned maintenance activities.

21. Compliance with the emissions limits for planned non-ILE maintenance activities for EPNs: EM-CT1S, EM-CT2S, and EM-ABS identified in Attachment B may be demonstrated as follows.

A. For each pollutant emitted during planned maintenance activities whose emissions are 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 planned maintenance activities whose emissions occur through a stack the permit holder shall for each calendar month determine the total emissions of the pollutant.

C. Sum all emissions from planned maintenance activities on a 12-month rolling basis for each EPN to show compliance with the MAERT.

Recordkeeping Requirements

22. The following records (written or electronic) 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 TCEQ, EPA, or any local air pollution control program having jurisdiction:

A. A copy of this permit.

B. Permit application dated January 23, 2014, and subsequent representations submitted to the TCEQ.

C. A complete copy of the testing reports and records of the initial performance testing completed pursuant to Special Condition No. 16 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.

23. 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, and O_2 emissions from EPNs: EM-CT1S and EM-CT2S to demonstrate compliance with the emission rates listed in the MAERT and Special Condition No. 5.

B. Raw data files 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 and the auxiliary boiler.

D. Records of the amount of natural gas fired monthly in each of the CTGs, duct burners, and the auxiliary boiler.

E. Records of emergency engines and firewater pump hours of operations to demonstration compliance with Special Condition No. 7.

F. Records of visible emissions, opacity observations, and any corrective action taken to demonstrate compliance with Special Condition No. 8.

G. Records of AVO checks, maintenance performed to any piping and valves in NH_3 service as required by Special Condition Nos. 12 and 14.

H. Records of accidental releases, spills, or venting of NH_3 and the corrective action taken.

I. Records of NH_3 monitoring pursuant to Special Condition No. 19.

J. Records of monitored or calculated maintenance emissions to demonstrate compliance with Special Condition Nos. 20 and 21.

Nonattainment New Source Review (NNSR) – NO_x Emission Reductions

24. This Nonattainment New Source Review (NNSR) permit is issued/approved based on the use of 252.5 tons per year (tpy) of NO_x emission credits (ECs) from TCEQ Emission Reduction Credit Certificate (ERCC) No. 2750. This ERCC provides offsets at the ratio of 1.2 to 1 for 210.4 tpy of NO_x emissions for the facilities authorized by this permit. The emission rates listed in the table below are for calculation purposes only and are not enforceable allowable emission rates.

EPN	Source	Project Increases (tpy)
EM-CT1S	Combined Combustion Turbine	103.13
EM-CT2S	Combined Combustion Turbine	103.13
EM-ABS	Auxiliary Boiler	3.21
EM-EDGV	Emergency Generator	0.83
EM-DFPV	Firewater Pump	0.09
EM-MSSFUG	Planned Maintenance, Startup, and Shutdown	0.0000012
Total		**210.4**

Nonattainment New Source Review (NNSR) – VOC Emission Reductions

25. This Nonattainment New Source Review (NNSR) permit is issued/approved based on the following

A. The permit holder obtain and provide 113.4 tpy of VOC ECs to offset 94.5 tpy of VOC project emission increase for the facilities authorized by this permit at a ratio of 1.2 to 1, through participation in the TCEQ Emission Banking and Trading Program (EMBT). The permit holder shall specifically identify the amount of ECs, by TCEQ ERCC number.

B. Alternatively, based upon the rules under 30 TAC § 101.372(a) and the TCEQ/EPA approved NO_x to VOC 2.735 to 1 inter-pollutant ratio, 41.5 tons per year of NO_x ECs from TCEQ ERCC No. 2750 can be used to satisfy the 1.2 to 1 VOC offset requirements. This option requires prior approval from TCEQ and EPA.

C. The permit holder shall, prior to the commencement of operation, obtain approval from the TCEQ EMBT Program for the ECs being used and then submit a permit alteration or amendment request to the TCEQ Air Permits Division (and copy the

TCEQ Regional Office) to identify approved credits by TCEQ ERCC number. The permit holder shall specifically identify the amount of ECs, by TCEQ Emission Reduction Credit Certificate (ERCC) number.

Additional Permit Requirements

26. No later than 60 days prior to startup of the first CTG, the permit holder shall submit an alteration to remove the CTG option that was not chosen for construction, any associated special conditions, and any associated emissions from the MAERT. In addition, the permit holder shall specify whether aqueous or anhydrous ammonia will be used in the SCR and alter the Special Conditions accordingly.

Dated:

Attachment A

Permit Numbers 117026, PSDTX11390, and N194

Inherently Low Emitting (ILE) Planned Maintenance Activities							
Activities	EPN	Emissions					
		NO_x	CO	VOC	PM	SO_2	NH_3
Miscellaneous PM filter maintenance[1]	EM-MSSFUG				X		
Catalyst handling and maintenance[2]	EM-MSSFUG				X		
Boiler general maintenance[3]	EM-MSSFUG			X			
Management of sludge from pits, ponds, sumps, and water conveyances[4]	EM-MSSFUG			X			
Inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment, process instruments including sight glasses, meters, gauges, CEMS, PEMS	EM-MSSFUG	X	X	X	X		X
Small equipment and fugitive component repair/replacement in VOC and NH_3 service[5]	EM-MSSFUG			X			X

Date:

[1] Includes, but is not limited: baghouse filters, ash silo/transfer filters, coal handling filters, process-related building 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 pre-heater basket handling and maintenance, refractory change-out, fan maintenance and balancing, damper, air heater, and soot blower maintenance, and any other general boiler maintenance that does not exceed the worst-case emissions representation in the application.

[4] 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.

[5] 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 anhydrous/aqueous ammonia systems.

Attachment B

Permit Numbers 117026, PSDTX11390, and N194

Non-ILE Planned Maintenance Activities							
Activities	EPN	Emissions					
		NO_x	CO	VOC	PM	SO_2	NH_3
Combustion unit tuning[6]	EM-CT1S EM-CT2S EM-ABS	X	X	X	X	X	X

Date:

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

Preliminary Determination Summary

Eagle Mountain Power Company LLC
Permit Numbers 117026, PSDTX1390, and N194

I. Applicant

Eagle Mountain Power Company LLC
1601 Bryan Street
Dallas, Texas 75201

II. Project Location

Eagle Mountain Steam Electric Station
10029 Morris Dido Newark Road
Tarrant County
Fort Worth, Texas 76179

III. Project Description

Eagle Mountain Power Company, LLC (Eagle) owns the Eagle Mountain Steam Electric Station (EMSES). Eagle is proposing to construct two new combined cycle combustion turbines (CTGs) which will generate electric power for sale on the wholesale electric market. The ancillary equipment includes an auxiliary boiler, a firewater pump, an emergency generator, a steam turbine, and various support facilities.

Combustion Turbine and Heat Recovery Steam Generator

The station will consist of two CTGs each equipped with a supplementary fired [duct burners (DB)] heat recovery steam generator (HRSG). The CTGs and DBs are fueled with pipeline quality natural gas. The CTGs will operate in combined cycle mode.

The gas turbines will be one of two options:

(1) Two Siemens Model SGT6-5000F(5)ee CTGs each rated at nominal capacity of 231 megawatts (MW). Each CTG will have a duct fired HRSG with a maximum heat input of 500 million British thermal units per hour (MMBtu/hr).

(2) Two General Electric Model 7FA (GE7FA) CTGs each rated at nominal capacity of 210 MW. Each CTG will have a duct fired HRSG with a maximum heat input of 349 MMBtu/hr.

Selective Catalytic Reduction and Ammonia Handling Systems

The CTGs will use an aqueous or anhydrous ammonia-based selective catalytic reduction (SCR) system to control nitrogen oxides (NO_x) emissions. The system will be comprised of the ammonia storage and handling equipment, an ammonia vaporizer, an ammonia injection grid, and catalyst bed modules. The ammonia injection grids and the SCR catalyst beds will be installed in the HRSG housings at locations where exhaust temperatures will promote the NO_x reduction reactions. The ammonia will be delivered by tanker truck, which will use vapor balance to capture emissions during filling of the storage tanks. In addition, the ammonia will be stored in pressurized tanks equipped with pressure relief valves to prevent emissions. However, piping and fittings associated with the tanks and the transfer of ammonia throughout the system will be sources of fugitive emissions.

Auxiliary Boiler

The natural gas-fired auxiliary boiler will have a maximum heat input of 73.3 MMBtu/hr. The boiler will provide turbine fast start steam requirements and steam to assist in warming up the steam turbine and HRSGs.

Firewater Pump

A diesel-fired firewater pump will be installed to provide water in the event of a fire. A diesel storage tank is included with the pump housing.

Emergency Generator

A diesel-fired emergency generator will be installed to provide electric power during emergencies. A diesel storage tank is included with the generator housing.

Natural Gas Piping Fugitives

Natural gas will be delivered to the site via existing pipelines and then metered and piped to the combustion turbines. The piping and fittings associated with the pipeline will be sources of fugitive emissions.

Maintenance, Startup and Shutdown (MSS)

Planned MSS emissions are being authorized in this project. This will result in separate emission rates for MSS in the table entitled “Emission Sources - Maximum Allowable Emission Rates,” (MAERT). The startup and shutdown will have separate short term (hourly) limits and the annual emissions are not expected to exceed the normal operations annual emissions and are included in the annual emissions limits in the MAERT. The durations of startups and shutdowns are included in the Special Conditions of the permit.

Maintenance Activities are identified in Attachment A and B. The emissions are quantified on the MAERT as Emission Point Number (EPN): EM-MSSFUG.

IV. Emissions

Emission sources for the proposed project consists of two turbine power blocks, lube oil vents, auxiliary boiler, firewater pump, emergency generator, and equipment fugitives.

V. Federal Applicability

The EMSES Project is located in Tarrant County which is classified as serious nonattainment. The site is an existing major source with respect to the Prevention of Significant Deterioration (PSD) and Nonattainment (NA) New Source Review programs (NSR).

The new project will have the potential to emit emissions greater than the major modification significance level for the pollutants identified below.

The following charts illustrate the annual project emissions for each pollutant and whether this pollutant triggers PSD or NA review. The worst case emission increases from the two scenarios were chosen for this demonstration. These totals include MSS emissions.

Table 1. PSD Major Modification Trigger

Pollutant	Project Increase (tpy)	PSD Netting Trigger (tpy)	Netting Required (Y/N)	Net Emission Change (tpy)	PSD Major Mod Trigger	PSD Review Triggered (Y/N)
NO_x	210.39	40	**Y**	210.39	40	**Y**
CO	411.23	100	**Y**	411.23	100	**Y**
VOC	94.45	40	**Y**	94.45	40	**Y**
PM	166.25	25	**Y**	166.25	25	**Y**
PM_{10}	166.25	15	**Y**	166.25	15	**Y**
$PM_{2.5}$	166.25	10	**Y**	166.25	10	**Y**
SO_2	72.15	40	**Y**	72.15	40	**Y**
H_2SO_4	27.26	7	**Y**	27.26	7	**Y**

Table 2. NA Modification Trigger

Pollutant	Project Increase (tpy)	NA Netting Trigger (tpy)	Netting Required (Y/N)	Net Emission Change (tpy)	NA Major Mod Trigger (tpy)	NA Review Triggered (Y/N)
NO_x	210.39	5	**Y**	210.39	25	**Y**
VOC	94.45	5	**Y**	94.45	25	**Y**

VI. Control Technology Review

As part of the BACT/LAER review process, the Texas Commission on Environmental Quality (TCEQ) evaluates information from the Environmental Protection Agency's (EPA's) RACT/BACT/LAER Clearinghouse (RBLC), on-going permitting in Texas and other states, and the TCEQ's continuing review of emissions control developments.

Combustion Turbines

NO_x Emissions

NO_x emissions from combustion turbines are generated through the oxidation of nitrogen in the high temperature combustion zones. Dry low NO_x (DLN) combustors and SCR technology will be used to limit NO_x emissions to 2.0 parts per million by volume dry (ppmvd) corrected to 15 percent oxygen (% O_2) on a 1-hour average. A search of the RBLC and the TCEQ Gas Turbine List for facilities permitted since 2010 identified 47 natural-gas fired turbines. Of the 47 turbines only 5 of the turbines listed LAER as the determining factor in setting the emission standard. One of the turbines did not have an emission standard listed and the other four turbines listed 2.0 ppmvd NO_x corrected to 15% O_2 with averaging times ranging from a 1-hour to a 3-hour average. All of the turbines listed the use of an SCR, DLN combustors, water injection, or steam injection as acceptable controls. The proposed use of SCR, DLN combustors, and a 1-hour averaging time meets LAER requirements.

Carbon Monoxide (CO) Emissions

CO emissions are the result of incomplete combustion of the carbon in a fuel. Good combustion practices and an oxidation catalyst will limit CO to a level of 2.0 ppmvd corrected to 15% O_2 on a rolling 24-hour average. A search of the RBLC and the TCEQ Gas Turbine List for facilities permitted since January 2010 show that the CO emission limits ranged from 1.5 to 15.0 ppmvd corrected to 15% O_2 with averaging times ranging from 1-hour to 24-hour. Of the 47 turbines found over 50% listed good combustion practices and the use of an oxidation catalyst. The proposed controls and emission limits are consistent with the top levels of control for natural gas-fired combined cycle turbines; therefore, BACT is satisfied.

Volatile Organic Compound (VOC) Emissions

VOC emissions will result from the incomplete combustion of the natural gas. The use of pipeline-quality natural gas, good combustion practices, and the use of an oxidation catalyst will limit VOC to 2.0 ppmvd corrected to 15% O_2. A search of the RBLC and the TCEQ Gas Turbine List for facilities permitted since January 2010 shows that VOC emissions range from 0.7 ppmvd to 4.0 ppmvd corrected to 15% O_2 with averaging time ranging from 1-hour to 3-hour. Of the 47 turbines found the majority listed good combustion practices or did not specify a control and 40% listed the use of an oxidation catalyst. There were no LAER determinations found for VOC. The proposed controls and emission limits are consistent with the top levels of control for natural gas fired for combined cycle turbines; therefore, LAER is satisfied.

Particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less ($PM/PM_{10}/PM_{2.5}$) Emissions

$PM/PM_{10}/PM_{2.5}$ is emitted from combustion processes as a result of the presence of ash and other inorganic constituents contained in the fuel, particulate matter in the inlet air, and incomplete combustion of the organic constituents in the fuel. Because the combustion turbines will only fire natural gas, $PM/PM_{10}/PM_{2.5}$ emissions will primarily be limited to the incomplete combustion and are anticipated to be relatively low. A search of the RBLC and TCEQ Gas Turbine List shows that no add-on controls are required for natural gas-fired combustion turbines to control $PM/PM_{10}/PM_{2.5}$. Therefore, the use of pipeline-quality natural gas and the application of good combustion practices is BACT for $PM/PM_{10}/PM_{2.5}$.

Sulfur Compound Emissions

Emissions of sulfur dioxide (SO_2) will occur as a result of oxidation of sulfur in the natural gas-fired in the combustion turbines, with the majority of the sulfur converted to SO_2. A portion of the SO_2 will be further converted to sulfuric acid (H_2SO_4), with a conversion contribution due to the action of the SCR. The formation of SO_2 and H_2SO_4 will be minimized by using pipeline-quality natural gas with a sulfur content not exceeding 5.0 grains sulfur per 100 standard cubic feet (gr/100 dscf) on an hourly basis and 1.0 gr/100 dscf on an annual basis. A search of the RBLC and TCEQ Gas Turbine List for facilities permitted since January 2007 did not show any post-combustion SO_2 control technologies.

Therefore, the use of sweet natural gas with the sulfur content listed above is BACT for SO_2 and H_2SO_4.

Ammonia (NH_3) Emissions

Eagle will operate the SCR systems in such a manner that NH_3 slip (i.e., the emission of unreacted NH_3 to the atmosphere) is minimized while ensuring that the NO_x emissions limits are met. Eagle is proposing to use aqueous or anhydrous ammonia and careful control of the NH_3 injection system and operating parameters will be maintained to control NH_3 slip in the HRSG exhaust stream to levels not exceeding 7.0 ppmvd corrected to 15% O_2. This level of emissions control meets the requirements of BACT for NH_3 slip as specified in the TCEQ's BACT Requirements table for combined cycle combustion turbines.

Startup and Shutdown Emissions

Operation of the combustion turbines will result in emissions from startup and shutdown. The combustion turbines will be started up and shut down in a manner that minimizes the emissions during these events. BACT will be achieved by minimizing the duration of the startup and shutdown events (consistent with market demands), engaging the pollution control equipment (e.g., the SCR system in combined cycle) as soon as practicable (based on vendor recommendations and guarantees), and meeting the emissions limitations on the MAERT. The duration of each startup is limited to 240 minutes hours and each shutdown is limited to 60 minutes.

Maintenance Emissions

Specific planned maintenance activities have been identified/ quantified in the permit application and are listed in Attachments A and B. BACT for these planned maintenance activities is minimizing emissions by minimizing the duration of these activities and operating the facility in accordance with best management practices and good air pollution control practices.

Other Emission Sources

Auxiliary Boiler – The use of natural gas, a NO_x limitation of 0.01 pounds per MMBtu (lb/MMBtu), and CO limitation of 0.037 lb/MMBtu represent LAER/BACT.

Emergency Firewater Pump/Emergency Generator - The engines will each be limited to 100 hours per year and will fire ultra-low sulfur diesel fuel, containing no more than 15 parts per million (ppm) sulfur by weight. This represents BACT.

Fugitive Emissions - Include VOC which originate from the natural gas fuel lines and NH_3 from the NH_3 delivery system of the SCR.

- Periodic audio/visual/olfactory (AVO) inspections will be performed for NH3. Any leaks will be repaired when detected. BACT is satisfied.
- Given the nature and quantity of emissions from the natural gas fugitives no control is BACT is satisfied.

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

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels was 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], the EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr NO_2 and 1-hr SO_2 NAAQS.

The applicant provided an evaluation of ambient $PM_{2.5}$ monitoring data, consistent with EPA guidance for $PM_{2.5}$[3], for using the $PM_{2.5}$ De Minimis levels in the NAAQS analysis. If monitoring data shows that the difference between the $PM_{2.5}$ NAAQS and the monitored $PM_{2.5}$ background concentrations in the area is greater than the $PM_{2.5}$ De Minimis level, then the proposed project with predicted impacts below the De Minimis level would not cause or contribute to a violation of the $PM_{2.5}$ NAAQS and does not require a full impacts analysis. See the discussion below in the air quality monitoring section for additional information on the evaluation of ambient $PM_{2.5}$ monitoring data.

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[1] www.epa.gov/region07/air/nsr/nsrmemos/appwso2.pdf
[2] www.epa.gov/nsr/documents/20100629no2guidance.pdf
[3] www.epa.gov/ttn/scram/guidance/guide/Guidance_for_PM25_Permit_Modeling.pdf

The applicant also provided an evaluation of ambient $PM_{2.5}$ monitoring data for using the $PM_{2.5}$ De Minimis levels for the PSD Increment analysis. If the difference between the $PM_{2.5}$ increment and the change in ambient monitored $PM_{2.5}$ background concentrations in the area is greater than the $PM_{2.5}$ De Minimis level, then the use of the De Minimis levels are reasonable. See the discussion below in the increment analysis section for additional information on the evaluation of ambient $PM_{2.5}$ monitoring data.

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

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

Pollutant	Averaging Time	GLCmax (μg/m³)	De Minimis (μg/m³)
SO_2	1-hr	16	7.8
SO_2	3-hr	14	25
SO_2	24-hr	5.6	5
SO_2	Annual	0.14	1
PM_{10}	24-hr	4.8	5
PM_{10}	Annual	0.38	1
$PM_{2.5}$ (NAAQS)	24-hr	2.9	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.34	0.3
$PM_{2.5}$ (Increment)	24-hr	4.8	1.2
$PM_{2.5}$ (Increment)	Annual	0.38	0.3
NO_2	1-hr	23.1	7.5
NO_2	Annual	0.41	1
CO	1-hr	3481	2000

Pollutant	Averaging Time	GLCmax (µg/m³)	De Minimis (µg/m³)
CO	8-hr	913	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.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 8-hr CO exceeds the monitoring significance level and requires the gathering of ambient monitoring information.

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

Table 2. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (µg/m³)	Significance (µg/m³)
SO_2	24-hr	5.6	13
PM_{10}	24-hr	4.8	10
NO_2	Annual	0.41	14
CO	8-hr	913	575

The GLCmax for all pollutants and averaging times represent the maximum predicted concentrations over five years of meteorological data.

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

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 484391006 located at 600 ½ Congress St., Fort Worth, Tarrant County. The applicant used a three-year average (2011-2013) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value (23 µg/m³). The applicant used a three-year average (2011-2013) of the annual mean concentrations for the annual value (10.2 µg/m3). The use of this monitor for $PM_{2.5}$ is reasonable based on this monitor being in the same general area as the project site and based on a quantitative analysis of source emissions located within 10 kilometers (km) of the project site and monitor location.

Background concentrations for CO were obtained from the EPA AIRS monitor 484391002 located at 3317 Ross Ave., Fort Worth, Tarrant County. The applicant used the high, second high (H2H) 1-hr (1,945 µg/m3) and 8-hr (1,001 µg/m3) values from the most recent year (2013). The use of this monitor for CO is reasonable based on this monitor being the closest CO monitor to the project site (approximately 15 km to the southeast) and a quantitative analysis of source emissions located within 10 km of the project site and monitor location.

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 1-hr and 24-hr SO_2, 24-hr and annual $PM_{2.5}$, 1-hr NO_2, and 1-hr and 8-hr CO 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 3. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m3)	Background (µg/m3)	Total Conc. = [Background + GLCmax] (µg/m3)	Standard (µg/m3)
SO_2	1-hr	64.5	16.2	80.7	196
SO_2	24-hr	5	5.9	10.9	365
$PM_{2.5}$	24-hr	9.5	23	32.5	35
$PM_{2.5}$	Annual	0.66	10.2	10.86	12
NO_2	1-hr	104.8	76.7	181.5	188
CO	1-hr	3370	1945	5315	40000
CO	8-hr	797.5	1001	1798.5	10000

The 1-hr SO_2 GLCmax is the maximum five-year average of the 99th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor across five years of meteorological data.

The 24-hr $PM_{2.5}$ GLCmax is the maximum five-year average of the 98th percentile of the annual distribution of predicted 24-hr concentrations determined for each receptor across five years of meteorological data. The annual $PM_{2.5}$ GLCmax is the maximum five-year average of the annual concentrations determined for each receptor across five years of meteorological data.

The 1-hr NO_2 GLCmax is the maximum five-year average of the 98th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor across five years of meteorological data.

The GLCmax for all other pollutants and averaging times are the maximum H2H predicted concentrations across five years of meteorological data.

Background concentrations for SO_2 were obtained from the EPA AIRS monitor 481130069 located at 1415 Hinton St., Dallas, Dallas County. The applicant used the three-year average (2011-2013) of the 99th percentile of the annual distribution of the daily maximum 1-hr concentrations for the 1-hr value. The applicant used the H2H 24-hr concentration from the most recent complete year (2013) for the 24-hr value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative analysis of source emissions located within 10 km of the project site and monitor location.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 484391006 located at 600 ½ Congress St., Fort Worth, Tarrant County. The applicant used a three-year average (2011-2013) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value. The applicant used a three-year average (2011-2013) of the annual mean concentrations for the annual value. The use of this monitor is reasonable based on this monitor being in the same general area as the project site and based on a quantitative analysis of source emissions located within 10 km of the project site and monitor location.

A background concentration for NO_2 was obtained from the EPA AIRS monitor 484390075 located at 14290 Morris Dido Newark Rd., Tarrant County. The applicant used a three-year average (2011-2013) of the 98th percentile of the annual distribution of the maximum daily 1-hr concentrations for the 1-hr value. The use of this monitor is reasonable based on this monitor being in the same general area as the project site and based on a quantitative analysis of source emissions located within 10 km of the project site and monitor location.

Background concentrations for CO were obtained from the EPA AIRS monitor 484391002 located at 3317 Ross Ave., Fort Worth, Tarrant County. The applicant used the H2H 1-hr and 8-hr concentrations from the most recent year (2013). The use of this monitor is reasonable based on this monitor being the closest CO monitor to the project site (approximately 15 km to the southeast) and a quantitative analysis of source emissions located within 10 km of the project site and monitor location.

The applicant provided an evaluation of secondary $PM_{2.5}$ impacts that considers modeling results of the directly emitted $PM_{2.5}$ emissions, ambient background monitoring data representative for the project site, and proposed allowable emission rates of SO_2 and NO_x:

- Adding the modeling results from the directly emitted $PM_{2.5}$ emissions to representative background concentrations gives total concentrations below the NAAQS.

- The proposed emissions of SO_2 and NO_x are greater than the SO_2 and NO_x significant emission rates (40 tons per year [tpy]). Secondary $PM_{2.5}$ formation occurs as a result of chemical transformations that occur in the atmosphere gradually over time and only a portion of the SO_2 and NO_x emissions would be affected. Furthermore, secondary $PM_{2.5}$ formation from SO_2 and NO_x are unlikely to overlap in space or time with nearby maximum primary $PM_{2.5}$ impacts associated with the project sources.

- The applicant considered the potential contribution of secondary $PM_{2.5}$ from the proposed precursor emissions for the project expansion with a comparison to existing regional $PM_{2.5}$ precursor emissions based on 2011 National Emissions Inventory database (NEI) and determined that the precursor emissions from the project (1548.3 tpy) are a small percentage of the precursor emissions from the region (263,591 tons).

- In addition, only a portion of the proposed SO_2 and NO_x emissions would be expected to convert to secondary $PM_{2.5}$ in the form of ammonium sulfate and ammonium nitrate. The applicant reviewed $PM_{2.5}$ speciated monitoring data from a nearby monitor to provide an estimate for the potential secondary $PM_{2.5}$ sulfate and nitrate concentrations associated with the proposed project. Based on this analysis, the applicant determined that the total sulfate and nitrate are a small fraction of $PM_{2.5}$.

Eagle Mountain Power Company LLC is located in Tarrant County, which is part of the Dallas-Fort Worth ozone non-attainment area. Therefore, an ozone analysis is not required as part of the AQA.

D. Increment Analysis

The De Minimis analysis modeling results indicate that 24-hr SO_2 and 24-hr and annual $PM_{2.5}$ exceed the respective de minimis concentrations and require a PSD increment analysis.

The applicant used representative monitoring data to justify using the $PM_{2.5}$ De Minimis levels for the PSD Increment analysis. Ambient concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 484391006 located at 600 ½ Congress St., Fort Worth, Tarrant County. The applicant evaluated the difference in ambient concentrations for the time period between the most recent complete year and the major source baseline date (2010-2013). A comparison of the 24-hr and annual monitored concentrations for 2010 and 2013 show a change in ambient concentrations of 2.86 µg/m³ and -0.3 µg/m³, respectively. When the changes in ambient concentrations are subtracted from the applicable increments (9 µg/m³ and 4 µg/m³, respectively), the differences are greater than the De Minimis levels. Therefore, the use of the $PM_{2.5}$ De Minimis levels is reasonable.

Table 4. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m³)	Increment (µg/m³)
SO_2	24-hr	5	91
$PM_{2.5}$	24-hr	6.9	9
$PM_{2.5}$	Annual	0.44	4

The GLCmax for 24-hr SO_2 and 24-hr $PM_{2.5}$ are the maximum H2H predicted concentrations across five years of meteorological data. The GLCmax for annual $PM_{2.5}$ is the maximum predicted concentration of the annual concentrations across five years of meteorological data.

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 primary and secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with the opacity requirements of 30 TAC 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

The ADMT evaluated predicted concentrations from the project site to determine if emissions could adversely affect a Class I area. The nearest Class I area, Wichita Mountains National Wildlife Refuge, is located approximately 230 km from the project site.

The H_2SO_4 24-hr maximum predicted concentration of 1.2 µg/m^3 occurred approximately 925 meters from the property line towards the north. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 30 km from the proposed sources, in the direction of the Wichita Mountains National Wildlife Refuge Class I area is 0.074 µg/m^3. The Wichita Mountains National Wildlife Refuge Class I area is an additional 200 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 Wichita Mountains National Wildlife Refuge Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of 40 km from the proposed sources in the direction of the Wichita Mountains National Wildlife Refuge Class I area. The Wichita Mountains National Wildlife Refuge Class I area is an additional 190 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Wichita Mountains National Wildlife Refuge Class I area.

F. Minor Source NSR and Air Toxics Review

Table 5. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	18.5	1021
H_2SO_4	1-hr	7.1	50

Pollutant	Averaging Time	GLCmax (µg/m³)	Standard (µg/m³)
H_2SO_4	24-hr	1.2	15

Table 6. 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	105	170
ammonium sulfate 7783-20-2	1-hr	9.5	50

The GLCmax for 1-hr ammonia is located along the property line. The GLCmax for 1-hr ammonium sulfate is located approximately 21.5 km from the property line towards the west. The applicant did not provide a GLCni.

VIII. Offsets

The proposed project is a major source of NO_x and VOC in an ozone NA area. The permit holder is required to offset 210.4 tons per year (tpy) of NO_x with 252.5 tpy emission credit reduction credits (ERCs) and to offset 94.5 tpy of VOC emissions with 113.4 tpy of VOC ERCs. These ERCs provide offsets at the rate of 1.2:1.0 since the Dallas-Fort Worth ozone NA area is classified as serious.

IX. Alternative Site Analysis and Compliance Certification

The applicant demonstrated that the benefits of the proposed locations and source configurations significantly outweigh the environmental and social costs of that location. The applicant certified that all sites owned by it are in compliance with or are on a schedule for compliance with all applicable state and federal emission limitations and standards.

X. Conclusion

Eagle has demonstrated that this project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The proposed facilities and controls represent BACT and/or LAER. The modeling analysis indicates that the proposed project will not violate the NAAQS, cause an exceedance of the increment, or have any adverse impacts on soils, vegetation, or Class I Areas. In addition, the modeling predicted no exceedance of ESLs at all receptors for non-criteria contaminants evaluated.

The Executive Director of the TCEQ proposes a preliminary determination of issuance of this permit for Eagle to construct the electric power generating facilities and the associated support facilities, as proposed.